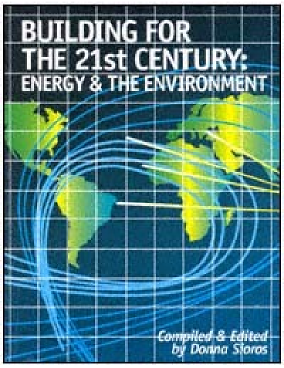
BUILDING FOR
THE 21st CENTURY:
ENERGY & THE ENVIRONMENT
Compiled & Edited
by Donna Sioros

Building for the 21st Century: Energy & the Environment

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INTRODUCTION

This book represents the contributions of the authors who have presented their work at the World Energy Engineering Congress (WEEC) and the companion GeoExchange Conference & Expo, Plant & Facilities Expo, Environmental Technology Expo, OSHA Compliance Expo, Strategic Gas Forum and the Energy Service and Power Marketing Center. The World Energy Engineering Congress recognizes the contributions of the Association of Energy Engineers, the presenters and the more than 8,000 members.

This comprehensive reference book details technologies and new tools to improve the efficiency of buildings and industrial plants. Emphasis is placed on changes in the energy marketplace as a result of global warming policy initiatives and a deregulated environment. Case studies illustrate energy cost reduction programs. Subjects covered including new lighting technologies, improving the performance of heating, ventilation and air-conditioning systems, continuous process improvement and power quality, load shaping and new electrical technologies.

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SECTION 1—
ENERGY MANAGEMENT

Chapter 1— Distributed Resources: The Next Wave (Or Regulatory Barriers to New Solutions)

David P. Hoffman
Celerity Energy

Abstract

Deregulation in the US is proceeding more slowly than predicted five years ago, but will continue to progress driven by factors such as demand from large-use customers, innovations in technology and global considerations. Deregulation at the wholesale level is proceeding successfully, and price differentials from state to state have motivated large-use customers in areas of high rates to push for further deregulation in order to take advantage of expected price leveling. Deregulation of wholesale markets has led to broker trading of electricity as a commodity which has helped bring prices down and spawned cost-cutting measures within the industry. Impediments to rapid deregulation of retail electricity include the fragmented nature of regulation in the US and concerns from consumer advocacy groups. These impediments result in less investment in the Generation and T&D infrastructure and in erosion of system reliability. Meanwhile, smaller distributed resource technologies make entry into the generation and energy services market more feasible for non-utilities Both the emerging and increasingly competitive new technologies and new applications of underutilized existing distributed resources are creating new products/services in the energy marketplace. All these factors must be considered within the framework of the global electric industry. Deregulation of the US industry and emerging technologies allow investment to flow both inward and outward and presents opportunities for strategic alliances and partnerships between energy companies in the US and other countries.

Introduction

For more than a century, vertically integrated utilities have produced and sold most of the electricity in the United States. Now large-use customers, new technologies and a global trend toward deregulation are transitioning the industry from vertically integrated and regulated monopolies to functionally unbundled companies and a competitive market for generation. As deregulation continues, unbundling of long-distance transmission, local distribution, and marketing will evolve, and customers will choose not only the suppliers of their electricity but also the related products and services that competition spawns. This more competitive industry is spurring technological innovations and creating lower prices as markets drive down costs and prices by reducing inefficiencies.

Although the eventual benefits of deregulation are apparent, there is no question that deregulation in the US is progressing more slowly than predicted five years ago. Several reasons account for this. A primary factor is the complexity of regulation, with each of the 50 states controlling the industry within its borders. Legislators and regulators in each of the states have unique views on how to go about deregulation in the way most likely to benefit residents in their state. In addition, large-use customers in areas of low electricity costs are less eager to rapidly deregulate the industry for fear that they may see historically low electricity prices increase. Their concerns are heard when states determine the best process for deregulating the industry in their jurisdictions. Also, the need for an equitable solution to the issue of stranded costs creates caution. All this has led to an uneven and lengthened deregulation process when viewing the US as a whole. Nonetheless, utilities, large customers, regulators, legislators and consumer groups continue to desire competition within the industry.

The negative impact of the slow pace of deregulation in the US is also apparent. Uncertainty is leading to limited investment in the T&D infrastructure. Reliability concerns are rising. Federal, state and private organizations are conducting numerous studies to access system reliability and propose policy to prevent widespread system interruptions. This is creating an opportunity to apply emerging technologies and develop a whole new set of products and services in the energy sector.

Background

The US has 3,195 electric utilities, which sold 3.1 trillion kilowatt-hours of electricity in 1996 for $210 billion in operating revenues. Total generating capacity of the system is about 776,000 megawatts. The structure of the industry varies greatly across the country. In some areas, a single large utility serves millions of consumers in several states. In other areas, several tiny utilities serve portions of a single small state.

Historically, utilities developed as vertically integrated, regulated monopolies serving as the sole provider in a specified service territory. Federal regulations and legislation apply to interstate issues and federal utilities such as the Bonneville Power Administration in the Northwest and the Tennessee Valley Authority in the Southeast. In addition, each of the 50 states has a regulatory agency with authority over investor-owned electric utilities within the state. Utilities that operate in more than one state must develop strong relationships with state and federal legislators and regulators to ensure compliance with the different regulations of each area.

Utilities may be investor-owned utilities (IOUs), publicly owned utilities or rural electrical cooperatives. Publicly owned utilities often serve a municipality and frequently purchase their power under wholesale contracts with IOUs. Most publicly owned utilities are not regulated by the state. Rural cooperatives, which also typically purchase their power, are owned by the customers they serve. In 1995, approximately 245 IOUs sold 75 percent of all retail electricity and 40 percent of all wholesale electricity in the US and collected $184 billion in revenues. Approximately 940 rural electrical cooperatives served 30 million customers.

Historically, regulators have allowed IOUs to recover their cost of providing service plus a regulated rate-of-return from customers in exchange for meeting an "obligation to serve" meaning that IOUs provide enough generating capacity to meet the load of customers in their service territory. IOUs have attempted to meet this obligation to serve while keeping rates for industrial customers low by providing large-use customers with time-of-day pricing and interruptible service. These steps allow IOUs to keep their costs lower because they can build fewer generation facilities to meet their obligation to serve during peak demand. Because regulated monopolies were allowed recovery of costs, there has been little incentive to lower costs. Instead, utilities have traditionally focused on reliability of service and building generation necessary to meet the obligation to serve.

Another driver in the US is a trend toward deregulation of all industries, as evidenced by the deregulation of the natural gas, airlines, and telecommunications industries among others[1]. Originally, protecting consumers was a primary motivation for decisions to impose regulatory constraints on the electric industry. Today, legislators and regulators are attempting to reach the same goal by instituting laws and rules that promote competition. They believe that consumers will benefit more from an industry whose members must compete for customers than from an industry composed of regulated monopolies.

Federal Legislative and Regulatory Activities

Deregulation in the US electric sector started with the 1978 Public Utility Regulatory Policy Act (PURPA). PURPA initiated wholesale competition by allowing non-regulated entities to enter the wholesale market. Regulated utilities were required to purchase power from these non-regulated entities at the cost the regulated utility avoided because it did not have to build and operate a new plant to meet demand. This is referred to as PURPA's "must buy" provision.

In 1989, the Federal Energy Regulatory Commission (FERC) required Utah Power and Light and Pacific Power and Light to open access to their transmission networks as a condition of the merger of the two utilities. This opening of transmission lines was a precursor to opening transmission lines throughout the West and helped establish the large number of participants in the Northwest power market.

The 1992 Federal Energy Policy Act and related rules later instituted by FERC further deregulated wholesale electricity markets by requiring all utilities to allow other utilities to transmit wholesale power over their transmission systems. Utilities were permitted to recover from the applicant all costs incurred.

In 1996, FERC issued Rules 888 and 889 intended to further deregulate wholesale trading, lower the cost of power, and ensure an orderly transition to competitively priced bulk power markets. These rules had the effect of making utilities separate their transmission activities from generation and marketing activities so they could accurately assess transmission costs and equitably recover such costs from others using their transmission facilities.

State Legislative and Regulatory Activities

Whereas, the federal role deals primarily with interstate commerce, state governments have the prime responsibility for governing intrastate aspects of deregulation Each of the US's 50 states has a regulatory body with authority over all investor-owned utilities in the state. These state public utility commissions approve cost-based retail prices and establish service standards for investor-owned utilities, but do not have jurisdiction over public utility district prices for the main Because of the authority they exercise over the electricity market within a state, these state public utility commissions will for the most part determine how deregulation evolves within a particular state's borders. States will no doubt continue to exercise regulatory authority over utilities that provide local distribution even after deregulation of other parts of the industry is achieved.

Some states have moved faster than others have by passing restructuring legislation and instituting retail pilot programs. As shown in Table 1, several states have already enacted restructuring legislation or have issued a comprehensive restructuring regulatory order.

TABLE 1[2]

STATUS OF STATE ELECTRIC INDUSTRY RESTRUCTURING ACTIVITY AS OF JULY 1, 1999

Restructuring Legislation Enacted	Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Pennsylvania, Rhode Island, Texas and Virginia
Comprehensive Regulatory Order Issued	Michigan, New York and Vermont
Legislation/Orders Pending	Missouri, Oregon and South Carolina
Commission or Legislative Investigation Ongoing	Alabama, Alaska, Colorado, District of Columbia, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Nebraska, North Carolina, North Dakota, South Dakota, Tennessee, Utah, Washington, West Virginia, Wisconsin and Wyoming

Source: Energy Information Administration

Regulatory and Legislative Outlook

Concerned with the lack of market uniformity across state boundaries and, to some extent, a slow pace at the state level in proceeding with deregulation, the branches of the federal government have several initiatives of their own. The US House of Representatives and US Senate are considering numerous bills related to utility restructuring. However, Congress is divided on the need and the importance of such legislation resulting in a slow pace. As a result, little action is expected in the near term. In an effort to spur interest, the Clinton Administration proposed the Comprehensive Electricity Competition Plan and subsequently proposed a legislative bill, the Comprehensive Electricity Competition Act, projected to save consumers an estimated $20 billion a year, improve the environment, promote new products and services, strengthen service reliability, and protect consumers.

Key provisions of the Administration's proposed Comprehensive Electricity Competition Act are as follows:

All electric consumers would be able to choose their electricity supplier by January 1, 2003, but a state may opt out of retail competition if it believes its consumers would be better off under the status quo or an alternative, state-crafted plan.

The US Secretary of Energy would be authorized to require all retail electric suppliers to disclose, in a uniform format, information on prices, terms, and conditions of service; type of energy resource used to generate the electric energy, and the environmental attributes of the generation (including air emissions characteristics).

A Renewable Portfolio Standard would be established to ensure that by 2010 at least 5.5 percent of all electricity sales are covered by generation from renewable energy sources.

A Public Benefit Fund would be established to provide matching funds of up to $3 billion to states for low-income assistance, energy-efficiency programs, consumer information, and the development and demonstration of emerging technologies, particularly renewable energy technologies.

The Federal Energy Regulatory Commission (FERC) would have the authority to require transmission utilities to turn over operational control of their facilities to an independent system operator.

States would be encouraged to allow the recovery of prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated.

All participants in transactions on the transmission grid would comply with mandatory reliability standards. FERC would approve and oversee a private, self-regulating organization that would develop and enforce these standards.

Various Federal electricity laws would be revised, including repealing the Public Utility Holding Company Act of 1935 and the "must buy" provision of the Public Utility Regulatory Policies Act of 1978.

Issues Remaining in Deregulation

The issue of **stranded costs** continues to present one of the most difficult challenges to deregulation. Stranded costs or stranded assets are typically generating facilities that utilities prudently built so the utilities could serve load within their monopoly territories. Regulators subsequently approved the facilities as appropriate investments. However, as generation technology develops, new generation facilities can be built and operated at costs lower than many existing power sources. Resolving this issue has proven to be very complicated especially as the federal regulatory agency has steered away from intrastate deregulation matters and is leaving the recovery of stranded assets up to each state. IOUs argue that recovery of stranded assets must be uniform across all the states to be fair. If utilities in one state are burdened by high stranded costs, they cannot compete equally with utilities in states that allow full recovery of costs. Some IOUs argue that denying full recovery in all states will lead to a slower transition to competition. Ultimately, legislation and consumer advocates will ensure that the best solution for customers is reached. That could mean that shareholders bear the cost of stranded assets, estimated to be in excess of $200 billion nationwide[3]. Estimates are based largely on book value versus presumed market value.

Impacts of Deregulation

The limited deregulation undertaken to date already has begun to transform the industry. Future steps will intensify that change. To begin, electricity is increasingly being seen as a commodity, like natural gas, crude oil, and other energy products. Power brokers and some utilities are using spot markets as alternative sources of wholesale power. The Pacific Northwest/Pacific Southwest AC inter-tie transmission facility at the California-Oregon Border (COB) and Palo Verde Nuclear Power Plant hi-voltage switchyard in Arizona (Palo Verde) are the two largest trading centers. New centers are developing throughout the US. Power brokers buy electricity, transmission, and other services and sell them to wholesale customers.

Another impact of pending deregulation is the attempt by IOUs to make their businesses cost competitive. One such cost-cutting approach resulted in an increase in mergers among IOUs. These mergers or acquisitions involve electric and gas utilities, energy companies and telecommunication companies both domestic and international. Since 1994 when one merger was announced the pace has accelerated. There are now more than a dozen transactions pending.

Also as deregulation unfolds, the vertically integrated utilities of the past are expected to unbundle their business, most likely into the following components:

Generating companies (GENCOs) that will produce commodity bulk power and succeed or fail on their ability be competitive. Their customers may be distribution utilities, end-use customers, and brokers.

Transmission companies (TRANSCOs) that will deliver wholesale power for the GENCOs and brokers among others. Federal agencies will likely regulate access and rate-of-returns.

Independent system operators (ISOs) will oversee transmission in designated control areas ensure that all buyers and sellers of electricity have access to the transmission system, control the dispatch of generation, and provide real-time balancing of load and generation. ISOs will likely function as quasi-governmental entities or not-for-profit corporations under governmental oversight. As of July 1998, four ISOs were in operation and seven were planned. However, because many utilities have not yet joined an ISO, transmission via ISOs remains fragmented.

Power exchange operators (PXs) that in some areas will provide common generation purchasing or pooling services.

Ancillary services, including spinning reserve, frequency control, and reactive power supply, will be provided to ISOs via competitively bid contracts.

Distribution companies (DISCOs) will deliver energy to retail customers in franchise service areas and continue to be regulated by state utility commissions. Investments in infrastructure will be based on meeting demand for power while complying with common standards for quality and reliability. Competition may eventually evolve to DISCOs undergoing periodic bidding to provide such services within the franchise area.

Energy service companies (ESCOs) will provide the array of value-added products and services ranging from power purchase services, onsite distributed generation and cogeneration, premium power quality and reliability, and energy efficiency and demand side management. Advanced technology-based products and services will be key for success.

Questions of Reliability

How will deregulation effect the reliability of the North American electric grid? What opportunities and concerns are there with system reliability under deregulation?

In the wake of two high-profile outages that blacked out much of the West Coast in 1996, one with a particularly bad sense of timing occurred during the Republican National Convention in San Diego, steps were taken to review the reliability of the Grid and how it would be effected by deregulation. So far only one issue is undisputed. The North American Electric Transmission Grid is significantly constrained, and pushing it beyond its physical limitations will cause reliability problems.

While every transmission line has a rated capacity, the actual capacity available is a function of the remaining lines and network. Network limits can result from thermal overloads of rated capacity, voltages out of proper ranges and instability from generation losing synchronization. Historically, most US utilities have networks that were designed to deliver generation to nearby load centers and not delivery across large distances. The average network capability distance for US utilities is only 200 miles[4]. Compare that to the United Kingdom, a model that deregulation proponents like to use because competition in electricity supply was introduced there years ago. Power suppliers in the UK have an average network capability distance of 600 miles, three times the US average, thanks to a planned, high-voltage super grid that was over built on the existing regional networks.

The UK's higher network capability distance is that much more impressive when you consider that in the small British isles, the farthest distance between generation and load is only one-fifth of that in the US. Further complicating the reliability issue, and simple comparisons to the UK, is the fact that there are more than 3000 independent utilities making up the transmission system in North America. However, in the UK, deregulation required the breakup of just one state-owned utility. Building a "super grid" in North America, on top of the existing utility systems, would require a massive construction program and current costs that would have to be factored into the price of electricity-at a time when customers have been promised price reductions from deregulation. On top of the staggering costs, environmental concerns make massive construction projects virtually impossible.

What then is involved in producing a reliable Grid?

In the age of regulation, power plant operators concerned themselves with kilowatt-hours, while control centers looked after support functions, such as spinning reserve, reactive power, black-start capacity, and network stability. These functions are the generation-supplied components that contribute to transmission reliability and are referred to as ancillary services or, more recently, Interconnected Operations Services (IOS). Under Federal open access rules, these ancillary services and transmission service itself will be unbundled from distribution and generation services. At stake is the reliability of the entire North American power network.

The Federally mandated OASIS (Open Access Same Time Information System) is the electronic means by which the ISO will facilitate the spot market on the PX, providing such supply information as:

Available transmission capacity

Total transmission capacity

Transmission-service products and prices

Transmission-service requests and responses

Ancillary offerings and prices

Regional variations are beginning to appear among the different ISOs. In New York, for example, existing power pools will migrate their systems to handle integrated PX and ISO functions. Meanwhile in California, separate PX and ISO entities have been created. In the Midwest, the picture is muddled, as rival Utilities seem to form and disband new ISOs frequently. Regional differences are driven by the number of existing Utilities volunteering to participate, historical operations and relationships, and the geographic makeup of the transmission infrastructure.

To define Ancillary Services, an IOS Working Group was formed in the US, supported by the North American Electric Reliability Council and the Electric Power Research Institute. According to the Working Group, there are 13 separate constituent services to be supplied, largely tied to generation capability and generation response characteristics.

Some experts, however, believe that the Working Group's definitions leave many questions unanswered and are pushing for further study. While there is yet no US, much less International, consensus on the definition of Ancillary Services, it may be instructive to examine the definitions applied in the United Kingdom. There, three areas are explicitly defined: reactive power, black start, and power reserve. Power reserve, in turn, has several sub-components.

It is important to point out is that the term "Ancillary Services" is somewhat of a misnomer. It implies something subordinate or supplementary. In fact, Ancillary Services are absolutely essential to the reliable workings of the grid.

Regardless of how you define them, accounting for the cost of Ancillary Services is important. In the past, this was done by each utility as it covered its native load, or was organized by an Area Control Center to cover the load inside a defined area. The variable cost of the service was not calculated; rather, it was rolled up or "bundled" into the overall cost of producing electricity.

Role of New Technology, Especially Distributed Generation

It is in the area of Ancillary Services that the emergence of Distributed Generation (DG) shows the most promise and profit. DG is typically generation units in the 0.5 to 10.0 MW. Networking or pooling of those resources produces assets that can compete on the typical bid blocks used in the regional PX. The capabilities and response of the DG pool is, by design, indistinguishable at the ISO level from say a combustion turbine or central generating plant. DG can address all areas of ancillary services better than central plants. DG is quicker to site; lower at first cost and properly designed can have a positive impact on air quality issues. It can provide a quicker, more measured response when compared to a central plant. But, most importantly because DG is deployed on the demand side of the grid it relieves Transmission and Distribution constraints.

Current grid standards, and those proposed, do not value or take advantage of DG's potential faster response time; its avoidance of the transmission loss and capacity component; its ability to inject kVARs on the demand side of the system. Also, air quality standards will have to recognize that we're all on one planet and moving pollution one state over is not a solution. Air quality must be valued based on kW consumed not kW generated to capture the locational value of DG.

In the emerging deregulated environment DG, properly managed, can enhance grid stability and reduce the risk inherent in a competitive market. Also, it allows for the deferment of building new large, central facilities.

897A further justification of DG comes through Ancillary Service solutions. When you add in the additional benefits and potential revenue from siting units at the customer, the DG solution results in a significant return for the investor.

Other technology innovations are being tested or close too moving from the laboratory to implementation that well transform how energy is generated, delivered, and used. Collectively, these can be referred to as **Distributed Resources.**

Improvements in technology have decreased the importance of economies of scale. It is no longer necessary to build a 1,000-megawatt generating plant to achieve generation efficiency. New gas turbines as small as 10 megawatts can be efficient. Diesel and gas-fired internal combustion engines make distributed generation and cogeneration increasingly feasible today, while advanced fuel cells and microturbines offer added potential in the future. Along with energy storage technologies, such distributed resources will provide alternatives to the traditional central generation facility. Distributed resources are a very attractive alternative to building an expensive transmission and distribution infrastructure, and provide a convenient vehicle for new entrants to challenge traditional utility markets. The US Energy Information Agency projects these smaller generation technologies will account for 80 percent of the 302 gigawatts of new generating capability to be added by 2015.

New technologies will also drive how electricity is delivered and used. Computers today allow monitoring of the distribution system with real-time information. They show where the load is, where crews are, what switches is open—all on a desktop computer screen. Sophisticated switches in the field automatically report problems and allow restoration of service more quickly after an outage and provide instant read-outs of equipment status and automated reports of voltage fluctuations. All of this improves customer service, reliability, resource productivity, and helps lower costs.

Traditional and innovative sustainable generation is increasingly important. New advances in wind turbine technology and photovoltaic solar power may make these older "green" technologies more feasible. Emerging technologies include advanced fuel cells and biomass generators. Emerging energy storage technologies, such as advanced batteries, ultracapacitors, and flywheels, offer opportunities for demand-side management as well as hybrid renewable power systems. With the global need for sustainable development increasingly underscored these green technologies take on greater importance.

Conclusion

Deregulation is changing the electric industry. The US is feeling the effects of these changes in different permutations, but there is also a global effect. Some observers believe that the industry will evolve with room for only a handful of mega-IOUs, much as has occurred in the oil industry. Mega-IOUs, it is believed, will use economies of scale and financial strength to prosper[5]. As a result, some of the largest companies in the electric power industry are expanding their investments to energy service companies; to cogeneration and independent power production; to oil and gas exploration, and to development. In addition, some utilities are using worldwide trends in privatization and restructuring to enter foreign electric utility markets.

Reliability of the electric supply will almost certainly have some rough "bumps in the road" as the states and federal government evolve the policies to govern a market driven energy economy. The emergence of new technologies and uncertainties in regulatory requirements will result in new supply and delivery systems to assure customer energy demands are met. Opportunities will come from expanded products and services. Power marketing, risk management, equipment maintenance, communication and security systems, and others are estimated to have a potential of $360 billion annually in the US market alone[6].

While it is important to assess the progress of deregulation in individual nations, it also is crucial to bear in mind that deregulation is only part of the issue. With changes is the regulatory structure and processes new providers are entering the marketplace. They are bringing new products and services. The emerging energy and communications technologies are transforming the way energy is produced, delivered and used. While traditional vertically integrated utilities may survive the transition, they will have to change just like other monopolies. The need to provide equitable, reasonably priced electricity to every home and business worldwide is critical for humanitarian reasons as well as practical ones. To do these things, the "deregulated" electric industry must develop as efficiently as possible, by prudent policy and the application of new, innovative solutions to fit all stakeholders.

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Chapter 2— Fundamentals of Energy Outsourcing

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Abstract

This paper addresses the fundamentals of Energy Outsourcing. It also discusses concerns that should be addressed prior to outsourcing energy activities. Elements to watch for when entering into agreements for outsourcing services are identified.

Outline

Introduction
What is Outsourcing?
Energy Outsourcing
Planning Steps
What to Outsource
Barriers to the Success of Outsourcing
Characteristics of an Energy Management Firm
Conclusion

Introduction

As states around the country begin allowing retail customers to choose their electricity provider, industries of all types, shapes, and sizes are becoming concerned with the question of preparedness. Will my company be prepared when the day comes? What are the risks? What's the upside? What's the downside? These are questions that must be asked and more importantly must be answered now. Planning for this major change in the energy industry will require most companies to devote a three year effort before they will be totally ready for all systems to operate smoothly. Note the Y2K correction effort that continues today, having been highlighted over 10 years ago. Therefore, it is essential that a company begin as early as possible. In most cases, outside help will be required and should be hired early into the program (during the initial planning stages).

To cope with many of these changes in this era of downsizing, rightsizing, restructuring, etc., companies are considering outsourcing their total energy requirements, not only electricity, but also natural gas, and other energy-related commodities. This paper discusses the fundamentals of outsourcing, how to prepare for outsourcing, and what to look for in an outsource company. Pitfalls and issues of concern that should be considered prior to entering into agreements with an outsource company are identified.

What Is Outsourcing?

Outsourcing, like beauty, is in the eye of the beholder. While it may have a different meaning from one individual to another, it basically is the process of turning over the function or activity of a group, department, or company to another entity specializing in that function. A clearer understanding may come from looking at the goal(s) of outsourcing.

Outsourcing is not a new concept. It has been around for many years. Over the last several years, it seems to have gained momentum in certain industries. The Information Technology and Information Systems functions have been major users of the concept. Using third parties to operate computers and other electronic equipment to store and compile data, credit card operators have used outsourcing to manage billing and data management functions.

Some companies have used third parties for the manufacturing of products. The primary company continues to manage the marketing efforts while the third party is responsible for all fabrication and/or manufacturing.

The automobile industry has used outsourcing for many of its parts and assemblies. In cost comparisons for one item, car seats, the average labor cost of the seat by Ford or GM is approximately $45 an hour with benefits. Parts suppliers can do the job for an average of $27. This is the reason for the success of companies like Lear Corp., the largest freestanding supplier of auto interiors. Before beginning to debate the unionization issue, recognize that both Lear and the auto companies are working under an agreement with the United Auto Workers.[1]

By the way, Nike does not make shoes. Nike sells its own design, but outsources the manufacturing.[2]

Pharmaceutical companies are using third parties for research and development of new drugs. Where hundreds of millions of dollars are spent to bring a drug to market, the ability to use third-party research laboratories and technicians lets the primary companies spend their efforts on marketing and obtaining governmental approvals.

So what is outsourcing? It has been defined as the contracting for services other than core company activities. With the success that outsourcing has brought to many companies, it is becoming defined as contracting for service other than a company's competency. Either definition conveys the concept of hiring an outside company to be responsible for a function or operation that the primary company does not wish to expend resources on to develop or maintain when that function can best be accomplished by an outside party with the necessary expertise. Reducing the primary company's administrative costs and performing the function at a reduced rate are the basic features of outsourcing.

Many companies today have some form of outsourcing included in their current operation. It may be the mail service, or sections of the Departments of Human Resources, Relocation, Travel, Information Systems, Security, Plant Maintenance, Accounting, etc. The requirements of expanding outsourcing to more vital operations for most companies is the same as for any change in any other company policy. Educating senior management and defining the limits and control of the outsourcing activities are musts.

While it may not take very much effort and education to convince senior management that outsourcing nonvital elements of the company can be cost-effective, it obviously requires a more in-depth education and greater effort to initiate an outsourcing activity of a dollar intensive function such as energy. Nevertheless, there are economic advantages to outsourcing the energy function. Those companies that do not have complete energy expertise in-house will be forced to seek outside help. The energy industry is becoming far too complex for "part-time" energy management. Even at small plants, the Plant Manager, who has been performing the energy procurement tasks in the past, will no longer be able to stay abreast of the changes in the energy industry well enough to be able to make informed decisions. The stakes will be too high and the risk factors will begin to escalate as the energy industry becomes competitive.

Some companies may find that developing a full time energy group is an investment it does not wish to undertake. In any event, outsourcing may provide the ideal opportunity for companies to manage their energy needs.

Energy Outsourcing

Energy outsourcing does not mean to simply contract with an outside party and forget about energy altogether. The ultimate responsibility of the energy activity continues to remain with the primary company. The third-party contractor will work alongside the primary company's representative, but it cannot set policy for the company. It cannot determine on its own what the company's energy strategy will be, nor can it implement the company strategy without the company's approval and direction. Therefore, it is extremely important that certain steps be taken in order for outsourcing to be successful.

Planning Steps

There are several steps that a company should follow in the development of an outsourcing plan.

1. Obtain information on the energy commodities and establish a reference source. This may be through ajoint in-house effort or by hiring an energy advisor to provide that function.

2. Consolidate the historical records of energy usage for all areas. It is extremely important that the company's energy requirements are known and evaluated for prioritizing and for identifying high cost and potential problem areas.

3. An in-house energy team should be established. The team should include all stakeholders inside the company. This would normally include Purchasing, Production, Finance, Engineering, Middle Management, and usually consultant(s) and outside contractors. It is important that middle management participate in order to provide support for the initial efforts, as well as to provide the pipeline to senior management when it is time to bring them into the program.

4. The team should then establish goals, develop strategies, and obtain senior management approval. Before establishing goals, it is important that the team becomes informed about the laws and regulations applicable to their area. This may be obtained through various sources: attorneys, energy advisors and group associations participating in energy activities.

5. Prepare a Request for Proposal (RFP) to solicit proposals from energy outsourcing firms. The RFP is an excellent tool for learning about new options available in the marketplace and to confirm that conventional options are available at competitive prices. It also assigns the control of the project to the issuing party. This is important in maintaining a focused effort on the progress of the project.

The RFP is normally distributed to a "long list" of firms consisting of usually 10–12 companies. Based upon the evaluation of the responses to the RFP, the list will be reduced to a 2–4 firm "short list" for detailed discussions and formal one-on-one interviews. A final selection is made from the "short list" of companies based upon the combination of the RFP evaluation and the information obtained during the interview.

The development of the RFP will require the service of an energy advisor in order to focus on the appropriate objectives, to identify qualified outsourcing companies capable of performing the function, and to properly evaluate the proposals, objectives, and contract business terms. Attempting to achieve this step without the proper knowledge and experience could result in a less than satisfactory performance of the outsourcing effort. Therefore, it is emphasized that experienced help be involved in this stage.

6. Monitor the program. After the proposals have been evaluated, the successful firm selected and the contract executed, the work does not stop. It continues. Each aspect of the energy activity must be reviewed, and goals and objectives revised to comply with changing laws, regulations, and company policy. The economics of the venture should also be evaluated on a continuous basis to ascertain that the program is working. The evaluation should be performed as an energy team function.

7. In order to properly evaluate the success of the program and to identify issues to be addressed with suppliers and other parties when contracts are up for renewals, the activities of the energy team and the outsourcing company should be recorded in a written report.

8. Start early. It is not too soon to begin planning for a successful energy program.

What to Outsource

What to outsource depends upon the nature of the primary company, its core business, and its competencies. The normal energy commodities include electricity, natural gas, coal and fuel oils. The activities would encompass the procurement, contract negotiations, bill review and reconciliation, general management and reporting functions.

Other areas to consider are the Energy Island and the Energy Center concepts. These two concepts normally provide for the conveying of physical energy-related assets to an outsourcing (third party) company. With both concepts, the third party will conduct operating efficiency studies and improve the efficiency of the equipment, of the operation, and the overall energy supply chain inside the facility's fence. The Energy Center is very similar to the Energy Island concept except that it will normally include new generation equipment in addition to the efficiency improvements of the Energy Island. With either concept the revamped operation should produce improved energy savings to the host company. In addition, the company will normally be able to reduce its operating and maintenance cost by transferring the obligation to the third party as part of an equipment lease or ownership. The company is then free to direct its capital toward core business activities. The preferred concept depends upon the host company's requirement for onsite generation.

One other advantage of an outsourced function is the ability to aggregate energy usage at multiple sites. This will be a very significant advantage for some companies when the electrical power industry is restructured. Pipe line companies should find aggregation very attractive.

Barriers to the Success of Outsourcing

Many companies that have utilized outsourcing as a tool have experienced a great deal of success. Nevertheless, as with any activity, there is the exception. There have been reports of cases where outsourcing has not been successful.

One reason given for the reported failure is that the outsourced operation did not have the experience necessary to accomplish the work. This can be attributed to inexperience of the outsourcing company.

A reason given for other failures was that the outsourced finction was a major operating element of the primary company's core business and the coordination of activities among the various operating groups (including the outsource company) was not effective. This appears to be a communication problem rather than an outsourcing issue. An additional point to remember is that in order to maintain a smooth transition and effective operation, it is extremely important to bring all of the operating groups in on the project early and obtain their "buy-in" to the project.

A third reported factor leading to an unsuccessful outsourcing operation was that the function was not managed well. This is not a surprise. It is difficult to think that anything will be a success if it is not managed effectively. As stated earlier, the work continues after the contracts are executed.

It is very important that a competent company be contracted to manage the outsourced function. It is equally important that the primary company work directly with the outsource company. Success is a function of planning, implementation, and management/control.

Already there are a number of companies involved in the energy management function. It has become a very competitive industry. The "Buyer Beware" is certainly sound advice for anyone to consider when contracting for energy management services.

Be cautious of companies offering to perform the energy management function based upon compensation determined as a percentage of energy cost savings. It is difficult for a third party to perform this function in an unbiased manner. Savings can sometimes be identified by exercising options that are not suited for the primary company's operation. This leads to false economy and in some cases to additional cost. As a minimum, it is very likely that the primary company will seriously over pay for the energy management services. While this option may in certain cases provide a benefit, proper guidance in its use is recommended.

Characteristics of an Energy Management Firm

When selecting a firm to manage the company's energy, consider the following.

1. The firm must be experienced.

2. The firm must be objective. It is very difficult to imagine that any firm that is in the business of selling a commodity can be unbiased when advising a company on the purchase of the commodity. This is akin to "hiring a wolf to watch the hen house." Yet, there are businesses that continue to hire companies that do exactly that, thinking that the commodity can be purchased at a discount. The discounted portion of the rate, if it is discounted, is usually recovered in some other fashion. In a multiple year contract, the second year rate may make up for the first year discount. Be cautious when dealing with discounts. Be sure that all details are disclosed and that the rate is fully understood.

3. The firm must be results oriented. The goals set must be achieved and the results tabulated. Only then will the true value of the venture be validated.

4. Be cautious when contracting for either the Energy Island or Energy Center. If the program includes a third-party capital spending option, consider that in most circumstances the amounts of funding that the third party contributes to the venture must be returned. If there is only one party purchasing base load energy from the venture, then that party will be returning the capital plus any incremental return on investment to the third party. The capital outlay by the third party then becomes merely a loan to the primary company. Usually the primary company will do better to obtain the loan through its own sources. However, if the primary company wants to keep the debt off of its balance sheets, then the third-party capital contribution approach may be acceptable.

Conclusion

With the proper planning, education, and monitoring/control, outsourcing can be an effective alternative to the time and expense of developing the in-house expertise. Real operating cost savings can be achieved, and company dollars diverted from the development cost of energy groups are usually needed for capital improvements in the core businesses of the primary company.

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Chapter 3—
Perspectives and Barriers for Energy Efficiency Performance-Contracting Implementation in Ukraine

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Abstract

The paper presents the overview of the major problems facing a nascent ESCO business in Ukraine. Some examples of significant ESCOs and energy efficiency projects are given. Prospects for overcoming the barriers for performance-contracting are described.

Outline

Introduction

Ukraine is one of the least energy-efficient countries in the world. It accounts for 1.9% of total world energy consumption while its population is only 1% of the world's total. Main reason for that is extremely inefficient energy usage in all branches of the economy. In 1995, cost of consumed energy resources accounted for about 25% of Ukrainian GDP compared, for example, to less than 3% in France [1]. Producing domestically only about 50% of required energy resources, Ukraine is forced to spend much-needed hard currency on fuel imports (more than $7.5 billion in 1996 and now about $5.5 billion annually). Energy payments over-burden chronically deficient budget, causing under-funding of other budgetary items and creating a threat to economic survival of Ukraine. Energy saving is becoming one of the national priorities of Ukraine, and that's why the State Committee of Ukraine for Energy Conservation (SCEC) was created in June 1995.

However the activity of government bodies by itself cannot solve the country's energy efficiency problems, which require the investments that the state cannot provide under current economic crisis. Real large-scale energy efficiency begins only where there is a financial interest behind it, and the government can create the incentives and improve the environment for commercial activity in this sector. Maybe the most feasible contribution of the SCEC to this process was setting up UkrESCO, a first large energy service company in Ukraine, and securing $30 million EBRD loan to finance its operations. Initial work was done by Agency for Rational Energy Use and Ecology (ARENA-ECO) together with the SCEC and the French company International Consulting on Energy (ICE) in the frame of SYNERGY Program [2].

But even without the government support, private business in energy efficiency in Ukraine arose out of the mere fact that during post-Soviet time fuel prices reached the world level and energy saving became cost-effective. First energy service companies (ESCOs) appeared in Ukraine in 1996. Although now there is a number of smaller private ESCOs operating in Ukraine, this business is still far from starting to really impact current wasteful pattern of energy consumption. Besides, these companies still practically do not use performance-contracting. There is a sharp necessity to further develop energy saving business in Ukraine and substantially increase the number of ESCOs. Ukrainian ESCOs need whatever help they can get—both in Ukraine (from governmental and legislative authorities) and from abroad (foreign investments, technical assistance etc.).

Potential demand for energy services in Ukraine is great indeed, but existing environment for ESCO activities is far from easy. Major difficulties checking the development of business in the field of energy saving can be grouped in the following way:

financial (lack of own financing, restrictions of bank);

legal (mostly taxation problems);

investment risks (repayment uncertainties);

institutional (tariff dynamics);

informational (low awareness of owners about efficiency opportunities and ESCO arrangements).

Problems and Prospects in Detail

Taxation

Energy saving performance contracting (ESPC) is a financial mechanism for reducing energy costs to the client, under which ESCO installs energy efficiency equipment using its own or third-party financing, and then gradually recovers its costs from a share in the client's energy savings. Although simple in principle, this mechanism depends on a lot of financial, legal and institutional arrangements affecting its viability. That's why newly created ESCOs in Ukraine preferred to work with the customers (enterprises) on usual contracts, supplying and installing efficiency equipment and getting paid for it at once. This approach is often preferable for enterprises as well, as under current taxation system they can attribute to production costs modernization expenses up to 5% of the value of their fixed assets.

However, at this moment Ukrainian enterprises are severely short of working capital and usually cannot finance efficiency improvements from their own resources. In any case, for industry managers efficiency upgrades are less of priority than improvements of production process. In this situation, ESPC requiring no initial investment from the customer and financing present efficiency measures from future energy costs could provide a win-win solution for all parties involved.

A sticking point in taxation issue is that lower energy consumption reduces production cost and increases enterprise's taxable profit. So cost savings from efficiency measures become 30% less, which effectively destroys many otherwise sound energy saving projects. There is only one way out—amend the legislation by making energy efficiency a privileged form of business activity and provide tax credits for the profit resulting from efficiency measures. Appropriate proposals have been submitted to the Ukrainian Parliament.

It should be noted that due to severe deficit of budget revenues, legislative and executive branches of power have a strongly negative attitude to any taxation privileges. At the same time, Ukraine simply cannot any longer afford its disproportional energy consumption (130,800 Btu per 1$ of GDP compared to 16,700 Btu in the U.S., according to U.S. Energy Information Administration data for 1996). Ukrainian legislators and government start to understand that energy efficiency is the only way out of country's energy problems. Certain further steps are needed to make the efficiency business more commercially attractive, the only thing that could bring serious results. It is high time for Ukraine's legislative power to provide effective economic incentives to energy saving.

Bank Financing

Typically ESCOs spend their own money (working capital) only on preparation of projects while physical installation is financed from a bank loan. Situation in Ukrainian banking sector is such that interest rates (18–40% in US$ and 60–120% in local currency) are virtually forbidding for energy efficiency projects. Ukrainian commercial banks prefer to finance export-oriented and trading companies with short-term loans. Usual loans are for several months and do not exceed $100,000, with the required collateral about 200% of the loan amount.

Loans provided by international financial institutions are more affordable. For example, there is a EBRD credit line for support of small and medium business in Ukraine that offers $50,000–$100,000 loans for 1.5–2 years with 15% interest rate. EBRD has also provided a loan of US$ 30 million (at LIBOR + 1%) to UkrESCO that will work with small and medium-sized enterprises and public sector institutions to implement energy saving measures within ESPC mechanism. UkrESCO received the loan under sovereign guarantees, and ratification of the loan agreement by Ukrainian Parliament indicates growing realization of the urgency of energy saving. Loan approval by the EBRD also shows to Ukrainian banks financial opportunities in energy efficiency, the thing new to the banks more accustomed to financing profit-making than savings-making investments.

It is also a good sign for foreign investors in energy efficiency. Potential market for efficiency technologies in Ukraine is huge, and many companies (North European in particular) show great interest in working here. ARENA-ECO has been preparing several projects for efficiency upgrades at Ukrainian industrial plants and district heating companies. Typical cost-effective measures include installation of boiler controls or replacement of boiler, installation of steam traps, efficient lighting systems, compressor stations upgrades, etc.[3]. An attractive option for financing these projects is to create joint venture ESCOs with foreign partners that could take bank loans in partner's home country to finance energy saving projects in Ukraine. Anyway, securing foreign investments is critical, and with international financial institutions leading the way, private investors will hopefully join in.

Leasing

Leasing (especially capital leasing) could be an excellent option for installation of energy efficiency equipment but some legislation problems hinder its application. First, lease term is tied to full depreciation period that is too long under existing legislation, while mid-term and long-term financing is expensive and difficult to obtain in Ukraine. Second, Ukrainian government arbitrarily introduces lowering coefficients for depreciation (0.6 in 1998 and 0.8 in 1999), which creates problems with definition of lease term. Third, sub-leasing is not defined in current legislation, which prevents leases from foreign lessors through Ukrainian leasing companies to Ukrainian customers. Then, Ukrainian legislation stipulates that in capital leasing all risks are assumed by the lessee, while there is no definition of economic risks in the context of financial relations. And finally, compared to other countries Ukraine still has almost no tax preferences for leasing operations.

Repayment Problems

Ensuring stable repayments over the contract period is the main concern for an ESCO doing business in Ukraine. Given present economic slump, situation of almost all Ukrainian enterprises is unpredictable. Uncertainty is increased by ongoing privatization process—ownership of an enterprise may be changed during project period, enterprise could be restructured, split, merged etc.

Preparation of the EBRD loan for UkrESCO is a vivid example of the instability of current situation—out of about 30 projects whose identification started 2 years before loan approval, none is considered entirely viable today. Enterprises that were making good profit couple of years ago are now struggling for survival. Working capital is very limited and so is the ability to pay in cash for operating expenses. For example, industrial enterprises make cash payments for less than 20% of their energy bill, with the rest either not paid for or covered by various barter arrangements.

To reduce non-payment risks, Ukrainian ESCOs use various forms of collateral envisaged by existing legislation. To accelerate introduction of energy saving measures, given difficult financial state of enterprises, ESCOs often agree to barter arrangements with the customer and receive payments for their services in the form of enterprise's products. Some ESCOs have special commercial departments to perform barter operations.

Tariffs

Another component of unpredictability of returns if based on physical savings is the changing dynamics of energy tariffs. Utilities purchase fuel at approximately world prices but are often pressed to keep down the tariffs for heat and electricity because of political considerations. For example, Ukrainian Parliament for about half a year prevented increase in utility rates, despite sharp devaluation of local currency that resulted in twofold increase of fuel cost to utilities. Later, when Parliament's decree was overruled by Constitutional Court, tariffs increased only little because of unpopularity of the measure in view of upcoming presidential elections. In view of recent mayor elections in Ukraine's capital Kiev, increase of utility rates was suspended by municipal pricing department that has a substantial influence on rates definition process. Nevertheless, throughout

Ukraine utility rates are steadily recovering their dollar value, which means restoration of economic incentives to energy savings.

Public or Industrial

As described above, shortage of working capital, unstable situation and taxation problems currently make ESPC projects in industry difficult to carry out. In view of that, more attractive are the projects where energy payments are budget-financed, for example projects with public buildings. Some time ago it was decreed by the Cabinet of Ministers of Ukraine that energy payments should be singled out and financed as a separate budgetary item, which provides relatively stable basis for handling energy costs. However it is necessary to distinguish between capabilities of state and local budgets.

Budget Code of Ukraine is now being discussed by the Parliament. It envisages much more locally collected financial resources to be at local authorities' disposal. This is a general trend in the current process of reforms. For example, recently adopted Law on the City of Kiev states that no less than 50% of all taxes, duties and obligatory payments in Kiev go to the local budget, including 100% of individual and corporate income tax and rent payments for the land. This makes local budgets better positioned for ESPC projects than the state budget. The city of Kiev covers all current utility bills for its buildings whereas buildings financed from the state budget usually accumulate debt that is later offset for utilities' tax payments.

There is an example showing good prospects for energy efficiency projects in locally financed buildings. Using U.S. DOE technical assistance, ARENA-ECO and U.S. Pacific Northwest National Laboratory (PNNL) have developed a large-scale efficiency program for Kiev public buildings (healthcare, educational and cultural) [4]. Total cost of the program is about US$ 30 million to be jointly financed by the World Bank loan and municipal budget. At the initial stage, the program was even larger and comprised the buildings owned by the Municipality, Ministry of Education and Ministry of Health. Both ministries are financed from the state budget and at later stage failed to confirm their participation in the program because of budget constraints. Unlike them, the Municipality not only confirmed its contribution but started implementation of the measures even before formal approval of the World Bank loan. The Bank has already issued the Project Appraisal Document, and loan approval is expected this fall.

Other Options in Buildings Sector

ARENA-ECO is also exploring other possibilities in buildings energy efficiency. In residential buildings there exists a large potential for energy saving still almost unrealized. Main reason for that is the shortage of finance to cover initial costs and low awareness of population about cost-cutting benefits of efficiency measures. Besides, ongoing privatization process have created mixed ownership structure in municipal buildings, which complicates decision-making and cost-recovering process. These problems are more easily solved in cooperatively owned buildings—a very significant building stock in most Ukrainian cities.

In cooperation with Switzerland, ARENA-ECO is currently implementing a pilot project in cooperative buildings in the city of Kiev. Main idea of the project is to establish sustainable mechanism for financing installation of efficiency measures. This mechanism includes a revolving fund created with the participation of the city's district authorities. This fund covers majority (or all) of initial expenses for efficiency improvements in cooperative buildings. Then, during several years cooperatives under performance contract will make repayments to the fund based on achieved savings. The contract guarantees certain cost reductions, and savings sharing scheme provides incentives for cooperatives to use energy more efficiently. Repayments are accumulated in the fund and then reinvested in other buildings. Cooperatives do not have initial expenses and actually receive preferential loan from the fund to finance energy saving measures.

These scheme seems promising even under present difficult economic conditions in Ukraine. However some aspects for expansion of the project are yet to be clarified, including risks distribution (currently assumed by the Swiss side), protection of accumulated repayments from inflation, taxation etc.

Awareness

As already mentioned, lack of awareness is also a serious problem for spreading ESPC projects. This lack of awareness is felt at all levels—with local authorities, industry managers, population in general. Many managers at industrial enterprises in Ukraine do not even know that cost-reducing efficiency technologies exist. Those who are aware of such technologies often consider them too expensive. However there is a lot of affordable options, and performance-contracting eliminates initial costs to the customer. In current situation, big challenge of Ukrainian ESCOs is to dissolve misconceptions about energy efficiency and promote introduction of favorable environment for performance-contracting. That's our work and we are doing it.

Conclusion

Growing energy prices and reformation of the economy giving more freedom to private sector have led to appearance of Ukrainian ESCOs and development of energy services market. At present there exist a number of legal, financial, institutional and other barriers hindering further development of this business and spreading of performance contracting mechanism. Nevertheless, since improving the effectiveness of energy usage is now one of Ukraine's national priorities, there is a strong hope that legislative environment for performance contracting will soon change for the better. Other problems arising from transitional processes in Ukrainian economy should also be solved with the progress of reforms. Potential for business in energy efficiency in Ukraine is huge and foreign investors financing energy saving performance contracting projects have a chance to take a better portion of the efficiency market. Cooperating with existing Ukrainian consultancy firms and setting up joint venture ESCOs could be the best way to enter this market.

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Chapter 4—
Modernizing a 30 Year Old Office Building a Case Study in Energy Efficiency

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Abstract

This paper presents recent experiences related to the planning, design and implementation of a comprehensive Building Modernization and Energy Management Project. The project timeline included an 8-month window to complete all due-diligence and feasibility studies, engineering design and construction. Given the aggressive remodel schedule, the 1st task was to develop a delivery strategy that addressed each modernization element in a manner that minimized conflicting critical path tasks.

We present this strategy herein. The project was completed on budget, on schedule and with only minor "surprises". Today, this building stands as one of the most energy efficient buildings in Southern California and has recently been honored with an "ASHRAE Chapter & Regional Technology Award".

Introduction

251 S. Lake Avenue (SLA), Pasadena is a 30-year, 10 story, office building, with approx. 210,000 sf. of tenant and common areas. As part of the 4-building "Corporate Center Pasadena", 251 SLA is owned by Allegis Realty Investors, LLC and managed by Insignia/ESG.

The engineer of record is Engineered Automation Systems, Incorporated (EASI). Modernization objectives included, but were not limited to upgrading central plant and HVAC systems, maximize energy efficiency, cost effectiveness and comply with current lifesafety, ADA & indoor air quality requirements.

This project included extensive mechanical (central plant, air distribution, plumbing), controls, electrical & architectural measures.

These measures transformed this building from an outdated, single tenant building into a "modern, high efficiency and Class A, multi-tenant office building."

The development team consisted of Owner's representative, construction manager, architect, engineer and property manager. Due to the existence of multiple project upgrade elements, the project was implemented as a series of independent "Bid Packages" to avoid critical path overlaps.

With Ownership support and a strong design team, the construction manager took on the role of General Contractor. She managed multiple prime contractors, each possessing strength applicable to the focus of the particular bid package.

Summary of Bid Packages

The following is a summary of Bid Packages included in this modernization project:

BP-1	Central Plant Feasibility Study & Chiller Owner Pre-purchase
BP-2	Core Mechanical, Electrical & Plumbing Upgrades
BP-3	Emergency Power System Upgrades
BP-4	Environmental & Energy Management Control (DDC) system
BP-5	Fire Alarm & Protection System
BP-6	Base Building Restroom & Lobby Upgrades

Bid Package 1—
Central Plant Feasibility Study & Chiller Pre-Purchase

1. Included chilled, Hot & Condenser Water Generation & Distribution Systems. Task 1 included an engineering feasibility study to identify alternatives and determine the most technically, appropriate/cost effective upgrade strategy. The feasibility study included evaluating the following system components, options and strategies:

a. Alternative gas, electric & hybrid water chilling & heating options.

b. Alternative primary & secondary chilled water piping and pumping configurations.

c. Alternative cooling tower water piping and pumping configurations to support chiller heat rejection, water-side economizer & supplemental air conditioning unit condenser water service.

d. "Smart Sizing" strategies for prime movers based on projected load profiles during normal and after hours operation, with consideration to economizer assistance and redundancy requirements.

e. Hot and chilled water piping distribution modifications required to support air distribution system changes.

f. Integration of the chiller plant at 251 SLA with a second chiller plant located at adjacent high rise office building (225 SLA).

g. The final results from the engineering, economic and energy analysis performed as part of this work are summarized in Table 1 for the three (3) highest ranked options studied.

TABLE 1. HIGHEST RANKED CHILLER PLANT MODERNIZATION OPTIONS SUMMARY

Option No.	Measure Description	Annual Cost Summary			Annual Savings ($/years)	Budget Cost($)	Simple Payback (years)
		Electrical Cost ($/year)	Natural Gas Cost ($/year)	Total Cost ($/year)			
Base	Existing, Bldgs. 225 & 251	$876,486	$132,099	$1,008,584	–	–	–
251-2a	2 new Gas-fired, 2-stage Absorption Chillers Serve B-225 & B-251	$790,291	$60,670	$850,961	$157,623	$1,395,247	8.2[(1)]
251-1a	2 new Elect. Chillers Serve B-225 & B-251	$833,480	$31,142	$864,622	$143,962	$959,273	6.7
225-1	1 new 600 ton Cent. Chiller in B-225 Serve B-225 & B-251	$842,807	$31,142	$873,949	$134,635	$947,728	7.0

[(1)] Payback includes a $100,000 utility company rebate

2. Option 251-2a—replacement of the existing steam absorption chillers with (2), 350 ton, direct fired, (2) stage absorption chillers & inter-connection with the central plant currently serving the adjacent building (225 SLA) was selected and constructed. The absorption chiller selection worked well in spite of its rooftop location for the following reasons:

a. The original chiller plant included 2 steam absorption chillers and large steam boilers. The structural reinforcement was built into existing rooftop and space was available for the new absorption chillers.

b. Existing gas service and cooling tower capacity were adequate to support the new absorption chillers.

c. The absorption chiller option avoided costly upgrades to the electrical distribution system, not originally designed to support electric driven chillers.

3. The resulting system consists of (2) integrated chiller plants, (1) utilizing electricity & (1) utilizing natural gas as primary fuel sources. The system takes maximum advantage of time-of-use fuel sourcing and loading parameters to gain optimum cost economy.

4. **Figure 1** (attached) shows a Single Line Chilled & Hot Water System Piping Diagram.

5. Participation by The Southern Calif. Gas Co. with technical and financial support during the feasibility study and engineering phases was a critical factor in final system selection.

6. Once the system concept and budget were finalized, it was determined that pre-ordering and direct Owner purchase of the absorption chillers was the practical strategy to assure compliance with schedule restraints and performance requirements. A separate RFP was prepared to facilitate Owner pre-purchase of the absorption chillers.

The following factors were used to select the chiller/manufacturer:

a. First Cost

b. Delivery Schedule

c. Ability to achieve lowest supply chilled water temperature.

d. Part & full load chiller performance

e. Experience with similar projects.

7. The Trane "Horizon" Series, 400 ton, direct fired, double effect, absorption chillers was selected. Trane was able to meet most performance requirements. Equipment delivery to the job-site was on time in spite of a mid-construction burner re-design. The re-design was required to comply with newest AQMD regulations that became effective during the chiller construction cycle.

BP-2—
Core Mechanical, Electrical & Plumbing Upgrades

1. BP-2 included mostly mechanical & plumbing upgrades with supporting electrical service and minor structural work. Therefore, this bid package was awarded to a prime mechanical contractor and managed by the project construction manager.

2. BP-2 included the following construction components:

a. Installation of new chilled & hot water systems developed as part of the feasibility study previously described as BP-1.

b. The following air distribution system upgrades were necessary to modernize old equipment, comply with current lifesafety requirements and achieve optimum energy efficiency:

1) Reconfiguration of duct shafts & air handling units originally used to condition the East and West exposures. Duct shafts are now used for stair pressurization, fresh air supply and exhaust.

2) Reconfiguration of typical floor mechanical systems by consolidating and modifying (3) air handling units/floor to achieve variable air volume heating and cooling. (2) fan coil units per floor were added above the ceilings to replace rooftop air handling units previously used to condition the East and West exposures.

3) Complete cleaning and refurbishment of air handling units for reuse. Including but not limited to new automatic and manual shut off valves, variable frequency drives and high efficiency motors, belts and sheaves.

c. Plumbing upgrades included relocation of hot water heating equipment, upgrades to the domestic water booster pump and backflow prevention station.

BP-3—
Emergency Power System

1. BP-3 was required to comply with current emergency power & lifesafety requirements. Work included the following equipment, architectural, plumbing, electrical & structural appurtenances:

a. 400 kva emergency generator with code required/rated enclosures, ventilation, structural & engine cooling systems.

b. Plumbing to support engine exhaust system, fuel oil storage/pumping and generator room drainage.

c. Electrical switchgear and distribution system to loads that require emergency power. These include, but may not be limited to emergency elevators, fire pumps, lighting & exit signs, fire alarm, security & critical signal systems and smoke control systems.

2. This work was primarily electrical in content, so the package was bid & awarded to a prime electrical contractor and managed by the project construction manager

BP-4—
Environmental & Energy Management Control (DDC) System

1. To support the Ownership objective of energy efficiency, the modernization project included a new, state-of-the-art, environmental & energy management control (DDC) system. Since the other buildings at Corporate Center Pasadena were equipped with Siemens controls, it was Ownership's objective to keep the property as a single product site while maintaining a competitive bidding environment and avoiding sole sourcing both the product purchase and installation.

2. To accomplish this objective, schematic design drawings and performance specifications were prepared. The project was offered to control contractors who were qualified to install Siemens Equipment. Ownership purchased hardware direct and the independent control system contractors installed, programmed & commissioned the system. To their advantage, the competitive process saved Ownership upwards of 30%, while achieving their objectives of quality controls and a single manufacturer site.

3. The new DDC controls were installed for the following systems and equipment:

a. Central Plant—Chilled, Hot and Condenser water generation & distribution systems.

b. Air handling and distribution systems.

c. Ventilation systems.

d. Zone terminal units.

e. Lighting systems (optional).

BP-5—
Fire Alarm & Protection System

1. The fire alarm and sprinkler systems were treated as design/build projects. The construction manager negotiated and managed the upgrades by individual sub-contractors.

2. The fire alarm system was replaced with a code current, high rise fire alarm system comprised of the appropriate sensing, indicating and annunciating devices required for the base building and tenant improvement projects.

3. The building was previously sprinkled. Therefore upgrades to this system were minimal to prepare for future tenant improvements.

BP-6—
Base Building Restroom & Lobby Upgrades

1. The ground floor, typical lobbies and restrooms on all floors were thoroughly remodeled. The redesign included architectural and ADA improvements, supplemented by appropriate mechanical, electrical and plumbing upgrades. A General Contractor was selected as the prime contractor.

2. The added square footage required by ADA upgrades to restrooms created a need to re-configure selected plumbing risers and vertical air shafts. This bid package also included the following items:

a. HVAC improvements such as VAV boxes, terminal ductwork, diffusers, registers & controls for developed lobbies and restrooms.

b. Lighting & Power Distribution systems to support development of core lobbies and restrooms.

Tenant Improvement Standards

1. Tenant standards & improvement strategies were developed to assure consistency of products and workmanship, while optimizing energy efficiency and occupant comfort. EASI was assigned as the "Building Engineer". In this role, EASI has provided engineering services on most tenant improvement projects and peer review for tenant improvement project not engineered by EASI.

2. In addition, while overseeing the overall tenant development process EASI is maintaining current records on electrical and thermal load vs. capacity on the main bus duct and chilled water systems respectively, a process often overlooked in tenant development projects in high rise office buildings.

The integrated central plant should enable less operator intervention and require less maintenance since fewer components will operate more fully loaded.

Operations & Maintenance

Consolidation of property management and maintenance staff with minimum increases in personnel is made possible in part by automated controls, which continuously monitors and reports normal & alarm conditions.

To Conclude

1. Optimum energy efficiency and cost effectiveness was achieved every step from cooling tower through terminal diffusers by incorporating the following features into the modernization design:

2. Replace low efficiency steam driven absorption chillers with higher efficiency, direct fired absorption chillers and integration with an adjacent central plant equipped with electric chillers to create a "multi-plant, hybrid chilled water system". This strategy enables near continuous and maximum loading of the gas absorption chillers, resulting in maximum cost effectiveness.

3. Conversion of chilled & hot water distribution systems from constant volume to a variable volume, primary/secondary pumping arrangement.

4. Conversion of low pressure constant volume air distribution systems to variable air volume for primary air handling and distribution.

The newly released, Titus Z-Com variable air volume diffusers which operate down to 0.1" of pressure and equipped with digital zone controls has become the building standard for terminal zone control.

5. Installation of a new distributed digital control system and after-hours HVAC control/billing system serving both central plants, all air distribution and general lighting systems.

Success of this project resulted from many factors. They include, but are not limited to a proactive Owner, their Representatives, a quality team of Design Professionals, supportive Utility Companies, Manufacturers and Contractors.

-End of Paper-

About the Speaker

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EASI specializes in the full range of energy management and control systems engineering services for new and retrofit construction projects.

Mr. Ellner has over 20-years of specialized experience in full service energy systems engineering, design assistance, feasibility studies, constructibility analysis, construction coordination, startup, testing and commissioning. Applications include control and measurement systems, central plants, energy efficient heating, ventilating and air conditioning systems, fire lifesafety and security systems for new and retrofit commercial projects.

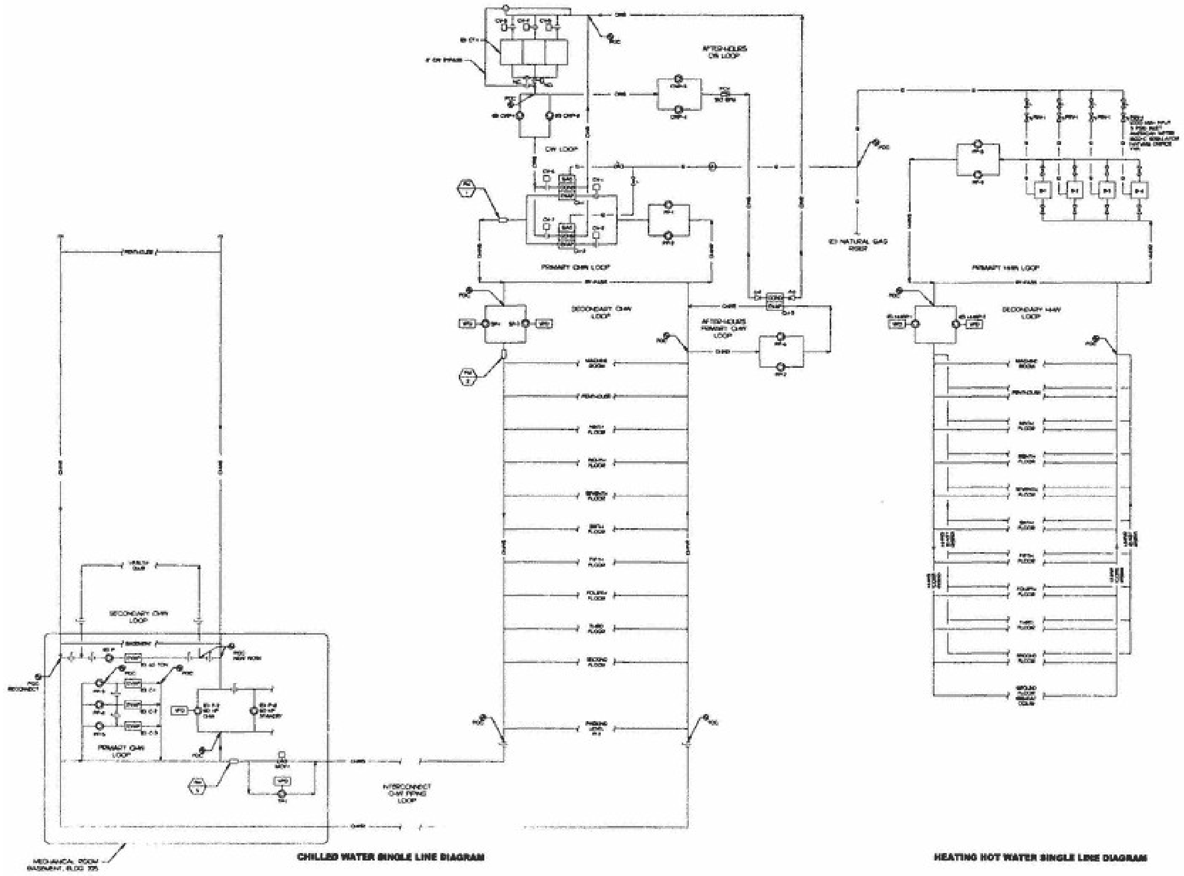

Figure 1
Chilled and Hot Water Systems Single Line Diagram

Chapter 5—
Energy Conservation Program in the San Diego Unified School District—The HVAC Elements

by Verle A. Williams & Ron Rybak

Introduction

The San Diego Unified School District (SDUSD) embarked on a District wide energy conservation program in 1995 by engaging a consultant to identify their needs and develop the program for their 206 job sites, 12 million square feet in over 1200 buildings.

Program

This effort developed a $44 million District Energy Efficiency Program (DEEP), which was later renamed the District's Facility Improvement Program (FIP). The cost included construction, project management contingencies, studies, design, commissioning, training, and additional operating personnel. Projected utility savings amounted to $5.5 million per year, which equated to 48% of the annual cost of gas, electric, water and sewer.

Results

The monitored results indicate that the actual savings exceed projections, even though the District purchased over 10,000 computer systems in 1997–98, and $10,000,000 was returned to the Chief Financial Officer from construction cost, so the program has been extremely successful.

Background

With San Diego's mild climate and the age of many of the schools, approximately two thirds of the schools are not air conditioned. Many of those are ventilated only by opening the windows.

The type of heating systems varies from floor slab hot water radiant heating to in-classroom gas fired unit heaters, to individual heat pumps with and without auxiliary electric heating elements, to central heating, and ventilating (H&V) units, to gas fired multizone H&V units, to central constant and variable air volume systems with hot water boiler heated hot water coils or electric coils. The age of the schools ranged from just opened to over 50 years old. The construction types included mostly single story wood and metal frame stucco, with a mixture of concrete block, tilt-up concrete panels, etc. Nearly all roofs are flat composition type. Some schools are in the International Airport flight pattern and were slated for a noise abatement retrofit, requiring the addition of air conditioning and non-operable windows.

The last major construction program was in the '70s, when windowless schools were "the only way to go". These schools are fully air conditioned, primarily with electric cooling and heating multizone units. Only 7 schools throughout the District were cooled by central water chillers. The rest of the air

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conditioned schools utilize roof-mounted package units.

Development—HVAC Element

Due to the size of the District and the priority placed on "results", it was decided in the early stages of the program that the program implementation would be prioritized by school, by energy consumption and/or annual utility cost. This would maximize the dollars returned to the District and would reduce the total time to complete the program.

Audit teams evaluated each school site addressing the following:

HVAC equipment, including specific nameplate data for inputting to the Computerized Maintenance Management System (CMMS). (A bar code was applied to each system and entered into the CMMS to upgrade and expand the use of the system.)

Condition of equipment, with estimated time and cost replacement of major upgrade/overhead

Potential energy and water efficiency improvement projects

Recommend operating and maintenance (O&M) improvements

Operating hours—especially for after hour community service functions within the building(s), such as church services

Special requirements of a control system

Number and location of gas, electric, and water meters for future hookup to the Energy Management System (EMS).

Number of spare telephone lines, if any, and location of the Telephone Terminal Board (TTB) for future EMS intertie.

Digital photograph of any unique situation or any unused condition

considered worthy of advising O&M personnel (such as plugged coils, broken damper linkage, warped access door, leaking pipe, fitting, valve, etc.)

This data was entered into a Palmtop computer to optimize the data tabulation process and to minimize errors in transferring data from field notes to the final reporting mechanism. The data was automatically dumped into the computer network for future retrieval by any team member to fulfill the various tasks required.

Energy engineers worked with the auditing staff to develop the energy efficiency improvement projects and the recommended O&M modifications. A report was developed for each site. Normally, this was a 3 or 4 page report, including tables as appropriate. Important photos were included in an appendix, or, if appropriate, directly in the text.

Implementation

The first HVAC project implemented was actually completed before the audit teams passed the 50% completed mark. The District had 70 major rooftop HVAC (multizone) units located on 12 sites. The total cooling capacity was 2,087 tons. The controls had been revised, in response to the first "energy crunch", to prevent simultaneous heating and cooling. This negated any zone control when the system was on cooling and left many economizers non-functional. In other words, these units were energy hogs and, to make matters worse, the occupants were very uncomfortable. The consultant team then had a major challenge to develop the optimum system that would provide comfort for the occupants and remain more energy efficient throughout the operating cycle. To add to the challenge, the load (weight) on the roof could not exceed the existing unit weight without an excruciatingly painful and long permitting review process, in addition to the added expense for significant structural upgrades. All of this cost money, detracted from the total program, and delayed the results beyond acceptable limits. And, to top it off, there were no empty classrooms to permit moving students and shutting the HVAC system down for a school day, so the replacement must be accomplished during a single weekend.

Special Unit Developed

Energy models were developed and analyzed for at least 6 different types of systems for all school types and operating conditions, and the 3 primary microclimates experienced inside the San Diego City School District boundaries.

The winning unit was an aluminum frame and skin roof-top heating-cooling VAV unit with open discharge air plenum to house a VAV box for each zone (most units had 11–13 zones). (See Figure 1.) Normally, heating is used only for warmup—up to occupancy time. Once the building is occupied, the load is primarily ventilating and cooling, so the heating is deactivated. When the outside air temperature is below 42°F (5°C), the unit may be switched to or left on heating, since the required minimum outside air drops the supply air temperature below 55°F (13°C), which overcools the space.

A District energy standard permits cooling only above 75.5°F (24°C) and heating only below 70°F (21°C). As a significant benefit of the EMS, with individual zone Direct Digital Control (DDC), a ventilation setpoint has been implemented. This permits operating the economizer dampers to maintain ventilation setpoint, usually 72°F (22°C). This provides maximum comfort with minimum energy consumption.

Occupancy sensor signals are input into the EMS to close the VAV box flow damper when no one is in the space. (The warm-up sequence bypasses the occupancy sensor to permit the damper to be modulated by the space sensor.) As an added efficiency feature, and as a means of assuring that the required outside air is supplied to the space, the minimum outside air damper control loop is programmed to modulate farther open as the fan speed reduces. Since air flow stations are not sufficiently accurate (for this Engineer), this has been determined to be a superior method of controlling the ventilation air quantity to meet the intent of ASHRAE's ventilation standard of 15 CFM per person. It also permits reducing the quantity of outside air during low occupancy periods. (Carbon dioxide (CO_2) sensors are often used to modulate the minimum outside damper to maintain an acceptable maximum level of CO_2).[1]

The units were specified to include different sized screw compressors, insofar as feasible, to provide 3-stage cooling control.

Factory Testing

The EMS manufacturer was required to deliver the HVAC unit controls to the unit factory for factory installation. Prior to shipping the units, the EMS technician, from the manufacturer was required to calibrate and test the complete control system and the unit operation prior to shipping the unit. This permitted the contractor to start-up the unit after completing the field installation without requiring the control supplier to be on the job site to commission the controls immediately.

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[1] ASHRAE Standard 62-1989 "Ventilation for Acceptable Indoor Air Quality" American Society of Heating, Refrigeration and Air-Conditioning Engineers, Inc.

A Miracle Happens:
(*But, if it is by design, it shouldn 't be called a miracle*)

The largest schools had 13 units each. The contractor successfully pulled the old units off the roof and installed the new units in 4 3/4 hours! Teachers and students left the school Friday afternoon with the old HVAC units operating and returned Monday morning with the new units in operating. Everyone was very pleased—especially the Contractor.

Only 1 of the 70 units required any field modification to fit existing ductwork. This was a tribute to the Contractor and the equipment manufacturer for the excellent job of field data gathering prior to manufacturing.

The units have worked very good. The energy budget has been met and the occupants don't wear sweaters in the summer! Following an extensive commissioning effort, the systems are performing very well. It is important to require (or demand) the control systems manager and the unit manufacturer to certify the factory tested performance of each unit. Do not slack-off on this requirement. It pays big dividends in the end. It is also recommended that the District representative visit the factory for an inspection of the first shipment prior to finalizing the shipping order.

In conclusion, up front planning and site analysis provided winning results for this $5.5 million HVAC element of the overall FIP project. Up front planning enabled a seamless transition from old to new highly efficient custom VAV system, without interruption of the school teaching and learning process. Through site analysis and detailed engineering (without lots of safety factors) resulted in a sophisticated control system strategy and reduced total cooling capacity from 2,087 tons to 1,621 tons. This was all accomplished while improving building occupant's comfort, and saving energy!

(It might be noted that San Diego experienced the hottest and highest relative humidity summer in history, measuring 25% greater cooling load than normal design criteria. Not one lacked cooling capacity to do the job.)

The District is very pleased with the total results.

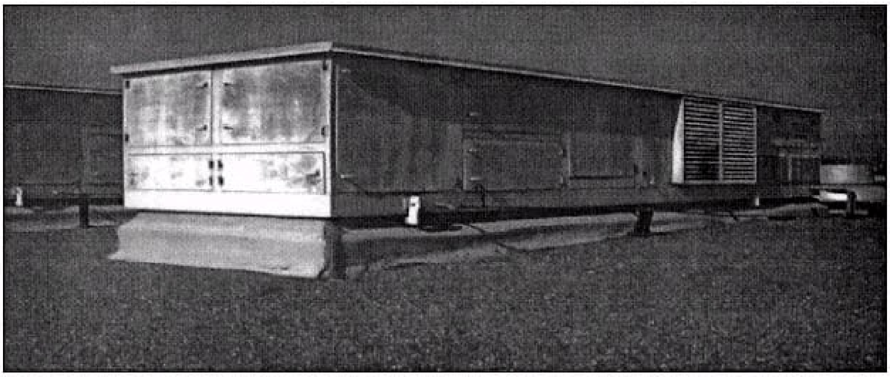

Figure 1
Custom VAV Unit. Unit has heavy hinged access doors and a
large access door for accessing the VFD and control system.

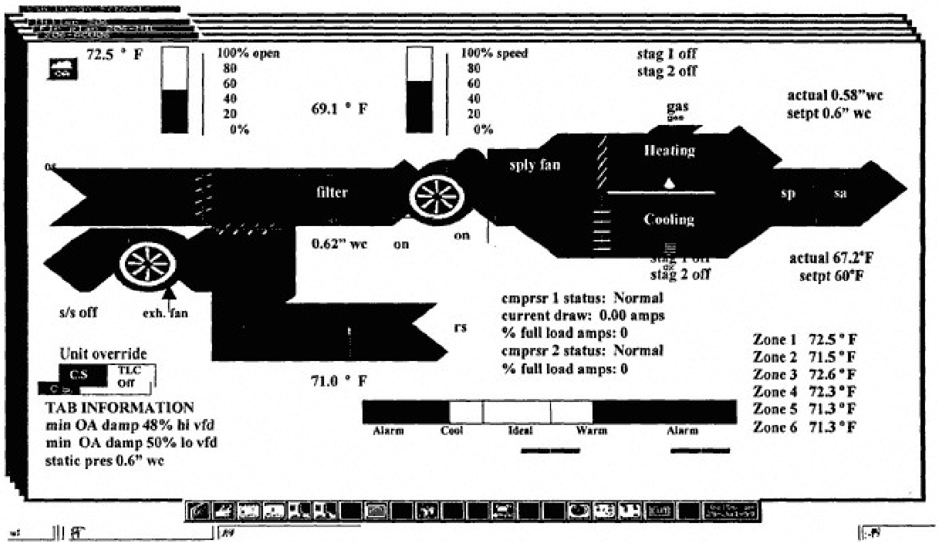

Figure 2
Graphic Display. The EMS is operated via graphic displays. All data are strategically
displayed on the screen to permit nearly instantaneous diagnostics

Chapter 6— Creating a Quality Building Environment with a Building Automation System

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Abstract

A *Quality Building Environment* (QBE) is efficient, productive, comfortable, safe, healthy and supports the business needs of the occupants. Building owners and managers face several challenges in establishing optimum levels for each of these components of QBE. Building owners invest in Building Automation Systems (BASs) to automate their buildings. However, empirical evidence suggests that over 90% of the BASs are under-utilized. Many BASs are used as glorified time clocks or digital windows to the mechanical equipment in the building. A BAS is capable of much more. A well-utilized BAS helps operate a building at optimum efficiency, lowers operating costs, enhances comfort levels, increases productivity, improves code compliance and maintains a QBE. This paper discusses how the utilization of a BAS can be enhanced from being a monitoring station to a seamlessly-integrated platform that can be used to create and maintain a QBE. The topics presented discuss how a BAS can have a positive impact on each component of QBE.

History of Building Environments

Ever since man has inhabited indoor environments, he has sought to improve comfort, health and safety. Even cave dwellers realized that there were benefits in removing smoke from cooking and heating fires and utilized crude vents. In 1600, King Charles of England enacted the first building code for ventilation. He declared that ceilings in houses should be at least 10 feet tall and that windows should be higher than they are wide to aid the removal of smoke odors and heat. Since then, numerous standards for improved indoor environments have been published. Today, ASHRAE Standard 62-1989 is the most widely-accepted standard for indoor air quality, which is a critical component of OBE.

QBE Business Drivers

Several factors have contributed to the recent refocus of attention on health, efficiency, productivity and comfort in buildings. There is a greater awareness of the link between health and environmental conditions.

Employers are concerned with the impact on employee productivity of building-related illnesses. The spiraling cost of health care and insurance premiums is also a strong incentive for companies to encourage healthy lifestyles and to provide working environments that are not detrimental to employee health and productivity. There is a growing awareness that buildings are a variable in corporate performance rather than just a fixed asset in which corporate performance takes place. A 1995 White House report suggests that better-constructed facilities could increase employee productivity and comfort up to 30% nation wide in the USA. The Office of Science and Technology Policy released the report.

Threats of unoccupied space and litigation are forcing building owners to move toward improved comfort and health in their leased facilities. New standards and regulations are addressing the way that buildings are designed, constructed, operated and maintained, all in the interest of quality environments.

To support this new building paradigm, facility managers have a mission to create a QBE. Facility managers are:

- becoming less "equipment" focused and more "asset management" focused
- taking a process-oriented approach to facility management by defining and documenting procedures

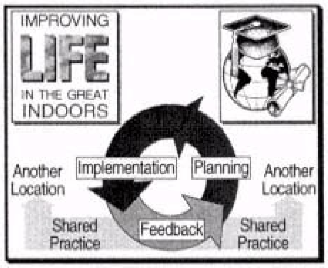

Figure 1
Process Oriented Approach

Taking a process-oriented approach to facility management allows the sharing of practices. Good facility management processes include feedback for benchmarking. We are living in a new era of facility management. Building owners today have more information about their buildings than ever before. Today, building operations are expected to contribute to bottom-line performance. Labor costs, energy costs and operating costs for buildings are continuing to rise. This has also contributed to the increasing trend to leverage technology to lower building operating costs and increase operating efficiency.

The use of computers is helping to facilitate some of these changes. The initial cost to the owner is recovered through longer building and system life, more stable tenants, reduced sick building liability, reduced medical costs, improved productivity of occupants, and reduced operation costs.

A BAS Creates and Maintains a QBE

A QBE does not just happen by accident; it must be planned for, created and maintained. It involves designing, implementing and managing programs to address the areas impacting the indoor environment. These include energy, building maintenance and indoor air quality. These three areas complement each other. A BAS can bring them together on one common platform. A BAS can be used to automatically implement operation and maintenance strategies that lower costs, improve efficiency, and enhance comfort levels. A BAS can be used to create and maintain a Quality Building Environment. Each and every component of a QBE can be impacted by a BAS. Leveraging a BAS to create and maintain a QBE is not a one-time event. It is a process and needs to be monitored. The dynamics within a building environment make it even more important to constantly track and tweak the performance of a BAS to maximize its potential.

Building owners and managers who have utilized their BAS well have realized significant benefits such as:

1. Operating cost reduction (includes energy costs and maintenance costs)

2. Increase in operating efficiency and reliability

3. Enhancement in staff and occupant productivity

4. Improvement in comfort levels

5. More safe environment

6. Increased code compliance

7. Better returns on investments made in BAS

A BAS is an effective troubleshooting tool when used to collect historical and current data for analysis and documentation. Today's BASs can capture the history of operations and changes, simply by keeping the log as an integral part of the system. Moreover, a BAS can also enhance asset life.

A BAS Improves Operating Efficiencies and Lowers Energy Costs

Rising energy costs are a growing concern for building owners. As buildings grow older, the operating efficiencies of building systems drop and subsequently energy costs go up. As was mentioned earlier, efficiency is an integral part of a QBE. A BAS can support a QBE by continuously improving operating efficiencies and eventually lowering energy costs. Many building managers make modifications to their building operations to lower energy costs, but are often disappointed, when they do not realize the expected results. What they don't realize is that energy management is a process and not a onetime event. Before an energy retrofit is implemented, a BAS can be used to develop a baseline of energy usage and environmental conditions. This makes it easier to calculate energy savings and compare environmental conditions to verify the performance of the retrofit. Once a retrofit is completed, performance variables need to be monitored and tweaked in order to maximize the savings potential. Precaution must be taken to not impact comfort and productivity adversely.

The energy consumption is compared to the baseline consumption to calculate savings. The entire process can be done using a BAS. Some BAS can interface with other Windows-based applications, such as MS Word, Excel, Access, etc. This allows the BAS to generate customized energy reports on a daily, weekly, monthly or annual basis.

A BAS can also be used to track operating efficiencies and notify the building's energy manager when the efficiencies drop below a certain level. Some examples include:

1. Automatic trending and reporting of a building's key performance indicators such as energy cost per square foot ($/Sq.Ft), energy cost per widget produced, energy cost as a percentage of net income, etc. In other words, a BAS can link the operating efficiencies to the building owner's core business output.

2. Comparison of operating efficiencies between several floors of a building. For example, when a BAS reports that Floor 2 costs $2.00 more per square foot of conditioned space than Floor 3, the building manager knows that there is some problem with Floor 2 that needs to be checked. Further investigation could result in determination of a piece of equipment, such as a chiller, that needs to be replaced or repaired.

Several research studies have indicated that the operating efficiencies of a building can be improved by 10–20% by simply utilizing a BAS effectively. Depending on the equipment controlled by the BAS, there are several ways of using a BAS to lower energy costs. Some specific examples include:

1. Scheduled Start-Stop of lights, HVAC, and process (manufacturing) equipment

2. Automatic reset of HVAC and/or process-controlled variables, such as temperature, static pressure, humidity, flow based on actual load conditions

3. Automatic load shedding and load shaving to take advantage of cheaper fuel during certain hours of the day—a major advantage to building owners in a deregulated market

4. Equipment interlocking to ensure that equipment consumes energy only when necessary

Empirical evidence indicates that a BAS can reduce energy consumption by 15–30%. Thus, we have seen that a BAS can be used as a tool which will support a QBE by tracking, reporting and fine-tuning variables that impact operating efficiencies and eventually energy costs.

A BAS Lowers Maintenance Costs, Improves System Reliability and Enhances Staff Productivity

A study conducted by the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) indicated that over the life of a building, 50% of the building costs can be attributed to its operating costs. Maintenance costs make up a significant percentage of a building's operating costs. Unfortunately, most building managers give more importance to first costs than operating costs, when making buying decisions. Implementing the right maintenance strategies can help improve operating efficiencies and subsequently maintenance costs can be significantly reduced. Moreover, selecting the appropriate maintenance strategy will also improve the building's operating reliability and subsequently staff productivity. High operating efficiencies, low operating costs and high productivity are all critical for a QBE. A BAS can be leveraged as an effective tool in achieving the above-mentioned objectives. Before we discuss how, it is important to understand how maintenance management has changed over time.

Like energy management, maintenance management is an ongoing process. Maintenance technology has evolved over the last few years. Today, BAS technology allows us to apply science to service. Several years ago, the maintenance management was primarily reactive, which meant that equipment was not repaired until it failed. Later preventive maintenance evolved, which defines time-based tasks for equipment. An example of preventive maintenance is oil changes on an automobile after every 3,000 miles.

Recently, predictive maintenance has been introduced. This style of maintenance allows building managers to identify and detect problems before they cause failures. An example of this style of maintenance would be oil analysis on machines. Technology has now made it possible to go one step further and detect the source of the problem. This is called proactive maintenance. Examples of proactive maintenance include vibration analysis on fans and pumps, which helps detect problems such as improper balancing or misalignment.

These newer service strategies may not be appropriate for every piece of equipment. An optimum maintenance management process involves choosing the appropriate service strategy for different pieces of equipment, based on equipment criticality, redundancy and potential for secondary damage. This process is often referred to as *"Results Oriented Service"* because the service strategy for every piece of equipment is selected based on the building owner's business objectives. This strategy is also sometimes called *"Reliability Centered Maintenance"*.

From reactive maintenance to proactive maintenance, a BAS can be leveraged to collect and analyze critical data and then take appropriate actions. A BAS can notify someone when a problem is detected. Notification can be in the form of an on-screen visual alarm, a text message sent directly to the pager of the appropriate person, a work order in a computerized maintenance management system, a phone call or an email message. Alarm management is a crucial feature of a BAS. Notification can be initiated based on how long an equipment has been running (time-based monitoring for preventive maintenance strategy) or could also be based on the condition of an equipment (condition-based monitoring for predictive/proactive maintenance strategy). For example, if the BAS senses an unacceptable vibration level in a chiller that supports a data center, the BAS will automatically notify someone of the problem, before the problem gets worse, thus preventing unscheduled downtime.

Building managers' involvement in maintenance varies from building to building. Selecting the appropriate maintenance strategy, increases equipment life, reduces operating costs and increases staff productivity. By applying science to maintenance, building owners have realized maintenance cost savings of 10–40%. Benefits realized by leveraging a BAS in the process of maintenance management include:

- Increase in system reliability and system efficiency
- Reduction in maintenance costs
- Increase in maintenance staff productivity
- Increase in equipment life

In other words, a BAS, when integrated with the right maintenance strategy, can support the objectives of a QBE.

A BAS Enhances Comfort Levels

Occupant comfort is an important requirement for a QBE. A BAS is an effective tool in maintaining comfort levels in a building. It allows the building manager to monitor and control the space temperature, pressure and humidity from a centrally-located computer. Sometimes the information provided by a BAS could be overwhelming. A BAS can be set up to generate customized, "management-by-exception" reports that display all the information that the building manager needs to assess the comfort levels in the building.

In today's digital age, data is critical. However, the data needs to be presented in a format that's easy to understand and interpret for it to be meaningful. With new technologies, BAS today can present the data in several possible ways. This allows the building manager to be presented with "management-by-exception" reports that identify problem areas. Moreover, as an example, a BAS can also be set up to notify the building manager if a room temperature is too high and determine what the cause of the problem might be. The BAS could check to see if the air-conditioning unit fan is on. If the fan is on, then the BAS could check the compressor itself. Based on the diagnostics, it will help identify the source of the problem. This allows the building manager to take corrective action, before the problem gets out of control. Using artificial intelligence, the BAS can also be set up to take corrective action on its own. This could be very advantageous, in the event that the BAS operator is not available or busy doing something else. The key benefit of this is that occupant comfort is not sacrificed.

Below is an example of one of several ways that critical data can be displayed on a BAS. The problem areas clearly stand out in the data visualization technique shown below, thereby allowing the building manager to address the problems, before the occupants feel uncomfortable.

Starfield Display

The center dot or "star" indicates the on/off status of a system, such as an air conditioning system. If the center dot is large and green, the fan is on and normal. If the center dot is small and green, the fan is off and normal. If the center dot is red, it means the fan is not in a normal operating condition. The dots surrounding the central dot or star indicate the status of points, such as room temperatures associated with each system. A large screen that displays several starfields will provide the building manager with quick and easy access to the environmental conditions in the entire building.

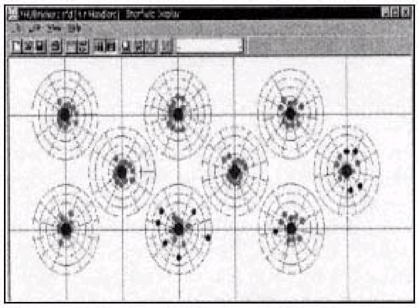

Figure 2
Starfield Display

Customized reporting by a BAS can help a building manager in creating a comfortable environment for the building occupants, thereby helping create and maintain a QBE.

A BAS Creates a Safer Environment

An environment that does not address occupant and equipment safety is not a QBE. A BAS can be integrated with the other building systems, to enhance the safety levels in the building. When multiple building systems are integrated with the Building Automation System, the Operator Workstation becomes a single seat user interface (see Figure 3). A single seat user interface brings the following benefits:

Improved safety

Improved security

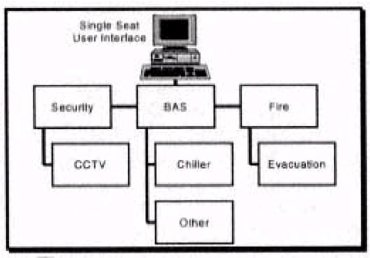

Figure 3
Single Seat User Interface

Improving Safety

Many of the automatic responses to a fire condition are laid out in the local codes. This includes turning off the air-handling unit on the floor of incidence and homing the elevator. The types of responses required by fire codes are under the direct control of the fire alarm system. Other building systems can provide a secondary response. Examples of secondary responses, that can be co-ordinated by a BAS include:

Turning on lights on the floor of incidence to aid evacuation

Turning on air-handling units on the floors above and below the floor of incidence to contain the egress of smoke (this is sometimes called a sandwich system)

Inhibiting HVAC alarm reporting on air-handling units turned off by the operator to concentrate on the fire condition without distraction

Sending audible evacuation messages based on the occupancy of the zone

Sending textual and graphical evacuation messages to users of the office automation network, to information kiosks and other public displays

Unlocking selected security doors to aid in evacuation

Inhibiting alarm reporting on selected security doors (i.e. fire exit doors leaving the building) to allow the operator to concentrate on the fire condition without distraction

Automatic printing of a report listing all occupied zones to help manage evacuation

Presenting an integrated floorplan showing the fire devices to assist the operator in visualizing the condition on the floor.

Improving Security

Most security systems are connected so that a security alarm triggers local CCTV cameras to be displayed on a dedicated monitor and recorded on a VCR. Locking out elevator operation for the floor in response to a security alarm will delay egress of the intruder. Often, the most appropriate response to a security alarm is to turn on all lights in the area. Automatically turning on lights in response to a security alarm has the following advantages:

Lights can scare away intruders before they have a chance to do damage

Having the lights on will protect the guard sent to investigate

Local CCTV cameras will be able to record a better image with the lights on

The above examples of improving safety and security illustrate how a BAS can be utilized to create a QBE.

A BAS Improves Building Health

A healthy building is an integral component of a QBE. Building health can be impacted by several factors that exist inside and outside the building. From wall furnishings, indoor air to the physical surroundings of a building, several factors affect the quality of the building's indoor environment. Sometimes, the building's environment can become harmful to the occupants' health. Without continuously monitoring and tracking key factors that can impact occupant health, a building manager can be overwhelmed with an abundance of possible causes, when the problem gets out of control. A BAS allows a building manager to not only monitor a building's health, but also make appropriate decisions to prevent the building's health from degrading. Indoor air quality (IAQ) is one variable, that has captured a lot of attention in recent years. The example below illustrates how a BAS can monitor and control the indoor air quality, which has tremendous potential for degrading a building's health.

The American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) has done considerable research in indoor air quality and has published a standard, ASHRAE Standard 62–1989, Ventilation for Acceptable Indoor Air Quality. One of the key parameters contained in the standard is the amount of fresh air required per person for various types of building environments. For example, for office environments, the minimum amount of fresh air is specified to be 20 cubic feet per minute (CFM) per person. Hence, it is important to measure the quantity of fresh air being introduced.

A BAS can be used to calculate the percentage of fresh air in the supply air stream, using one of several methods. One of the easiest and most reliable methods is the Carbon Dioxide (CO_2) method. Using CO_2 sensors, the level of CO_2 can be measured in a zone, the supply air stream and the return air stream. If the CO_2 level in the return air stream exceeds 800 ppm (parts per million), an output signal is sent to the fresh air damper to allow more fresh air into the building. In other words, the required fresh air CFM can be tied to the occupancy level, thereby lowering the amount of fresh air being brought into the building, during unoccupied hours and thus saving substantial cooling/heating energy. This is also referred to as Demand Controlled Ventilation strategy. This strategy can be controlled from a BAS. It helps not only improve the building's health by ascertaining that the occupants receive adequate amounts of fresh air, but it also helps realize energy savings and enhances code compliance, a major concern for building owners today.

There are several other instances in which a building manager can leverage a BAS to help maintain a healthy indoor environment, which is an essential component of a QBE.

A BAS Supports Occupant Business Needs

In order for a building to provide a QBE, it must be able to support its occupants' business needs. Ways of doing business are changing and the successful office buildings will be those which can effectively support these changes. One of the most significant changes for buildings is the shift in occupancy patterns. In the past, building occupancy was almost a binary function; fully occupied or fully unoccupied. In the future, buildings will be spending a much greater percentage of the day in part occupancy. Figure 4 illustrates this change.

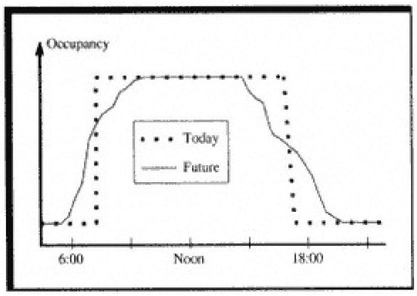

Figure 4
Changing Occupancy Patterns

Globalization and increasing competitive pressures are the two main factors influencing this change.

Today's buildings need to be responsive and automatically adapt to the current occupancy level. Safety, security, HVAC and lighting need to be zoned and controlled to accommodate part load usage of the building. There must be sufficient granularity in the zoning of these building systems and the building systems need to be integrated to provide a total building response to the current building usage. In order to be responsive, the building needs to "know" the current occupancy pattern in the building. With a BAS, there are many technologies available to determine the occupancy of a zone. These technologies can be used individually or together as required:

Time Schedule—the simplest approach may be to fix a default time schedule for each zone that may be overridden by one of the other technologies.

Card Access—when an access card is presented, either to enter the parking lot or to enter the building, the security system can advise the other building systems that the zone(s) associated with the card holder can be considered to be occupied.

Occupancy Sensor—a motion detector using passive infrared technology is often used as an occupancy sensor. At certain times, the occupancy sensor can also be used as a security device.

Door Lock Indicator—a microswitch activated by the latch set can be used as both an input to the security system and as an occupancy sensor.

Telephone—many facilities have installed a telephone interface to their BAS. When occupants want to change the occupancy modes of their zones, they call the BAS and a voice prompting system allows them to enter passwords, current location and specific requests. The telephone interface also allows occupants to change local temperature setpoints.

Web Browser—many building systems are becoming web-enabled allowing tenants limited access through the company Intranet.

Electronic Mail—some building systems are able to accept electronic mail messages requesting overtime usage of space.

Facility Booking System—a facility booking system is used to reserve conference rooms and other shared resources and the booking information is automatically passed to the building services.

When a zone is occupied, the building systems can be programmed to operate as follows:

Sensitivity of smoke detectors is set to LOW to avoid unwanted alarms due to dust and smoke generated in the space (depending on capability of integration with fire alarm)

Selected security devices in the zone have alarm reporting inhibited (depending on capability of integration with security system)

Temperature setpoints are changed to the occupied level

Ventilation requirements (CFM per person of fresh air) are set to the occupied level

Lights in the zone are turned on

Thus, a BAS offers buildings the flexibility to be responsive and automatically adapt to the occupancy levels at various hours of the day. By doing this, a BAS essentially supports occupants' business needs and helps create and maintain a QBE.

Conclusions

A QBE is efficient, productive, comfortable, safe, healthy and supports the business needs of the occupants. Building owners and managers face several challenges in creating and maintaining a QBE. QBE is a concept that is driven by the needs of the building owners and building occupants. Building owner needs are prestige, reduced operating costs and a quality indoor environment that supports business needs. The most important issue to the building occupants is an environment that is productive, comfortable, safe and healthy. The overall needs of the building owners and occupants can be met by integrating BASs into the building operations management processes. Several building owners that have leveraged BASs for building operations management have been successful in creating and maintaining QBE.

Each and every component of a QBE can be impacted by a BAS. For efficiency improvement, a BAS can be used as a tool used for tracking, reporting and fine-tuning variables that impact operating efficiencies and eventually energy costs. On the other hand, a BAS, when integrated with the right processes, can help reduce maintenance costs, improve operating reliability and enhance employee productivity. When integrated with other building systems, a BAS is capable of providing a safe and secure environment and is also responsive to occupant needs, which is a critical component of a QBE. Moreover, a BAS that is designed well can prevent building-related illness, improve indoor air quality and enhance individual comfort.

The important lesson to be realized from this paper is that creating and maintaining a QBE is not a one-time event; it is an ongoing process, that needs to be carefully designed, implemented and monitored to verify optimum performance. A QBE should also offer the flexibility to make appropriate changes to its operations to maximize building potential.

Technology is allowing us to do things differently today. The world that we live in today is a lot smaller and faster-paced than a few years ago. Increased levels of competition have forced the BAS industry to evolve quickly and continuously improve. Customers have more options and more complex choices to make as they strive to drive cost out of their bottom line and technological advances are reshaping the very nature of the enterprise of which we are a part. Today, the BAS industry is riding the technology wave. The automation systems that once connected down to the field control devices, must now communicate upward to information networks that are owned and operated by Information Technology professionals. This new world of enterprise computing will open a new set of doors that will allow us to get more from our BASs and enable building owners and managers to create Quality Building Environments.

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Abbreviations Used

QBE—Quality Building Environment

BAS—Building Automation System

VAV—Variable Air Volume

AHU—Air Handling Unit

CCTV—Closed-Circuit Television

HVAC—Heating, Ventilating, Air Conditioning

Chapter 7— Joint Brazil/USA Energy Audits: A Case Study

Drs. A. Mesquita, D. Cruz, J.N. Ortiz, and J.W. Sheffield

Abstract

This paper presents the success of a joint energy audit conducted in Brazil by a combined team of faculty and students from the University of Missouri-Rolla (UMR) and the Universidade Federal do Para (UFPA). This international exchange examined the potential for technology transfer of the Industrial Assessment Center program that is sponsored by the U.S. Department of Energy—Office of Industrial Technologies.

The paper describes the methodology applied by the international team to identify opportunities for energy conservation through on-site audits of the manufacturing plants. Energy conservation opportunities are classified according to potential areas for savings (i.e. lighting, air compressors, motors, etc.) and are depicted in terms of the associated cost savings, energy savings, implementation cost, and payback period.

The paper presents a case study associated with a manufacturing plant located in Belem, Para. A review of one-year metrics, that lists energy conservation opportunities found through UMR-IAC's ninth year of operation, is presented for illustration purposes. The metrics are based on twenty five audits conducted in the USA and include energy savings, demand savings, cost savings, implementation cost, and payback periods. It also describes the conduction of the joint energy audits as a valuable two-way international project.

The paper concludes by stressing both the advantages of a joint approach when performing energy audits overseas and the potential for the development of a more ambitious international program for technology transfer. The educational value of the above experience, for the faculty and the students involved in the academic exchange, is also seen as a window opportunity for follow-up activities.

Background

The Industrial Assessment Center program, funded by the U.S. Department of Energy (DOE) and operated by the University City Science Center and Rutgers University is a proven way to help improve the energy efficiency and energy cost control of small and medium-sized manufacturing companies. The IAC's services are offered at no direct cost to manufacturers. Since 1989, the Industrial Assessment Center at the University of Missouri-Rolla has:

Served 275 manufacturing plants.

Proposed 2,000 energy conservation opportunities.

Identified 60 million BTU per year of energy conservation.

Recommended 25 million dollars per year of cost savings with a corresponding average payback of less than 20 months.

The IAC program has been a very successful and cost-effective national effort, resulting in much greater benefits in energy cost savings than the cost to operate the program. The current cost to the Department of Energy of an IAC audit is approximately $6,000 and the total savings shown in the Final Audit Reports substantially exceed this cost.

Industrial Audits are performed by engineering faculty and students from local universities with officially accredited engineering programs. They have the technical competence in energy-efficiency improvement to help these companies. Individual universities are responsible for the companies in the regions around their physical locations. This is because there are regional factors associated with energy supplies, energy costs, and business operations that must be addressed on a geographically distributed basis rather than through a single, national IAC.

The University of Missouri-Rolla's Industrial Assessment Center (UMR-IAC)

UMR-IAC provides energy, waste, and productivity audit services to small and medium-sized manufacturing companies within a 150 mile radius of Rolla, Missouri. The UMR-IAC provides audit services to qualified facilities in the SIC Codes 20–39. The recommendations are primarily associated with the specific manufacturing processes in use by the particular companies. Process equipment and process operational changes are considered. The industrial building energy use are also considered, including lighting, heating, ventilating, air conditioning, and any other large-consuming energy use.

The Universidade Federal Do Para—Mechanical Engineering Department

In 1997, UMR representatives visited UFPA and presented a graduate lecture on Energy Management and Conservation. The Mechanical Engineering Department at UFPA hosts a master's program that includes energyrelated studies. An average of 20 graduate students currently attend the program and have participated in the joint energy audits.

IAC-DOE Methodology

Once a manufacturing facility has been selected for audit, these energy analysis and diagnostic process steps are followed:

- Pre-visit
- Site Visit
    - Introductory Discussion
    - Plant Tour
    - Information/Data Gathering
    - Audit Review and Recommendation Development
    - Wrap-up Meeting
- After the Visit
- Final Report

Pre-Visit

Prior to the site visit, the IAC staff confirms that the facility is eligible for IAC services by obtaining and reviewing the plant's four digit SIC code, the number of employees, and the annual sales. The energy bill requirements are verified during a preliminary analysis of the plant's energy consumption records for the preceding year. A list of the major energy consuming processes and equipment is very helpful in advance of the visit.

Selected plants are requested to supply a complete set of bills for all of the forms of energy used at that location, information on utility rate structures for electric and gas services, and rates for any other energy supplies. This data is analyzed in advance of the plant visit and the cost is displayed graphically to show trends, and to potentially discover peaks in usage. One purpose of the audit is to find the reasons for any anomalies.

Site Visit

Once a plant has been selected for an audit, and the preliminary information has been obtained and analyzed at the IAC, the next action is to conduct the actual site visit.

Introductory Discussion

A UMR-IAC audit team consisting of the IAC Director, Assistant Director, Audit Team Leader, and student engineers meets with the designated representatives to discuss plant operations and concerns about energy, waste, and productivity related matters. During this discussion, the preliminary information on the plant (SIC codes, employees, sales, and energy costs) is verified. The graphs of energy cost and consumption are discussed, and the audit team gives several documents to the plant representatives to identify the UMR-IAC, the audit team members, the name of the principal contact at the IAC, and a brief description of the audit process.

Plant Tour

Following the introductory discussion, the audit team and one or more plant representatives tour the plant to observe operations and determine the flow of materials from input or receiving, through processing, and finally to shipping. The audit team is responsible for both taking notes on the manufacturing processes and operations, and compiling an inventory of major energy using equipment.

During the plant tour the experience of the IAC staff is key in order to make a major impact on the quality of the results. Knowledge of manufacturing processes, equipment, and operating procedures is necessary to rapidly spot the areas where energy conservation and energy-efficiency improvements can be made. Inefficient process heating equipment, low-efficiency motors, large quantities of wasted heat, poor match of fuel forms to process needs, poor process or personnel scheduling, and inefficient scheduling of large electrical loads are some of the potential areas for good Energy Conservation Opportunities (ECOs), Waste Minimization Opportunities (WMOs), and Productivity Enhancement Opportunities (PEOs).

Information/Data Gathering

Following the initial plant tour, the audit team secures their measuring equipment and proceeds to take and record quantitative information about the equipment in the plant. It is usually best if one of the plant maintenance people accompanies the assessment team and works with them to get the necessary measurements. If a plant maintenance person is helping, plant management is less concerned that the audit team will cause some problem. In some cases, the plant person may prefer to take the actual measurement while the audit team confirms the correct procedure.

Combustion efficiency is measured for all major fuel-burning equipment. At the minimum, excess oxygen and stack temperature are measured in oil and gas boilers. Carbon monoxide and carbon dioxide levels are measured if equipment is available.

Efficiency and power factors of large motors and motor-driven equipment are measured when there is reasonable and safe access to power conductors. Single-phase or three-phase measurements are taken as appropriate to obtain the efficiencies and power factors. Similar measurements are taken when safe and practical for all other large electrically powered equipment.

Other factors that affect energy consumption are measured including equipment temperatures, and working temperatures in various plant and office areas. Light levels are measured in most areas of the plant and offices.

Audit Review and Recommendation Development

After the measurements have been completed, the members of the audit team meet to compile their data, perform elementary analyses, and prepare preliminary recommendations. Using the preliminary information and data, the team identifies a series of ECOs WMOs, and PEOs to reduce energy and wasted-related operating costs and to improve productivity in the plant. The primary focus of these recommendations is to improve the plant's manufacturing processes. Equipment modifications and replacements are considered, as well as potential changes in the plant operating schedule or operational procedures.

Wrap-up Meeting

The audit team meets with the plant representatives after their audit for an informal discussion about the audit procedures and any preliminary audit results.

After the Site Visit

After completing the site visit and presenting preliminary recommendations of ECOs, WMOs, and PEOs the IAC staff prepares a formal Final Report to be sent to the manufacturing company. The report contains a description of the plant operation, equipment, energy costs and consumption patterns, and recommendations together with detailed economic evaluations. After the IAC staff has thoroughly analyzed and evaluated the plant operation and process equipment, there are usually additional suggestions for improvements. The IAC staff also conducts research on processes and equipment after the audit visit, to identify technological products or processes that could help make the particular plant's operation more efficient in terms of energy, waste, and productivity.

Final Report

The Final Report is sent to the manufacturing company within 60 days of the audit. A copy of the Final Report, without proprietary information, is also sent to University City Science Center for their review, suggestions, and final approval.

Case Study

A joint energy audit of a paper pulp facility was performed in Belem by the combined team UMR-IAC and UFPA in August 1998. Electric rates for this facility were found to be \$0.08/kWh, \$21.00/MMBtu, and \$53.00/kW per year, respectively.

A few opportunities for energy conservation were outlined by the combined team: Install Energy-Efficient Motors, Install Variable Speed Drives, Shift from Heavy Oil to Lighter Diesel Fuel, Reduce Electric Peak Demand, and Reduce Compressed-Air Pressure. Additional energy conservation measures were proposed: Install Metal-Halide Lamps, Install Cog Belts, and Use Synthetic Lubricants.

UMR-IAC Annual Metrics

During the period October 1997 through September 1998, twenty-five energy audits were conducted by the UMRIAC team, in Missouri and Western Illinois, within the IAC-DOE program. Average electric rates were found to be \$0.06/kWh, \$14.74/MMBtu and \$44.66/kW.

Most of the energy conservation opportunities were found in the following areas: electrical motors (45%), air compressors (27%), and lighting (21%). Total implementation cost was estimated as $344,464 with an associated payback of 14.1 months. (See **Tables 1 and 2**)

Table 1. Energy Conservation Opportunities (UMR-IAC)

Area	Cost Savings
1. Electrical Motors	$147,319 /yr
2. Air Compressors	$88,977 /yr
3. Lighting	$69,834 /yr
4. Others	$20,540 /yr
Total	$326,670 /yr

Table 2. UMR-IAC metrics (Oct. 1997–Sept. 1998)

Audits Conducted	25
Cost Savings	$326,670 /yr
Energy Conservation	21,528 MMBtu/yr
Demand Reduction	1,156 kW per year
Implementation Cost	$344,464
Simple Payback	14.1 months

A comparative annual metrics for UFPA's joint audits is not available yet, but it is anticipated that it will be very useful for benchmarking purposes.

Two-Way International Project

The conduction of the joint energy audits can be described as a valuable two-way international project.

Even though, the standard IAC-DOE program procedure is followed, differences due to local conditions can be easily found. For instance, typical energy conservation opportunities that the UMR-IAC team normally spots in Missouri and Western Illinois such as "Use Outside Air For Compressors' Intakes" and "Replace Incandescent-based Exit Signs with LED Units" do not have much application in Northern Brazil due to climatic conditions and the non-use of exit signs, respectively.

The UMR-IAC team has also been working on waste minimization opportunities for the last three years, and more recently on productivity enhancement opportunities; therefore, an overview of these activities was also shared with the UFPA team using the joint energy audit as the natural platform.

The UFPA graduate students have a solid background in Mechanical Engineering and each year a new batch starts the program.

From the academic point of view, the experience was also successful. It gave both the UMR-IAC and UFPA teams the opportunity to be exposed to a different culture which also contributes to enhance their professional development through a common language: engineering.

In general, the conduction of the energy audit served to both teams as a means for crossing boundaries and shifting paradigms about the identification of energy conservation opportunities in local manufacturing plants by applying a general methodology from the IAC-DOE program.

Conclusions and Recommendations

It can be concluded that the joint energy audit performed in Belem, Brazil in August 1998 by the combined teams from UMR-IAC and UFPA was very successful in facilitating the application of the IAC-DOE program.

More over, it proved to be a two-way international project wherein both teams learned from the brain storm process. It also served as a means for UMR-IAC to share with UFPA some of the experiences observed in similar facilities with regard to waste minimization and productivity enhancement aspects. It is possible that UFPA may have the opportunity to establish a collaborative IAC program in the near future.

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Chapter 8—
IAC's Positive Effects on the Powder Coating Industry

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Abstract

The Hofstra University Industrial Assessment Center IAC has conducted over 190 energy audits over the past 8 years and has had a high success rate. This past summer the members of the IAC conducted return visits to two customers who had excellent results from the implementation of the recommendations the center made for them as a result of the plant visit. The recommendation on the report consisted of suggesting the company insulate their curing ovens in order to save on energy costs. Both companies had expressed to us problems in their plant as a result of the high heat that was given off by the ovens. We therefore knew that the results of insulating the oven would not only be lowered energy costs but also higher worker comfort, which leads to increased productivity, but also lowered waste due to the fact that an important piece of equipment works more efficiently in cooler temperatures.

We visited the plant during the 1997 contract year. The resulting reports recommended that the company insulate its ovens. After 6 months, we called back to see what recommendations had been done. We were informed that one company had had results which were even more favorable than what had been suggested leading to increased cost savings and the other company had insulated more surface area than what we had suggested and also had very favorable results. We therefore asked both companies if we could return to their plants to quantify more precisely what the results of the implementation had been.

Background

The Industrial Assessment Center (IAC) Program is a federally funded program by The Department of Energy. Its mission is to help out small to mid-size businesses by providing them with teams consisting of engineering faculty and students and performing plant assessments at no cost to the company. The plant assessments focus on three main areas when a company is visited: energy conservation, productivity enhancements and waste minimization. The idea is that by helping companies in three main areas the company will be able to remain competitive and will be more successful in doing business.

Some recommendations however, provide more benefits than were originally imagined, our continuing visits to plants which were left very satisfied by our initial recommendation proved to us that not only were savings to be found in tangible results but also in some of the more intangible areas, like worker comfort and better work environment. Though these areas of savings may be more difficult to quantify easily they are still very much real and are a direct result of the initial recommendation. The Hofstra University IAC performed plant assessments for two companies in the powder coating industry. Both of these companies had the same situation at their respective plants: lack of appropriate insulation on the curing and steam cleaning ovens. The Hofstra University IAC therefore provided both companies with the same recommendation to insulate their ovens. The center provided these recommendations with one quantifiable purpose in mind, the amount of energy that can be saved by not allowing the oven's heat to escape to the surrounding environment. Though we had envisioned that there were going to be other areas of savings from our initial recommendation we did not know that the savings would come from so many different areas.

The powder coating industry is a relatively new manufacturing industry where metal parts are painted in a spray booth using a powdered paint which when cured in an oven dries to a finish that can be very rich and shiny. Its finish is similar to an enameled part. Metal parts arrive at a plant and are hung by an operator on a traveling conveyor which will transport the parts along the entire cleaning and painting operation. The parts need to be steam cleaned first in order to insure that the parts' surfaces are clean of any grease, dust or dirt and thereby assuring that the powder coat will adhere properly. Once the parts are taken through the steam cleaner they are taken to the painting booth. In the paint booth is an operator who paints the hanging parts with the use of a spray gun. The paint booth gets its powder from a cyclone which is attached to the paint booth. The cyclone collects the excess powder and moves it around and assures that the powder will not settle and thereby clump together. If the powder sticks together into clumps then it won't flow correctly and the operator will not be able to paint well. Clumping of the powder is avoided by the use of the cyclone but is mainly caused by high temperatures in the plant. High temperatures lead to higher humidity levels which put moisture into the powder and facilitate the clumping.

Once the parts are painted they are taken to the curing oven where they are dried. It was these two ovens, the steam cleaning oven and the curing oven, that we recommended to the two companies that they insulate. The energy that we said they would save and the consequent cost savings from those energy savings is shown as follows:

Anticipated Savings

The annual energy savings, ES, resulting from covering the oven for one of the companies was estimated as follows:

ES = HL x DELTA T x A x HP x F

where

HL = 2.3 Btu/h·ft^2 °F, from

NIST Handbook

DELTA T = measured temperature difference between the oven surfaces and the ambient air temperature,

(top surfaces are generally 10° warmer) which are:

(1) steam cleaner: 110 - 75 = 35° F
Top: 120 - 75 = 45° F
(2) dryer: 120 - 75 = 45° F
Top: 130 - 75 = 55° F
(1) curer: 145 - 75 = 70° F
Top: 155 - 75 = 80° F

A = exposed side surface area of the ovens, ft^2

HP = annual hours during which oven are operating, h/yr

F = fractional reduction in heat loss due to exposed side surfaces, no units, = 0.75 (from manufacturer's data)

C = Conversion Factor, 0.000001

therefore for the side surfaces,

$ES_{steam\ cleaner}$ = 2.3 x 35 x 1,200 x 4,160 x 0.75 x 0.000001
ES = 301.4 MMBtu /yr
ES_{dryer} = 2.3 x 45 x 1,200 x 4,160 x 0.75 x 0.000001
ES = 387.5 MMBtu /yr
ES_{curer} = 2.3 x 70 x 1,620 x 4,160 x 0.75 x 0.000001
ES = 813.8 MMBtu /yr

and for the top surfaces,

$ES_{steam\ cleaner}$ = 2.3 x 45 x 230 x 4,160 x 0.75 x 0.000001
ES = 74.3 MMBtu /yr
ES_{dryer} = 2.3 x 55 x 230 x 4,160 x 0.75 x 0.000001
ES = 90.8 MMBtu /yr
ES_{curer} = 2.3 x 80 x 700 x 4,160 x 0.75 x 0.000001

ES = 401.9 MMBtu /yr

Total ES for all surfaces of all ovens is calculated as follows:

Total ES = 301.4 + 387.5 + 813.8 + 74.3 + 90.8 + 401.9 (all units are MMBtu)

Total ES = 2,069.7 MMBtu /yr

Therefore, the annual cost savings which we calculated for this plant for insulating the ovens for this plant, CS, with natural gas costs for this particular company of $ 8.13 /MMBtu are estimated as:

CS = 2,069.7 MMBtu /yr x $8.13 /MMBtu
CS = $ 16,827 /yr

The other company for which we recommended the insulation, we estimated that they would annually save 310.3 MMBtu /yr and consequently $ 1,474 /yr.

Both companies then proceeded to follow our recommendations and insulate their ovens. One of the companies had an implementation which consisted only of the materials. Thereby, their implementation cost was less than half of what we had told them that it would cost. By doing the work themselves the company was able to avoid the labor costs of having a contractor come in to the plant to do the work. Also, the work was done over a weekend so there was no loss of production time due installation of the insulation. The tools which were needed to install the insulation was rented from a local hardware store.

Quantifying the results of our recommendation has been difficult for both companies due to the fact that business has improved for both. Therefore, actually quantifying the exact amounts of energy that have been saved has been difficult. However, we have been able find other results from our recommendations.

Results

First and foremost has been the change in environment for the employees. The employees in the plant now feel more comfortable and can work better. Through many interviews with employees in both plants we were told that the heat during the summer months has been greatly reduced. Plant officials at one of the companies told us that twice during the summer previous to the installation of the insulation the plant had to be shut down in order to send the workers home due to the high heat during the heat waves. The avoidance of the loss of production according to management at the plant paid off the cost of the insulation. Workers at the end of the painting process where they remove the parts which are hanging from the hooks were the ones who felt most comfortable. The fact that they could now feel more comfortable allowed them to stay better concentrated on their work and to better inspect the work that was being produced before it went out of the plant. This then led to fewer parts returning to the plant and a higher quality of work leaving the plant.

Another interesting result was the fact that plant officials could now more easily work in the environment of the plant due to the reduced heat during the summertime. Before the insulation and when the heat in the plant was very high the officials in the plant tended to stay in the offices and rarely went out to inspect the product before it went out. Now that the officials came out onto the floor more frequently the employees tend to be more careful with the manufacturing process and take better care of the powder, in terms in recycling the excess powder and better cleaning out the machines between color changes. Workers now see that plant officials are better inspecting the work that leaves the plant. This in turn leads to more productive work from the workers and as they feel that they are being more closely supervised.

The amount of material that was lost due to the high temperatures was also eliminated. The powder that is bought arrives at the plant in large bags. The powder in the bags tends to clump up due to the high heat in the building. If the powder in the bags got to the point that it was too clumped then that bag of powder was lost. At one of the companies, the amount of storage room in the plant was so limited that the powder was stored in very close proximity to the oven. Before the insulation some of that powder was lost. After the insulation the loss of powder was practically eliminated.

The insulation also led to the fact that the ovens could be more closely monitored and that their respective temperatures could be kept more precise. This was due to the fact that now that the temperature of the oven is now not as dependant on the ambient temperature. This then led to not only less gas consumption but more fine tuning with regards to the speed at which the parts were going through the ovens. By having better control of the temperature the company could then focus on passing the parts through the ovens faster and find ways to paint the parts at a higher rate.

Conclusion

The results that we have seen from these two powder coating companies have shown us that the savings that came from a recommendation which at first was strictly based on the amount of energy that was to be saved came not from there. The two companies experienced more savings from the increase in productivity issues: more worker comfort, less material loss due to the high heat in the plant, a higher willingness by plant officials to go out on to the plant and better inspect the painted parts before they left the plant, and the necessary control over their equipment to then focus on increasing their efficiency in other areas.

Chapter 9— Cooling Tower Fan Control for Energy Efficiency

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Abstract

The paper evaluates the economics of alternative cooling tower capacity control methods. Annual fan electrical energy requirements are calculated for towers with single-speed, two-speed, and variable-speed fans. Fan energy requirements are determined for counter-flow and cross-flow towers designed for low initial cost and for energy efficiency. Effectiveness-NTU equations are solved to predict cooling tower performance with the fan running at various speeds. Natural convection, which determines the cooling capacity when the fan is off, is accounted for using a mean enthalpy difference. Ambient conditions are simulated using typical meteorological year data for five locations. The results show that potential savings are not strongly dependent on the approach temperature, but are dependent on the range in colder climates. The potential for saving is greatest for cooling towers designed for low initial cost, and is generally higher in locations where the wet bulb temperature remains relatively constant throughout the year. Two-speed fans that can run at half speed are generally more suitable for low cost cooling towers. Two-speed fans that can run at 2/3 speed are better for towers designed for energy efficiency and are generally better when the range exceeds 10 F.

Introduction

A cooling tower in a manufacturing plant may be required to cool a constant flow of water to a prescribed constant outlet temperature throughout the year. In some cases the water inlet temperature may also be constant, but it is typically higher in the summer than in the winter. In HVAC applications it is desirable to cool a flow of water to the lowest possible temperature for given ambient conditions, as long as the water temperature remains above some minimum value. A cooling tower must be selected that is large enough to satisfy the load in the summer when the ambient wet bulb temperature is at its highest value. Capacity control is required to prevent the tower from cooling the water below the prescribed outlet temperature when the load or wet bulb temperature is low.

Capacity control is usually accomplished by changing the air flow[1]. Fan cycling is a common method for controlling the capacity of small and medium sized towers. Some units are equipped with two-speed fans. Modulating dampers, variable speed fan motors, and variable pitch propeller fans are additional options.

Capacity control of cooling towers is an important consideration for effective energy management in manufacturing plants. It is well known that towers with variable speed fan motors consume significantly less electricity over the course of a year than towers with single speed fans. However, because of the high initial cost of the variable speed drive, the overall economics may be unfavorable. The payback period depends on the design of the cooling tower, the load and the operating hours, and the climatic conditions.

The objective of this work is to identify the conditions that make alternative capacity control methods for cooling towers cost effective. We will evaluate the annual fan electrical energy requirements for several types of cooling towers operating under various loads. The effects of range and approach temperatures will be established from parametric analysis. Case studies will evaluate the potential savings depending on the operating schedule and the climatic conditions. Ambient conditions for five locations are simulated using typical meteorological year data [2].

Cooling Tower Performance

The size of a cooling tower is typically expressed in nominal tons. This rating specifies the amount of water that can be cooled from 95 F to 85 F at a wet bulb temperature of 78 F. A cooling tower that can cool 3 gpm of water at these conditions is said to have a capacity of 1 nominal ton, or 15,000 BTU/hr, corresponding approximately[3] to the heat that would be rejected from a 1-ton refrigeration system. The change in the temperature of the water in a cooling tower is called the range, and the difference between the water outlet temperature and the ambient wet bulb temperature is called the approach. At nominal conditions, the range is 10 F and the approach is 7 F. The range and approach change as the ambient wet bulb temperature and the air flow change. The values of range and approach given in this paper for different applications refer to design conditions.

The air flow is not specified at nominal conditions. Typical values from manufacturer literature[4,6] range from about 200 scfm/ton to about 300 scfm/ton. Towers designed for energy efficiency typically have small fans and large heat transfer surfaces. Towers designed for low initial cost usually have small heat transfer surfaces and large fans. Typical values of fan horsepower for induced draft towers range from about 0.04 hp/ton to about 0.08 hp/ton. Forced draft towers with exhaust ducts for indoor use[7] may require a fan horsepower of 0.18 hp/ton.

A cooling tower with a capacity of 100 nominal tons would have a water flow of 300 gpm when tested at standard conditions. Typically[4] this same tower would be capable of operating efficiently with water flows as low as 150 gpm, or as high as 600 gpm. The limits of the acceptable water flow depend on the design of the water distribution system[5]. If the water flow is too low, the distribution system cannot provide a uniform coverage of water on the heat transfer surfaces. If the flow is too high, the hot water basins overflow, or the spray nozzles do not operate correctly.

The actual capacity of a cooling tower is dependent on the operating conditions. The 100 ton tower designed for a flow of 300 gpm at standard conditions might be used in a manufacturing plant in which a flow of 215 gpm must be cooled from 92 F to 82 F at a wet bulb temperature of 78 F. In this case the approach is only 4 F, and the rate of heat transfer between air and water is reduced. The actual capacity of the 100 ton tower is about 72 tons at these conditions. Equations for predicting cooling tower performance at off-design conditions are developed below.

In a cooling tower, heat and mass is transferred from water to air. A cooling tower with an effectiveness of 100% would exhaust saturated air from the tower at the temperature of the entering water. In actual towers, the air leaves at a temperature less than the entering water temperature and a relative humidity less than 100% because the air flow is too high and the heat transfer area is too small. Effectiveness, ε_a, is defined[8] in terms of the enthalpy of moist air as follows:

$$\varepsilon_a = (ha_o - ha_i) / (hsw_i - ha_i) \qquad (1)$$

In Eqn. (1), ha_i and ha_o are the enthalpies of the air into and out of the tower, and hsw_i is the enthalpy of air saturated with water at the inlet water temperature.

Effectiveness is a dimensionless variable which can be determined from knowledge of only two additional dimensionless variables, m* and NTU.

$$m^* = (m_a C_s) / (m_w Cp_w) \qquad (2)$$

$$NTU = (h_c A) / (m_a C_s) \qquad (3)$$

The dimensionless variable, m*, can be determined from the known air flow and known water flow. In Eqn. (2), Cp_w is the specific heat of water, and C_s is the effective specific heat of moist air defined by:

$$C_s = (hsw_i - hsw_o) / (Tw_i - Tw_o) \qquad (4)$$

From Eqn. (3), NTU depends on the heat transfer coefficient, h_c, the heat transfer surface area, A, the air flow rate, m_a, and the specific heat, C_s. Energy efficient cooling towers with large heat transfer surfaces and small fans might have nominal NTU values of 4.5 or more. Low initial cost towers with small heat transfer surfaces and large fans might have nominal NTU values of 1.5 or less.

Since h_c depends on the air flow rate and the water flow rate, the NTU value of a tower operating at off-design conditions will not be the same as the NTU value at design conditions. An empirical equation[9] useful for predicting NTU at off-design conditions is:

$$NTU = a (m_a)^m (m_w)^n \qquad (5)$$

The constants, a, m, and n, in Eqn. (5) are to be determined from published performance data. In some cases, this data is unavailable. A less accurate formula[10] for predicting the performance of cooling towers for which limited published data is available is:

$$NTU = c\,(m_w / m_a)^n \qquad (6)$$

Typical values[10] of n are in the range $0.4 < n < 0.6$. If a typical value of n is assumed, the value of c can be determined from m_a and m_w at nominal design conditions. Once c and n are known for a particular cooling tower, the cooling tower performance can be predicted at any operating condition given the water inlet temperature, Tw_i, the ambient wet bulb temperature, Twb, and the flow rates, m_a and m_w.

Values of c and n were determined from performance data provided by several manufacturers. Calculations for a wide range of operating conditions showed that the performance characteristics of large induced draft single cell towers with axial fans could be predicted accurately with c = 2.66 and n = 0.634. These towers were all from the same manufacturer, and had nominal capacities in the range 200 tons to 1000 tons. The performance of a 16 ton tower produced by a different manufacturer could be predicted accurately with c = 1.33 and n = 0.4. The low value of c for this tower indicates that the heat transfer area is small for the air flow. The performance characteristics of a 68 ton induced draft tower with a large heat transfer surface could be predicted with c = 3.0 and n = 0.4.

For counter-flow cooling towers, the relationship between $_a$, m*, and NTU is[8]:

$$\varepsilon_a = (1 - \exp(NTU(m^*-1))/(1 - m^*\exp(NTU(m^*-1)) \qquad (7)$$

The temperature of the water leaving the tower can be determined from an energy balance. In English units, Cp_w = 1Btu/lb/F, and the resulting equation is:

$$Tw_o = 32 + (m_{wi}(Tw_i - 32) - m_a(ha_o - ha_i))/m_{wo} \qquad (8)$$

The exit water flow, m_{wo}, in Eqn. (8) can be determined from the humidity ratio, W, of the air entering and leaving the cooling tower.

$$m_{wo} = m_{wi} - m_a\,(W_o - W_i) \qquad (9)$$

Braun et al. (1989) recommend a procedure for calculating the humidity of the air leaving the tower, W_o. This procedure was followed in our calculations. However, as an approximation it can be assumed that the air leaving the cooling tower is saturated. The water outlet temperature calculated from Eqn. (8) is not sensitive to small errors in the value of W_o.

The equations listed above may be solved to determine the water outlet temperature when the fan is running and the air flow is known. When the fan is off, air continues to flow through the tower because of natural convection. The cooling capacity of the tower due to natural convection must be estimated to determine the time that the fan remains off in capacity control options that involve fan cycling. In this work, the volumetric air flow due to natural convection, cfm_0, is calculated from the following equation:

$$cfm_0 = C_0\,(cfm)\,(\Delta h / \Delta h_n)^{0.20} \qquad (10)$$

where C_0 is a constant, cfm is the capacity of the fan, and h and h_n are mean enthalpy differences. At the top of the tower, $h_o = hsw_i - ha_o$. At the bottom, $h_i = hsw_o - ha_i$. The mean enthalpy difference is:

$$\Delta h = (\Delta h_o - \Delta h_i) / \log(\Delta h_o / \Delta h_i) \qquad (11)$$

In Eqn. (10), h is the enthalpy difference with the fan off and h_n is the enthalpy difference for the case when the fan is running with Tw_i = 95 F, Tw_o = 85 F, and Twb = 78F. The constant, C_0, is the ratio of the air flow with natural convection to the air flow with the fan running. It must be determined for each cooling tower. Towers with large heat transfer areas and small fans would have relatively high values of C_0.

Equation (6) assumes forced convection, and does not apply when the fan is off. For natural convection, the heat transfer coefficient should increase in proportion to the air flow so that NTU remains constant.

Predicted Performance

Figure 1 illustrates how cooling tower performance is determined. To construct this figure, $_a$ is calculated from Eqn. (7) for given values of m_a/m_w and NTU. The exhaust air enthalpy, ha_o, determined from Eqn (1) is then substituted into Eqn. (8). The water outlet temperature, Tw_o, is plotted as a dimensionless ratio, $_w$. The curve for $m_a/m_w = 0.6$ is typical of well-designed cooling towers at nominal conditions. The curve for $m_a/m_w = 0.30$ represents a tower operating with high water flow, or with the fan at half speed. The lower curves represent a tower operating with the fan off.

The dashed lines in Figure 1 are determined from Eqn. (6). The dashed curve with c = 1and n = 0.4 represents a tower designed for low initial cost. The dashed curve with c = 3 represents a tower designed for efficiency. The intersections of the dashed curves and the solid curves determine the water outlet temperature. For example, with c = 3 and $m_a/m_w = 0.6$, the point of intersection gives $_w$ =

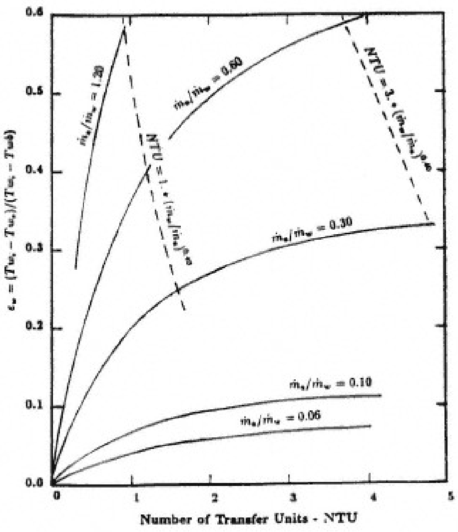

Figure 1
Cooling Tower Performance Calculations

0.585. For Tw_i = 95 F and Twb = 78 F, the water outlet temperature is Tw_o = 85 F.

If this tower operates with the fan at half speed, the point of intersection at m_a/m_w = 0.30 gives $_w$ = 0.33. In this case the calculated water outlet temperature is Tw_o = 89.4 F.

When the fan operates at half speed, the range is reduced from 10 F to 5.6 F. Thus, the capacity of the tower operating with the fan at half speed is 56% of the rated capacity. Calculations for the tower designed for low initial cost, c = 1, show that the capacity with the fan at half speed is 68% of the rated capacity.

Figure 2 compares predicted and published[5] data for a tower operating with a fixed load. The range is 10 F. When the fan is on, the performance data is predicted accurately with c = 3.0, n = 0.4, and m_a/m_w = 0.6. When the fan is off, the air flow is calculated from Eqn. (10) with C_0 = 0.134.

For a wet bulb temperature of 78 F and a water inlet temperature of 95 F, the tower of Figure 2 has a capacity with natural convection that is about 23% of the rated capacity with the fan on. Other manufacturers[4] indicate that the capacity with natural convection is about 10% of the rated capacity. For these towers, the appropriate value is C_0 = 0.056.

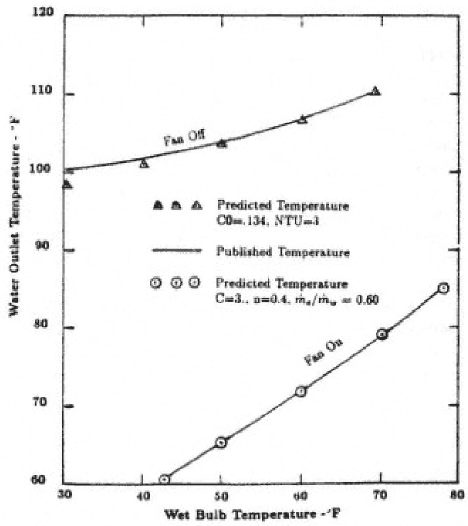

Figure 2
Cooling Tower Performance Predictions

For cross-flow towers, the relationship[11] between effectiveness, m*, and NTU is:

$$\epsilon_a = (1 - \exp(m^*(\exp(-NTU) - 1))/m^* \qquad (12)$$

Cross-flow towers cannot achieve a nominal approach temperature of 7 F for $m_a/m_w < 0.8$. At nominal conditions, most cross flow towers operate in the range $0.8 < m_a/m_w < 0.9$. A typical value of c in Eqn. (6) is in the range $2.5 < c < 5.5$. Although the air flow is relatively high in these towers, the required fan power is still in the range 0.04 hp/ton to 0.08 hp/ton. There is less fluid friction in cross-flow towers, so higher air flow can be maintained with the same fan power needed by a counter flow tower. For c = 2.5, a cross-flow tower will maintain 65% of its nominal capacity when the fan runs at half speed.

Capacity Control

For towers with single-speed fans, the temperature of the cold water basin is maintained within a prescribed dead band by cycling the fan on and off. The basin and the dead band must be large enough to prevent the fan motor from overheating. Large fan motors should not be started more than once or twice in an hour. Fans with two-speed motors can provide more precise capacity control, and also have potential for saving electricity.

Figure 3 shows how fan power changes with ambient wet bulb temperature for a counter-flow tower that operates with a constant load. This is a hypothetical case that neglects natural convection when the fan is off. The upper curve is for on-off fan cycling. When Twb = 52 F, the fan operates one half of the time, and the average power requirement is one half of the rated fan power. The lower curve is for a two-speed fan motor. When Twb = 58 F, the two-speed motor operates at half speed and uses one-eighth of the rated fan power. When Twb is above 58 F the motor cycles between full speed and half speed. When Twb is below 58 F, the motor cycles between half speed and off. The electrical savings made possible by the two-speed motor can be determined from the difference between the two curves in Fig. 3.

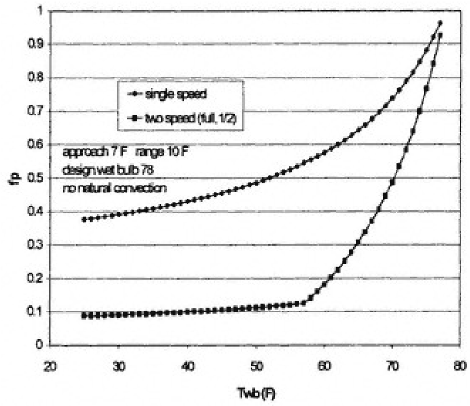

Figure 3
Capacity Control With No Free Convection

Natural convection is accounted for in Fig. 4. With on-off cycling at Twb = 52 F, the average fan power has now dropped to about 33%. Natural convection helps when the fan is off. Thus, it helps the tower with on-off cycling over the entire temperature range. It has no effect on the two-speed fan until Twb drops below 58 F. At lower temperatures, the average power of the two-speed motor is low, and the potential for savings is relatively small. Thus, the overall effect of natural convection is to reduce the advantage of the two-speed fan. This is apparent from the smaller area between the curves of Fig. 4.

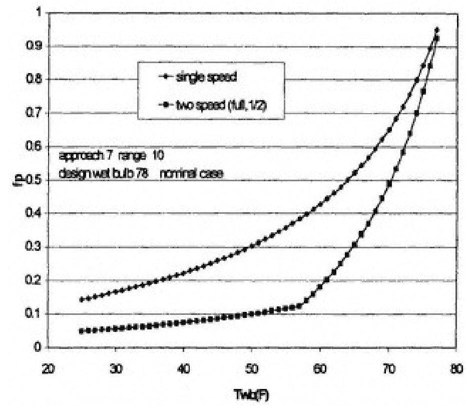

Figure 4
The Effect of Free Convection

Figure 5 compares the fan motor power requirements for a counter-flow cooling tower operating with a constant load. For this case, the motor that operates at 2/3 rated speed is better at ambient wet bulb temperatures above 62 F while the motor that operates at half speed is better at ambient wet bulb temperatures below 62 F.

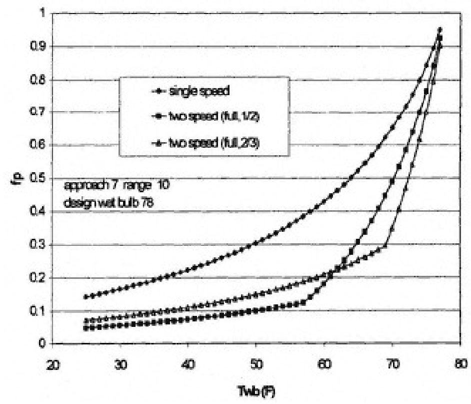

Figure 5
Fan-Speed Options, Range = 10 F

Figure 6 compares several control alternatives for a case when the range is relatively large. The hot water enters the tower at 122 F throughout the year, and the fans cycle to maintain the water outlet temperature at 82 F. The 2/3-speed motor is better than the half-speed motor for wet bulb temperatures above about 24 F in this application, and is almost as good as the motor with a variable speed drive or an adjustable propeller. When the range is large, the mean temperature difference between the water and the air is not strongly dependent on the ambient conditions. The heat transfer rate at moderate ambient conditions is not much greater than the rate at hot conditions. In Fig. 6 the single speed motor still runs half of the time when the wet bulb temperature is 40 F. As the range increases, there is more opportunity for energy savings.

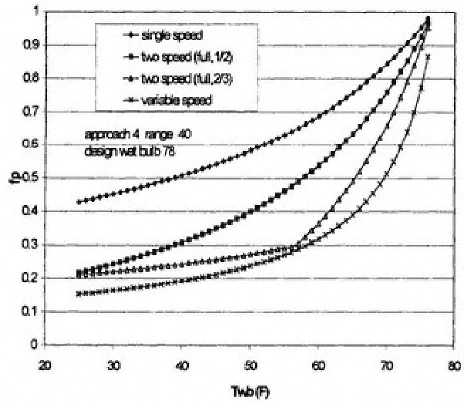

Figure 6
Fan-Speed Options, Range = 40 F

Case Studies

The effect of range on annual fan energy requirements for a counter-flow tower is shown in Fig. 7. The results are for a system that returns cold water at 85 F throughout the year. The entering hot water temperature is also constant, and depends on the range. The results are for a counterflow cooling tower designed for efficiency, c = 3, n = 0.4, C_0 = 0.134, operating in moderate climatic conditions. The fan power at nominal design conditions is 0.0455 hp per nominal ton, which is typical for this type of tower. The electric motor efficiency is taken to be 0.90. The figure shows that the fan electric energy consumption increases with range. This is because the fan remains on for longer periods of time during the winter, as shown in Fig. 6. The potential savings, which depend on the differences between the various curves, are not strongly dependent on range for this climate.

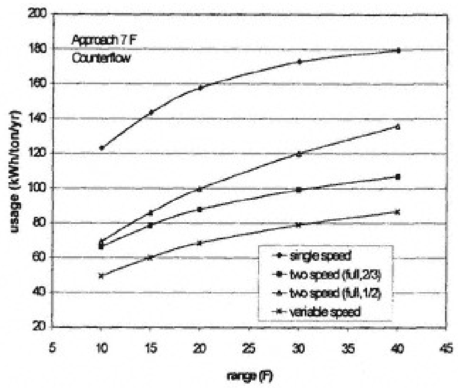

Figure 7
Annual Fan Energy Consumption,
Approach = 7 F, Raleigh, Nc

Table 1 lists the energy requirements for a single-speed fan motor and the annual savings for different capacity control options at several values of range and approach. For this climate, the fan with a variable speed drive would use about half the electricity of a fan that cycles on and off, and the two-speed motor running at 2/3 speed is better than the motor that runs at half-speed. The potential for fan energy savings decreases at approach temperatures above about 12 F, and increases slightly as the range increases. The opportunity for savings is a little higher for counter-flow towers than for cross-flow towers.

Table 2 shows the effects of load variations and tower design variations not considered in Table 1. All of the cases in Table 2 have an approach of 7 F. Cases 1, 2, 5, and 6 have a range of 10 F. The range is modified in Cases 3 and 4 as described. The savings listed are the difference between the electrical energy requirements of a tower operating with on-off fan cycling and a tower operating with a two-speed or variable speed fan. Case 1 is listed for reference purposes. It is a constant load case for an energy efficient tower. Case 2 is for a tower that has half as much air flow due to natural convection. The high potential savings for Case 2 demonstrate the importance of natural convection to energy efficiency.

TABLE 1—FAN ENERGY SAVINGS AT CONSTANT LOAD, RALEIGH, NC

Type	Approach (F)	Range (F)	single speed usage (kWh/ton/yr)	two-speed (2/3) savings (kWh/ton/yr)	two-speed (1/2) savings (kWh/ton/yr)	variable speed savings (kWh/ton/yr)
counter-flow	7	10	123.2	56.9	53.8	73.7
counter-flow	7	15	143.5	65.0	57.5	83.4
counter-flow	7	20	157.6	69.8	57.9	89.1
counter-flow	7	30	172.7	73.7	52.8	93.8
counter-flow	7	40	179.5	72.5	43.4	92.9
counter-flow	4	10	92.9	48.4	51.0	63.1
counter-flow	12	10	155.9	58.7	47.8	76.4
counter-flow	20	10	190.1	49.5	28.1	66.9
cross-flow	7	10	95.0	46.4	45.6	59.07
cross-flow	7	15	110.0	53.6	50.0	67.58
cross-flow	7	20	121.5	58.7	52.4	73.66
cross-flow	7	30	136.5	64.3	53.0	80.52
cross-flow	7	40	143.2	66.2	50.3	82.65

Case 3 applies to a plant in which a manufacturing process has been eliminated so as to reduce the load on the cooling tower by one-third. As a result, the cooling tower is oversized, and the fan cycles on and off even during the hottest day of the summer. The results show that there is less benefit from two-speed or variable speed fans for this case. Interestingly, this operating condition favors a two-speed motor that operates at half of its rated speed.

In all of the cases considered to this point, the load has been held constant throughout the year. However, even with a constant heat load from process equipment, the load on the cooling tower may decrease in the winter due to line losses. To model this type of load, the entering hot water temperature was programmed to change in accordance with the ambient dry bulb temperature, Ta. For Case 4, a linear relationship between Twi and Ta is assumed. The load is reduced by one-half on the coldest day of the winter.

Case 5 is for a plant that operates one shift, five days per week. The cooling tower is assumed to operate between 7 AM and 5 PM. The results show that the potential energy savings are reduced in proportion to the operating hours. Daytime wet bulb temperatures are higher than average, but this appears to have minimal effect.

Case 6 applies to a tower designed for low initial cost. The fan power for this case is 0.0625 hp per nominal ton, and c = 1.33. Opportunities for energy savings increase significantly for this type of tower compared to the more energy efficient tower.

The impact of climate on cooling tower fan energy usage and potential energy savings is estimated using typical meteorological year data for five

TABLE 2—FAN ENERGY SAVINGS FOR COUNTERFLOW TOWERS, RALEIGH, NC

Case	single speed usage (kWh/ton/yr)	two-speed (2/3) savings (kWh/ton/yr)	two-speed (1/2) savings (kWh/ton/yr)	variable speed savings (kWh/ton/yr)
1	123.2	56.9	53.8	73.7
2	150.7	76.6	79.0	101.2
3	70.8	36.6	42.0	48.8
4	93.3	44.2	43.0	57.1
5	39.0	17.1	15.8	22.3
6	202.9	118.0	135.2	159.9

TABLE 3—FAN ENERGY SAVINGS FOR VARIOUS LOCATIONS

City	Design Wet Bulb (F)	Approach (F)	Range (F)	single speed usage (kWh/ton/yr)	two-speed (2/3) savings (kWh/ton/yr)	two-speed (1/2) savings (kWh/ton/yr)	variable speed savings (kWh/ton/yr)
Raleigh	78	7	10	123.2	56.9	53.8	73.7
	78	7	40	179.5	72.5	43.4	92.9
	78	12	10	155.9	58.7	47.8	76.4
Columbus	75	7	10	111.1	50.8	52.8	67.4
	75	7	40	172.3	75.6	50.1	93.2
	75	12	10	145.1	58.2	51.5	75.0
Denver	63	7	10	134.0	60.2	60.1	78.9
	63	7	40	194.8	84.1	59.6	104.9
	63	12	10	165.7	64.3	57.0	84.1
Houston	79	7	10	160.5	59.9	50.8	80.3
	79	7	40	204.4	60.9	32.4	84.6
	79	12	10	189.1	53.2	38.0	73.0
Los Angeles	69	7	10	168.4	79.4	68.6	99.6
	69	7	40	219.1	84.8	42.7	109.1
	69	12	10	196.6	73.1	46.1	91.1

locations listed in Table 3. The fan energy savings in this table are for a tower characterized by Eqn. (6) with c = 3 and n = 0.40. The heat transfer by natural convection is calculated from Eqn. (10), assuming $C_0 = 0.134$. The fan power is 0.0455 hp/ton. In each case, the load is held constant throughout the year. It is assumed that the tower is correctly sized for the load so that the fan does not cycle at design point conditions. The design point wet bulb temperature for each city is listed in the table.

The energy savings in Table 3 are for a counter-flow tower that operates with a steady load for 8760 hours per year. As an approximation, the savings for towers that operate fewer hours can be reduced in proportion to the operating hours. Fan motors that operate at 2/3 speed are more energy efficient than motors that operate at half speed for these towers.

For variable speed motors and for motors that run at 2/3 speed, the potential savings are insensitive to the approach temperature in every location. However, it is to be expected that the savings would decrease if the approach were to exceed 12 F. In Los Angeles and Houston, the potential savings are insensitive to range. In Raleigh, and to a larger extent, in Columbus and Denver, the savings increase with range.

Figure 8 is a plot of potential fan energy savings at nominal conditions versus location. The cities are arranged in order of increasing design wet bulb temperature. This plot shows that the type of two-speed fan with the most energy savings changes depending on location, but is apparently unrelated to the design wet bulb temperature. The variation of savings depending on climate is most likely explained by the temperature swings through the year. The more moderate climate would require the fan to operate more hours close to design wet bulb temperature, and therefore present a better opportunity for energy savings. In Columbus, Ohio the fan energy requirement for a range of 10 F is small throughout the fall, winter, and spring. Therefore, there is little opportunity for energy savings.

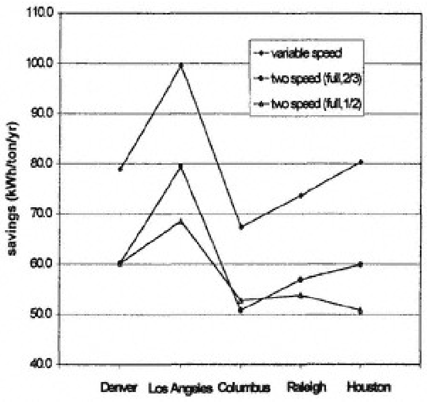

Figure 8
Fan Energy Savings, Range =10f,
Approach =7f, c=3, n=0.4, C_o=0.134

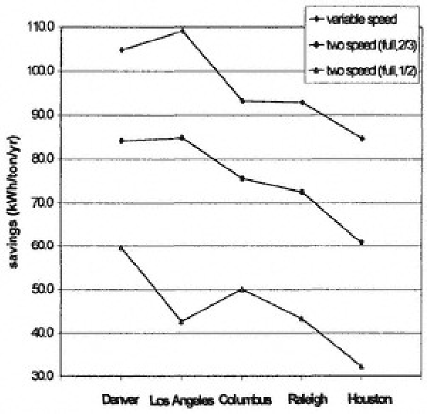

Figure 9
Fan Energy Savings, Range =40f,
Approach =7f, c=3, n=0.4, C_o=0.134

Figure 9 shows the potential savings for alternative capacity control methods when the range is 40 F. The fan motors that operate at 2/3 speed are more energy efficient than the motors that operate at one-half speed for each location. The advantage for the 2/3 speed motor over the one-half speed motor increases as the range increases.

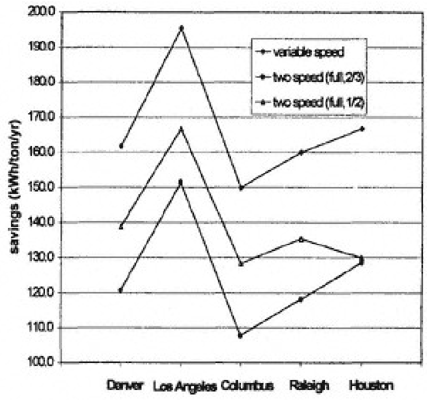

Figure 10
Fan Energy Savings, Range =10f,
Approach =7f, c=1.33, n=0.4, C_o=0.056

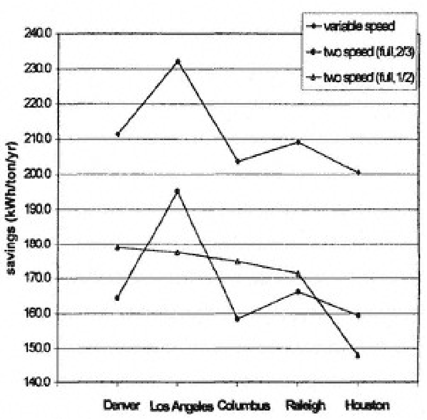

Figure 11
Fan Energy Savings, Range =40f,
Approach =7f, c=1.33, n=0.4, C_o=0.056

Figure 10 shows that the one-half speed fan is better than the 2/3 speed fan for cooling towers designed for low initial costs with moderate loads (range = 10 F). However, as the range increases, the 2/3 speed fan becomes more advantageous relative to the one-half speed fan. Figure 11 shows that the best choice for towers designed for low initial cost is dependent on location for high loads (range = 40 F).

The savings in Table 3 are in the range of 50 to 100 kWh/ton/yr. For a fan power of 0.0455 hp/ton, a small tower with a 1 hp fan would have a nominal capacity of about 22 tons. Thus, the electrical energy savings for the small tower would be in the range of 1100 to 2200 kWh/yr. If electricity cost $.05/kWh, the dollar savings are in the range of $55/yr to $110/yr. The dollar savings for a 1650 ton tower with a 75 hp motor are in the range of $4100/yr to $8200/yr.

The cost for installing two-speed motors or variable speed drives on cooling towers depends somewhat on the cooling tower capacity. A single-speed 1hp motor for a small tower might cost $150/hp, while a 75 hp motor for a large tower might cost only $50/hp. Two-speed motors can be expected to cost twice as much. Variable speed drives will probably cost $800/hp for small motors and $200/hp for large motors.

Thus, the cost to replace a 1 hp single-speed fan motor with a two-speed motor would probably be in the range of $500. The payback period is 5 to 10 years. The cost to replace the single-speed 75 hp motor is probably in the range of $7500, and the payback period is in the range of 1 to 2 years. For smaller towers with belt driven fans, the most cost effective solution is to install a second motor to drive the fan at slower speed. For example, a tower with a 25 hp motor would require a 7.5 hp motor to drive the fan at 2/3 speed. The economics will be better in locations where the cost of electricity is higher than $.05/kWh, and for towers with small heat transfer areas for which the nominal fan power would be considerably greater than 0.0455 hp/ton. The economics will be worse for plants that operate one shift and in plants where the tower is oversized.

Summary

Calculations based on typical meteorological year data show that fan energy savings for alternative capacity control methods do not depend strongly on the approach temperature. In colder climates, the potential savings increase by 25% to 40% when the range increases from 10 F to 40 F. The potential savings are strongly dependent on the amount of natural convection that occurs when the fan is off. The greatest potential for savings occurs in towers designed for low cost. The fan power for such a tower would be in the range of 0.08 hp/nominal-ton, and the air flow due to natural convection would be small in comparison to the fan capacity. A tower with a fan power of 0.04 hp/ton benefits more from natural convection, and has less potential for energy savings. There is less potential for savings in cross-flow towers than in counter-flow towers. Also, the potential savings are lower when the cooling tower is oversized, or when the plant operates one shift instead of three shifts.

Two-speed fans that operate at 1/2 of the rated speed are suitable for low cost towers at moderate loads. Two-speed fans that operate at 2/3 of the rated speed are a better choice for energy efficient towers in most locations, especially at higher operating loads. At nominal conditions of approach = 7 F and range = 10 F, the potential savings are highest in locations where the wet bulb temperature remains close to the design value through much of the year. The potential energy savings at nominal conditions in Los Angeles are about 50% higher than the savings in Columbus, Ohio.

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Chapter 10— Applications of an Integrated Manufacturing Planning and Control System for Facilities in a Deregulated Energy Market

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Abstract

An integrated Manufacturing Planning and Control (MPC) system that can help facilities reduce their costs in the deregulated energy market and in a stricter environmental scenario is presented in this paper. The functions of this system are to quantify the cost of energy usage and waste disposal that would result from a given production schedule and help decide how to reduce these costs. The main focus of this paper is in two functions of the energy module that would apply to facilities under a Real-Time Pricing (RTP) tariff: (a) management of energy suppliers and (b) modifications to the production schedule. The final section of the paper presents an overview of the results obtained from several solution methods that were studied and developed for these functions of the integrated MPC.

Background

The paper is organized as follows. After explaining the role of traditional MPC systems in a manufacturing environment, the proposed integrated MPC system is presented, followed by a description of its operation and possible applications.

Most manufacturing processes require energy (such as electricity and natural gas) and produce waste streams (such as scrap metal, solvents and air emissions). Until a few years ago, the energy cost and disposal cost of waste streams were not usually included in the strategic or the day-to-day production decisions. But the increasing energy costs, stricter environmental regulations and stronger competition have led to the development of energy and waste management practices to help managers reduce these costs. These practices are far from being completely integrated into production scheduling decisions in typical manufacturing systems.

Figure 1 shows how industrial facilities use the manufacturing planning and control system (MPC) to obtain information about the flow of materials, use of resources (people and machines), suppliers and customers (Vollman et. al., 1992). The MPC system first determines the quantity and type of parts needed to satisfy customer orders (the master production schedule or MPS). It then verifies machine and labor availability and inventory levels (and will announce the need to issue purchase orders or schedule overtime if not enough resources are available) to help the scheduler develop a "production schedule". This schedule is a detailed plan of machine loading (with sequence and processing times for each operation) and the materials needed for the MPS. Production schedules are usually developed to improve a particular performance measure (such as total tardiness, number of tardy jobs, machine loading, etc.). This is an iterative process because manufacturing environments are complex and unpredictable due to unexpected events such as order changes, machine breakdowns, etc. (Park et. al., 1996).

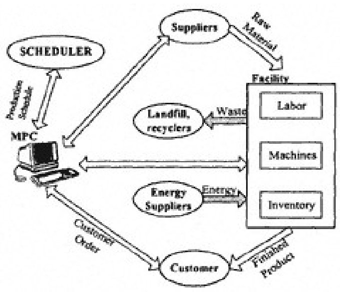

Figure 1
Interactions of the Manufacturing
Planning and Control (MPC) System

The execution of the production schedule greatly determines the energy usage of the facility: the total energy usage is composed by the energy used by the manufacturing system (executing the production schedule) and by "ancillary systems" (such as lighting, air conditioning, air compressors, etc.). In the case of waste, the execution of the production schedule is the main determinant in the amount and types of waste streams generated by industrial facilities.

New Opportunities

Traditional energy conservation opportunities usually include measures such as improving the efficiency of equipment (for example, energy-efficient electric motors or efficient lamps), shedding loads (for example, turning off some air conditioning units during peak hours), switching to alternative fuels (such as natural gas) or generating electricity onsite. The deregulation of the electric market at the retail level will bring customers new opportunities to reduce their operating cost. Many states are presently promoting programs that allow customers to obtain electricity from other suppliers than their host utility and in innovative rates such as "Real-Time Pricing" (RTP) tariffs. The natural gas market has been deregulated and now some customers can purchase natural gas in the spot market.

With deregulation, cheap energy will no longer depend on the host utility, but on the selection of suppliers that will provide cheap, reliable and good-quality energy and the customer's ability to manipulate its energy load profile to take advantage of the seasonal/hourly price differences.

In the environmental area, some important changes that are making customers change their waste management practices are the increasing disposal costs, the issuance of stricter environmental regulations and requirements of a "green" image to gain access to new markets (e.g., ISO 14000 certification).

An Integrated MPC System

The proposed integrated MPC system (Figure 2) uses an "energy module" and a "waste module" to help the scheduler quantify and reduce the total cost of energy usage and waste disposal of the facility.

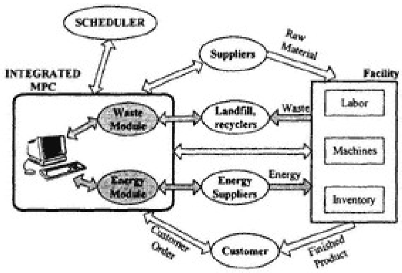

Figure 2
Proposed Integrated MPC System

This integration will help improve profitability by capitalizing from new opportunities in the future energy and environmental scenario. With this integration, managing an industrial facility would change in several ways:

Strategic planning. Strategic decisions would be made by also considering their energy usage and waste disposal costs. This could be done with what-if scenarios based on historical production data and historical (or forecasted) energy cost and waste disposal costs. The integrated MPC system can be used to evaluate the following:

— *Plant expansions*

— *New energy suppliers*

— *Financial instruments to hedge risk from fluctuating energy cost*

— *Economic feasibility of "peak-shaving" equipment*

— *Backup sources and alternative fuel*

Design of industrial processes. The design of industrial processes and the selection of equipment can be improved by considering the energy and waste impacts of different alternatives such as different types of equipment, raw materials and layouts of industrial processes. These comparisons could also be used for benchmarking a plant's processes. In the environmental area, the integrated MPC could also be used to determine the required permits for the waste streams generated by the selected processes (such as the Clean Air Act –CAA- permit for NOx emissions or the National Pollutant Discharge Elimination System—NPDES- permit for discharges on water).

Day-to-day operations. The management of facility operations would also consider its energy costs, waste disposal costs and compliance with the its environmental permits. Some examples are the following:

— *Manage of energy suppliers*

— *Develop recommendations to change the production schedule*

— *Estimate waste disposal costs of a given production schedule*

— *Verify the facility's compliance with its permits and other regulations.*

An interesting and current application of the integrated MPC would be to help customers take advantage of the Real-Time Pricing (RTP) tariff. This type of rate usually consists of the following charges:

A charge based on the customer's historical energy consumption. This historical profile is usually called Customer Baseline Load or CBL.

A charge (or credit) based on the marginal energy usage (with respect to the CBL). The marginal energy usage is usually charged at hourly prices that customers usually receive a day in advance.

The remaining of the paper focuses on the following function of the energy module for facilities under RTP: (a) management of energy suppliers and (b) modifications to the production schedule. The next sections describe the energy and waste modules

"Energy" Module

The energy module would give a facility more flexibility to schedule production by also considering energy costs. The functions of this module could be added to controllers such as those already available in the market.

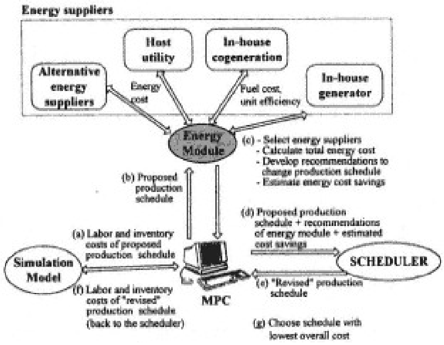

Figure 3
Interactions of the Energy Module with the System

Figure 3 shows the interactions of the energy module with the MPC system. Given a production schedule ("proposed schedule"), a simulation model of the facility would estimate its labor and inventory costs (a). After receiving the proposed schedule (b), the energy module would perform the following tasks (c):

Task #1: Manage electricity suppliers. The energy module would select the energy suppliers and determine the amount of energy to buy from each of them ("power schedule") in order to reduce the total energy cost while satisfying electric power demand constraints. The energy suppliers could include cogeneration units, generator sets, alternative energy suppliers (for example, independent power producers or IPPs, other utilities, etc.) and the host utility. The module would also calculate the savings associated with using the optimal power schedule with respect to obtaining all the power from the host utility (assumed to be the base case). The output from this task would be the "power schedule" and a set of marginal energy costs.

Task #2: Develop recommendations to change the production schedule. Using the set of marginal energy costs from Task #1, the energy module would develop recommendations to change the production schedule to reduce its energy cost while satisfying production goals. For example, this could consist of shifting loads from high-electricity cost periods to low-electricity-cost periods. It is important to note that these changes could increase labor costs (due to overtime) and inventory holding costs (due to the increased inventory levels of work-in-process parts or finished parts to satisfy production requirements). The module will calculate the savings associated with implementing these changes against the facility's default scheduling rule.

The energy module sends the "power schedule" and the recommendations to the MPC system, which in turn transmits them to the scheduler (d). After considering these recommendations, the scheduler will develop a "revised schedule" that satisfies production and deadline constraints (e). Then, the MPC determines inventory levels, employee and machine loading requirements for the "revised schedule" in order to estimate the labor and inventory costs (f). The scheduler will compare the overall cost (which includes energy, labor and inventory costs) of the "revised" and the "proposed" schedules (g) and will choose the best one. This would result in an iterative process, which could be repeated until no appreciable improvement is obtained between successive iterations or until a maximum number of iterations is reached.

Interactions between Tasks #1 and #2

The energy module would develop recommendations to minimize the energy cost of a production schedule in an iterative way. This can be expressed by the next equation:

$$\text{Min (energy cost)}_{\text{production schedule}} = \text{Min [(power schedule cost)}_{\text{production schedule}} + \text{(production schedule cost)}_{\text{power schedule}}] \ldots (1)$$

The two terms in the right-hand side of equation 1 depend on each other. The power schedule cost depends on the electric load profile of the entire facility, which changes with the production schedule. The production schedule cost is a function of the facility's hourly electricity cost, which in turn depends on the power schedule.

Task #1 ("manage electricity suppliers") requires information about the energy suppliers as well as the hourly electric load profile of the facility (from the "energy model"), which depends on the facility's production schedule. The solution of Task #1 determines the optimal "power schedule" for every hour of the planning horizon, which in turn, determines the facility's hourly marginal electricity cost. These costs are required by Task #2 ("determine changes to production schedule") to determine a production schedule that reduces the electricity cost of the facility. A new electric load profile of the facility is obtained from the new production schedule. This new load profile is sent again to Task #1.

Then, the solution of the problem to reduce the electricity cost of the facility results in an iterative procedure in which the solution of each task is used by the other one to obtain a better solution. The scheduler specifies the stopping criteria for the energy module, which would consist on a maximum number of iterations or a minimum percentage of cost reduction between two successive iterations of the energy module. If the stopping criteria are not satisfied, the energy module performs another iteration by sending to the energy model the production schedule determined by the solution of Task #2.

"Waste" Module

Industrial waste streams can be classified according to its physical characteristics (e.g., air emissions, water emissions and solid waste streams) and hazardous constituents. Examples of industrial hazardous wastes are solvents, paint sludge, oil, rinsing water and NOx emissions from boilers. Management of waste streams will become more important as environmental regulations get stricter and factors such as access to international markets and improved environmental image gain more importance (e.g., ISO 14000 certification). The waste module can help industrial facilities reduce the volume and toxicity of their waste streams and their disposal costs.

The operation of the waste module would be similar to that of the energy module. After the MPC system sent the "proposed" production schedule to the waste module, the module would interact with a simulation model of the facility to estimate the amount, type and estimated disposal cost of the generated waste streams. The module would recommend changes to the "proposed schedule" (such as using an alternative machine or process) to reduce the cost (or amount) of the waste streams. The scheduler would modify the proposed schedule according to these recommendations. The process is repeated until an acceptable schedule (from the scheduler's point of view) is obtained.

Summary of Results

Several solution methods were studied and developed for the two functions of the integrated MPC that studied in this paper. The following is an overview of the results of this study:

Task #1: Management of power suppliers. The study found that the solution methods used by electric utilities in the area of power generation and control can be used to solve this task. These solutions methods solve the "unit commitment" and "economic dispatch" problems.

Task #2: Development of recommendations to change the production schedule. Several heuristics were developed and tested against a common scheduling rule used in industry. The following factors were used in the generation of test cases:

— Size of machine shop. This factor defines the number of machines and jobs in the manufacturing environment. It was defined at two levels: {5 jobs-5 machines, 10 jobs-10 machines}.

— Capacity of storage buffers. This factor defines the size of storage buffers located between machines. Studied at two levels: {small, high}.

— Tightness of job deadlines. Studied at two levels: {tight, loose}.

The heuristics used this information to develop production schedules with reduced energy cost. The best heuristics reduced the energy cost of the production schedule by up to 46% when compared to the energy cost of the default scheduling rule. These costs were on the average 8% higher than the minimum (optimum) costs that can be obtained. Average computation time (in a P-133 MHz processor) was 2.2 second/test case.

Acknowledgments

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Chapter 11— Six Technologies to Revolutionize Field Service

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Abstract

This paper describes a number of technology developments that have converged to revolutionize the field service industry. These technologies include the Microsoft CE operating system, handheld PCs (HPCs), wireless data communications, the Internet, thin-client architecture, and commercial software.

Introduction

Successful field service organizations have used technology to streamline office operations, including scheduling and dispatch, accounting functions, and inventory systems. As a result, these companies have seen marked improvements in the efficiency of their home offices. So what happen to radically change perception—and the reality—of field service automation? Simply put, the technology of field service automation finally caught up with the vision. For the first time, companies of virtually any size can successfully implement systems to link the mobile technician with all members of the home office and with customers.

In 1998, a series of major developments in software, handheld computers, wireless communications, the Internet, thin-client architecture and commercial software set the stage for true mobile software solutions to help field service organizations increase productivity, reduce costs, increase profits, and enhance customer service.

Windows CE

In 1998, Microsoft® introduced the Windows® CE operating system, a sophisticated software platform for mobile computing. Created as a series of build blocks, Windows CE offered an industry standard operating system for mobile computing that provided unparalleled flexibility to meet the needs of individuals and companies requiring requiring untethered or wireless computing. Projected to eventually top 120 million licenses, surpassing its Windows desktop platform, Windows CE is designated by Microsoft as its base for mobile computing. So tremendous functionally is available from both Microsoft and software companies that are developing applications to run on CE.

Handheld Computers

A popular device for field service technicians, the handheld PC, a pocket-sized computer, offers a touch screen, instant on, and a full-day battery. Because HPCs do not have a hard drive, which damage easily, they stand up to the real work of the field service technician, a key factor in the success of field service automation. HPCs running Microsoft CE are manufactured by more than a dozen vendors. Most consumer models are priced at under $1200 (ruggedized versions sell for about twice that amount).

The new generation of HPCs offer excellent wireless data communication capabilities, with integrated and external modems, which allow for real-time connectivity between the field and the home office. Note that wireless computing, as opposed to cellular phones, is the sending of data rather than voice.

Wireless Communications

The wireless communications industry has recently matured, providing field service companies with unprecedented business advantages. Wireless coverage in the U.S. has topped 90 percent in the major metropolitan service areas. As a result, technicians are virtually always within range for real-time communications. For the few instances when a technician is out of range, a well-designed mobile application automatically stores, sends, and receives updates upon re-entering a coverage area.

And, the cost of wireless communications is continuing to decline as more providers enter the market. Many carriers now offer flat rate pricing for unlimited wireless data transmissions at $50 to $60 per month. As wireless data exchange with HPCs becomes affordable, field service companies can eliminate many of the costly communications devices currently in use. These devices include two-way radios, cellular phones, and standard and vice pages. Instead companies can communicate almost exclusively using an HPC.

Wireless communications helps keep technicians and dispatchers productive and armed with the most up-to-date information, while eliminating half or more of all calls between dispatch and the technician.

The Internet

Perhaps the most sweeping change in recent commercial history is the impact of the Internet on business computing. International Data Corporation, a research and analysis company, estimates that 320 million people will have access to the Web by 2002, dramatically increasing the access to business information. Field services companies can capitalize on these computing revolution to reap a variety of benefits.

With the Internet, customers can instantly access the status of their service request, or even initiate new work orders. Self-service has the advantages of reducing dispatch workload, eliminating miscommunication between the service requester and the dispatcher, and eliminating the "on hold" complaint. In addition, customers can access their service history at any time, providing added value with no workload impact to the field service company.

Just as customers can have instant access to information so can the company's employees. Technicians, sales representatives, dispatchers, and executives with an Internet connection now have customer information at their fingertips—reducing the costs of connecting while improving productivity and performance. Today, information captured by dispatch or the technician at the job site is most frequently written on a work ticket that is then filed and never seen again, if indeed it is written down at all.

Thin-Client Computing

Thin-client computing describes a software application that has been designed to operate over the Internet, including intranets and extranets. The software self-loads on the client as required.

The thin-client architecture of an enterprise software program lends itself perfectly to field service companies. With thin-client computing, the vast majority of the application resides on the server, with only a minimum of software on the client, for example, on an HPC. So all software configuration, installation, and administration tasks are performed centrally and self-install on the desktop PC on demand, substantially reducing the total cost of ownership.

Commercial Software

Field service software applications are now available that take advantage of all of the technologies discussed previously. These applications, unlike previous solutions, require little customization and integrate easily with other needed applications. For example, you can view flat rate pricing tables from one vendor on using a mobile application from a different vendor. Yet, using commercial software, you can still make the software "look like your business" via customization choices, for example, field names, and business rules.

Summary

Windows CE. Handheld PCs. Wireless communications. The Internet. Commerical software. Each technology has a number of benefits for field service companies—but it is the convergence of these technologies that is so promising. So how do field service companies exploit this convergence?

The surest and most cost-effective way is to partner with a company that has already created a field service automation solution based on these leading technologies. With enterprise-class software, a technician move through his entire workflow more efficiently, from wirelessly receiving a work order to automatically generating an invoice. And during each step of the process, both the home office and the customer can have instant and complete knowledge of the service actions and status.

Author

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Chapter 12— Photovoltaics Run Geothermal Heat Pumps at EPA's Laboratory in Ada, Oklahoma

Steven C. Ganzer, C.E.M.

Overview

The United States Environmental Protection Agency (EPA) awarded an Energy Savings Performance Contract (ESPC) in August 1999 for a comprehensive energy systems upgrade at the National Laboratory in Ada, Oklahoma. Using ESPC procedures, EPA's goal was to establish an energy showcase among environmental laboratories. The project would reduce source emissions, energy consumption, and energy costs, while improving the overall integrity of the mission. The Energy Performance Contractor met EPA's requirements for life-cycle reductions of emissions and energy consumption by utilizing high-efficiency heating, ventilating and cooling equipment, and exploiting free energy from renewable sources (photovoltaic and geothermal).

Background

Laboratory facilities have unique indoor environmental requirements that are predicated on ensuring the health and safety of the facility occupants. For this reason, laboratory designs have depended upon systems and equipment with a proven history of reliability. The trade-off for laboratory safety has been intensive energy consumption and a design and operational attitudes of "business as usual." Depending on the fuel mix of local electric generation, these laboratory practices, which do result in high energy consumption in the name of laboratory safety, may be putting the rest of society at risk through atmospheric emissions because of the required power's generation.

In general, building designers and equipment manufacturers have begun to respond to the challenges of energy efficiency by introducing new building designs and energy consuming equipment, including heating, ventilating, and cooling technologies. These efforts in commercial office buildings have quite successful, with efficiency gains of thirty (30) percent or better. However, when considering the requirements of a laboratory, what energy options are available? And what efficiencies can be achieved?

To begin to answer of these questions, the Energy Service Company began to study various HVAC equipment options for the Robert S. Kerr Environmental Research Laboratory, Ada, Oklahoma. From this assessment, the Energy Service Company found that a variety of advanced technologies could be integrated through designs that orient laboratory HVAC equipment as a process for delivering laboratory conditioning and ventilation. Johnson Controls and WEDGCO Engineering determined that significant energy reductions will only result by combining the most advanced technologies that optimize component interactions, using a mix of energy types (including waste energy streams) and automating building air management.

On this basis, Johnson Controls, Inc. developed several concept designs which indicated that efficiency gains of greater than fifty (50) percent were possible.

Case-in-Point

In May 1995, Federal Civilian Agencies were permitted to use private financing for energy efficiency projects through amendments to the Federal Acquisition Regulations. This financing through Energy Savings Performance Contracting could provide the necessary funds for the Agency's concept designs. But would there be firms willing to finance EPA's laboratory energy program?

To test this possibility, EPA offered its Robert S. Kerr Environmental Research Laboratory located in Ada, Oklahoma for an Energy Performance Contract. Robert S. Kerr Environmental Research Laboratory's annual utility consumption and costs provided ample economic opportunity for an ESPC project, given the potential twenty-five (25) year contract term authorized by statute. The 84,000 square foot laboratory annually consumed approximately 2,989,819 kWh for Oklahoma Gas and Electric Company and 90,389 Therms of natural gas form ARKLA Gas Company. The approximate breakdown of Ada Laboratory's $218,000 annual energy bill.

Purpose

The Robert S. Kerr Environmental Research Laboratory was targeted for the Agency's use of the Federal Department of Energy's Regional Super Energy Performance Contract based on several considerations, including:

Robert S. Kerr Environmental Research Laboratory's energy consumption was 2,989,819 kWh, 90,389 Therms, 19,243,219 kBtu at a cost of $218,000.

The laboratory facility was nearly 40 years old. Its major energy infrastructure equipment was nearing the end of its useful life, requiring frequent repairs. Its electrical distribution system was in need of retrofitting and upgrade.

The facility's two (2) chillers, package rooftop equipment, boilers were in need of modification or replacement to eliminate the use of CFC refrigerant. Furthermore, this equipment did not serve Robert S. Kerr Environmental Research Laboratory's needs reliably or efficiently.

Robert S. Kerr Environmental Laboratory's five (5) major air handling units were inefficient and nearing the end of their useful life.

The facility's limited pneumatic control systems were mostly unreliable and completely outmoded, requiring complete replacement.

The fume hood exhaust system was outdated and consuming the majority of the laboratory's energy consumption. The fume hood exhaust was being exhausted below the laboratory fresh air intake.

Environmental Protection Agency's ESPC contract was to function as a capital improvement program. Its financing was carried exclusively on the reduced energy consumption, water conservation, and operations and maintenance cost savings resulting from improving the energy efficiency of the facility's HVAC system.

Goals and Requirements

The ESPC project had the following goals which were assessed by EPA according to evaluation to the guidelines set by the Federal Department of Energy (USDOE) in their Super Energy Performance Contract Program.

1. Meet or exceed Federal energy reduction mandates, as prescribed by the Energy Policy Act of 1992 (EPAct), which requires 20% site energy reduction relative to a 1985 baseline in Federal facilities by 2000, and Executive Order 12902 which requires an additional 10% by 2005.

2. Reduce source emissions, consistent with EPA's mission of environmental protection.

3. Optimize energy cost savings.

4. Eliminate or replace CFC's with a refrigerant material consistent with EPA guidance and reflecting sound engineering practices.

5. Minimize energy waste by reducing it to the extent that is cost-effective.

6. Retrofit or replace obsolete and aging energy consuming equipment.

7. Utilize renewable energy to meet the requirements of Sections 304 and 307 of Executive Order 12902, which establish goals for Federal facilities to use photovoltaic, solar thermal, passive solar, biomass, wind, geothermal, hydro-power, and other alternative technologies where cost-effective.

Photovoltaics

General

Photovoltaics (PV) or solar electricity is a well-proven and reliable technology used increasingly by Federal facilities to provide power in remote or difficult-to-access locations.

PV systems are used throughout the United States, but they are cost effective most often in areas with abundant sunlight, as the size and cost of the PV array for any application are directly related to the availability of the solar resource. The only major drawback of PV systems in the high initial cost for capital equipment. However, when the life-cycle costs (LCCs) of PV systems are compared to alternatives such as engine generators or long utility line extensions.

Technology

Photovoltaic (PV) is a descriptive name for a technology in which radiant light energy (photo) is converted to electricity (voltaic) by semiconductor devices. It is used worldwide to provide electricity, especially in remote or difficult-to-access locations. Unlike solar thermal technologies that provide heat, PV converts sunlight to direct current (DC) electricity.

The PV modules that perform this conversion have no moving parts, emit no exhausts, are completely silent, and require only sunlight as fuel. They are also very durable and PV systems can generate electricity anywhere the sun shines (even in space), but their cost usually limits their applications to remote or difficult-to-access locations where line-tied utility power is either unavailable or too expensive to install. Some line-tied PV systems are currently being used for high-value applications such as utility distribution line support demonstration projects and peak load shaving for buildings but they are, for the most part, not cost effective at this time.

PV System Components

PV systems have individual components that are assembled to serve the needs of a specific load or loads. With certain applications such as outdoor area lighting and water pumping, PV systems may also include the loads (the light or pump) because they are specifically designed to operate with PV systems.

Depending on the nature of the load, each PV system may include:

PV arrays, which convert light energy to DC electricity.

Batteries, which store electricity for use when the sun is not shining.

Battery charge controllers, which protect the battery by preventing overcharging and over dis-charging.

Inverters, which convert DC to alternating current (AC).

Converters, which convert PV system voltage to a higher or lower voltage.

Solar trackers, which optimize the solar gain of the PV array by tracking the sun.

Engine generators (for hybrid systems), which provide backup power and power for charging batteries.

Robert S. Kerr Environmental Research Laboratory Photovoltaic System

Introduction

The PV ECM is a building integrated photovoltaic system. This PV system is to incorporate solar electric arrays directly into a building envelope. The scope of this Energy Conservation Measure for the Robert S. Kerr Environmental Research Laboratory is to engineer and install a 60KW AC reliable, and last at least 20–30 years. PV modules power virtually all satellites and have been important to the space program since 1958, when the first PV system went into orbit with the Vanguard I satellite.

out, peak photovoltaic array system that will supply electricity for the operation of the fifty-two (52) ton heating and cooling geothermal water to air rooftop heat pump system for the LCCF facility. The photovoltaic system will be connected to the building's existing electrical service and produce an estimated 100,740 kWh.

Technical

The LCCF facility is a portion of the Robert S. Kerr Environmental Research Laboratory that is a 13,902 square foot two story building consisting of offices, conference rooms, computer room, and employee wellness center. The building consumes 332,398 kWh, 16 Therms of natural gas, and 1,134,473 kBtu's,

The heating and cooling system that has been chosen for the LCCF facility is an energy efficient geothermal heat pump system. The geothermal heat pump system equipment consists of nine (9) rooftop seven (7) ton rooftop water to air heat pumps, one (1) source pump and one(1) load pump, variable frequency drive for each pump. The geothermal heating and cooling system consumes 80,592 kWh annually and 274,980 kBtu's annually.

The photovoltaic system will be connected to the Robert S. Kerr Environmental Research Laboratory's facility electrical grid. The photovoltaic system will provide 60KW peak electrical demand and 100,740 kWh annually.

The heating and cooling equipment that the photovoltaic system will provide AC electrical power for is the geothermal source and load pumps with variable frequency drives, and the nine seven ton individual heat pumps' electrical requirements. When the building's heating and cooling demand is less than the maximum requirements the excess KW and kWh will be put into the laboratory's facility building electrical grid.

The photovoltaic system consists of a non-tracking grounded array of 4 rows with fifty-four (54) modules (total of 216 modules), safety disconnect, and 60KVA inverter. The array will be located on the ground located in front of the building.

The cost of the photovoltaic system energy conservation measure is estimated at $550,000 with a savings of $15,464.75 per year. The EPA is asking for a $300,000 grant from US DOE to be applied to this ECM making the simple payback 16.2 years.

Conclusions

This system will have several benefits to EPA besides reducing their energy consumption and utility costs. The EPA will be meeting their mission of reducing source The benefit that this system (ECM) will have for the photovoltaic industry is that it will show how space conditioning requirements can be met for facilities that are remotely located without using expensive fossil fuel cost (natural gas, propane, etc.) or adding the expense of running utility distribution lines (electric and natural gas) to these facilities.

Acknowledgment

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Glossary

PV Array—The primary component of a PV system, it coverts sunlight to electrical energy; all other components simply store, condition, or control energy use.

Inverter—PV arrays and batteries are typically configured to provide 12, 24, or 48 volts of DC power. However, many applications require 120 or 240 volts of AC power. DC is converted to AC with a separate component called an inverter. emissions and utilizing renewable energy (geothermal and solar).

Converter—Occasionally the voltage output of a PV array, battery, or inverter will not match the voltage requirement of the load. When this occurs, converters are used to step the DC voltage up or down to meet the needs of the load.

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2. National Renewable Laboratory, Golden Colorado

3. United States Department of Energy

4. International Ground Source Heat Pump Association

5. Geothermal Heat Pump Consortium

Appendix

PV Power Plant Parameters

Direct Normal Irradiance	1,000 Watts/Sq. Meter		
Module Efficiency		Baseline Factor	
		Lens Eff.	90.0%
Peak Solar Cell Efficiency	16.7%	Cell Cover	94.0%
Optical Intercept Factor	82.9%	Packing Fact	98.0%
Peak Module Efficiency	13.8% (Note 1)	Opt. Factor	82.9%
Sum of Modules At Peak DC Power		93 KW (DC)	
Field Efficiency (Wiring & Mismatch)	95.0%		
Efficiency Subtotal	13.2%		
Peak Field DC Power		88 KW (DC)	
Power Conversion Unit Efficiency	100.0%		
Efficiency Subtotal	13.2%		
Peak Field AC Power		88 KW (AC)	
Cell Operating Temperature Factor	86.0% (Note 2)		
Field Wiring Loss Factor to Switchgear	99.0%		
Efficiency Subtotal	11.2%		
System/Field Operational AC Power		75 KW (AC)	
Annual Performance			
Annual Tracking Efficiency	92.0% (Note 3)		
Annual AC Conversion	10.3%		
Assumed Annual Solar Efficiency Available		1,825 kWh/Sq. M.- Year	
Annual AC Electricity Generated		125,903 kWh/Year	
		1,679,000 kWh/KW (AC)	
Physical Parameters			
Total Collector Aperture Area		670 Square Meters	
Total Number of Rows		3	
Total Number of Modules (72 Per Row)	216		
Aperture Area/Ground Area	21.3%		
Land Area Required		0.77 Acres	

Note 1 At Standard Test Conditions (Direct Sunlight = 1 KW/Sq. M., Cell Temp. = 25 Deg. C)

Note 2 Value based on average 20 C ambient air temperature.

(table continued on next page)

(table continued from previous page)

Note 3 Value based on 35 deg. Latitude and flat site. Value will change with changes in slope, latitude, and north—south spacing.

60 KW AC Peak Output
100,740 kWh (AC) Per Year

Chapter 13— Sustainable Energy and Economic Strategy for the 21st Century

Arun Jhaveri

Introduction

It has become very clear during this past quarter century, since the first major oil embargo of 1973/74, that it pays to integrate public policy issues with emerging technology and societal impacts, before making far reaching long-term decisions that not only affect the quality of life of the present generation but also can leave a worthwhile legacy for future generations. The interrelated issues of energy, environment, sustainability, resource management, and community/economic development give us an excellent example of how to structure a holistic strategy that becomes a win-win situation from a public/private partnership development viewpoint. Inherent in it are the necessary qualitative & quantitative characteristics of responsibility, accountability, leadership, teamwork, action plan, and performance. This may sound abstract in theory but nonetheless there are sufficient success stories and case studies that can demonstrate the significant benefits that result from this unique/innovative approach to balance the three-legged stool of energy, environment, and economy (3 E's), now and in the future, practiced by many engineering & management professionals within the United States and abroad, as we enter into the very exciting and challenging arena of global competitive economy.

Specifically, this paper will attempt to highlight the number of successful practices & initiatives that have significantly improved the quality, performance and quantity of the 3 E's profession. Included among these, but not limited to, are a) performance contracting, b) climate change initiative, c) global economy/international trade, d) energy efficiency/renewable energy technologies, e) whole building sustainable design, and f) environmental pollution prevention—all of these from a sustainability strategy or perspective. Once the mechanisms have been tested, verified, and incorporated into everyday working environment, the long-term public, societal, and economic benefits from a life cycle consideration, will far outweigh the initial cost investments. Thus, we must make these innovations a model for future replication.

Discussion

Sustainable energy and economic development concepts are not necessarily new. However, the focus and strategy for each of the sustainable developments—energy, environmental, economic, and community—have been evolving dramatically during the past 25 years in general, and during the nineties, in particular. The event that has significantly changed the meaning and course of sustainability, both nationally and internationally, was the 1992 Earth Summit in Rio de Janeiro. Issues such as energy efficiency, environmental pollution prevention, global climate change, resource management, urban/community development, global economy, whole building design, renewable energy/clean energy technologies, and alternative/innovative, financing as part of the universal sustainability, became the cornerstone of both short-term and long-range planning, implementation, and public policy deliberations within the USA and abroad.

Let us examine some of the unique characteristics of sustainable energy, environmental, and economic strategies, in terms of policies, projects, case studies, action plans, and cost-effective implementations, associated with buildings/facilities, communities, and national/international program initiatives, particularly those successfully completed and documented in the USA.

A) Energy Efficiency/Renewable Energy Technologies—In the federal sector, the U.S. Department of Energy's Federal Energy Management Program (FEMP) has taken a lead to accomplish the challenging task of energy reduction by 35% between the base year of 1985 and year 2010, as required by the new Executive Order 13123, signed by President Clinton on June 3, 1999. The energy & cost savings from this mandated goal alone could be as much as 25% in some 500,000 buildings/facilities of the federal government or equivalent of $2 billion per year. When similar requirements are put into practice at the state and local government levels, the resultant savings could be $5 billion per year, not to mention the even higher cost reduction potential in the private sector. We are now seriously taking advantage of this win-win situation through the application of cost-effective technologies, management tools & training, and energy savings performance contracting, just to name a few innovative approaches. Not only do these techniques help modernize the vast public infrastructure, but they also extend the economic life of the buildings, facilities, equipment, and systems without compromising the quality, performance, functionality, environment, and missions of the participating governmental agencies. Some of the case studies included in this presentation relate to Sustainable Design Principles, Greening, Performance Contracting, Renewables & Emerging Clean Energy Technology Applications, Building Commissioning, Retrocommissioning, and Greenhouse Gas Emissions Reduction.

B) Environmental Pollution Prevention/Resource Management/Global Climate Change—With the help, guidance, and limited resources from the federal and state governments, these activities do make a significant difference in the quality of life of hundreds of millions of citizens/residents at the grass-roots level, both nationally and internationally. Urban, suburban, and rural communities through visioning, comprehensive planning, and action plan implementation policies have and can accomplish enviable progress toward managed growth, without compromising the character, integrity, vitality, and economic development potential of their respective jurisdictions. Among the prime movers in this initiative are the U.S. Environmental Protection Agency (USEPA), President's Council on Sustainable Development (PCSD), International Council for Local Environmental Initiatives (ICLEI), Intergovernmental Panel on Climate Change (IPCC), and U.S. Agency for International Development (USAID). Each of these organizations has contributed significantly towards achieving environmental, CO_2 emissions reduction, indoor air quality, recycling, resource conservation (e.g., water), sustainable communities, and whole building system goals, by empowering citizens & communities alike to help mitigate environmental impacts and at the same time creating sustainable locally based economic development and employment.

C) Community/Economic Development—As we move into the next century and the millennium, the challenges and opportunities abound for everyone in this competitive global environment. The need for trained workforce in the energy, environmental, telecommunications, biotechnology and international trade fields is anticipated to drastically lag behind the exponential growth of these markets. The role of community & technical/vocational schools & colleges will steadily grow to train and supply the ever-increasing demand. The towns, cities, and counties will be called upon to develop successful public/private partnerships that sustain the anticipated economic development spearheaded by visionary businesses, industries, and commercial operations worldwide. There is a strong tendency to control the destiny of people at the local level through democratic institutions and ownership, but at the same time to remain current with the state-of-the-art technologies, tools, and training in emerging global markets.

One excellent example: USAID's work encouraging private investment in clean, efficient energy systems has produced significant, sustainable results in more than 50 countries. Through its program in energy during the last decade, the agency has—with a relatively small investment—helped bring about a transformation in the energy sectors of assisted countries that has opened up a U.S. export market in energy products and services valued at more than $50 billion per year. The USAID model is now being widely replicated by other development-assistance agencies, both in energy and other infrastructure sectors. By fiscal year 2003, USAID expects its program in energy sector to have produced results that include -

avoidance of more than 25 million tons of greenhouse gas (GHG) emissions

leveraging more than $1.3 billion of public and private sector investments to finance environmentally sustainable energy development

adoption of 65 policies by national and state governments to provide the incentives & regulations required for sound energy development, and

access to energy generated from solar, wind, mini-hydro, and other renewable sources for as many as 3.5 million rural and urban dwellers

Similar projections have been made for the nearly $200–300 billion U.S. export market in environmental products & services, mainly in the developing economies of Asia, Africa, South & Central Americas, Eastern & Central Europe and Middle East.

Conclusion

Based on the discussion above and associated presentation material of success stories, case studies, and references cited, it is clear that well-developed and carefully implemented sustainable strategies for energy, environment, and economy (3 E's) in the 21st century, can and should significantly enhance the quality of life of hundreds of millions of people around the world, without compromising the integrity, economic development, and stability at all levels of the global community, thus leaving a strong legacy for future generations. Therefore, there is no excuse to delay or procrastinate, since the needed tools of technology, investments, partnerships, training, management, and communications are available using teamwork and systems approach.

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Chapter 14— The Use of Low-Cost Data Loggers in Monitoring Building Systems Performance

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Abstract

This paper explains the benefits of using low-cost data loggers for monitoring the performance of various building systems. The importance of gathering accurate data and the ability to analyze this information efficiently will be discussed. Various data logging applications will also be explained. Upon completion of this paper, the reader will have a good understanding of the features they should look for when choosing data loggers for use in systems monitoring.

Outline

What Is a Data Logger ?

A data logger is an electronic instrument that records measurements of temperature, relative humidity, light intensity, on/off and open/closed state changes, voltage and events over extended periods of time. Typically, data loggers are small, stand-alone, battery-powered devices that are equipped with a microprocessor, memory for data storage and sensor(s). Most data loggers interface with a personal computer and utilize software to activate the logger and view/analyze the collected data.

Benefits of Using Data Loggers

One of the primary benefits of using data logging devices for systems monitoring is the ability to collect data on a 24 hour, around-the-clock basis. Upon activation, the loggers are deployed and left unattended to gather and record information for the duration of the monitoring period. This allows for a more complete and accurate picture of the target system's overall performance. Because some condition changes take place over long periods of time or when no one is present, the use of data loggers is much more efficient and feasible than performing "spot checks" to gather data manually.

Another important benefit is the ability to collect data in hard-to-reach areas through the use of built-in or external sensors. Temperature, relative humidity, CO_2, voltage, amperage, pressure, light, many other types of data can be monitored in areas that would otherwise be too difficult or cumbersome to access such as electrical junction boxes, air return vents, water recovery tanks, motor and fan housings, to name a few. Loggers with external input capabilities may be wired to existing gauges and sensors that have voltage output terminals, thereby allowing these devices to be monitored and recorded, also.

Data loggers incorporate the latest in digital technology making them smaller, less expensive, more accurate and more reliable than chart recorders. Furthermore, data is stored in digital format which allows for more convenient analysis, presentation and storage. There is no need for costly and inconvenient chart supplies because the data is viewed on a PC or laptop computer. The small, unobtrusive size of some data loggers makes them easy to hide for inconspicuous data collection.

Additionally, many benefits can be realized from choosing data loggers over data acquisition systems for performance monitoring. Data acquisition systems often require the installation of extra circuit boards and controls in the PC along with the connection and wiring of cables and sensors. These systems work well in permanently configured, on-line applications but can be very expensive and difficult to implement, especially when short-term monitoring is all that is required. Data loggers significantly reduce the price per channel for most logging applications, are easier to deploy and can be placed in areas that permanent, digital systems can not reach. They can also be easily removed and reused in other application studies, because they require no extra wiring and are stand-alone devices.

Useful Applications

Data loggers are used in many different applications to monitor and collect specific types of information. The following are just a few examples of "real world" applications where data loggers can make the task of gathering information a lot easier and much more efficient.

Monitoring Comfort Level Complaints

Many of the people that I speak with are service technicians, consultants and engineers in the HVAC/R industry. One of the more common complaints that they hear from their customers is that the heating or air conditioning system is not working properly. It's either always too hot or always too cold. These types of comfort level complaints are very easy to monitor and verify with the use of temperature data loggers.

Temperature data loggers employ a sensor that reacts to changes in temperature. The logger monitors and records these changes at preset intervals and stores the data with date and time information in its memory for later retrieval. Many temperature loggers are small enough that they can be placed in hidden, "out-of-the-way" locations to gather information without being seen or disturbed. Depending on the amount of built-in memory and the interval for taking readings, the loggers can realistically collect data for several months at a time, before reaching their full capacity.

This temperature data, upon later analysis, offers a much more accurate and complete picture of the actual temperature activity that occurred throughout the entire monitoring period. "Spot checks" or manual readings would not provide this type of extensive coverage. The data can then be used to ascertain where problems in the heating system might exist, before making an informed recommendation to the customer or client. The savings in manpower alone, are enormous, especially if the study is being done in a multiunit residential or commercial building.

Temperature loggers can also be used in many other applications. Here are a few examples:

1) Verify nighttime temperature setback strategies.

2) Monitor air handler temperature fluctuations.

3) Analyze gradient temperature changes.

4) Monitor equipment operating temperatures.

5) Compare outdoor conditions to indoor comfort levels.

6) Assess operating temperatures of motors.

Logging Motor/Compressor Cycling Performance

"State" loggers are another very useful type of data logger that can be used to monitor the run times of motors, fans and compressors. These loggers record the "on" and "off" run times along with time and date stamps. This information is very useful in detecting short-cycling and recording the overall usage of the equipment being monitored.

Motor On/Off loggers with built-in vibration sensors are often used to monitor the start and stop times of compressors and pumps. The adjustable sensor detects the vibration when the compressor is turned on and records this event with a time and date stamp. When the compressor or pump is shut down, the logger will also record this event with another time and date stamp. This data can be used to show the total amount of time the equipment was operational. Further analysis of the data can show where short-cycling may have occurred, the peak usage times and percentage of time that the equipment was on or off.

For electrical devices that do not produce measurable vibrations (small fans, motors, etc. . .), AC-field sensor loggers are used to monitor On/Off state changes. These loggers detect the electromagnetic field produced when the device is turned on, through the use of a built-in sensor. The loggers can be placed directly on the outside of electric motor housings, and may also be mounted on one of the phases of power being supplied to the motor or device being monitored.

There are "State" loggers that also record "open" and "closed" events as well as contact closures. These loggers can be wired to passive relay-switches and dry contacts. When a contact is made, or when the relay switch is "tripped", the logger records this data with a time and date stamp for each On/Off or Open/Closed state change.

When evaluating motor, fan or compressor cycling and performance, "State" loggers are an invaluable tool. These loggers can detect and log events that might otherwise go unnoticed, or would be difficult to monitor manually. They offer the capability to capture events, whenever they may occur.

Monitoring Electric Light Usage

When performing baseline studies on power consumption in buildings, knowing how much electricity being used for lighting is very important. There are data loggers available that detect and record light usage.

Light On/Off loggers, are similar to "State" loggers in that they record data only when a "state" change occurs. These loggers employ a sensor that detects changes in light intensity. There should be a sensitivity control so that the threshold between light and darkness can be adjusted by the user. This will allow the logger to know the difference between "on" and "off". Lighting conditions vary from room to room, and having the ability to adjust the sensor is important. Care should also be taken to make sure that the light sensor directly faces the source of light being monitored. Sunlight and other reflected light sources may trigger these loggers giving inaccurate readings. When the lights are turned on, the logger will record this state change along with date and time stamps. When the lights are turned off, this information is also recorded.

This type of data is valuable in determining how often electric lighting is being used. Peak hours and periods of non-usage can also be analyzed. This information is very useful, especially when making recommendations for retrofits and estimating the electrical demand for lighting.

Power Usage Logging

Tracking power consumption and usage is essential in evaluating a system's overall performance. The efficiency and energy demands of equipment can be monitored and recorded through the use of data loggers.

Readings of current, amperage and voltage may be taken manually with hand-held meters and probes. These methods of collecting data are common and work well, when short monitoring periods are required. However, when longer studies are necessary, data loggers can gather information for extended, uninterrupted periods of time.

Loggers with the ability to accept external inputs are an excellent choice for collecting power data. These loggers are programmed by the user to take readings at preset intervals. The external inputs on these types of loggers usually accept voltage inputs from external sensors and preexisting gauges. Current transformers, meters and gauges can be used with external input loggers, provided that these sensors have voltage output characteristics compatible with the input voltage requirements of the data logger. Current transformers are simply attached around the phases of power being monitored. (In most cases, no hard wiring is necessary). The logger, upon activation, will take readings at the preset intervals and record the amperage, voltage or current information with time and date stamps. Some of these loggers have multi-channel capabilities and can collect data from various different sensors simultaneously. Recording data from all 3 phases of power, allows for a more complete picture of the total power being used as well as the peak hours of usage.

By relying on manual readings, events such as power spikes, surges and fluctuations may go undetected. Data loggers with external current probes and sensors attached can perform unattended studies for days, weeks and months around the clock. Data can be gathered at times that would not otherwise be practical or efficient.

Air Quality Monitoring

The performance of air quality systems can also be monitored and recorded using data loggers. Temperature readings for supply and return vents can be recorded and compared to help identify air balance problems. CO_2 levels and relative humidity information can also be monitored to obtain important air quality data.

Various data loggers are available that have built in temperature and RH sensors so that these types of data can be collected simultaneously in the same location. Other loggers with external input capabilities can be effectively used by attaching external temperature, RH and CO_2 sensors for placement in hard to reach areas. Hybrids of these two types of loggers are also available. They offer built in sensors as well as the capability to attach external sensors, for even more monitoring possibilities.

External temperature sensors can be placed inside air vents, and attached to heating coils and pipes for accurate readings. Temperature and RH readings can be taken inside and outside of buildings for comparison. CO_2 levels can be monitored when the building is occupied and unoccupied for later evaluation of the ventilation system.

By collecting data from various locations simultaneously, valuable information about overall air system performance can be obtained. Later analysis of the data will identify energy saving opportunities in over-ventilated spaces. Complaints about air quality or insufficient ventilation can be studied objectively. Performance of heating and air conditioning systems can be evaluated. Temperature changes can be analyzed to verify proper heating and cooling operation.

Through the use of data loggers, more accurate and usable data can be obtained with much less expense and over longer periods of time, than can be obtained by manual, hand-held monitor readings.

Analyzing the Data

Now that you have collected all of this valuable data, what are you going to do with it?

Most data loggers operate with some type of proprietary software. This software allows the user to set certain operating parameters within the logger. Sampling/reading intervals, delayed start times, alarm ranges, external sensor selection, a descriptive header for the logger are a few examples. Information about the logger's battery status, clock synchronization and memory capacity may also be available. There should also be a software command to activate the logger. All of this is accessed through a serial port connection between the logger and the computer.

Upon completion of your study, the data must be off loaded from the logger into the computer. The information can then be viewed and analyzed with the logger software or spreadsheet programs.

Software features vary among data logger manufacturers. At a minimum, the user should be able to view the data files with date and time information in graphical and tabular formats. The capability to export data files into other spreadsheet programs is also a very useful feature found in some data logging software programs. Other software features to look for are:

1) Capability to display multiple data files on one graph.

2) Zoom in on data of interest.

3) Copy and paste graphs into other applications.

4) Compare multiple parameters, from multiple loggers.

5) Multiple value axis on one graph. Set axis ranges.

6) Calculate on/off run times and percentages.

7) View and overlay data from successive deployments.

8) Y2K compliance.

9) Capability to customize graphs, colors, legends, etc . . .

10) Good Technical support.

Software packages with these features allow for easier analysis of the collected data. Specific data points can be filtered out for more accurate comparisons and study. Graphs and tabular data can be printed for use in reports and evaluation of long term studies. A major advantage of using data loggers over hand-held monitoring devices and chart recorders is the capability to define, target and store massive amounts of information relevant to the study—something not possible with chart recorders. Good, comprehensive analytical software is as important as the data logger itself, when evaluating systems performance.

Features to Look for in a Data Logger

By now, the benefits and advantages of using data loggers should be clear. Listed below are some of the basic features that you should look for when choosing data loggers for use in your performance studies.

1) Ease of use . . . The logger should be user-friendly, easy to set up, activate and off load data.

2) Size . . . The loggers should be small and easy to install in hard to reach locations. Easy to carry. Portable.

3) Self-powered . . . Data loggers that are self-powered can be placed in areas and locations where electricity is not readily available.

4) Flexibility . . . You should be able to define reading intervals, select external sensors, customize and modify data easily. Be able to deploy the loggers where needed.

5) Reliability . . . Choose loggers that have a proven track record for accuracy, reliability and dependability.

6) Durability . . . Look for loggers that are designed for rugged indoor/outdoor use. They should be able to withstand the rigors of harsh environments (extreme heat and cold, excessive moisture, pressure, etc . . .)

6) Technical Support . . . Even in the best situations, there will always be questions about software. Questions about whether or not the logger is suitable for certain applications. Questions on how to change the batteries. Choose your loggers from a manufacturer that provides good, informative and useful answers to your questions. There may be unforeseen problems that crop up, and having good technical support is a must.

7) Comprehensive Software . . . The data that you have collected is useless if you can't analyze it. Make sure that the logger software is easy to use. You should be able to access and customize data files easily. Make sure that software is Y2K compliant. Once again, access to expert technical support is essential.

8) Data Shuttle Capability . . . Data shuttles are convenient, hand-held devices that allow you to off load and relaunch data loggers, while in the field. There is no need to bring the loggers back to the computer. The shuttle holds the data and is easily off loaded to the computer, instead. This allows the loggers to remain in place. Not all data loggers are shuttle compatible, however this is a very nice feature that makes data collection even easier.

9) Cost . . . Collecting data can be expensive, especially if it is done manually. Data loggers can range in price from less than $100 to over $1,000. Although factors like accuracy, flexibility and reliability are very important so is the cost of the logger, itself. Memory and computer processor prices have fallen sharply over the past few years making data loggers more accessible than ever before. The technology is readily available, inexpensively, for small companies and large firms alike. When choosing data loggers, their cost is an important factor to consider when planning a building systems performance study.

Conclusion

Data loggers are effective, inexpensive tools ideal for monitoring and measuring building systems performance. They can be used to collect important data from many types of devices and equipment, whether you are there or not. They take the guess work out of trying to evaluate the efficiency of a particular system, by providing accurate information. The benefits obtained from being able to print and easily store graphic and tabular data for analysis and evaluation are numerous. Data loggers are inexpensive and they offer huge savings in manpower alone. They log data non-stop, around the clock, day and night, gathering information that might otherwise go undetected. Loggers can be placed in hard-to-reach, out-of-the-way areas. The inexpensive cost of computer memory has put data loggers within the reach of everyone. By using data loggers to collect the information, your valuable time can be spent elsewhere, analyzing and evaluating the overall performance of the system.

Biography

Gregg Daly has been Sales Manager at Onset Computer Corporation since 1996. Prior to that he spent 11 years in the International Management Consulting field, as a Marketing Director.

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Chapter 15—
A Simple and Reliable Variable Speed Drive Technology Resolves Premature Motor Failure and Power Quality Issues

Paul "Dewey" Boggs III, C.E.O.
Coyote Electronics, Inc.

Introduction

Variable Frequency Drives (VFD's), or Inverters, have become the universally accepted method of variable speed control of AC motors and their respective loads.

The most common type of VFD used today is the PWM (pulse width modulated) inverter. It is the popular choice because of its excellent operating efficiency and lower front end costs compared to other types of variable frequency speed control methods.

The PWM drive however, has proven to be one of the leading sources of noise and motor related problems in variable speed drive applications. Many technical papers have been written recently identifying the reasons for the problems and offering solutions, yet the same concerns that are directly associated with PWM drives continue and to this day have not been totally resolved.

The leading issues with PWM drives today are:

- Motor winding failure

- Motor bearing currents (premature bearing failure)

- Current harmonics and voltage distortion (affect on facilities power quality)

- Additional motor heating (shortened motor life)

- Low end operating speed range limitation

- Distance limits between motor and drive

- Nuisance dropouts

- Retrofits: cannot reliably use existing motors

- When to use line filters, isolation transformers, bypass disconnects, and special inverter rated wiring or cable

- Highly skilled service level requirements

This paper addresses an alternative method of reliable, efficient, and economical variable speed control of the load where none of the above listed issues are applicable.

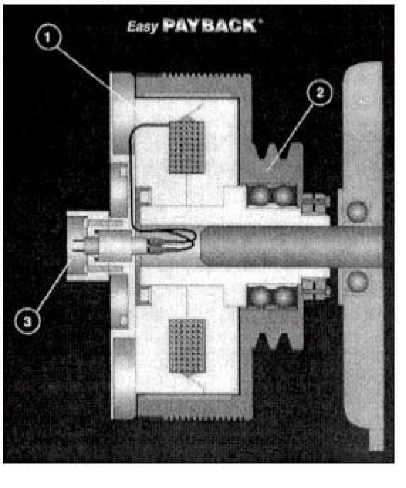
Also provided is a simple explanation of the basic principle of operation, a look at the developmental history of the magnetic coupled variable speed drive, the latest advances and improvements in the technology, the benefits, and the successful use of this technology in numerous and diverse applications.

Basic Principle of Operation

The magnetic coupled concept differs vastly from variable frequency drives in that there is no electrical power interruption to the motor. The motor is allowed to safely operate at its continuous designed speed, while precise, infinitely variable speed control of the load is accomplished by varying the magnetic coupling between the motor's output shaft and the load. The ideal configuration shown below comprises two primary elements:

(1) electromagnet (multi pole rotor)

(2) armature (steel drum/pulley)



The electromagnet (1) is affixed to the motor's shaft with a shaft locking device so as to run continuously at full motor speed. The steel drum with integral pulley (2) connects to the load. These two elements are separated by ball bearings which maintain a constant air gap between the two portions. When current is applied to the coil of the electromagnet via the brush-less rotary coupling (3), a polarized field is produced, magnetically coupling both components and causing the output portion to turn in the same direction as the motor. Output speed is dependent on the strength of the magnetic field, which is proportionately controlled by the amount of current applied to the electromagnet.

Evolution of the Magnetic Coupled Drive

Foot Mounted Style

In the 1940's and 50's, magnetic coupled devices known as eddy current clutches were used with AC motors and were a popular method of varying the speed of many industrial loads. Although bulky and inefficient, these workhorses were relatively reliable and were used in applications such as waste water pumping, punch presses, conveyors, winders and other machine tool situations. These were oversized foot mounted units that initially were designed as a separately housed clutch assembly with an input shaft and an output shaft to be coupled in line between the motor and the load. Also offered were motor and clutch combination (one piece) packaged units. In those days, the primary focus was in functionality, performance and maintainability, as energy efficiency was not as important a factor as it is today.

Shaft-Mounted Styles

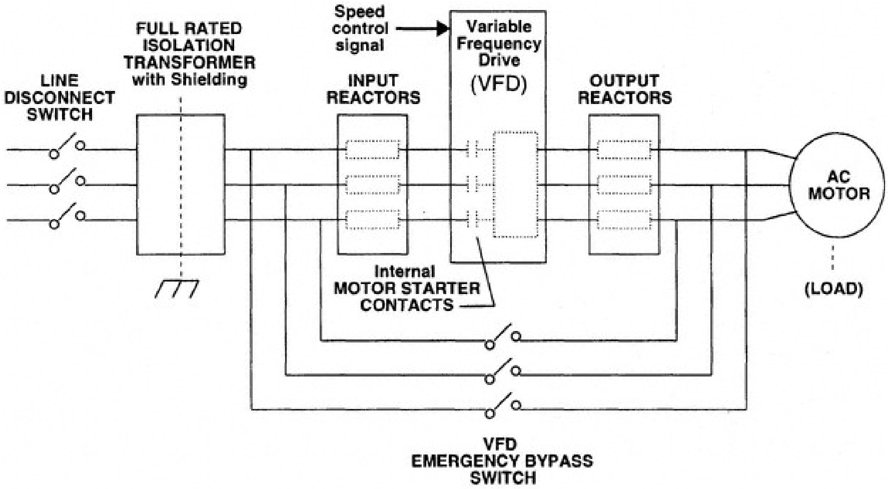
In the 1960's some of the first commercially available motor shaft-mounted magnetically coupled drives were offered to the industry. This new design was originally intended for small horsepower applications, and was novel in that the drive was totally supported by the motor shaft. The product did have some drawbacks, namely oversized slip rings and problems with brush alignment. It was the end users responsibility to align the brush holder with the slip rings. The intent was to mount the brush holder to the existing motor bolts. Unfortunately, motors supplied by different manufacturers varied significantly and alignment became difficult. Additionally the slip rings were provided on the drive at the motor shaft entry side, fabricated on a circuit board type material with copper rings facing the motor. Since the diameter of the outer ring was larger than the inner ring, the outer brush would wear faster. In addition to the uneven and rapid brush wear, the integrity of the circuit board and copper rings were compromised by the heat, causing separation of the rings from the base material. This design was abandoned soon after initial production.

In the 1980's the problem with brush alignment had been somewhat resolved by a new shaft-mounted design that incorporated a bracket supported by an additional bearing on the drive which maintained reasonable alignment between the brush holder and the slip rings. This design enjoyed some success in the machine tool and industrial market where reduced total running hours was somewhat forgiving to the drive. The basic design was still flawed however, as the slip rings were still located on the motor shaft entry side, causing them to be oversized and progressively larger to accommodate the larger horsepower motor shafts. This design created a major headache in the HVAC Air Handler marketplace, as it was soon discovered that 24-hour duty meant frequent brush changes, in some cases as often as every two to three months on the larger drives. Although an improvement over previous efforts, the location of the bearings, being cantilevered to the pulley grooves, caused premature drive bearing failure in many instances. The extra bearing required to accommodate the brush holder had an unacceptably high failure rate as well. This high maintenance drive design has become virtually obsolete in the air handler industry and has been routinely replaced by the more efficient and reliable new brush-less designs.

Another design consideration places the pulley grooves out on the outboard side of the drive, a distance away from the motor face. This, by far is the poorest of all approaches because it directly jeopardizes the motor bearings' life expectancy. Since the pulley grooves are not located over the nema shaft extension, applying full rated belt tension may exceed the overhung load rating of the motor in some instances. This outboard pulley design has many documented failures in the field, again compounded by drive bearing failure due to cantilevering effect and motor bearing damage as well.

Preferred Design

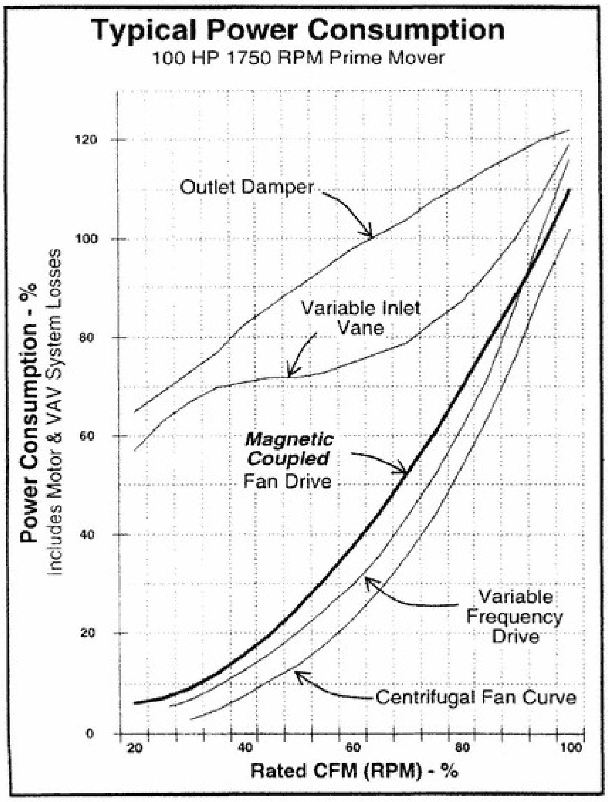
The most reliable design (shown on page 1) distinguishes itself in many ways from other versions. The rotor/coil assembly rotates constantly with the motor shaft. A one piece drum/pulley portion is the output driving member. The pulley grooves are located inboard, closer to the motor face than any other design. The drive's bearings are located directly under the pulley grooves so that maximum belt tension can be applied continuously on all models without harming the drive bearings and yet remains well under the overhung load capacity of the motor. Because the drum is copper lined, the brush-less drive runs cooler and is more efficient than other magnetic coupled drives. The drive's coil only requires one third to one fourth the wattage of other models. It has the fewest parts, weighs less and has the best operating performance of all previous designs. The proven six year track record allows for the longest drive warranty available in the industry.


Speed control signal
Variable Frequency Drive (VFD)
FULL RATED ISOLATION TRANSFORMER with Shielding
LINE DISCONNECT SWITCH
INPUT REACTORS
OUTPUT REACTORS
AC MOTOR
(LOAD)
Internal MOTOR STARTER CONTACTS
VFD EMERGENCY BYPASS SWITCH

Energy Savings

Because of the nature of the descending torque load itself and directly attributed to the affinity laws on variable torque loads such as centrifugal fans or pumps, the magnetic coupled drive provides substantial energy savings with variable speed of the driven load.

As can be seen in the typical power curve comparison graph below, the power curves are similar to VFD's on variable torque loads and the KW savings are significant as well. As a general rule, magnetic coupled drives are more efficient at the very top end of the curve and VFD's are more efficient further down the curve.



A typical magnetic coupled variable speed drive system is capable of energy savings up to 60% over dampers and 30 to 40% over inlet guide vanes.

Harmonics

Only the fundamental frequency (60 hertz), produces positive torque on the AC motor shaft. Since harmonic currents generate heat losses in the motor, transformer, and distribution wiring, it is highly desirable that all harmonic currents be as small as possible.

Unlike VFD's, magnetic coupled drives do not interrupt the motor power source. Therefore they do not produce harmonic currents, nor do they cause any voltage distortion.

Consequently, there is no requirement for the added expense of applying costly filtering devices such as line chokes (reactors), and full rated, three phase isolation transformers.

Motor Life

The magnetic coupling is electrically isolated from the motor and in effect operates as an infinitely variable, frictionless clutch, allowing the motor to operate as originally designed, at full speed continuously, and with pure uninterrupted AC power. Regardless of the drives operating speed, the motor never sees any additional heating contributed by the drive.

In fact, any additional heat is effectively dissipated by the drive itself, via slip, and not the motor. Unlike VFD's, there are no low end speed restrictions with the these types of loads, since the motor always runs COOLER with magnetic coupled variable speed technology.

(VFD's typically are limited at the low end of the speed range to prevent the motor from overheating). With a magnetic coupled drive, the motor fan is always operating at optimum efficiency and there are no unwanted harmonics produced by the drive. The fact that the Magnetic coupled drive allows the load to operate at ANY speed without degradation to the motor provides additional advantages over variable frequency drives.

Besides prolonging the motor life cycle by reducing the heat generated in the motor, additional up front savings can be realized with a magnetic coupled drive because there is no longer a requirement for the extra expense of constructing a pressure relief bypass duct system. This is sometimes necessitated by the direct result of the speed restrictions of the variable frequency drive itself.

Another common concern with VFD's that can affect the life of the motor relates to the distance of the drive from the motor. Known as "reflected wave" or "voltage ring up", the end result is damaging peak voltages at the motor caused by the impedance mismatch that is created by the long connection of the wires between the drive and motor. Higher operating frequencies of the VFD's and faster rise times on the output waveform provide for increased efficiency of the drive, but at the expense of the overall motor life expectancy. Filter reactors on the output side of the drive are generally required in these cases to minimize the rise times of the pulses and lower the peak voltage transients. However, it should be noted that some of the energy savings originally intended by the VFD will be negated by the installation of the filters.

The magnetic coupled drive has no real distance limitations between the drive and controller. The separation distance has been used successfully up to 2000 feet. The only requirement is that the two wires that provide dc power to the coil be sized large enough to allow for any voltage drop (say 14 ga. as example). No filters or any other devices are required. There is never any concern about causing damage to the motor or drive.

Lightning & Nuisance Dropouts

Since magnetic coupled drives are isolated from the power source, they provide the highest level of immunity to the effects of lightning.

By virtue of the inherently simple design, the drive is always active as long as the motor starter is energized. Transient over voltages, voltage sags, swells and harmonic distortion from other sources generally do not affect magnetic coupled drives unless the duration of power interruption is significant or long enough to actually drop out the motor starter circuit.

True Retrofit Capability

Magnetic coupled drives can be used safely with all standard AC motors. Since the technology cannot cause electrically induced winding or bearing damage to any motor, there is never any need for inverter duty motors.

Bypass

Another cost saving feature of magnetic coupled drives are built in mechanical lockup bypass. Electrical full speed bypass is accomplished by only one low current diode, and infinitely controllable variable speed bypass is also standard.

Power Factor Correction

Some utility companies in certain locations may charge a penalty if the facility's total measured power factor is below an acceptable pre-determined level.

Power Factor is generally not an issue with magnetic coupled variable speed drives. However, in the event that the power factor may require attention, low cost power factor correction capacitors can always be safely used with magnetic coupled technology.

(Power factor correction capacitors cannot be used with PWM variable frequency drives).

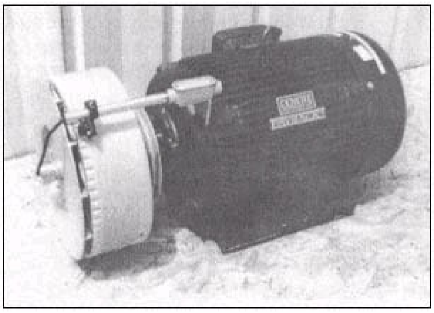
Maintainability

This simple technology does not require highly skilled personnel to maintain. The drive's bearings are permanently lubricated and do not require re-greasing.

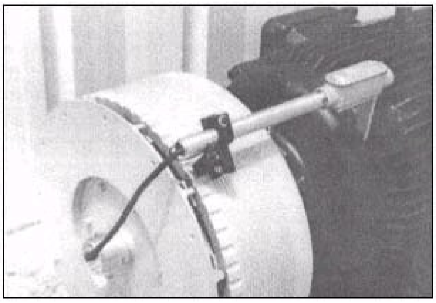
Typically the same small footprint, single phase, low wattage, plug-in controller is used on all drives, regardless of horsepower.

Unlike the high maintenance brushes and slip rings of the past, the rotary brush-less plug-in coupling cartridge can be swapped out in a matter of seconds.

Shown here is a typical brush-less, motor mounted magnetic-coupled variable speed drive.



Below is a close up view of the connection to the rotary coupling and optional speed sensor for sensing the notches on the surface of output drum. The speed sensor is used for providing a feedback loop in closed loop applications and also for speed indication.



Summary of Benefits and Advantages with Magnetic Coupled Drives

-Simple and economical to install

-Substantial energy savings with all variable torque loads

-Does not require highly skilled personnel to maintain or service

-Low cost of ownership, fast payback

-Allows motor to operate more efficiently

-No power quality issues, zero harmonics

-No special filters, reactors, or expensive three phase isolation transformers

-No expensive bypass circuitry

-No nuisance dropouts

-Highest level of immunity to the effects of lightning

-Does not cause additional motor heating, even at continuous low speed requirements (No speed range limitations)

-Does not cause across-the-line shorts, power surges, or voltage spikes

-Does not cause motor frequency noise

-Does not harm motor windings

-Does not cause electrically induced pitting of the motor bearings

-Does not require expensive inverter duty motors

-Controller can be located any reasonable distance from the motor/drive without fear of motor damage

-True retrofit capability, works with existing motors and existing wiring

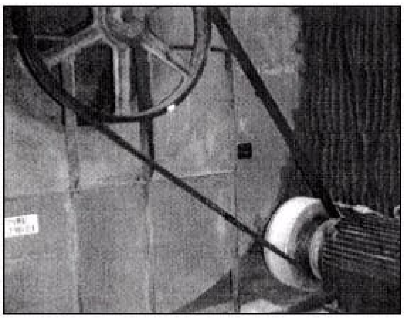
-Same compact, low wattage controllers for all horsepower drives

-Longer warranties for motors and drives

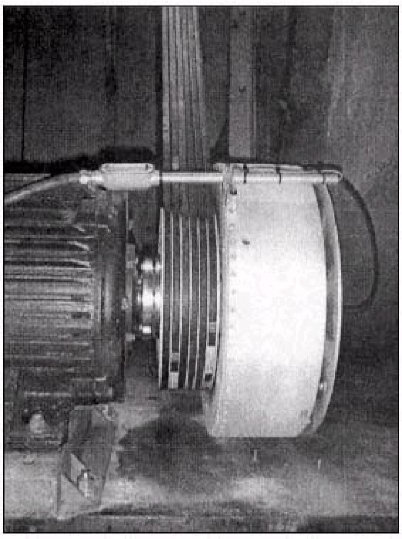
Installations & Applications

Since 1993, over 42 magnetic-coupled variable speed drives have been commissioned throughout the Dallas County Community College District as upgrade replacements for older, obsolete brush type drives. Horsepower sizes range from 3 hp to 150 hp. In over 5 years of operation, there have been ZERO reported drive failures and as of this writing, all are operating continuously without any maintenance.

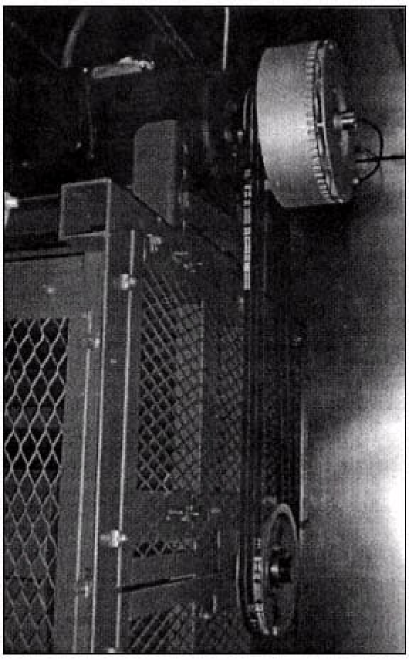
Shown here is a 150 hp drive installed in December of 1998.

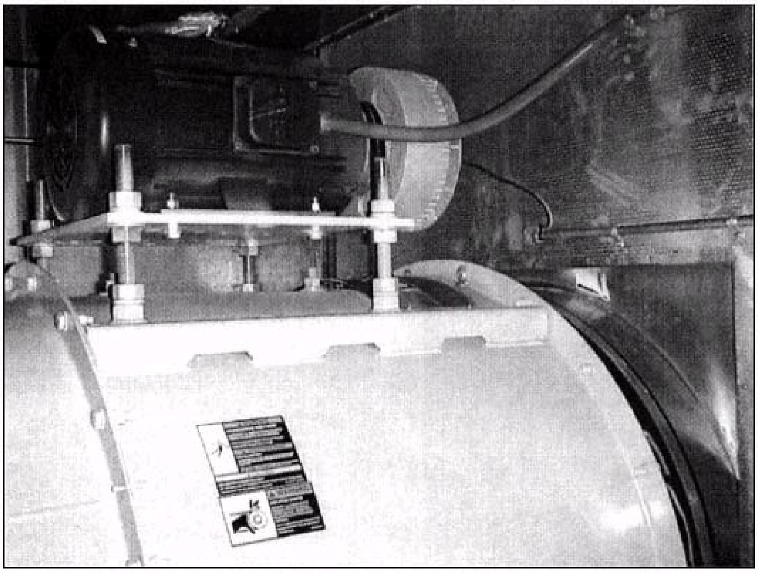


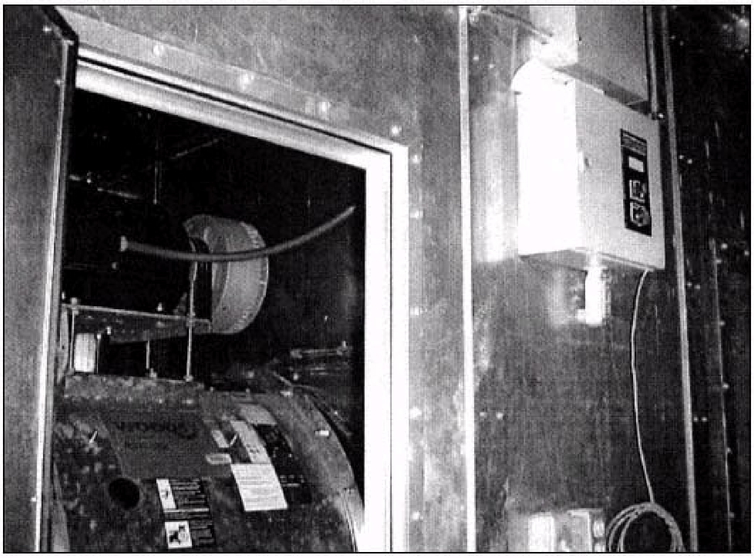
Eastfield College, Dallas Texas



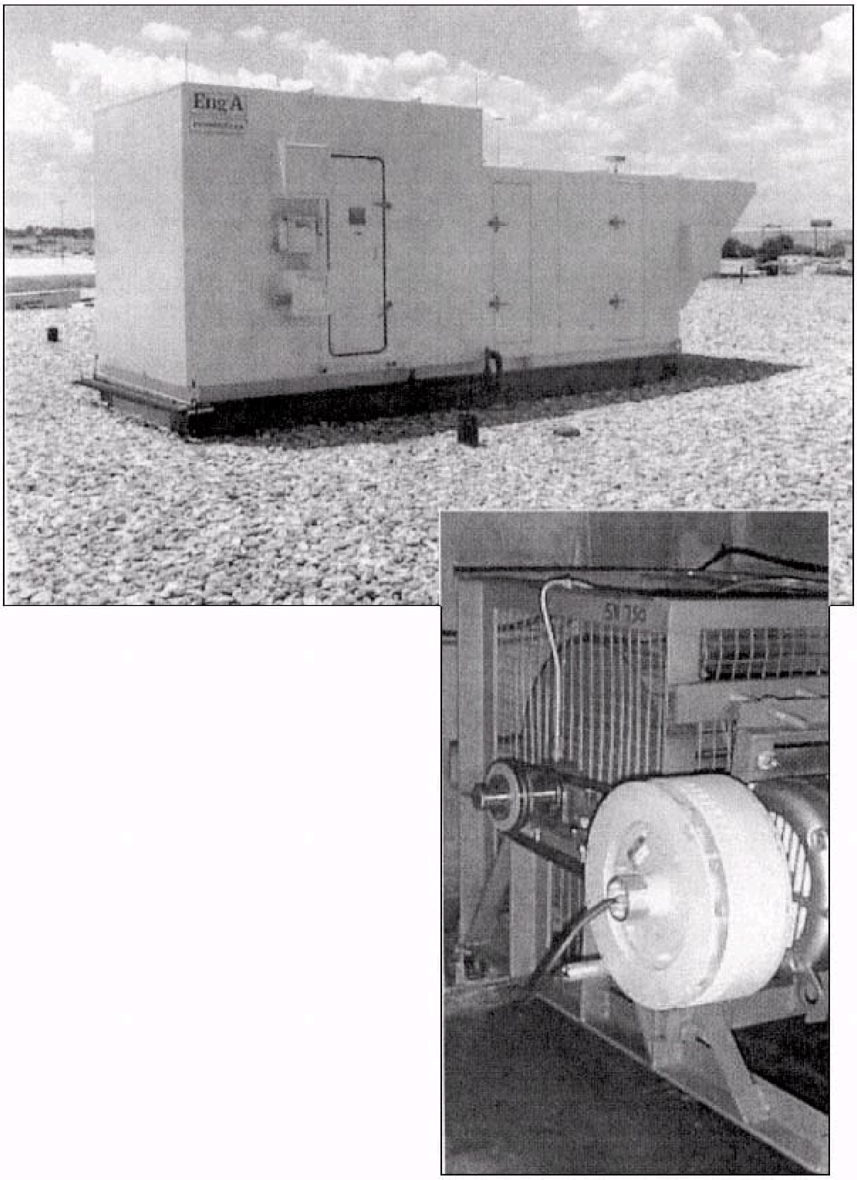
New construction, Twin Towers, Galleria,
Dallas Texas (31 Drives, 20–50hp)







FACTORY INSTALLED ROOFTOP UNITS

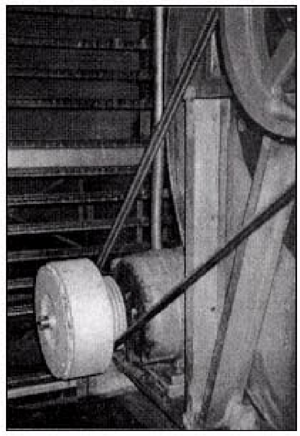


Multiple Air Handling Units Installed At A Hospital In Richland Hills, Texas

TYPICAL 75 HP VARIABLE FREQUENCY DRIVE

A GOOD CANDIDATE TO UPGRADE
TO A
MAGNETIC COUPLED VARIABLE SPEED DRIVE

PURE & SIMPLE RETROFIT



STEP #1:

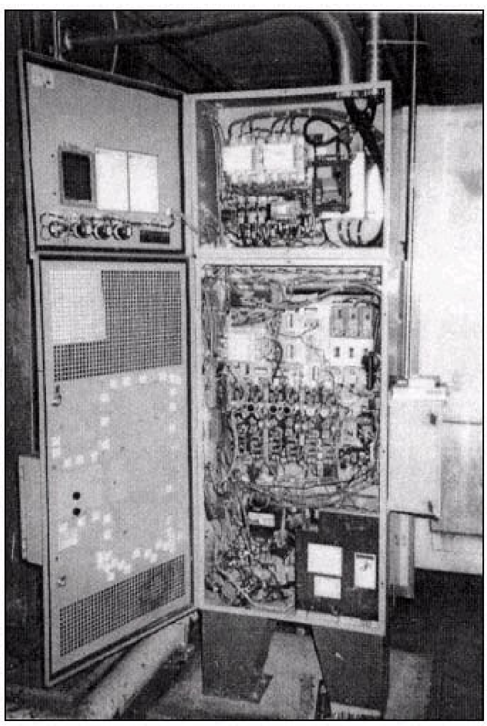
Replace motor pulley with Magnetic-Coupled Drive

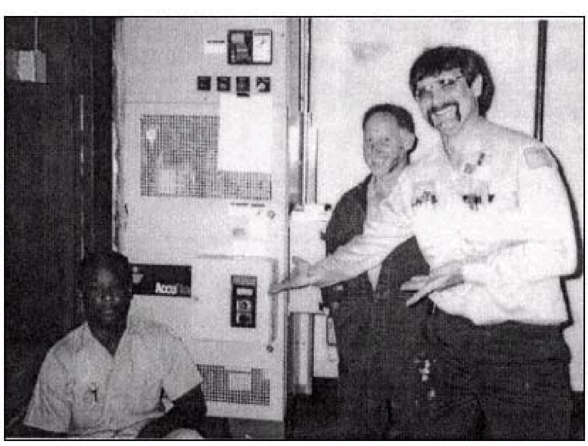
STEP#2:

Mount new controller on the door of the old VFD and connect two single phase wires

STEP#3:

Plug DC cable into Magnetic-Coupled Drive





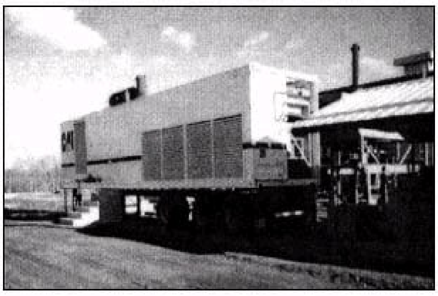
Installation Upgrade Performed By The Cheerful
Maintenance Team At The University of Alabama-Birmingham

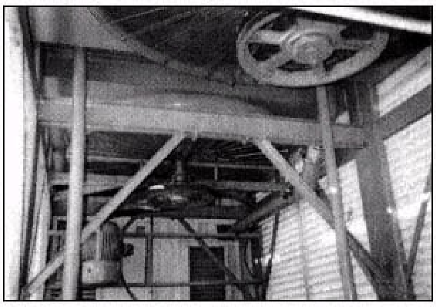
LANDFILL APPLICATION:
POWER GENERATION

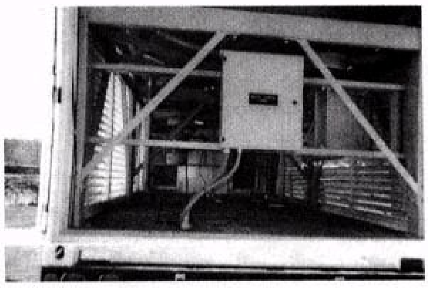
Methane Gas Powered Engine Generators

Problems:

- Excessive start/stops
- Reduced Equipment life
- High inrush fan motor current
- High motor loading during cycle on time
- High audible noise levels

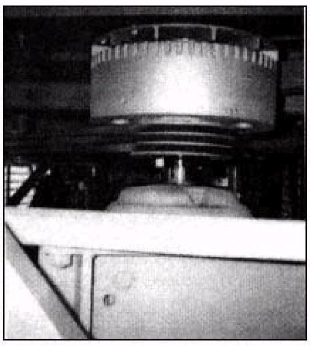






Solution:

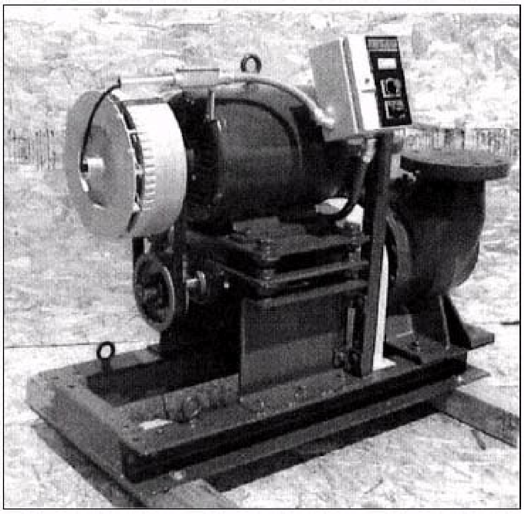
- Eliminates start/stops
- Extends equipment life
- Motor runs cooler
- Noise abatement
- Tighter engine temperature control by improved fan speed regulation

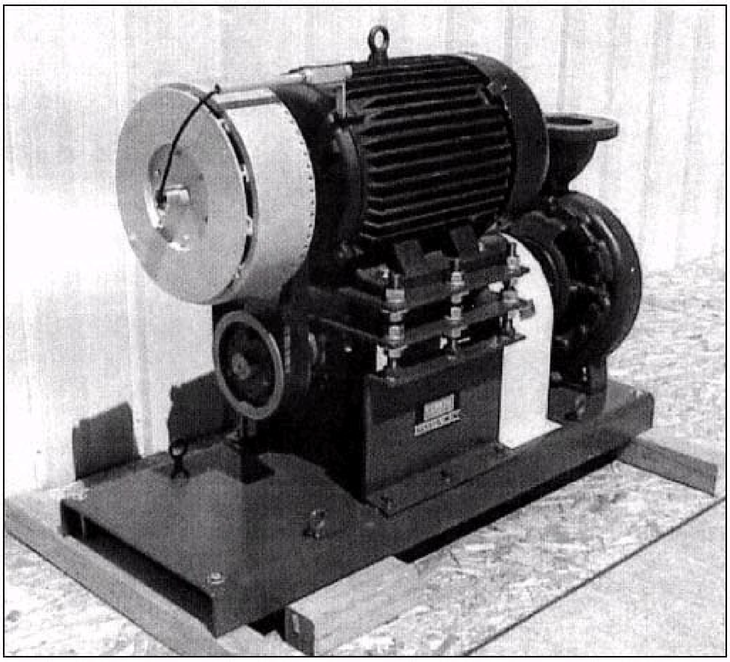


BELT DRIVEN
Variable Speed Pumps

Benefits:

- Saves energy
- Low maintenance
- Reduces vibration
- Reduces alignment problems
- Belts last longer due to controlled soft start
- Easy to change pulley during commissioning for correcting for full load rpm
- Zero harmonics

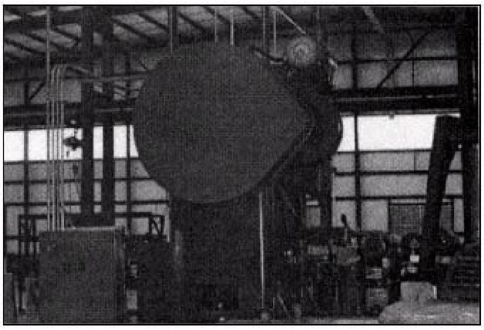


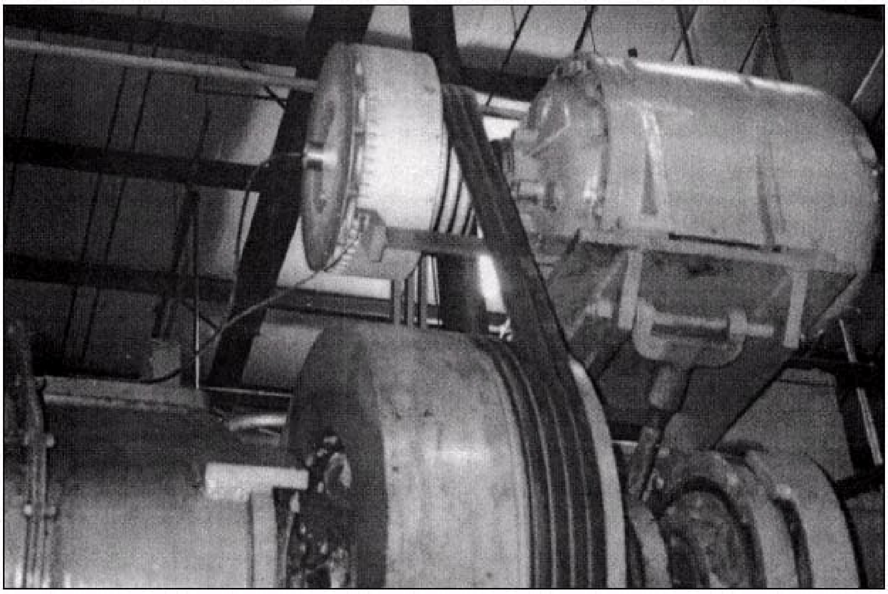


PUNCH PRESS
Magnetic-Coupled
Variable Speed Drive
RETROFIT

Benefits:

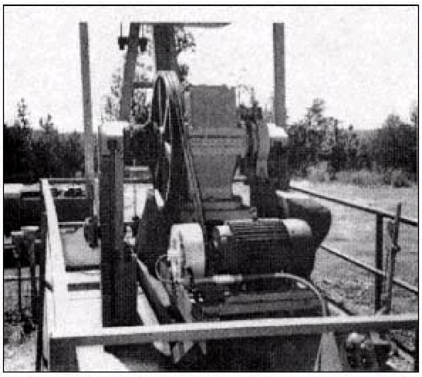
- Economical conversion to variable speed
- Easy to install
- Ability to adjust stroke when length of input product is changed
- Soft starting
- Reduced clutch-brake maintenance
- Driven equipment life is extended
- Improve process efficiency
- Drive maintenance is virtually zero

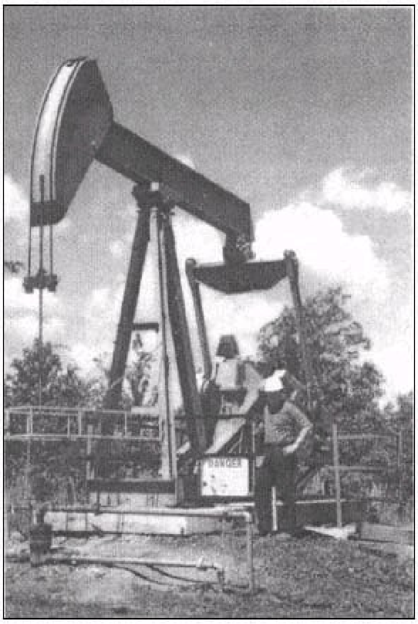




PUMP JACK APPLICATIONS

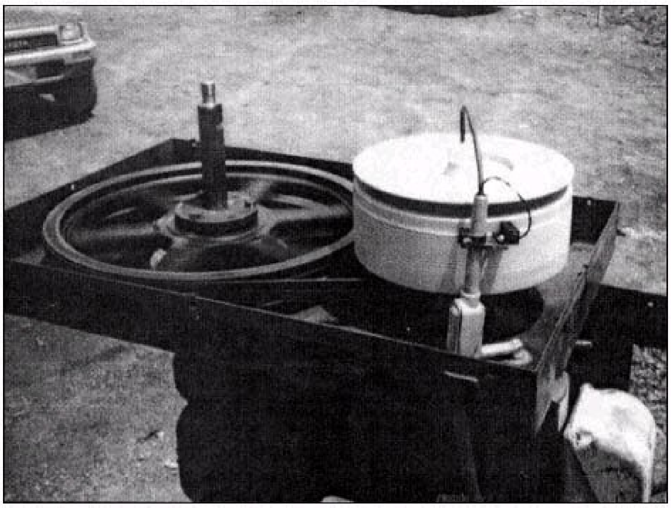
- Simple field retrofit
- Can use original Motors
- Does not require 3 phase power In rural areas





PROGRESSIVE CAVITY PUMP APPLICATION

Field retrofit shown with cover removed for illustration purposes. The drive simply replaces the original motor pulley.



Chapter 16— Continual Improvement of DOE's Super ESPC Program Through Project Facilitation

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Abstract

Since the inception of the Super Energy Savings Performance Contracting (ESPC) Program in 1997, the U.S. Department of Energy (DOE) has established six regional and three technology-specific Super ESPCs. Dozens of federal agency sites are now in the process of developing Super ESPC delivery orders.

Each Super ESPC project is a partnership between a federal agency's acquisition team and an energy service company (ESCO). A DOE project facilitator is assigned to educate the agency team, serve as the agency's representative or consultant, and lead it through the delivery order process to successful completion of the energy-efficiency project. The accumulated experience of the acquisition teams and DOE's project facilitators is beginning to contribute to the Federal Energy Management Program's (FEMP's) efforts to improve and streamline the Super ESPC Program. This paper describes what DOE project facilitators have learned about the areas where agency teams are requiring the most help and describes the strategies project facilitators are using to assure project and overall program success through continual improvement.

Background

In 1986 Congress gave federal agencies the authority to enter into shared energy savings contracts for the purpose of improving the energy efficiency of their facilities and cutting energy costs. This allows federal agencies to procure energy-efficiency upgrade projects without requiring capital appropriations to fund the projects. The contractor, or ESCO, capitalizes or acquires private financing for the project and then recoups the investment through a share of the cost savings generated by the installed energy savings measures.

Under the National Energy Policy Act of 1992, this concept was renamed energy savings performance contracting, although the basic concept remains the same. The contractor guarantees a minimum level of energy savings over the term of the contract, and energy savings are verified by an annual audit. The ESCO does not get paid unless the guaranteed energy savings are realized.

In an attempt to make ESPCs more accessible to federal agencies, DOE FEMP has developed indefinite-delivery, indefinite-quantity (IDIQ) Super ESPCs. Regional Super ESPCs are contracts with ESCOs that have been competitively selected and approved by DOE to fill delivery orders in their regional areas. Use of the Super ESPC "umbrella" contract allows a federal agency to negotiate a site-specific delivery order with one of the pre-selected ESCOs without having to start the contracting process from scratch.

The scope and design of Super ESPC projects can be defined by the government-agency customer (government- or agency-identified projects), or the agency can invite the ESCO to define a potential project based on information gathered from a walkthrough audit of the site (ESCO-identified projects). In both processes the agency develops a request for proposal defining the site-specific terms and conditions of the delivery order. For a government-identified project, the agency may either entertain and evaluate multiple proposals before selecting an ESCO or may decide to accept only one proposal from a single source. As defined in the IDIQ contract, the contracting officer may select the sole-source award approach based on the existence of specific circumstances. These circumstances include: the urgent need for the project, a highly specialized project (only one contractor can provide the level of quality required), to satisfy a minimum guarantee, or as a logical follow-on to a delivery order previously issued to a contractor on a competitive basis.

Flow charts are presented in Figure 1 and Figure 2 to depict the major steps or tasks involved in the delivery order award processes. After award of the delivery order the two approaches (government-identified and ESCO-identified) are essentially identical.

An ESPC project represents a partnership between teams representing the federal agency and the ESCO. The ESCO team comprises technical, management, and contracting staff with expertise in the identification, design, and, implementation of energy efficiency retrofit projects and Super ESPC contract requirements. Many federal agencies do not have comparable in-house energy management technical staff and resources available to support ESPC projects, and so may feel overwhelmed by the ESCO and the ESPC process. A principal role of the DOE project facilitators assigned to each project is to provide education, guidance and support for the agency during the ESPC process and to ensure that a balanced partnership is developed between the agency and the ESCO.

The DOE project facilitators have technical backgrounds, and are primarily Association of Energy Engineers (AEE) certified energy managers (CEMs) and registered professional engineers (PEs), with experience in all aspects of the development and implementation of energy efficiency retrofit projects. The standard level of support provided by the DOE project facilitators consists predominately of consulting-based services that are provided from the initial phase of project identification through the first annual verification of performance and energy and cost savings. If resources beyond this standard level of support are needed, they can be provided for a fee through the FEMP Service Network (FSN).

Lessons Learned in Project Facilitation

With dozens of projects now in various stages in the Super ESPC delivery order process, DOE project facilitators have identified the areas where agency acquisition teams are requiring the most help. The project facilitators are implementing various strategies to streamline the process, prevent delays, and assure project and overall program success through continual improvement. These strategies evolved primarily through experience with ESCO-identified projects, but can be applied to government-identified projects as well. In this section the problem areas and corresponding strategies are discussed.

Agency Preparation for the Kickoff Meeting

ESPC legislation, section 801 of 42 USC 8287, authorizes the head of a federal agency to enter into contracts for the purpose of achieving energy savings. Each contract may be for a maximum term of 25 years. Without other guidance the ESCO will likely base the proposed project on this maximum allowable term. Prior to the kickoff meeting, the agency acquisition team should determine their probable maximum contract term. Conveying this to the ESCO at the meeting will give them an important parameter to consider in developing the project. In a recent situation the initial proposal came in with a contract term of twenty years, while the agency wanted a maximum contract term of fifteen years. Because of this misapprehension of the maximum contract term, the project was delayed and the ESCO incurred unnecessary costs of reworking the proposal.

Agency Assessments of Wants and Needs

In all likelihood, all of an agency's wants and needs will not be met through an ESPC project. Before the kickoff meeting, the agency team should assess their wants and needs and establish which they think can realistically be satisfied through an ESPC project, and be ready to communicate their wishes and priorities to the ESCO at the kickoff meeting. The agency should understand that ultimately economics drives the project, which must be able to pay for itself through cost savings. The ESCO's job is to integrate agency goals into a financially feasible program, and this can best be done to the agency's satisfaction if expectations and priorities are clear from the outset.

Kickoff Meetings

A kickoff meeting is a highly recommended means of establishing communication, relationships, expectations, and protocols at the beginning of the delivery order project. The kickoff meeting should be arranged by the project facilitator and attended by representatives of the ESCO, the agency, and DOE. At the kickoff meeting, the steps involved in the project process and the roles and responsibilities of each participant are reviewed and discussed. This provides an opportunity for all the participants to meet face to face, get any unanswered questions resolved, and promote the team concept. Some of the key objectives for kickoff meetings are discussed in the following paragraphs.

Participation of the Agency Contracting Officer in the Kickoff Meeting

The common practice under the Southeast Region Super ESPC is to delegate contracting authority from the DOE contracting officer (CO) to the agency CO. For this reason, it is critical that the agency CO or a designated representative attend the kickoff meeting and come away with an understanding of his or her responsibilities and the project process. Valuable time can be lost if the agency CO is late getting on board and doing what is required to move the process along.

Develop a Delivery Order Milestone Timeline at the Kickoff Meeting

At the kickoff meeting, a timeline for milestones leading up to the signing of the delivery order should be developed and agreed to by both the agency and the ESCO (this timeline is not to be confused with a master timeline for design and construction of the project). Typical milestone goals may be marked as teams complete the site survey; develop, review, and approve the project profile; develop, review, and approve the initial proposal; issue the notice of intent to award and the delivery order RFP; conduct, review, and approve a detailed energy survey; develop, review, and approve a revised proposal; satisfy pre-award requirements; and sign the delivery order.

Discuss Agency Roles and Responsibilities and DOE Support at the Kickoff Meeting

Super ESPC projects will not go smoothly unless the members of the agency acquisition team thoroughly understand their roles and responsibilities and understand what kind of support will be provided by DOE as standard services. Agencies should also be aware of additional support services that can be procured from FSN. The kickoff meeting is the time for the DOE project facilitator to emphasize the agency's roles and responsibilities and ensure that they are well understood. A separate face-to-face meeting or telephone conference call (teleconference) between DOE and the agency should be held to review the agency's in-house resources and the standard services provided by DOE. Should the agency lack certain specialties or simply lack the time to accomplish certain tasks, DOE can provide a cost for these tasks to the agency for its consideration.

Establish a Communications Protocol at the Kickoff Meeting

Establishing a communications protocol at the kickoff meeting can ensure that all interested parties will know the status of ongoing activities throughout the ESPC project and that correspondence and action items will quickly reach those who need to attend to them. The communications protocol should identify the key individuals with DOE, the agency, and the ESCO, who should receive all correspondence and participate in all teleconferences. A policy should be set to require teleconferences at least once a month and more frequently during some stages of the project. Some ESCOs have relied on the agency to forward copies of their written correspondence and document submittals to the DOE project facilitator, which has resulted in unnecessary delays. The protocol should specify that the ESCO will send copies of all correspondence directly to the DOE project facilitator and the agency at the same time.

Preliminary Project Profile

Following the ESCO walk-through of the agency's facility and prior to the development of the initial proposal, the ESCO should develop a list of energy conservation measures (ECMs) that might be cost effective and a rough estimate of the costs and energy savings that would be associated with each. In a face-to-face meeting or teleconference, the list of potential ECMs can be reviewed by the agency, the DOE project facilitator, and the ESCO to eliminate any ECMs that the agency is not willing to support. The "scrubbed" list then becomes the preliminary project profile of the ECMs that the ESCO should consider in their initial proposal. Developing the project profile prevents the ESCO from wasting valuable time investigating ECMs that the agency cannot support or does not intend to implement.

Preparing the Delivery Order Request for Proposal

One of the most time-consuming tasks that the agency must perform is preparation of the delivery order request for proposal (DO RFP). This document defines the agency-specific requirements that will replace or supplement the requirements contained in the IDIQ Super ESPC contract. The agency should begin work on the DO RFP immediately following the kickoff meeting, while the ESCO is performing the site survey and preparing the initial proposal. The agency should never wait until after the initial proposal has been received and reviewed to start on the DO RFP.

"Hands-On" Assistance from the DOE Project Facilitator

Our experience with Super ESPC projects indicates that some federal agency customers need more "hands on" assistance from the DOE project facilitators, particularly assistance focused on critical milestones. An example of this type of "hands on" assistance is the support provided to one agency for development of the RFP. After providing focused training, the project facilitator followed up by helping the agency prepare the RFP document in two stages, which consisted of a "how-to" slide presentation followed by a working session. During the working session the project facilitator and the agency representatives edited a DO RFP template on a laptop computer. In cases where data were missing or questions remained unresolved during the working meeting, agency staff were identified to develop the required input, and a due date for input of the missing information was established. This process facilitated development of the DO RFP very effectively and demonstrates the type of assistance that is needed. The process can be readily adapted to other milestone deliverables such as the Site Data Package (SDP), Delivery Order Selection Document (DOSD), and Letter of Intent.

DOE/Agency Review of Submittals

To prevent unnecessary delays, the DOE project facilitator and the agency must provide timely reviews of all ESCO submittals. It is the agency's responsibility to provide resources, either in-house or procured from outside, to review submittals rather than relying solely on the DOE project facilitator for this service. The agency should plan for the required resources to be available and have reviews completed quickly. The DOE project facilitator can guide and coordinate the review process, but has no power to prioritize agency activities or dictate schedules. In coordinating the review process, the project facilitator should work with the agency to establish realistic deadlines. It is recommended that reviews be completed in one week. The project facilitator should compile all comments or clarifications from DOE and the agency, and deliver the reviewed documents to the ESCO within ten working days of its receipt.

ESCO Response to Comments and Clarifications on Submittals

The ESCO must develop responses to the comments and clarifications written in review of its submittals. Again, the project facilitator has no authority to establish ESCO and agency priorities and cannot dictate a schedule, but should encourage the ESCO to respond within ten days of receipt. It is also recommended that a meeting be held for the purpose of reviewing the ESCO's responses and reaching consensus that the ESCO has satisfactorily addressed all comments and clarifications. The ESCO should prepare and submit in advance of this meeting any items such as additional data or calculations that might require evaluation.

Initial Proposal Format

The ESCO should be reminded that the IDIQ contract defines the required contents of initial proposals for contractor-identified delivery orders and that this format should be followed. ESCOs should be able to develop initial proposals at modest expense, but they should also provide sufficient information for the agency to determine the feasibility of the proposed project. Several initial proposals did not follow the prescribed format and did not contain sufficient information about proposed energy savings. The IDIQ contract requires that the proposed energy savings be calculated using formulas and procedures based on accepted engineering principals and references should be cited for data, assumptions, or empirical formulas. Failure to include sufficient information results in delays while the required information is assembled and delivered.

Review of Initial Proposal

The initial proposal is based on a brief walk-through of the facilities rather than a detailed energy analysis and design. The intent is for the ESCO be able to develop preliminary proposals at a modest expense to demonstrate that a project does or does not have merit. DOE and agency representatives should balance the review of the initial proposal with the level of effort expended and the content requirements established in the IDIQ contract, with comments/clarifications organized into two categories. The first category should focus on issues that have a significant impact on the ECMs proposed and the economics of the proposal such as gross errors in calculations or assumptions. The second category should address issues that would have minor (5 to 10%) impacts on the estimates of savings or implementation costs and could be addressed in later stages of project development, such as in the revised proposal. At this stage, the project facilitator needs to focus on getting the agency to ask whether the initial proposal has enough merit to warrant allowing the ESCO to further develop the proposed project.

One-Time Ancillary Cost Savings

The IDIQ contract allows the agency to consider one-time ancillary cost savings, per the following: "If money is available for a project or task related to the energy systems being modified by the contractor, and that project or task will not have to be accomplished by the Government if the contractor performs the proposed delivery order, then that savings can be considered as one-time ancillary savings." A key to the use of one-time ancillary cost savings is that the money must be available to the agency to pay the ESCO. If an agency intends to use one-time ancillary cost savings and the ESCO is to include these savings in the cash flow analysis, the availability of the money should be verified before submission of the initial proposal. Including one-time ancillary cost savings and later discovering that the money will in fact not be available could mean that the project would not be feasible.

Summary and Conclusions

The primary role of the DOE project facilitator is to provide guidance to the ESPC team to ensure project success. Based on our experience in fulfilling this role, we feel that the strategies described in this paper can help any project facilitator streamline the process and prevent delays.

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1. Carroll, D. M. March/April 1999. Financing Energy Projects at Federal Facilities. *Energy Manager* Volume 2, Issue 3.

2. Department of Energy. National Energy Conservation Policy Act, Title VII, sections 801 to 804, Energy Savings Performance Contracts. 42 USC 8287.

3. Department of Energy. 1994. *Southeast Region Super Energy Savings Performance Contract Delivery Order Guidelines*. Version 2.0.

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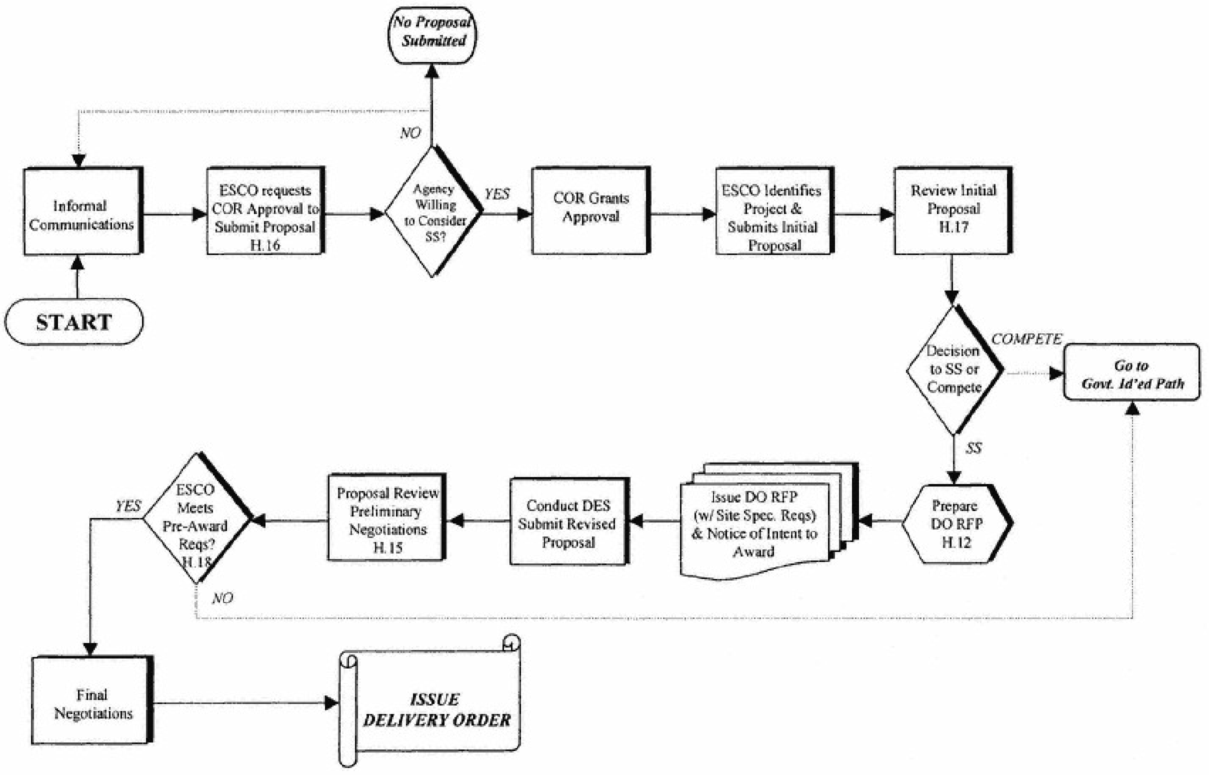

Figure 1
Esco-Identified Projects Award Process

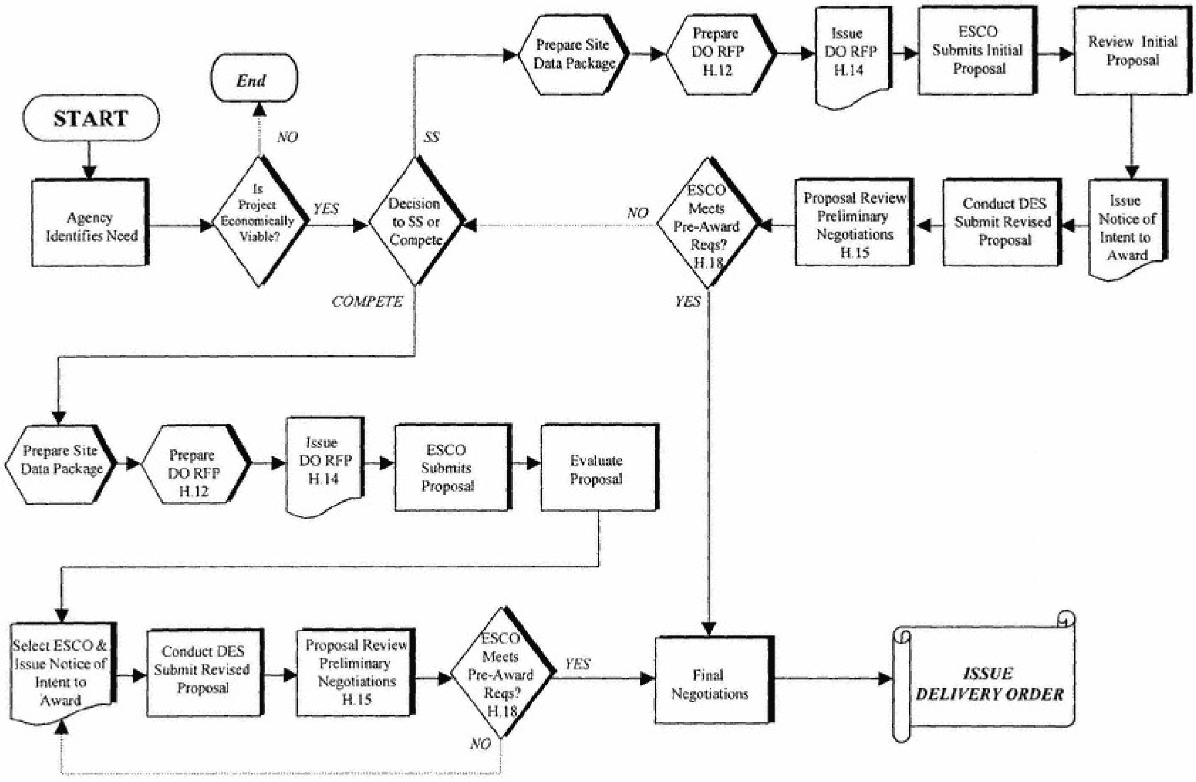

Figure 2
Government-Identified Projects Award Process

Chapter 17— Lessons Learned: Utility Financing of Energy Efficiency Projects at Federal Sites

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Introduction

Mandated energy savings goals for Federal agencies have now been increased with the issuance of Executive Order 13123 (Federal Register June 1999). These revised goals are in addition to those already set forth in the Energy Policy Act of 1992 (EPAct) and Executive Order 12902. The preferred route for completing projects necessary to meet the goals is to continue to utilize alternative financing tools available through Energy Savings Performance Contracts (ESPCs) or Utility Energy Service Contracts (UESC). Implementation of either form of alternative financing has the same objective, to reduce energy consumption and thus cost so agencies can operate in the most efficient manner.

Last year, information was presented on the progress of both alternative financing activities in the Federal sector through the U.S. Department of Energy's Federal Energy Management Program (FEMP) (Sandusky et al. 1998). Now that more detailed information has been collected on UESCs, the results and lessons learned from UESC implementation will be presented separately. The objective of this paper is to focus on those specific lessons learned through the implementation of UESCs. In addition, highlights of the Utility Service Program activities within FEMP will be reviewed in terms of redirections made as result of lessons learned. We again will share the expected program activities in FY-2000 based on the lessons learned and pace of UESC project implementation.

Utility Service Program

The Utility Service Program within FEMP continues to work toward its primary goal of developing successful partnerships between agencies and their serving utilities so private investments can be made at Federal sites through UESCs. One of the primary objectives continues to be providing focused information to both agencies and utilities so UESCs can be developed, limitations identified, and ultimately projects implemented in a rapid manner so agencies can benefit from the resulting cost savings. The other objectives include providing an avenue for continued awareness of activities that support UESCs at Federal sites. To signify this overall thrust, a program vision statement was developed to provide an anchor for current and future program activities and set the bound for program activities. The current vision statement is given below.

"The Utility Service Program will be a leader in the facilitation of partnerships between regulated utilities and their Federal customers for the identification, design, and implementation of cost-effective energy efficiency, water conservation, gas conservation, mobility, and renewable energy projects at Federal sites. In the restructuring area, we will focus on providing technical assistance on energy-efficiency projects, utility services, renewable energy project opportunities, and other value added services. The Program is committed to the highest standards of quality and objectivity in all its activities. All activities are in direct support of the mission of the Federal Energy Management Program effort to help agencies in reducing their energy-related cost of doing business.

We believe the program vision is founded on continual establishment and maintenance of an open and effective dialogue between utilities and their Federal customers and energy service providers. This will allow all parties to identify the best opportunities that serve the site needs, and work together to design and implement both energy and cost efficient activities in a rapid and effective manner. We believe this is best accomplished by creating a team of creative, innovative, and motivated staff that support all *program activity. This team will excel at integrating their capabilities into a tailored and comprehensive fashion that meet the needs of both utilities and Federal agencies.*

The program will be flexible due to the dynamic nature of the utility environment and will focus on continuous improvement that will strengthen existing partnerships and create a positive environment for the establishment of new ones."

Current work activities were broken down to closely follow the overall goal and objectives of the program. Common activities have grouped into specific tasks to provide a focus for all team members. The current program tasks are given below along with a short description of related activities.

Planning/Coordination: Provide method for information exchange among program participants regarding progress toward completing planned activities, identification of problems, and potential problem resolution.

Procurement Resolution: Development of agreements and memorandums to assist understanding of the overall UESC procurement process. Respond to Congressional request regarding the status of alternative financing activities within the Federal sector.

Communication/Outreach: Provide for continuous flow of information regarding activities and available support via conducting Federal Utility Partnership Working Group meetings, utility action kit enhancements, improved web site information, and providing the various Federal Partner Resource Centers with new FEMP tools and information documents.

Training Activities: Providing direct interactive training via both workshops and teleworkshops in the areas of the impact of utility deregulation and Utility incentives.

Technical Assistance: Participation in development the utility portion of the FEMP Service Network and providing direct technical assistance to critical project development.

Summary Information: Collecting and providing information regarding investments through UESCs to document the rate of investment and development of user friendly computer systems that provide information on Federal facilities, available utility incentive programs, and completed or ongoing UESCs.

Water Issues: Working with water utilities to create partnerships with agencies to develop and implement projects under available incentive programs.

Gas Issues: Working with gas utilities to encourage partnerships with agencies to develop projects at Federal sites under available incentive programs.

Utility Restructuring: Participate in activities of the restructuring subcommittee of the Interagency Energy Management Task Force that deal with competitive power procurement and dissemination of information regarding restructuring that have value to agencies.

Lessons Learned

During FY-1999, various problems and issues were encountered and solutions developed. Sharing of this information is key for continuing the overall thrust within the program. While some of the lessons listed below may be obvious, the resulting impacts is often more profound than expected.

Lesson 1—
Big Surprises Can Come in Small Packages

The Anti-Deficiency Act (31 U.S.C. §1341), prohibits an executive agency from making expenditures or incurring obligations in excess of available appropriations and also prohibits from making a contract or obligation for the payment of money in advance of appropriations. Thus, as a general rule, the cost a contract must be fully funded at the time the Government enters into any contract. The Act however, provides Congress the ability to authorize agencies to "contractually" obligate the Government without the availability of appropriated funding. Implementation of this authorization is embodied in guidelines set forth in Federal Appropriation Law.

Early in FY-99, a concern was raised within DOE, that UESCs are bound by the Anti-Deficiency Act and did not fall under the option of contractually obligated funding. Energy Savings Performance Contracts, on the other hand, through legislation have been exempted from any requirements set forth in the Anti-Deficiency Act. The resulting impact was that some agencies, including DOE, were hesitant in entering into UESCs fearing that procurement actions would be in violation of the Anti-Deficiency Act.

What seems to be a relatively simple issue to resolve actually became the major news story within the Utility Service Program. Various false starts, personnel changes, and difference of opinion within the DOE Office of General Counsel created a barrier that was not resolved until the later part of FY-99. In the interim, some sites resisted implementation of projects and in some cases utilities withdraw their plans to offer UESCs due to the long duration required in the decision making process. Thus, what initially was considered a relatively easy solution took far more time than was anticipated resulting in lost dollar savings to the agencies. The lesson learned was to stay on top of the process and request continual progress reports and develop information regarding the potential impact based on the length required to make a decision and provide that early to decision makers.

Lesson 2—
You Need to See It to Believe It

A focus of the Utility Service Program over the last year and a half has been to collect data on specific UESC projects at Federal sites. This data has been very revealing in identifying trends in the utilities investment with the Federal government over last several years.

By gathering specific information on cost and completion dates of projects, a trend in the rate of investment by utilities has been determined, as shown in Figure 1 below. These curves show the rate of investment for currently awarded and completed projects and projects which are anticipated to be completed in the future. The high rate of change in the completed and awarded curve demonstrates the major impact that utilities are currently making in financing and facilitating energy efficiency projects in the Federal sector. The rate of investment into the future shows the curves "flattening" out, which is probably due to the lack of data, but may be caused by the agencies conflict with the Anti-Deficiency Act (see Lesson 1).

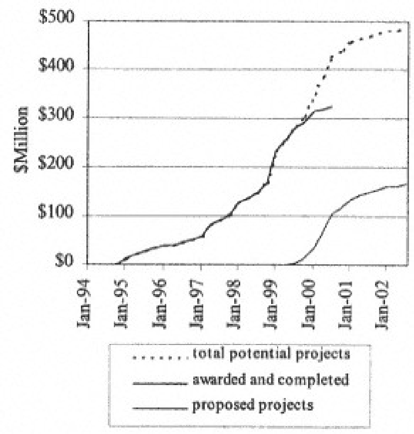

Figure 1
UESC Investments Rate of Change Over Time

Technology Breakout

The project data has also revealed an interesting trend in the types of technologies being implemented at Federal sites. Figures 2 and 3 show the predominant technologies for completed and awarded projects and proposed projects (proposed projects are all projects that are anticipated to be completed sometime in the future). For completed and awarded projects, the data reveals that many projects implemented singular technology upgrades, i.e., motor or lighting upgrades. In proposed projects, there is a much greater tendency toward comprehensive upgrades as shown in Figure 3.

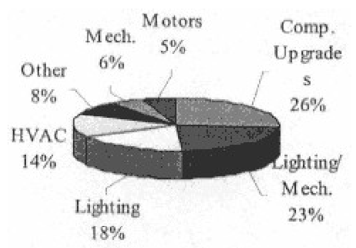

Figure 2
Completed & Awarded Projects Technology
Breakout (Based on Project Cost)

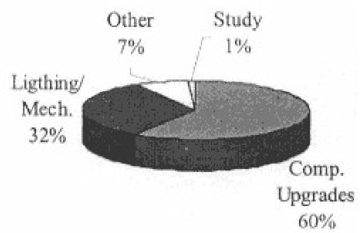

Figure 3
Proposed Projects Technology
Breakout (Based on Project Cost)

Finance Mechanism

The data is also showing that Federal sites are requiring more third party financing. Over the past few years, demand side management-type rebates and Federal appropriations have been rapidly declining, while third party financing of projects have been on the rise, as shown in Figure 4. This chart exhibits that although some traditional avenues for financing are declining, utilities are finding creative ways to work with their Federal customers, providing value-added services.

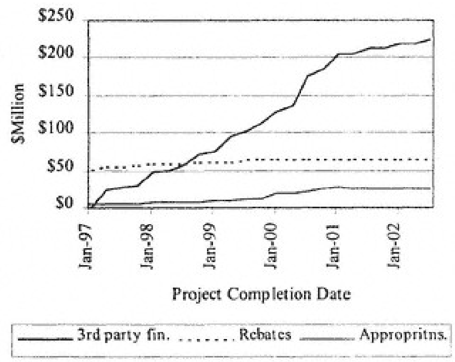

Figure 4
Finance Mechanism for Uesc (Based on Project Cost)

The lessons learned in the data collection process is that you need to know where you have been before you decide where or how to go. Having numbers regarding the overall level of investments through UESCs along with the types of technologies implemented is very useful for understanding the magnitude and type of projects under UESCs. It's also helpful in showing to individual sites the fact that UESCs is a viable alternative financing method. The more important lesson learned here was the data collection and analysis effort should have been designed and tested several years ago as the program was evolving. There was a tendency to hesitate on data collection until there was enough project data to make the effort viable. Instead, it would have been wiser to develop a sound methodology at the initial stages of development.

Lesson 3—
First Impressions Can be False

As the concept of alternative financing has matured over the past several years, one of the basic difference between using an ESPC versus a UESC has been the concern regarding the lack of interest by the utility industry to guarantee the expected energy savings. This created the impression that utilities were only interested in a very limited level of energy-efficiency and renewable projects. While utilities are not required to offer UESCs or guarantee savings, it is the responsibility of the Federal agencies to consider all alternative financing options that might be available.

In FY-99, the Edison Electric Institute, which represents investor owned utilities, worked with a core group of its members that offer UESCs at Federal sites, to developed an industry commitment to Federal energy efficiency and renewable energy goals. The basic objective of this commitment statement was the electric industry would provide their Federal customers with alternative financing and support services to implement at least $1.2 billion dollars in life-cycle cost effective facility improvement projects to achieve the goals set forth in EPAct and Executive Order 12902. The statement itself was a strong statement of partnership from the industry to support activities that ultimately would reduce the cost of going business in the Government. Some of the key elements of the statement include the following commitments.

Assist Federal customers in the appropriate levels of energy use at the lowest life cycle cost through integrated energy management techniques that include a fuel neutral analysis of the full range of opportunities for energy efficiency, renewable energy supply, and education regarding the competitive purchase of electricity commodity where such service is available.

Assist Federal customers in deployment of life-cycle cost-effective energy projects in support of National goals and initiatives, such as Million Solar Roofs.

Assist Federal customers in obtaining access to green power for Federal facilities.

Participate in partnerships with Federal agencies, equipment manufacturers, and the renewable industry to demonstrate and showcase both energy efficiency and renewable energy technologies.

Select contractors to execute work under UESC using a competitive process.

Offer monitoring and verification and performance guarantees, if desired by the Federal customer and available from the utility.

Conduct processes and accounting activities related to the specific Federal projects in an open book manner, as required by Federal law.

While the commitment statement doesn't apply to municipalities or cooperatives that might serve Federal sites, it does represent a goal by which the electric industry will be measured with regard to supporting Federal energy manager activities over the next five years. It also serves as a focal point for those utilities that want to provide value-added services to their Federal customers.

The ultimate lesson here was that first impressions can be false. By the customer dialoguing their needs, utilities can build a partnership that work well for both parties. Another important lessons learned was the acceptance by both parties that the commitment statement is a "living" document and modifications can and will be made as more data and information is obtained regarding implementation of UESCs at Federal sites.

Lesson 4—
Some Things are Easier Said than Done

In FY-99, a concerted effort was made to collect information regarding completed, awarded, and proposed UESC activities at Federal sites. The rationale for the data collection was to gather the necessary information to establish the time rate of change of investment (see Lesson 2). This information could then be compared to what was previously estimated necessary from UESCs so overall mandated energy savings goals would be met.

Again, what seems to be a fairly simple process actually was far more complex than anticipated for the following reasons.

Agencies much prefer to report data on an aggregated basis than by site.

If agencies were hesitant to provide data, the alternative source was utilities whom in most cases have legal requirements related to the release of information related to a negotiated UESC.

There were numerous request for presenting a cumulative summary data. This required that assumptions to be made regarding missing pieces of data for a specific project.

There was considerable debate if the cumulative data should be total project cost—capital plus financing cost, or just capital cost.

Some projects consisted of both appropriate funds used in conjunction with negotiated UESC. This created an accounting issue regarding the proper cost to be used in summarizing overall private investment through UESC.

The mandated savings goals are for buildings, while some UESCs included both water or were for mobility activities. This also created an accounting issue.

Some utilities want their UESC data aggregated across agencies within their service area instead of providing information on a site basis. In some cases, they are reluctant to provide information on the types of retrofit activity that was completed.

Several lessons were learned in the process of collecting and summarizing data. First, there should have been more time allocated toward determining how the data will ultimately be presented so the appropriate pieces of data are collected at the beginning. It's always frustrating when you have to make several request for information in your effort to have the most complete data set. Second, determining the expectations for the use of the data is important to consider. This will impact the data elements to be collected and the ability to provide summary information in various formats without additional data collection. Third, understand how agencies report information on UESCs. Agencies have a wealth of information, but typically located at a variety of sources. Fourth, ensure that utilities and agencies are aware of how the data **might** be ultimately presented. Then receive approval on public release of data at the time of data collection so that there is more flexibility in how the data is distributed and used. Fifth, understand how information is reported for other alternative financing options so data sets can be compared. Finally, expect to complete some form of a reconciliation of results to ensure quality. As was once said regarding another very large Federal data collection effort, "It's easier to recover from bad analysis than bad data."

Lesson 5—
There are Many Roads to Success, but Potholes Do Exist

There is no "standard" or universal UESC that can be applied to all sites. The method of contracting can vary according to the choice of the contracting officer. Contracting can be done through Basic Ordering Agreements, as site specific delivery order under a General Services Administration (GSA) Areawide contracts, or through an established Basic Ordering Agreement under an Areawide contract that GSA has in place with the utility. However, to assist in the development of a Basic Ordering Agreement, model agreements have been established for both Department of Defense agencies and civilian agencies. The most important element of the process is the utility has to be willing to develop a UESC with a Federal agency. Given the impact of deregulation in the electric utility industry, some utilities can't enter into partnerships under codes of conduct, or feel the need to given the low cost of electricity they are providing to the Federal sites.

Ahead in 2000

Alternative financing concepts, in terms of either ESPCs or UESCs, are in widespread use in the Federal government. While over the past several years the focus of FEMP has been to develop, award, and complete projects under ESPCs, the time has come to move toward an integrated alternative financing concepts that ensures all available options are considered. Therefore, FEMP will be moving to create an integrated alternative financing approach that treats all options in a manner useful to the customer.

The design for the creating this approach is still in the preliminary stages. However, information regarding UESCs, information regarding current success stories progress toward meeting desired goals will be a significant portion of the integrated program. It is important to note that FEMP's intention is to continue to foster the development of partnerships between utilities and agencies for the purpose of identification, design, and implementation of energy efficiency, water conservation, and renewable energy projects at Federal sites. Thus, activities such as the Federal Utility Partnership Working Group will continue to provide a medium for developing new and enhancing existing partnerships. Electric utility restructuring will continue to a focal point of activities at both the state and Federal level. FEMP activities supporting outreach, education, and summary reporting will increase markedly to provide agencies information so they can make informed decisions. As part of this effort, information on restructuring will become a major element of the FEMP home page.

For Additional Information

A vast array of information and tools are available from FEMP regarding the Utility Service Program that may be useful to agencies. The most comprehensive source is the FEMP home page under the *Financing Alternative* menu in the *Utility Incentives* section: http://www.eren.doe.gov/femp/financing/utilincentives.html

Additional information can be obtained via the following resources.

·*FEMP Help Desk:* ***1 (800) DOE-EREC***

FEMP Office Phone: ***(202) 586-5772***

FEMP Office Fax: ***(202) 586-3000***

Hard Copy material also can be obtained from the FEMP booth in the Trade Show of this Congress meeting.

Acknowledgments

The success of the Utility Service Program at FEMP has always been dependent on both the individual and collective efforts of staff at the national laboratories that support FEMP in this program. The major contributors include:

National Renewable Energy Laboratory: Mary Colvin, Chandra Shah, and Karen Thomas *Lawrence Berkeley National Laboratory:* Chuck Goldman *Pacific Northwest National Laboratory:* Mike Warwick

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This year the program suffered a major loss with the untimely death of Lou Harris, the FEMP Utility Service Program manager. His wisdom, guidance, and perseverance for excellence was an inspiration to every team member. He is deeply missed by all.

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Chapter 18—
The Retrofit & Upgrade of the Loews NY Hotel

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Harvey Scher, Director of Engineering
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Ali Deniz, Project Engineer

Abstract

This paper describes the upgrade carried out on a 35 year old hotel in midtown Manhattan, New York City. It follows the selection, design, construction, and start-up of the improved facility and provides useful guidelines for the upgrade of similar facilities. It describes the energy related improvements and controls incorporated into the design which will allow the facility to continue to provide outstanding services and comfort to the guests while reducing the cost of operation.

The Challenge

The Loews NY Hotel was constructed in 1963. It consists of 722 guest rooms and suites, health club, restaurant, lounge, lobby bar, and a dozen meeting rooms. The central plant which provides heating and cooling for this facility was 35 years old in 1998. It was time to retrofit and upgrade the physical plant for the new millennium. The Loews Corporation, with the leadership of the Hotel's Director of Engineering, wanted to maximize the benefits that could be achieved with the replacement of facility's now antiquated equipment, do it quickly in order to be ready for the next cooling season, and pay a reasonable price for the equipment and services to be provided. It was decided to seek proposals from several sources. These included an equipment manufacturer who offered "full-service" installations, and an energy management company.

The proposals required approximately 3 months to obtain from these various sources. The solicitation was informal and requested that each proposer provide a system of equipment replacement that would meet the Hotel's needs. The basic parameters outlined included new chillers with a capacity of 600 tons, new pumps, free cooling (if economical), new cooling tower, and new control system. Each proposer presented their written materials and made an oral presentation to the Loews engineering staff. The proposals received and the presentations made were used to select a company to provide the retrofit and upgrade services on a design-build basis. This process would be overseen by the Hotel's engineering department, who reported progress to Loews corporate engineering manager.

KeySpan Energy Management, Inc., an energy service company with headquarters on Long Island and serving the tri-state area was selected for their added value and energy efficient approach. KeySpan was able to quantify the various alternative energy consumption approach options available for the Loews corporate and facility personnel. The proposal offered two (2) 300-ton screw chillers, a 200-ton plate and frame heat exchanger for free cooling (when available), a 2-cell cooling tower, and a new control system. A letter of intent was issued in order to expedite the engineering required for the project. A contract was negotiated and signed by both parties while this engineering proceeded.

Design & Engineering

The design of Loews NY Hotel is an excellent example of the KISS (keep it simple, stupid) principle. It was reviewed by KeySpan's internal design, engineering, construction and operations department's personnel. Each of these disciplines brought their experience and expertise to bear on this design. The design department contributed a workable layout for the redesigned facility and equipment. The engineering department contributed equipment familiar to the Loew's staff which was historically reliable, sized to the site constraints, and which provided an equipment layout that would enhance the operation of the system. The construction department added the ease of installation to the design and brought many issues and details of the facility design into focus for both engineering and design personnel. Finally, the operations department reviewed the design for maintainability. They added flanges at specific locations to ease access and tap locations for sampling, corrosion coupons, and chemical additions. A simplified Schematic Diagram of the system is included as Figure 1. A photo of the new mechanical equipment room is included as Figure 2.

The economy of first cost is brought to the job by design in the selection of equipment for automatic control, as opposed to automatic isolation. This can be seen by reviewing the schematic diagram of the system. See Figure 1. Note that each flow circuit through a chiller has a single control valve. Isolation for off-line maintenance continues to be a manual function. This philosophy has been applied throughout the system design. It resulted in a system with 14 control valves, a minimum for the desired degree of automatic control. Each of the control valves is provided with internal limit switches and isolation for repair or replacement. Each control valve also has a manual override that allows the valve to be manipulated if it suffers a control failure.

The system pumps are provided with check valves instead of control valves. Isolation (manual) for pump repair or replacement is incorporated in the design, however, these valves are normally open and back-flow is prevented by the check valve at each pump discharge. The pumps are also innovative since the impeller is mounted directly on the motor shaft. This eliminates the coupling, its additional space requirement and its added maintenance and efficiency loss. Pump leakage along the shaft is controlled by mechanical seals and access is provided by a boxed insulation design. Photos of the new pumps and piping arrangement are included as Figure 3.

The system strainers have been selected for general protection and to protect the moving parts of the system. General protection is provided by a single 10-inch strainer in the condenser water supply from the cooling tower. This strainer can be blown down periodically and prevents the entry of tramp material from the cooling tower. It may be isolated from the riser for replacement or repair. It is also provided with local pressure gauges before and after it to assist in troubleshooting it's blowdown or to assist in determining it's blowdown or cleaning requirements.

The system instrumentation is designed to report "system" operation. Pressure differential is measured and reported across four (4) loops: the condenser water loop, the north loop, south loop, and mezzanine loop. Individual pressures are measured only by local gages. They are provided for troubleshooting and maintenance. The differential pressures report the operation of their respective loops to the control system to verify operation per the operator selections and automatic settings.

Temperatures are measured in a similar fashion. The supply and return temperatures for each loop are measured and reported to the control system. Temperature measurements are not duplicated in the system.

The original condenser water system was served by a single cooling tower cell with a constant speed 40 horsepower fan. The upgrade would replace this with a 2-cell tower with each cell having a 15 horsepower fan. In addition, the speed of the fans would be controlled by a variable frequency drive to maintain the cold water output at 3–7 degrees above the wet-bulb temperature. The combination of variable speed drive and split tower capacity would allow the tower to be run more efficiently. The upgraded tower was also provided with basin heaters for freeze protection and the lines above the roof were heat-traced and insulated. The cooling tower was now capable of operation for free-cooling. The new cooling tower is shown in Figure 4.

A 200-ton plate and frame heat exchanger was added to the facility mechanical equipment in order to capture those opportunities which would allow the outside wet-bulb air temperature to provide free cooling to the facility. This would be most useful to the Lobby and Restaurant (mezzanine loop) which experienced uncomfortably warm temperatures while the remainder of the building continued to require heating. This occurred in the spring and fall when free cooling was often available. In addition, a small chilled water pump was associated with this "free cooling" system to more efficiently provide up to 50-tons of cooling to the mezzanine loop. A main chilled water pump is used if more than 50-tons of cooling is required and available through the free cooling heat exchanger. Photos of this heat exchanger are included in Figure 5.

The major equipment was ordered shortly after the completion of the schematic design in order to meet the tight delivery and construction schedule of the project. This included the two 300-ton screw chillers, cooling towers, eight pumps, plate and frame heat exchanger, and motorized control valves.

Construction

The construction activities began with the selection of subcontractors for the various trades and tasks to be carried out. KeySpan's construction group acted as the general contractor for the job. The trades subcontracted included: demolition, rigging, mechanical, electrical, general construction and clean-up, controls, and insulation. All subcontracts were let in January and were within the overall budget for the project.

The schedule for the demolition of the old equipment and installation of the new equipment and systems was very aggressive. The demolition began in January, 1999. It was preceded by electrical disconnects and safeing. The demolition was held up for 2-weeks when asbestos was found on the old chillers. The asbestos work was the responsibility of the owner who quickly authorized KeySpan to correct this oversight and continue the construction. This was monitored and abated as quickly as possible and the demolition work resumed. The anticipated construction completion date moved from April 12th to April 26th due to this delay. However, KeySpan planned to compensate for this by bringing on the plate and frame heat exchanger first, along with a single condenser water pump and small chilled water pump, to provide chilled water to the mezzanine, if required.

The mechanical installations began with the delivery of the major equipment to the site in February, 1999. Equipment locations were established and the foundations and mounting pads were poured or modified from their original configurations. The piping installations began immediately after the major equipment was mounted.

In early March, 1999, the cooling tower was delivered to the site and hoisted by crane the 270 feet to the roof of the hotel. This work was carried out on a Saturday in order to minimize the effect it would have on traffic, the adjacent Police precinct and Firehouse. This operation was accomplished very smoothly.

The first major milestone of the installation was achieved on April 15th, 1999, when the plate and frame heat exchanger was put into operation to provide chilled water to the mezzanine loop of the hotel. It was decided to provide this measure of cooling first as a hedge against possible warm weather in April. This resulted in an available 50 tons of chilled water at 50 degrees F for the facility.

The second major milestone, the start-up of the first screw chiller was achieved on April 22nd. The second screw chiller was successfully started on May 3rd, 1999. Problems were experienced with several of the pump motors. One was meggered and found to have a short. It was removed and returned to the manufacturer for replacement under the warranty. Additional pumps would be removed or checked out in the field to allow the facility to be used during the cooling season. Other startup problems included an inoperative variable speed drive and a leaking valve on the chiller which required replacement. Each of these problems was identified and replaced or repaired under their original equipment warranty.

Operation

The equipment was initially operated manually until the control wiring was completed in the field. The startup and testing of the control system began with the checkout of the instrumentation wiring. This was followed by the installation and check-out of the control system program. The start-up of a control system is always problematic. The system requires de-bugging and modification to operate properly. The system labels require correction and the special needs of the operators are incorporated into the program.

The control system initially received an unusually large number of complaints. It was noted by the programmer that overnight or on weekends that games would appear in the computer software. Also, system features would become inoperative or mis-operate. This was thought to be the work of an operator who knew just enough to be dangerous. The mystery was solved by causing the system to log all changes. This log was then used to show the Hotel's engineering management that unauthorized access of the programming mode was the cause of the program changes. This was swiftly corrected. The program was also further modified to make the installation of other software more difficult and to lock-out program changes by other than authorized personnel.

The "Unipump" motors supplied for the chilled water and condenser water circulation exhibited a phase imbalance in the amperage drawn which has not been solved at the time of this publication. We are continuing to work with the supplier and manufacturer of these pumps and motors to correct this problem.

Control Features

The controls are designed to be versatile and user friendly. The operator has the option of setting up the equipment to operate in either "auto" or "standby" mode. The "auto" mode causes the equipment to be cycled on and off such that the operating hours are near equal (the unit with the least operating hours is started or the unit with the most operating hours is shut down). The "Standby" mode for any unit of equipment causes that unit to be started last and shut off first, thus accumulating less operating hours.

The control system is designed to take advantage of many energy saving opportunities. It includes temperature setback in the cooling mode to reduce conductive heat losses when the system requires less than full cooling capacity. This set-back also improves the efficiency of the screw chiller operation. The program provides for the initial set-back to raise the chilled water temperature 1 degree for each 10 degree drop in outside ambient temperature below 95 F. This set-back is operator adjustable (as controlled by management) within a preset range.

The condenser water temperature is automatically reset to a point 3 to 7 degrees above the wet bulb temperature. This is the "approach" temperature which the tower is capable of obtaining. The wet bulb temperature is determined by measuring relative humidity and dry bulb temperature. The control system computer uses this information to calculate the wet bulb temperature and carry out the reset function. The approach temperature is a function of the overall system capacity required. Since the tower has a fixed geometry, a lower approach temperature is attainable at less than full chiller capacity. Operating the cooling tower to cool the condenser water as low as can efficiently be obtained results in the most efficient operation of the screw chillers. In addition, it drives the condenser water temperature down, as the weather allows, to obtain free cooling.

A bypass valve controller is provided to temper the condenser water temperature to the screw chillers. This feature allows the condenser water to continue to cool down to the free cooling range while the condenser water to the screw chillers is maintained at the manufacturer's minimum of 65 degrees F. The bypass valve also acts to prevent the condenser water from going below 45 degrees F, if the tower is operated in such cold weather.

The control system is programmed to provide automatic switch-over to free cooling. This will ensure that the optimum economy in the operation of the free cooling system is obtained. The best of operators may not be aware of a free cooling opportunity for several hours. Since free cooling opportunities will generally occur at night during the shoulder months, the facility engineering manager is also not likely to be on duty to seek and capture such opportunities without the control systems assistance.

The control system has been programmed to automatically start and stop the second screw chiller to maximize chilled water production efficiency. This automatic function is carried out by the supervisory control computer based on the operational pumps (GPM of flow) and the supply and return temperatures to the three zones of the hotel. The efficiency of the screw chillers for various loads has been programmed into the control system. The actual demand for cooling is compared to the program for the operation of the most economical equipment. The chillers and other equipment are prevented from short cycling by appropriate minimum timer run settings.

The chilled water and hot water demands of each loop which are being satisfied by the HVAC system are displayed for the convenience and information of the operator. These loads are based on the calculations which the supervisory computer is making to determine the loads served. The supervisory control system's DATA SCREEN is included as Figure 6. The system data and calculated system information are displayed on a single screen for operator convenience. It also serves as a handy format to store system alarm conditions for later evaluation by engineering management.

The control system includes a "Sensaphone" which is programmed to dial for assistance in the event an alarm is not acknowledged within a predetermined time. The system is designed to first page the operator on duty. It is then programmed to call the engineering management team in a preselected order. The Sensaphone allows a caller from outside the facility to listen to the sounds being generated in the area of it's microphone, so equipment noise can be monitored.

Building & System Tuning

The control system will not be optimized until it is tuned to the building it's controlling. This requires the time and attention of the Facility Engineering Manager and the system operators. The control system provides the facility manager with an important tool for the proper operation of the buildings energy production equipment. The role of the operator becomes that of set-up and verification of proper operation. The operator should use the control system to best advantage by fine tuning its operation, within the limits of the system's variable inputs. A well designed control system will allow controlled operator input to the set-points around which this tuning takes place. At the same time, it will not allow set-points which are out of range to be entered into the system.

The operator continues to be an important part of a well operated and maintained facility. In addition to setting up the system for proper automatic operation, he also acts to isolate specific equipment for maintenance or inspection and to trouble shoot system problems which are beyond the control of the automatic system.

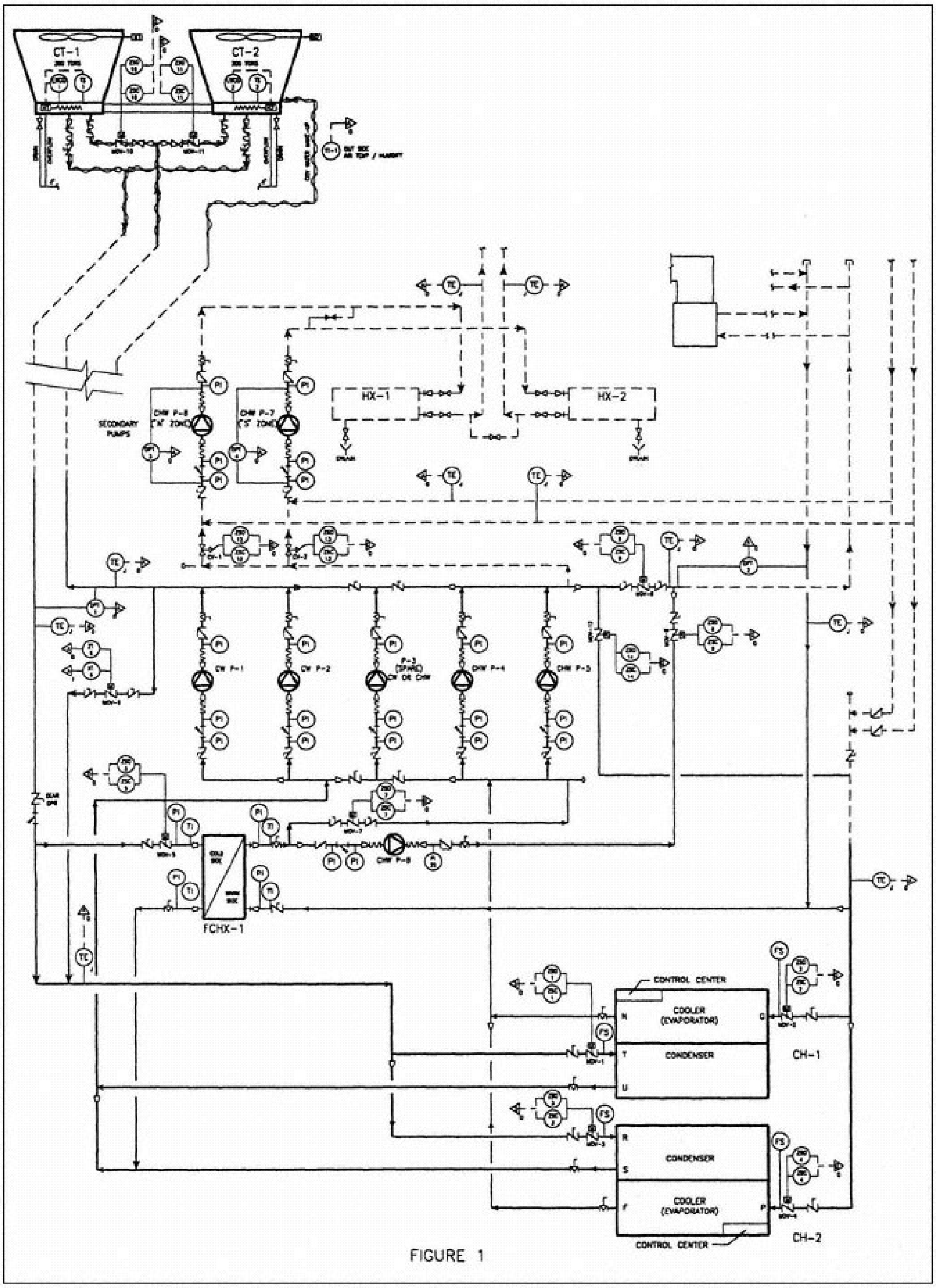
CT-1
CT-2
HX-1
HX-2
SECONDARY PUMPS
CHW P-1
CW P-2
CHW P-4
CHW P-5
FCHX-1
CONTROL CENTER
COOLER (EVAPORATOR)
CONDENSER
CH-1
CH-2
FIGURE 1

Figure 1

System Costs

The mechanical equipment cost was $278,300, the materials and installation labor cost was $668,800, and design, engineering, permits, fees, project management, and sales taxes accounted for an additional $185,000 cost. The total cost of the upgrade was $1,132,100. The capital cost items of the system designed and installed at the Loews NY Hotel is shown in Table 1.

Conclusion

The ultimate success of the retrofit and upgrade of the Loews NY Hotel is measured by the comfort of the Hotel's guests and the reduced cost of operation of the HVAC system. The systems and equipment installed and operated by the Hotel staff are an extension of the Hotel's policy of providing exceptional service to its clientele.

TABLE 1—LOEWS NY CAPITAL COST

Design, Engineering, Permits, Fees,		$185,000
Project Management, & Sales Taxes		
Mechanical Equipment		$278,300
Chillers		
Cooling Towers		
Pumps		
Motorized Valves		
Plate & Frame Heat Exchanger		
Misc. Materials & Installation Labor		$668,800
Mechanical & Piping		
Rigging		
Demolition		
Asbestos Abatement		
Electrical & Instrumentation wiring		
Controls & Instrumentation		
Insulation		
General Conditions		
	Total	$1,132,100

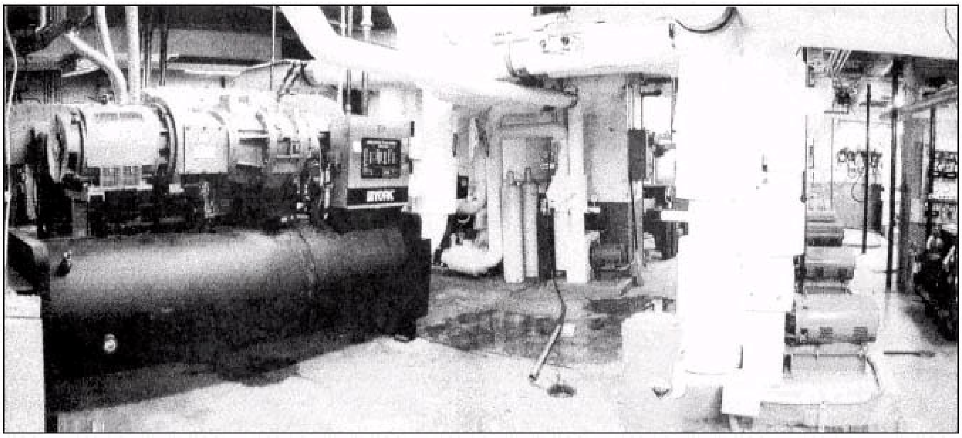

Figure 2
Mechanical Equipment Room

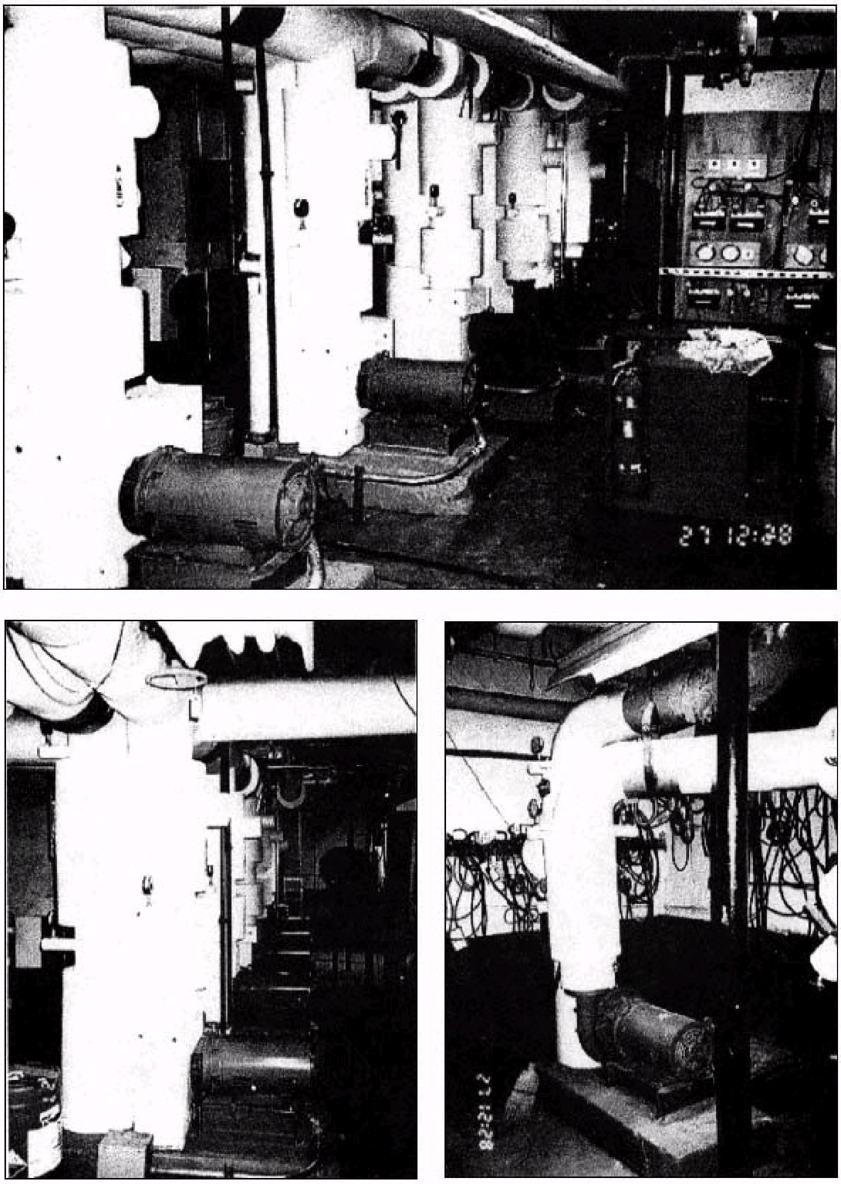

Figure 3
New Piping & Pumps

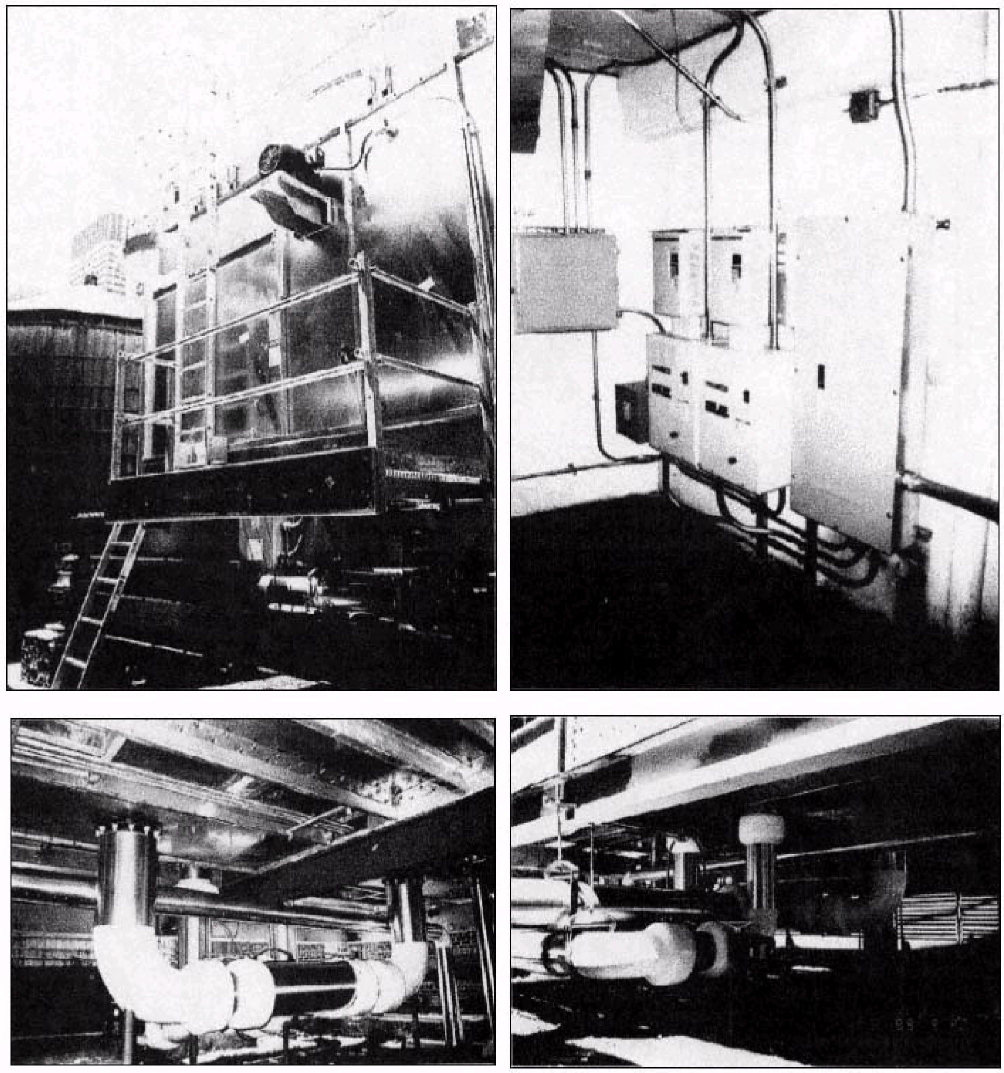

Figure 4
Cooling Tower & Variable Frequancy Drive

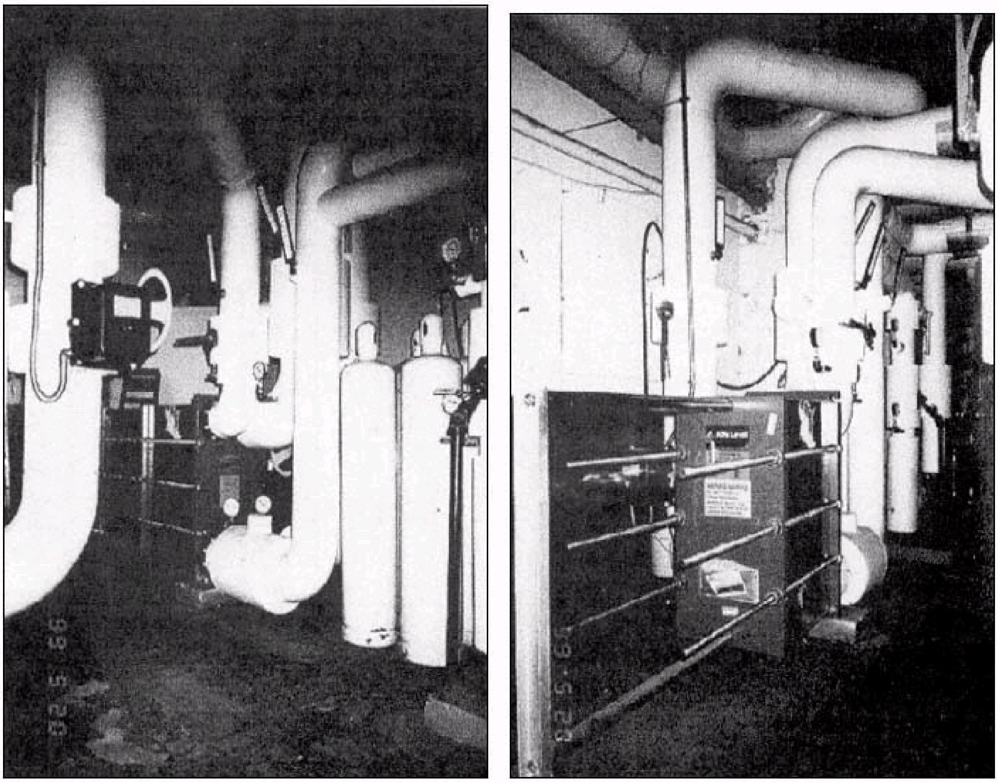

Figure 5
Plate & Frame Heat Exchanger

Loews NY Hotel | **DATA SCREEN** | **KeySpan Energy Management**

7/29/99 15:44

System Data		
TE-1	Tower Water Supply	nnn F
TE-2	Tower Water Return	nnn F
TE-3	N, S & L CHW Return	nnn F
TE-4	Mezz. CHW Return	nnn F
TE-5	Mezz. CHW Supply	nnn F
TE-6	North CHW / HW Supply	nnn F
TE-7	South CHW / HW Supply	nnn F
TE-8	North CHW / HW Recirc.	nnn F
TE-9	South CHW / HW Recirc.	nnn F
TE-10	Chiller Inlet CW	nnn F
TE-11	Domestic HW Supply	nnn F
TE-12	Domestic HW Return	nnn F
TT-1	Outside Air	nnn F
RHT-1	Relative Humidity	nnn %
DPT-3	North Loop Differential	nnn psi
DPT-4	South Loop Differential	nnn psi
DPT-2	Mezz. Loop Differential	nnn psi
DPT-1	Condenser Water Diff.	nnn psi

System Motorized Valve Status		
MOV-1	Chiller #1 CW	
MOV-2	Chiller #1 CHW	
MOV-3	Chiller #2 CW	Closed
MOV-4	Chiller #2 CHW	Closed
MOV-5	HX - CW Supply	Closed
MOV-6	CW By-Pass (% open)	nn
MOV-7	HX-CHW HiCap Pump	Closed
MOV-8	HX-CHW LoCap Pump	Closed
MOV-9	Mezz. CHW Supply	
MOV-10	West CT Supply	
MOV-11	East CT Supply	
CV-1	North CHW Supply	
CV-2	South CHW Supply	
MOV-14	Mezz. CHW Recirc.	Closed

	Auto	Chiller #1				nnnn Hrs
Leaving CHW	nn	F	Oil Temperature	nnn	F	
Setpoint CHW	nn	F	Oil Pressure	nnn	psi	
Entering CHW	nn	F	Diff. Filter Pressure	nnn	psi	
Leaving CW	nn	F	Evaporator Pressure	nnn	in hg	
Setpoint CW	nn	F	Condenser Pressure	nnn	in hg	
Slide Valve	nn	% open	Motor Current	nnn	amps	

	Auto	Chiller #2				nnnn Hrs
Leaving CHW	nn	F	Oil Temperature	nnn	F	
Setpoint CHW	nn	F	Oil Pressure	nnn	psi	
Entering CHW	nn	F	Diff. Filter Pressure	nnn	psi	
Leaving CW	nn	F	Evaporator Pressure	nnn	in hg	
Setpoint CW	nn	F	Condenser Pressure	nnn	in hg	
Slide Valve	nn	% open	Motor Current	nnn	amps	

Pump Status					
P-1	CW Pump #1				nnnn Hrs
P-2	CW Pump #2		off		nnnn Hrs
P-3	Standby Pump		off	CHW	nnnn Hrs
P-4	CHW Pump #1				nnnn Hrs
P-5	CHW Pump #2	Standby	off		nnnn Hrs
P-6	North Secondary Pump				nnnn Hrs
P-7	South Secondary Pump				nnnn Hrs
P-8	HX-CHW LoCap Pump		off		nnnn Hrs

Cooling Tower Data						
CT-1	West Tower Cell			nn	% speed	nnnn Hrs
CT-2	East Tower Cell	Standby	off	nn	% speed	nnnn Hrs

Calculated System Information			
North Loop Capacity	110 tons	Wet Bulb Temperature	76 F
South Loop Capacity	80 tons	CT Approach	4 F
Mezz. Loop Capacity	30 tons	CW Temp. Setpoint	80 F
Total Capacity	220 tons	CHW Temp. Setpoint	46 F

Figure 6
Data Screen

Chapter 19— A Guide for Designing Energy Efficient Buildings

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Abstract

Today there is a large movement to develop green buildings and to become an environmentally friendly business. Many companies have come to understand that at the present depletion rate of our natural resources, we are depriving future generations of a reasonably comfortable existence. To this end many companies have begun to develop green initiatives. The mantra of the day is to become a sustainable business. To achieve this, businesses must review their building construction practices, building operations, building occupant concerns and what is expected of facility managers. In this context, we must develop buildings that conserve all of the resources associated with construction, operation, usage, and management of buildings. The difficulty is to work towards these goals while we are still trying to define them.

This paper discusses a guideline for the "resource efficient" construction and operation of buildings. We developed a guide that would allow us to more economically achieve our goals of sustainability. It is true that there are already several guides and standards readily available. However, our interest lies in developing an easy to apply guide that can be used in every case, by laymen and experts alike.

Many times renovation and construction projects don't have the visibility or the initial structure to be developed as a resource efficient project. To require these less sophisticated projects to be "greened" according to the currently available guidelines would serve to increase the cost without assurance that the goals will be met.

By developing a guide that sets some very simple and easy first step specifications, we can economically start to turn an entire corporation or enterprise towards becoming a sustainable business.

The Environmental Problem (Briefly)

The earth and sun represent an essentially closed system. We have the life sustaining systems currently on our planet along with the solar energy imparted by the sun to support our activities. In this closed system we are supporting approximately six billion people. The population is expected to double in the next generation. As the population increases, we are more quickly depleting the planet's life supporting systems such as farm land, forests, clean water, and fossil fuels. At the same time, the byproducts from our current methods of day to day life, including residential, business, and industrial processes are building into a mountain of waste.

These unsustainable practices cannot last indefinitely. We must strive to become a sustainable business. This means doing business in a way that does not harm our future generations' ability to also do business. The business which can develop ways to manufacture products while using the least amount of energy and natural resources will provide value and the prospect of future prosperity for it's customers, employees and stockholders.

Organizational Issues

Today our business measurement systems have not caught up with a sustainable definition of value. We do not measure the lifecycle cost of a building we measure the first cost per square foot to erect. We should be thinking of the long-term financial impact on the corporation for every building we build. We must begin to formulate a new benchmark.

Some companies do realize the environmental problem or recognize that waste is actually expensive. Many of these companies have built a showcase building or are beginning to implement programs in other areas. The problem becomes one of culture and habit. Many of the environmentally responsible corporations also have other buildings and projects that pale by comparison or offer a sharp contrast to the showcase building. We need to continue educating our organizations until calculating the lifecycle cost of every decision is as second nature as putting on safety glasses while in the plant.

In some cases all of the services related to a buildings lifetime costs are not functioning under one roof. The maintenance and operation, construction, or engineering and planning may be different departments with different levels of coordination. It is important on larger projects to bring all of these functions together to make decisions that are beneficial to all groups and avoid saving money in one area and driving costs up in another area. On smaller projects we remain faced with the challenge of providing the correct amount of reliable information to promote the right energy decisions.

Financial Hurdles

Many times a project is not large enough to assemble a team to review decisions. It certainly doesn't make sense to assemble a team and meet three times a week to discuss a $5,000 window replacement project. The first year's savings would disappear. In most cases energy conservation opportunities are quite profitable and have approximately a three-year payback period. We need educate project and facility managers, and provide access to the correct information so that profitable decisions are made on small projects as well as large projects.

In addition, projects can change quite radically even when underway. In this case a project can approach the construction phase with many energy conservation opportunities still undiscovered. The problem is that even though an opportunity may have a 35 percent return on investment, it requires an initial capital investment. This means we are faced with requesting more capital or running over budget. If we can provide some basic cost equations, many simple opportunities can be incorporated into a project budget up front.

One Solution

We are developing a guide that provides basic cost and energy equations for simple renovations and also references more detailed technical documents for projects that can support more complicated engineering.

Outline

I. Panning and Design
II. Siting
III. Building Envelope
IV. Equipment and Systems
V. Construction
VI. Web Resources

I—
Planning and Design

Smaller is better. Optimize the use of space through careful design. Take a step back and look at the whole. Are there systems that can compliment and integrate with one another? Roofs with multiple elevations can create huge light shelves for clearstory windows, floors can double as thermal mass for passive solar heating, HVAC diffusers can provide white noise for an open office.

Procuring Design Services

The general goal for most buildings will be to produce "a beautiful, sustainable, cost effective building that encourages productivity, provides a pleasing quality environment, and consumes as little non-renewable energy as possible". Identify this goal in RFP and program documents.

Choose a firm with demonstrated knowledge and concern for energy conservation. Work with the firm to set some quantitative energy targets. The EIA average energy consumption for office buildings is about $1.50 per square foot.

Source: Energy Information Administration:
www.eia.doe.gov [2]

Corporate Maintenance Departments should be included early on in the planning stage to ensure that cost cutting in one area doesn't drive up costs in another. They should also be included regularly as the equipment is installed and commissioned.

Budgeting

Many methods that reduce energy costs are either code or found in professional standards. Compensate the A/E firm for innovative ideas that exceed published standards.

Engineering costs for unique or innovative energy conservation choices should always create a one-year payback. Minor single component evaluations should pay back the engineering costs in about six months or less. Absolute costs for energy engineering and consultation during the design and planning phase can range from $.10 to $.35 per square foot depending on the size and complexity of the building. The costs for engineering involvement throughout a project can vary from $10,000 to over $40,000 depending on the extent of the building models developed.

Source: FEMP web site: www.eren.doe.gov/femp [3]

II—
Siting

Renovate older buildings where possible. Renovation is the most sustainable construction.

Minimize parking lots (with dark pavement) on the South/Southwest building faces. These cause heat islands that will increase the temperature of the surrounding air.

Take advantage of trees and vegetation (microclimates). Planting leafy trees on the south/southwest sides of the building will create a cooler surrounding air temperature as well as shade buildings to reduce solar heat gain through the walls and roof. People like to see the trees too.

Preserve Open spaces and wildlife habitats.

III—
Building Envelope

Design for standard size materials to reduce waste. Buy materials that are manufactured locally. Reuse and recycle salvaged building materials.

Use high levels of insulation and high-performance windows.

Embodied Energy

Choose building materials with low embodied energy. An estimate of the relative intensity of various materials (by weight) is as follows:

TABLE 1. EMBODIED ENERGY OF BUILDING MATERIALS

Lumber	1
Brick	2
Cement	2
Glass	3
Fiberglass	7
Steel	8
Plastic	30
Aluminum	80

Source: Building and Environment, Vol. 27, No. 1 [4]

Windows/Doors

Spacious ceilings and generous visual areas are appealing, but they also require energy to heat and cool. Design wisely and use strategically located and sized windows to provide visual delight. Generous use of natural light makes any building more appealing. Moveable blinds can cut down solar heat gain, and give the occupants control of their space.

> *"There is nothing on the planet more beautiful than a butterfly or a flower, or sparkling water. If your architecture doesn't provide an efficient building that conserves resources, then I would offer that your building is not architectural but rather accidental. "*
> Author unknown

Remember as the amount of window area goes up the walls require more insulation and the windows should have a lower U value. Medium window area is considered to be between 10 percent and 25 percent for a window/wall square foot ratio.

Specifications: US. Department of Energy—Building Standards and Guidelines Program: www.energycodes.org/ [5]

Or

Specifications: ASHRAE 90.1—Chapter 8.5 Alternative Component Packages [6]

Orient windows to the South in cool climates and the North in warm climates. Allow for generous roof or window overhangs to shade windows from summer sun.

Planting well-located trees can reduce solar gain through glass in the summer, yet allow the sun to shine in the winter months. In warm climates use a SHGC of .40 or less. Don't use a SHGC glass in cool Northern climates.

In all climates use a window with a U-factor of .40 or less. The best available is .15. A simple double glazed metal frame window has a U-factor of about .7, whereas a double glazed low-E wood frame has a U-factor of .4.

Overhangs or roof projections will help decrease the heat gain in the summer. A Projection Factor of .3 or greater reduces the SHGC by an equivalent of .1 for your window choice.

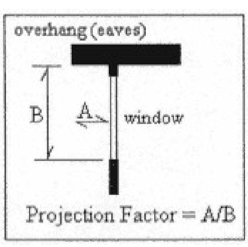

Figure 1
Roof

Specifications: U.S. Department of Energy— Building Standards and Guidelines Program: www.energycodes.org/[5]
Or
Specifications: ASHRAE 90.1—Chapter 8.5 Alternative Component Packages [6]

Walls/Roof

The wall and roof insulation is dependent upon the number of windows in the building. The more windows you have the more we need to reduce heat loss through the remaining walls. The roof should generally have a continuous R-value of 22 or greater. The walls should be R-11 or greater (R-13 in Michigan).

Specifications: U.S. Department of Energy Building Standards and Guidelines Program: www.energycodes.org/[5]
Or
Specifications: ASHRAE 90.1—Chapter 8.5 Alternative Component Packages [6]

Planting pine or Coniferous trees on the North/Northeast sides of the buildings can reduce the building infiltration due to wind.

Overhangs or roof projections will help decrease the heat gain in the summer. (See windows)

IV—
Equipment and Systems

Lighting

Use energy efficient equipment. The lifetime operating cost of most equipment is several times larger than the first cost. Follow the standards below.

TABLE 2. LIGHTING RECOMMENDED LEVELS

100–150 foot-candles	for detail prototype and bench work
50 foot-candles	for reading, and is accomplished by task lighting
60–80 foot-candles	for medium detail assembly, accomplished by task lighting
25–30 foot-candles	for an office general illumination
30–35 foot-candles	for a manufacturing area general illumination
20 foot-candles	for medium traffic warehousing
15 foot-candles	for a hallway or general indoor navigation
5 foot-candles	for a building entrance
1–5 foot-candles	for a parking lot, use 3–5 for entrances and intersections

Specification: Adapted from IESNA Lighting Handbook [7]

Use L.E.D. exit signs.

New luminaries should have an efficiency of 80 percent or greater. Retrofit kits should have an efficiency of 70 percent or greater. This number is readily available from the manufacturer or on a photometric report as "zonal percent lumens from lamp."

Use occupancy sensors in conference rooms, bathrooms, and other temporary areas.

Use generous daylighting. Studies show that people respond better, and are healthier in daylit areas.

Use daylight dimmers to insure lighting is not on when there is adequate daylight.

TABLE 3. LIGHTING ENERGY LIMITS NOT TO EXCEED

1.2 watts per sq. ft.	offices and general flexible space
.5 watts per sq. ft.	task lighting in offices and flexible space
.6 watts per sq. ft.	garages and warehousing
.12 watts per sq. ft.	parking lots
.4 watts per sq. ft.	loading areas
30 watts per linear ft.	entrance
.25 watts per sq. ft.	all other outdoor lighting

Specifications: ASHRAE 90.1—Table 6.1, 6.5 [6]

Allow your designer/architect to take a 30 percent credit to energy calculations of watts per square foot in order to meet the table above for any lights connected to daylight or occupancy sensors.

As a benchmark for incremental cost on renovations, you can spend $.26 per controlled watt in a building to yield a 20 percent return on investment.

Source: EPA Application Bulletin EPA 430-F-96-062 [8]

HVAC

Design the cooling system to take advantage of evaporative cooling and economizing cycles. If possible incorporate natural ventilation. As air moves people will feel cooler.

Right size the system and check to insure that the heat gain calculation (for cooling) and the heat loss calculation (for heating) has been tailored to your building. **Check again** just before ordering equipment to account for changes that inevitably happen.

TABLE 4. COOLING ENERGY LIMITS

Equipment type	Energy measure (full load)	Best in class
Chiller-screw type	.60 kilowatts per ton or less	.48 kW/ton
Chiller-Centrifugal	.65 kilowatts per ton or less	.60 kW/ton
11 tons or less (small) Packaged- air condenser	10.3 EER or greater	13.5 EER
Packaged- water/evap. condenser	11.5 EER or greater	12.5 EER
11–20 tons (medium) Packaged- air condenser	10.0 EER or greater	11.5 EER
Packaged- water/evap. condenser	11.5 EER or greater	12.5 EER
20 tons or greater (large) Packaged- air condenser	10.0 EER or greater	11.7 EER
Packaged- water/evap condenser	11.5 EER or greater	12.5 EER

Source: www.eren.doe.gov/femp/procurement/begin. html

Use a light colored roofing material, with a high solar reflectance. This is code in Georgia.

Plumbing

Use water efficient equipment.

TABLE 5. WATER USAGE LIMITS

Equipment	Minimum Standard	Best Available
Faucets	2.0 gpm or less	1.5 gpm
Faucets-self closing	.25 gallons per cycle	
Showerheads	2.0 gpm or less	1.5 gpm
Toilets	1.6 gpm or less	1.6 gpm
Urinals	1.0 gpm or less	0.0 gpm

Use vegetation and landscaping to treat all storm water on site.

Motors

About 75 percent of an industrial facilities energy cost are motor loads. On a first cost basis an energy efficient motor will pay back any incremental cost in two—three years for a 30–50 percent return on investment. Ask all equipment manufacturers to supply your equipment with energy efficient motors.

For replacement of failed or damaged motors determine the approximate running time of the motor. If it runs for one shift and is less than 17 h.p., then replace with a new energy efficient motor. If it runs for two shifts and is less than 65 h.p. then replace with a new energy efficient motor. If it runs for three shifts and is less than 125 h.p., then replace with a new energy efficient motor. Otherwise repair the motor for each case. When repairing the motor have the repair shop investigate higher copper rewinding options for increased efficiency. Many times the cost is negligible since they are rewinding the motor in any case.

Source: www.motor.doe.gov[10]

Transformers

Most times the incremental cost for an energy efficient transformer pays for itself in less than three years. Transformers have a very long life so be sure to calculate the Total Owned Cost for the transformer. This is your cost to own and operate the transformer throughout its life. Use the following formulas depending on how much of the time the building is occupied or in use.

Total Owned Cost (1 shift operation) = (NoLoadLoss * 8760) + (FullLoadLoss * 1.75) + purchase price

Total Owned Cost (2 shift operation) = (NoLoadLoss * 8760) + (FullLoadLoss * 3.50) + purchase price

Total Owned Cost (3 shift operation) = (NoLoadLoss * 8760) + (FullLoadLoss * 5.25) + purchase price

Formula Reference [1]

Source: www.eren.doe.gov/femp/procurement[9]

Office Equipment

Consider energy efficiency in all purchases of equipment such as task lights, office equipment, copiers, fax machines, computers, refrigerators, vending machines, ice machines, and microwaves. Design Common coffee bars where possible to minimize the use of multiple individual appliances. Install automatic controls and motion sensors where feasible.

V—
Construction Practices

Protect trees from damage during construction by fencing off the drip line around them and avoiding major changes to the surface grade. Minimize job site waste and find out where materials can be taken for recycling.

Buy materials locally to reduce transportation.

VI—
Web Resources

www.usgbc.org	U.S. Green Building Council
www.ebuild.com	Newsletter on environmentally responsible construction
www.ashrae.org	ASHRAE
www.ieee.org	IEEE
www.aeecenter.org	AEE
www.ecotech.org	Non-profit involved with earth centered thinking
www.aceee.org/	American Council for an Energy Efficient Economy
www.efficientwindows.org/	Energy Efficient Windows Collaborative
www.eeba.org/	Energy Efficient Building Association
www.eren.doe.gov/	Energy Efficiency and Renewable Energy Network
www.psic.org/	Passive Solar Industries Council
www.solstice.crest.org/	Center for Renewable energy and Sustainable Technologies
www.eia.doe.gov/	U.S. Energy Information Administration
www.iaeel.org/	International Association for Energy Efficient Lighting
www.lrc.rpi.edu/	Lighting Research Center
www.ecw.org/	Energy Center of Wisconsin

www.epa.gov/buildings/	DOE Energy Star Buildings Program
www.energy.wsu.edu/cfdocs/eic/energy solutions/	Energy Ideas Clearinghouse

Summary

By developing a guide that sets some very simple and easy first step specifications we can economically start to turn an entire corporation or enterprise towards becoming a sustainable business. We can change the baseline from first cost to lifetime or total owned cost.

I would like to thank Ralph Zamora and Monsanto, Inc., for their environmental leadership with the Monsanto guide; *Building Sustainability- Guidelines for Environmentally Sustainable Design, Construction, and Operation of Monsanto Facilities.*

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6. ASHRAE *90.1—Energy Efficient Design of New Buildings Except Low-Rise Residential Buildings*

7. IESNA *Lighting Handbook*

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Chapter 20—
Energy Efficient Design of Large Office Buildings

John Radford, P.E., C.E.M., Marlin S. Addison, Tracie Smith, P.E., C.E.M.

Abstract

This paper describes the implementation of a new method of designing state buildings in the state of Louisiana, designed to cut energy consumption in several large state office buildings, as well as provide a demonstration of energy efficient design of large office buildings, which will be accessible to the public. Included in this paper are discussions of the proposed energy conservation measures and the determination of their energy and cost savings. It is apparent from the analysis that the initial costs associated with the installation of the energy conservation measures are far outweighed by the benefits gained over the life of the measures.

Some of the cases presented are standard practice construction items currently used in Louisiana, and some are innovative technologies. They are simulated using new state-of-the-art building energy simulation software, and compared to the ASHRAE 90.1–1989 base case, which Louisiana has adopted as a minimum standard for all new commercial construction in the state. These buildings are expected to demonstrate the effectiveness of the energy saving measures, and will hopefully change the way future buildings for the state of Louisiana are designed.

Introduction and Background

The State of Louisiana conducted a study to determine the best long range solution to the high cost of rental office space. A State Plan was developed to move several State agencies from high cost rental properties to State-owned facilities located in the Capitol Complex area of downtown Baton Rouge. The plan is to construct over 1,000,000 square feet of office space to house the various State Agencies currently located in three older existing office buildings located in the downtown and two other large agencies located elsewhere in metropolitan Baton Rouge. Design on the first two buildings began in late 1997 and design on the third building began in the spring of 1999. Through a joint effort between the Louisiana Division of Administration and the Louisiana Department of Natural Resources, the design and construction of these buildings will be a demonstration of energy efficiency through the incorporation of energy conservation measures.

Each of the proposed buildings were modeled by M. S. Addison and Associates, Tempe, AZ, using *PowerDOE*®. Based on DOE-2.2, PowerDOE is the Windows-based "next generation" in the ongoing evolution of the DOE-2 building energy analysis software program. Jointly developed by Lawrence Berkeley National Lab, J. J. Hirsch & Associates, and the Electric Power Research Institute, *PowerDOE*/DOE-2.2 provides a graphical user Windows™ interface to the most comprehensive building energy use simulation software available today. Input to the simulation program consists of a detailed description of the building being analyzed, including hourly scheduling of occupants, lighting, equipment, and thermostat settings. Three models of each building were developed. The first model was based upon ASHRAE 90.1-1989 design standards. The second model was based upon the Architect's proposed basic design. The third model was used to evaluate the effects of the installation of various energy conservation measures. Energy consumption and cost over twenty-five years was calculated for each of the models and compared to the incremental cost of installation of energy conservation measures over and above the ASHRAE 90.1 standard model.

The objective of this study was to assess the energy and cost benefits associated with selected energy-efficient design alternatives, including exterior envelope and glazing options, integration of high efficiency lighting, and daylighting alternatives, and several HVAC optimization measures. The analysis results are compared to simulated performance that would have been achieved under ASHRAE 90.1-1989.

Building Descriptions

The facilities under investigation consisted of two large high rise office buildings temporarily named the "North Building" and the "West Building". The third building, temporarily named the "East Building", is currently in design and the simulation models have not been developed.

The North Building is an eight-story high rise building containing approximately 465,000 square feet of offices with some assembly areas (hearing and conference rooms) on the second level. Architects for the North Building are Grace & Hebert Architects, Baton Rouge, Louisiana, and Holly & Smith Architects, Hammond, Louisiana, with mechanical and electrical engineering by Associated Design Group, Lafayette, Louisiana.

The West Building is a twelve-story high rise building containing approximately 335,000 square feet of occupancy similar to the North Building, i.e., offices with some hearing and conference rooms. Architects for the West Building are Eskew + Architects, New Orleans, with electrical and mechanical engineering by Blum Consulting Engineers, Dallas and Assaf, Simoneaux, Tauzin, and Associates, Baton Rouge.

Method Used in Analysis

A detailed computer simulation was performed using *PowerDOE. PowerDOE* calculates hour-by-hour building energy consumption over an entire year (8,760 hours) using weather data for the location under consideration. Although PowerDOE is newly released, its predecessor, DOE-2, has been widely reviewed and validated in the public domain.

Input to the program consists of a detailed description of the building being analyzed, including hourly scheduling of occupants, lighting, equipment, and thermostat settings. *PowerDOE,* provides very accurate simulation of such building features as shading, fenestration, interior and envelope building mass, and the dynamic response of differing heating and air conditioning system types and controls. *PowerDOE,* also contains a dynamic daylighting model to assess the effect of daylighting on thermal and lighting demands. The simulation process begins by developing a model of the building based on building plans and specifications. A base line building model, using minimum ASHRAE 90.1 compliance requirements, is then developed to provide the base from which energy savings are calculated. Alternative analyses are made by making changes to the model that correspond to efficiency measures that could be implemented in the building. These alternative analyses result in annual utility consumption and cost savings for the efficiency measure that can then be used to determine simple payback, life-cycle cost, etc. for the measure and, ultimately, to determine the best combination of alternatives.

Due to PowerDOE's graphical user interface, user input time is greatly reduced, permitting comprehensive analysis to be conducted much more economically than was previously possible. Figures 1 and 2 illustrate typical PowerDOE input screens for building components. The simulations were conducted in very close coordination with key design team members to insure confidence in the analysis results.

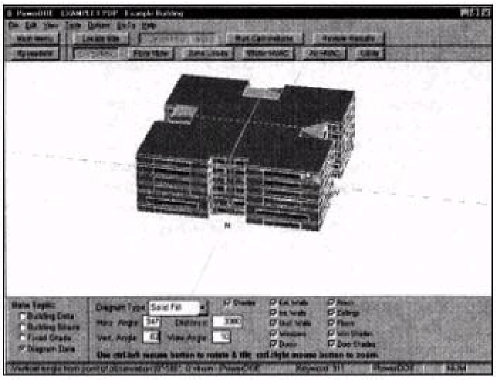

Figure 1
PowerDOE 3-D BUILDING VIEW provides graphical feedback on the overall building envelope. The user may easily tilt or rotate the view, and can suppress the display of any selected type of surface. The user may also select any building element to be edited simply by clicking on it. (The "North" Building is shown.)

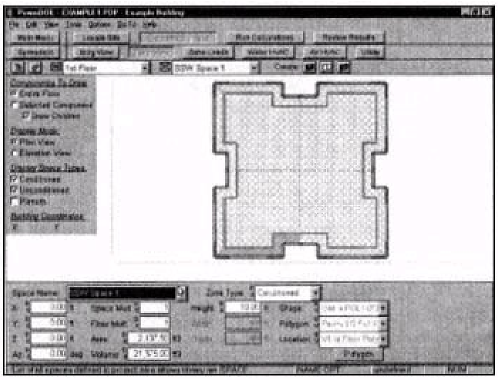

Figure 2
PowerDOE FLOOR VIEW The Floor View screen provides building designers with a familiar plan view of each floor within the building. Clicking on any building component (e.g., space, wall, window, etc.) displays data for the selected component at the bottom of the screen. (The "North" Building is shown.)

The North Building Study and Analysis

The North Building is depicted in Figures 1 and 2 above. Where necessary, e.g., on the longer facades, windows are modeled using multipliers to represent total composite areas of glass for each facade. Similarly, floors five through seven are modeled using a single floor with floor multiplier of three. Lighting and internal loads are expected to be the most significant components of energy consumption in this facility. Estimates for occupancy, usage scheduling, and office equipment loads were obtained from the design team and incorporated into the analysis. When acceptable, default ASHRAE 90.1-1989 schedules and load densities were used. A summary of key building characteristics, including internal load and design assumptions is provided in Table 1 below.

Table 1
BUILDING CHARACTERISTICS
NORTH OFFICE BUILDING, LOUISIANA STATE CAPITOL COMPLEX

ARCHITECTURAL FEATURES	ASHRAE 90.1-1989 Base Case	Proposed Design*
Gross Modeled Area	456,000 sqft	*
aspect ratio	2.5 to 1 (266ft x 106ft)	1 to 1 (252 ft x 252 ft)
orientation	long axis faces east/west	n/a (1:1 aspect ratio)
floor-to-floor height	13ft (all floors)	20ft. (2nd), 16ft (top), 14ft (others)
Exterior Wall Type	spandrel glass light frame	6 in precast HW concrete
Opaque Wall U-value (R-value)	0.15 (6.7)	0.043 (23.5)
Roof U-value (R-value)	0.073 (13.7)	0.045 (22.0)
Ext. Wall/Roof Color	0.7 (medium dark)	0.35 (light)
Window Type	single-glazed gray	double glazed low-e clear
assumed frame type	aluminum	aluminum, thermally broken
U-Value (incl. frame effects)	1.23	0.33
Shading Coefficient	0.67	0.43
Window Area	21.5% WWR	28.7% WWR
HVAC SYSTEM		
HVAC System Type	Fan-Powered VAV	*
Cooling/Heating Setpoint	73F/70F	*
Cooling Design Temps. (In/Out)	73DB / 94DB / 80WB	*
Heating Design Temps. (In/Out)	72DB/25DB	*
Outside Air Supply	25 CFM/person	*
Coil Leaving Temperature	51 F	*
Fan Static, Supply/Return	4.0 in/1.0 in	1.5 in /0.75 in
Economizer	none	enthalpy-based
Supply CFM	0.80 cfm/sqft, average	*
Central Plant Equipment		
Cooling Equip Efficiency	0.67 kW/ton	0.61 kW/ton (existing)
Distribution System	2-spd pumps	VSD pumps
Motor Efficiency	high efficiency	*
BUILDING OPERATION AND INTERNAL LOADING		
Occupancy Schedule	7am–11pm M-F, 7am–6pm Sat. *(see Fig. 3.2 above)*	
Lighting & Equipment Schedule	6am–11pm M-F, 7am–5pm Sat. *(see Fig. 3.2 above)*	
Fan Schedule	6am–11pm M-F, 7am–6pm Sat. *(see Fig. 3.2 above)*	
Internal Loads		
Lighting System Type	T-12 lamps, energy-saving ballasts	T-8 lamps, electronic ballasts
Lighting Power Density (W/sf)	1.7	1.25
Receptacle Load (diversified)	1.5	*
Occupancy Density (sf/person)	215	*
Occupant Sens/Lat (Btu/per)	250/200	*

** items unchanged from the ASHRAE 90.1-1989 base case are marked with an asterisk*

North Building ASHRAE 90.1 Base Case and Alternatives

The Base Case simulates the North office building as if it were designed to minimally comply with the ASHRAE 90.1–1989 energy standard. The base case building has the same conditioned area as the proposed building (approximately 456,00 sqft) but assumes an aspect ratio of 2.5-to-1, with the long facades facing east and west. Floor-to-floor heights reflect actual design (i.e., 20 ft for the second floor, 16 ft for the top floor, and 14 feet for all other floors). Envelope requirements are met via the system performance option. The minimally-compliant glass type is assumed to be uncoated monolithic gray.

For the 90.1 base case, the HVAC system is prescribed to be a builtup VAV system with perimeter re-heat, with 4.0 inches of supply fan static pressure and 1.0 inches of return fan static pressure. All fans are controlled using VSD's. Design conditions and loads are held constant for all subsequent cases (runs).

A total of thirteen design alternatives were modeled, each "on top of" the preceding. These are listed in Table 2, below.

North Building Projected Energy and Cost Savings Results

Cost-related results are summarized in Table 3. Each of the separate cases were evaluated by adding each new measure to the previous set of measures. For example, when the roof insulation upgrade (Alternative 2) was evaluated, this was evaluated "on top of' the building envelope improvements package (Alternative 1). Similarly, when Alternative 4 (mini blinds) was evaluated, it was evaluated "on top of' Alternative 3 (lighting system optimization); thus, each row in Table 3 represents a package of measures containing all adopted measures up to that point in the evaluation sequence. Note that the description for each measure indicates which previous measure, each new measure was run "on top of'. For example, Alternative 3, lighting system optimization, was run on top of Alternative 2, roof insulation upgrade, which is indicated by the description for Alternative 3, "2+Lighting Optimization".

Table 3 provides the results of each alternative's evaluation. Each alternative ECM's incremental first cost, 25-year energy cost savings, its simple pay back and cumulative improvement over the ASHRAE 90.1 base case. If all of the proposed alternatives were incorporated in the North Building, then projected energy consumption would be 41% less that the ASHRAE 90.1 base case.

Table 2
NORTH BUILDING ECM ALTERNATIVES

1 Building Envelope Improvements:

- Building Re-orientation and Reconfiguration,
- Atria, Standard Glass
- Light Exterior Surface Color, Precast Skin
- R19 Wall Insulation

2 R22 Roof Insulation

3 Lighting System Optimization:

- Window Setback, Light Shelves
- High Performance Daylight Glass,
- Reduced Lighting Power Density,
- T-8 lamps with electronic ballasts,
- Daylighting Controls,
- Occupancy Sensor Lighting Controls

4 Mini Blinds

5 Low "E" Insulated Clear Glass

6 Occupancy Sensor Controls for Ambient Lighting

7 Reduced Fan Static

8 Variable Speed Drive Pump Control

9 Natural Gas Preheat

10 Exhaust Air Enthalpy Heat Recovery with CO2-Controlled Ventilation Air

11 Chilled Water Piping Insulation

12 Optimum Start/Stop via EMS

13 High Efficiency Chilled Water Plant

Table 3
ANNUAL ENERGY USE AND UTILITY COST
NORTH OFFICE BUILDING

		Annual Energy Use & Costs			*Cumulative Savings (% savings)*			
	Measure # and Description	Source Energy Mbtu	Annual Utility Cost $	25 Year Life-Cycle System ($)	Source Energy Mbtu	Annual Utility Cost $	Simple Payback	25 Year Life-Cycle Utility ($)
0	Minimum 90.1 Compliance	80,607	$598,454	n/a	n/a	n/a	n/a	n/a
1	0+Envelope Reconfiguration	79,003	$583,612	$7,060,584	1604 (2%)	$14842 (2%)	24.9	$371050 (2%)
2	1+Additional Roof Insulation	78,984	$582,396	$7,433,422	1623 (2%)	$16058 (3%)	24.8	$401450 (3%)
3	2+Lighting Optimization	65,524	$485,281	$10,086,240	15083 (19%)	$113173 (19%)	16.3	$2829325 (19%)
4	3+Mini Blinds	64,938	$481,290	$10,184,647	15669 (19%)	$117164 (20%)	16.6	$2929100 (20%)
5	4+LoE Clear Glass	64,130	$472,661	$12,437,994	16477 (20%)	$125793 (21%)	17.2	$3144825 (21%)
6	5+Occ Sensor Lighting	60,634	$451,858	$12,747,994	19973 (25%)	$146596 (24%)	16.8	$3664900 (24%)
7	6+Low Static Duct System	57,185	$426,679	$15,359,770	23422 (29%)	$171775 (29%)	17.2	$4294375 (29%)
8	7+VSD Pumps at Bldg Level	56,975	$425,477	$15,759,911	23632 (29%)	$172977 (29%)	17.2	$4324425 (29%)
9	8+Gas Preheat	54,943	$416,737	$16,211,118	24750 (31%)	$181717 (30%)	17.1	$4542925 (30%)
10	9+Enthalpy Heat Recovery	47,518	$362,430	$18,363,503	33066 (41%)	$236024 (39%)	16.6	$5900600 (39%)
11	10+CHW Pipe Insulation	47,307	$361,175	$18,429,273	33277 (41%)	$237279 (40%)	16.6	$5931975 (40%)
12	11+Optimum Start/Stop	46,901	$360,770	$19,627,118	33684 (42%)	$237684 (40%)	16.6	$5942100 (40%)
13	12+Central CHW Plant	45,899	$352,889	$20,365,023	34686 (43%)	$245565 (41%)	16.3	$6139125 (41%)

The West Building Study and Analysis

The proposed new West Building is functionally similar to the North Building. A principal difference is that it is a taller building (12 stories) with a smaller footprint (335,000 square feet). As with the North Building, lighting and internal loads are expected to be the most significant components of energy consumption in this facility. Estimates for occupancy, usage scheduling, and office equipment loads were obtained from the design team and incorporated into the analysis. When acceptable, default ASHRAE 90.1–1989 schedules and load densities were used. A summary of key building characteristics, including internal load and design assumptions is provided in Table 4 below.

Table 4
BUILDING CHARACTERISTICS
WEST OFFICE BUILDING, LOUISIANA STATE CAPITOL COMPLEX

ARCHITECTURAL FEATURES	ASHRAE 90.1–1989 Base Case	Proposed Design*
Gross Area	330,000 sqft	*
aspect ratio	2.5 to 1 (266ft x 106ft)	1.85 to 1 (250ftx 135ft)
orientation	long axis faces east/west	long axis faces north/south
floor-to-floor height	13 ft (all floors)	15.5 ft. (1 st fl), 13.5 ft (all others)
Exterior Wall Type	spandrel glass light frame	4 in precast concrete
Opaque Wall U-value (R-value)	0.15 (6.7)	0.091 (11.0)
Roof U-value (R-value)	0.073 (13.7)	0.033 (30.0)
Ext. Wall/Roof Color	0.7 (medium dark)	0.4 (light)
Window Type	single-glazed gray	double glazed low-e bronze
assumed frame type	aluminum	aluminum, thermally broken
U-Value (incl. frame effects)	1.23	0.35
Shading Coefficient	0.60	0.42
Window Area	24% WWR	*
HVAC SYSTEM		
HVAC System Type	Fan-Powered VAV	*
Cooling/Heating Setpoint	73F/70F	*
Cooling Design Temps. (In/Out)	73DB / 94DB / 80WB	*
Heating Design Temps. (In/Out)	72DB/25DB	*
Outside Air Supply	23 CFM/person (~17%)	*
Coil Leaving Temperature	51 F	*
Fan Static, Supply/Return	4.0 in/1.0 in	*
Economizer	none	*
Supply CFM	0.80 cfm/sqft, average	*
Central Plant Equipment		
Cooling Equip Efficiency	0.67 kW/ton	0.61 kW/ton (existing)
Distribution System	2-spd pumps	VSD pumps
Motor Efficiency	high efficiency	*
BUILDING OPERATION AND INTERNAL LOADING		
Occupancy Schedule	7am–11pm M-F, 7am–6pm Sat. *(see Fig. 3.2 above)*	
Lighting & Equipment Schedule	6am–11pm M-F, 7am–5pm Sat. *(see Fig. 3.2 above)*	
Fan Schedule	6am–11pm M-F, 7am–6pm Sat. *(see Fig. 3.2 above)*	
Internal Loads		
Lighting System Type	T-12 lamps, energy-saving ballasts	T-8 lamps, electronic ballasts, direct
Lighting Power Density (W/sf)	1.7	1.25
Receptacle Load (diversified)	1.5	*
Occupancy Density (sf/person)	215	*
Occupant Sens/Lat (Btu/per)	250/200	*

** items unchanged from the ASHRAE 90.1–1989 base case are marked with an asterisk*

West Building ASHRAE 90.1 Base Case and Alternatives

The West Building Base Case also simulates the West Building as if it were designed to minimally comply with ASHRAE 90.1 energy standards. Base Case assumptions regarding ASHRAE compliance are very similar to those used in the North Building.

A total of six packages of design alternatives were modeled, each "on top of" the preceding. These are listed in Table 5, below.

West Building Projected Energy and Cost Savings Results

Cost-related results are summarized in Table 6. As was the case for the North Building, each of the separate cases were evaluated by adding each new measure to the previous set of measures.

Table 6 provides the results of each alternative's evaluation. Each alternative ECM's incremental first cost, 25-year energy cost savings, its simple pay back and cumulative improvement over the ASHRAE 90.1 base case. If all of the proposed alternatives were incorporated in the West Building, then projected energy consumption would be 41% less that the ASHRAE 90.1 base case (coincidentally same as the North Building).

Table 5
WEST BUILDING ECM ALTERNATIVES

1 Building Orientation and Fenestration:
- Reoriented Building,
- Window Setback,
- Precast Skin, Light Surface Color,
- West Patio Shading

2 Envelope Insulation:
- Increased Wall Insulation
- Increased Roof Insulation

3 Exterior Glazing Alternatives:
- "Standard Practice" Glass (Double Bronze)
- Low-E Insulated Bronze Glass,
- Low-E Insulated Daylight (Light Green) Glass

4 Lighting Upgrades:
- Reduced Lighting Power Density,
- Daylighting Controls,
- Occupancy Sensor Controls for Ambient Lighting

5 Mechanical Systems Upgrades:
- Variable Speed Drive Pump Control
- CO2-Controlled Ventilation Air,
- Central (Existing) Chiller Plant

6 Heat Recovery Wheel

Table 6
ANNUAL ENERGY USE AND UTILITY COST
WEST OFFICE BUILDING

		Annual Energy Use & Costs			*Cumulative Savings (% savings)*			
	Measure # and Description	Source Energy Mbtu	Annual Utility Cost $	25 Year Life-Cycle System ($)	Source Energy Mbtu	Annual Utility Cost $	Simple Payback	25 Year Life-Cycle Utility ($)
0	Minimum 90.1 Compliance	51,192	$397,969	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
1	0+Bldg Orient & Fenestration	47,933	$377,978	$3,794,156	3260 (6%)	$19991 (5%)	18.9	$499775 (5%)
2	1+Envelope Insulation	47,636	$369,987	$3,963,082	3557 (7%)	$27982 (7%)	14.9	$699550 (7%)
3	2+Standard Practice Glass*	46,599	$354,571	$5,321,131	4594 (9%)	$43398 (11%)	12.2	$1084950 (11%)
4	2+LoE Bronze Glass	45,626	$346,150	$5,387,631	5567 (11%)	$51819 (13%)	11.5	$1295475 (13%)
5	4+Lighting System	34,047	$262,299	$7,231,172	17145 (33%)	$135670 (34%)	14.8	$3391750 (34%)
6	5+Mechanical System	32,275	$248,946	$7,421,942	18918 (37%)	$149023 (37%)	14.3	$3725575 (37%)
7	6+Heat Wheel	30,793	$234,237	$7,553,012	20400 (40%)	$163732 (41%)	13.8	$4093300 (41%)

Results

For the North Building, this analysis predicts a 41% improvement and a 25-year utility cost savings of $6,139,125 over the reference ASHRAE 90.1 base case with an incremental investment of $4,002,000 (16 year simple payback). Nearly $2,947,950, or 41% of the total utility savings, resulted from lighting system improvements with an incremental investment of $1,761,400.

For the West Building, this analysis also predicts a 41% improvement and a 25-year utility cost savings of $4,093,300 over the reference ASHRAE 90.1 base case with an incremental investment of $2,266,000 (14 year simple payback). Here again lighting system improvements resulted in the greatest benefit. For an incremental investment of $1,416,810, a 25-year utility savings of $2,096,275 is projected. This is 51 % of the total savings.

The major benefit of this study has been to demonstrate a design process in which building design professionals, working together to achieve integrated energy-efficient design solutions, can achieve significant energy savings. Critical to this process is the availability of user-friendly comprehensive modeling tools that allow detailed whole-building energy analysis to be conducted in an affordable and timely manner. With this ability, Louisiana has demonstrated that energy conservation measures can be cost-effective and real cost savings can be realized if they are incorporated in these new large office buildings.

Chapter 21— Workspace-Specific Lighting and Control

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22nd World Energy Engineering Congress October 1999

Abstract

This paper discusses a revolutionary approach to office lighting and control in which each occupant receives the highest quality ergonomic lighting at the lowest possible energy cost. This new approach involves the optimal placement of luminaires, occupancy sensors and daylight sensors relative to the locations of office workers and their visual tasks. In addition, the local area computer network may be used to enable occupants to select their preferred workspace illuminance using on-screen controls. And to take advantage of real-time pricing, energy managers will need to control the lighting system from a central location, initiating dimming and scheduling strategies in response to rapidly changing price signals.

Building owners who incorporate this new approach will create conditions for enhancing productivity, minimizing energy use, and capitalizing on the opportunities emerging in the new electricity marketplace.

Introduction

Specifiers of energy-efficient lighting systems in modem office applications often strive to achieve an impossible goal: to optimize lighting quality, maximize energy savings, and meet the unique ergonomic needs of individual workers—while earning an attractive financial return. Although this is an impossible goal to achieve in most lighting applications, the unique characteristics of the modern office provide an opportunity to optimize the office lighting solution. The key to optimizing office lighting is to take a new approach—a "workspace-specific" approach to lighting and control.

Workspace-Specific Lighting

The illumination requirements for reading and writing are significantly higher than the illumination requirements for circulation areas. Yet traditional office lighting systems provide a uniform light level throughout the floor area, with little regard to where the visual tasks are located. Although task lighting can offer a satisfactory solution, consider the benefits of workspace-specific direct-indirect lighting.

As Figure 1 shows, a suspended luminaire over each workspace can provide the needed task and ambient lighting. Reading and writing surfaces can be appropriately illuminated by the downlighting component of the luminaire. Comfortable, uniform ambient lighting is provided by the uplighting as it reflects off the ceiling and brightens the walls and ceiling.

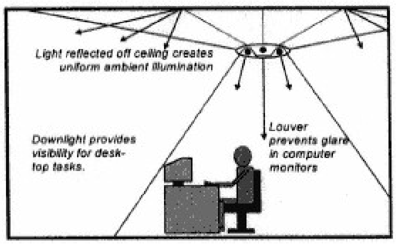

Figure 1
Workspace-specific direct-indirect
lighting systems provide both task lighting
(downlighting) and ambient lighting (uplighting).

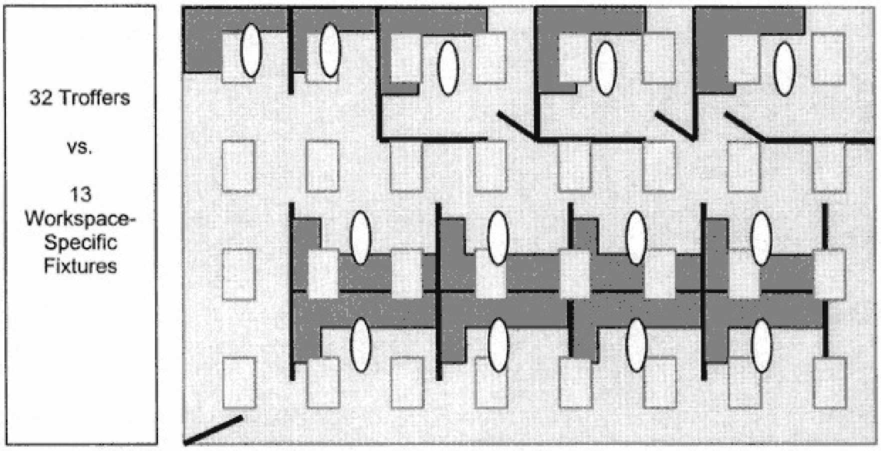

Figure 2
Workspace-specific lighting requires fewer fixtures to provide task-appropriate illumination throughout the office area. The uplighting from each fixture provides uniform indirect lighting for circulation areas. Additional fixtures may be installed over common visual task locations such as photocopying and filing areas.

Energy Performance

The workspace-specific lighting approach yields task-appropriate illumination with minimum energy use. For example, a typical 10'x12' office may be illuminated with two 2-lamp or 3-lamp fluorescent troffers. Assuming T8 systems are used, the power density will be in the range of 1.0 to 1.5 Watts per square foot. However, with the workspace-specific approach, only one 3-lamp direct-indirect luminaire will be needed in the office, resulting in up to a 50 percent reduction in power density, yielding only 0.75 Watts per square foot. And in *open* office areas, the installed power density of workspace-specific lighting can be as low as 0.6 Watts per square foot.

As Figure 2 shows, workspace-specific lighting can require fewer than half of the fixtures to light the office area. Fewer fixtures means reduced operating and maintenance expenses.

This level of energy-efficiency performance is achieved in part by the efficiency of direct-indirect luminaires in delivering light to the work surfaces. Table 1 compares the typical range of coefficients of utilization (CU) of fluorescent fixtures. Note that the higher coefficients of utilization for direct-indirect luminaires mean that they will deliver more footcandles per lamp lumen output.

Table 1: Comparison of Coefficients of Utilization (RCR= 1, Reflectances = 80/50/20)	
Lensed Troffer	65–75
Deep-Cell Parabolic Troffer	65–80
Direct-Indirect Luminaire	70–85

Lighting Performance

In order for workspace-specific lighting to be successful, it must provide the appropriate quantity and quality of light on room surfaces. Figure 3 shows the distribution of footcandles in a typical office environment with workspace-specific lighting. Note that by positioning fixtures in the

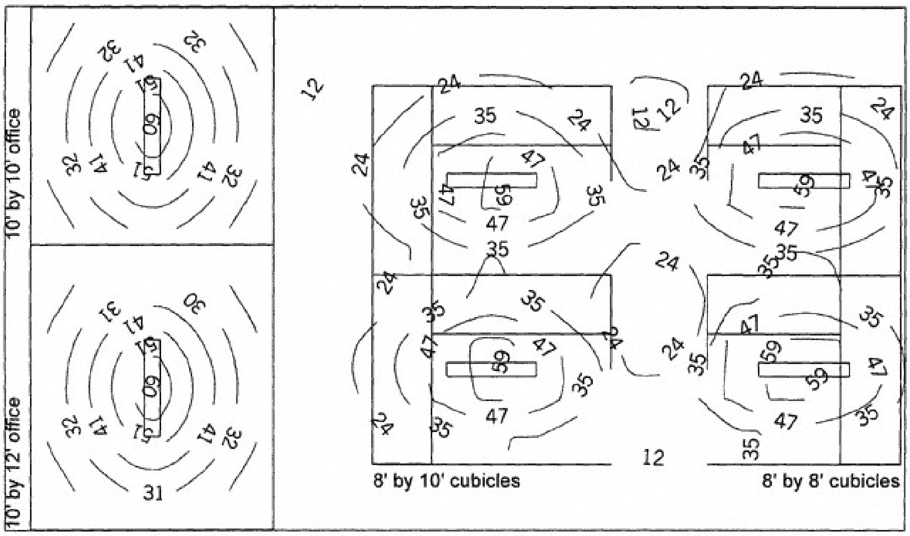

Figure 3
Illuminance distribution in typical offices using workspace-specific lighting. Note that visual task areas receive appropriately higher illuminance than circulation areas. Light levels are shown at desktop level (in footcandles).

proximity of the reading and writing visual tasks (the desk areas), the illumination is generally maintained in the range of 24–47 footcandles. Note also, that the illumination gradually drops off beyond the visual task area to a comfortable ambient level (12–24 fc) where circulation and short-duration visual tasks may be performed.

Because each workstation receives the same fixture placement, each worker receives the same quality and quantity of light. This approach overcomes a common problem in traditional open-office plans where some partitioned workstations can be left in the shadows. In addition, the direct-indirect lighting distribution brightens the ceiling and upper walls, minimizing the "cave effect" typically associated with the sharp cutoff of parabolic louvers.

Workspace-Specific Control

The workspace-specific placement of direct/indirect light fixtures opens up new opportunities to maximize energy savings with automatic lighting controls. In addition, workspace-specific lighting provides optimum conditions for convenient personal dimming control. To implement these control strategies, the fixtures must be equipped with dimmable electronic ballasts.

Workspace-specific lighting controls include:

Occupancy Sensing: automatic dimming or switching of lighting systems based on occupant motion sensed within the workspace.

Daylight Dimming: automatic dimming of lighting systems in response to increasing daylight conditions.

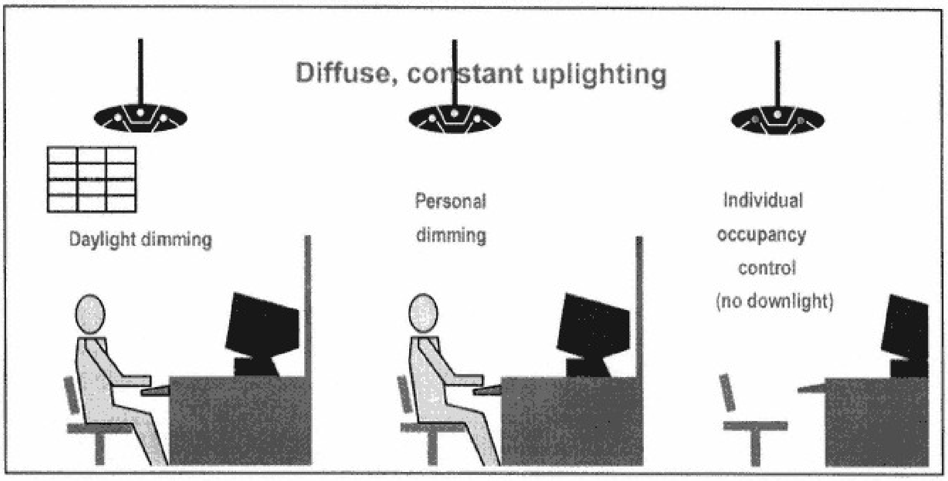

Figure 4
With workstation-specific lighting and control in open office environments, the uplighting remains constant while the downlighting varies based on manual or automatic control inputs.

Personal Dimming Control: controls that allow users to select their own preferred light level.

Workspace-Specific Occupancy Sensing

With light fixtures positioned directly over occupant task areas, the best possible location for the occupancy sensor is in the fixture itself. Using infrared occupancy sensors built into the workspace specific fixture, the distance between the sensor and occupant movement is minimized, resulting in very reliable motion sensing.

An important consideration in open offices is to minimize the sudden changes in room brightness caused by individually switching fixtures. As shown in Figure 4, occupancy sensors should be set to control the downlights (task lighting) while keeping the uplights (ambient lighting) on at a constant level. To further minimize distraction to neighboring workers in an open office, the downlighting should be gradually *dimmed* after the space becomes unoccupied. After a pre-set time delay, the sensor would eventually turn the downlighting off. The resulting visual impact will be a constant ceiling brightness with gradual changes in downlighting, causing subtle changes in louver brightness. In private offices, however, it makes sense to have the occupancy sensor dim and/or switch all lamps off.

The main advantage of workspace-specific occupancy sensing is energy savings. Because private offices and workstations can be unoccupied for over 40 percent of the time that lights are normally on, significant energy savings can result.

Workspace-Specific Daylight Dimming

The goal of any daylight dimming application is to maintain a constant level of work surface brightness as daylight contributes variable amounts of illumination. To achieve this goal, the light sensor must detect the luminance (brightness) of the work surface and control the electric light output as needed to maintain the chosen illumination level. Again, the most logical location for the luminance sensor is directly over the work surface—where the workspace-specific luminaire would be positioned.

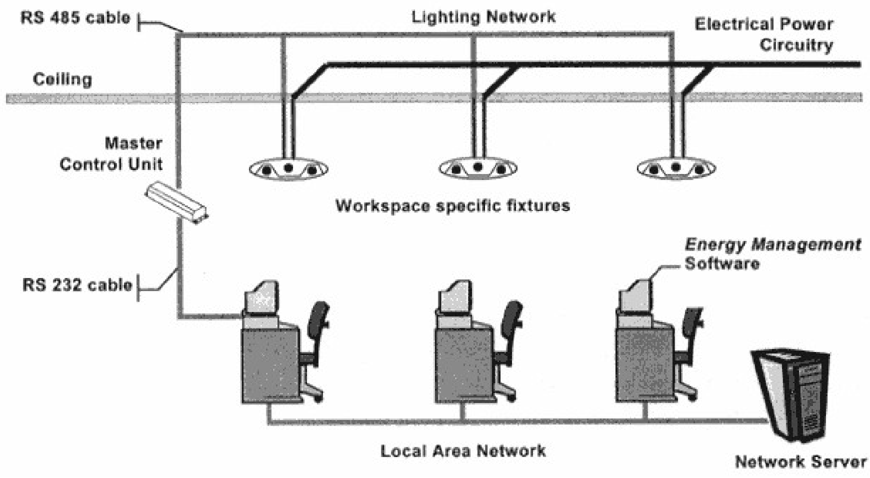

Figure 5
By connecting intelligent fixtures into a "lighting network", individual workers can control their assigned workspace-specific fixtures using their personal computer.

To minimize worker distraction, the best practice is to dim the lights in response to increasing daylight, rather than to simply switch lights off. And the rate of dimming is important as well—the dimming should be controlled at a very slow rate (30–60 seconds from maximum to minimum light output) in order to minimize occupant awareness of the dimming.

The primary advantages of daylight dimming are 1) energy savings of at least 30 percent in window-adjacent locations can be achieved without distracting occupants, and 2) these energy savings typically occur during periods of peak electricity demand, resulting in reduced utility demand charges.

Workspace-Specific Personal Dimming Control

One of the most common complaints about office lighting is that individual workers have no control over how much lighting their workstation receives. And if given a choice, most workers would prefer to have lower light levels than they now receive.

As shown in Figure 5, "intelligent" lighting control systems are available that enable workstation computers to control the light fixtures to which they are assigned. Now, with the use of their mouse, office workers can pull up a simple on-screen control panel and "click-and-drag" a dimming slider control, lowering their workstation illuminance to their preferred level.

The primary advantage of workspace-specific personal dimming control is the ergonomic benefit enjoyed by each worker. Instead of coping with the light levels dictated by the existing lighting system, workers will be able to control their own personal work environment—even if their work environment is a small cubicle. The results will be fewer complaints and working conditions conducive to maximum productivity.

Central Lighting Control

The use of LAN wiring and a lighting network opens up multiple opportunities for centralized lighting control from a designated network computer. The primary modes of central lighting control are load shedding and scheduling.

Load Shedding

As the utility industry continues its move toward deregulation, new kinds of electricity rates now offer very low prices for *off-peak* electricity in exchange for very high rates for *on-peak* electricity. To take advantage of these new rate structures, electricity customers will need a way to reduce power consumption in response to changing price signals.

Although one approach is simply to turn off "nonessential" electric loads during these high-cost electricity use periods, office lighting is seldom considered non-essential! However, by very gradually dimming the lighting system—typically 20–30 percent over 15–20 minutes—on-peak lighting electricity costs can be reduced by up to 30 percent without distracting workers. Because the human eye adapts to changes in brightness much faster than the load-shedding dimming rate, the change in brightness will be invisible. However, the reduced light level is only intended to be a temporary measure for minimizing peak electricity demand; full illumination levels should be restored—again at the same gradual rate—after the peak demand period has passed.

The primary advantages of load shedding are to take advantage of new "time-of-use" or "real-time pricing" rate options and to minimize utility costs associated with peak electricity demand.

Light Scheduling Control

Similar to the function of a timeclock, lightscheduling control is needed to ensure that manually controlled lighting systems are shut off at the end of the day. For example, if the workspace-specific lighting system in an open office has occupancy sensors that only control the downlighting, a scheduling control may be used to automatically turn off the uplighting at the end of the day (and turn it back on for the next workday).

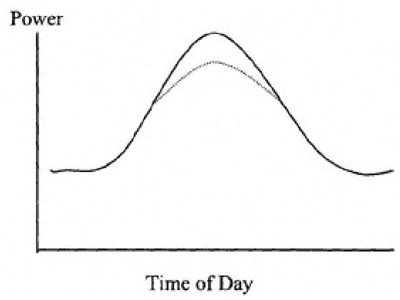

Figure 6
During periods of peak electricity demand when unit energy prices are highest, gradually reducing the lighting system power will yield substantial savings on utility bills with no impact on occupants.

Any scheduled "on/off" lighting control must provide a convenient means to workers to temporarily override the schedule for their specific area. For example, if an occupant needs to work late—beyond the scheduled "lights out" time, the occupant should be provided with a method to safely override the "lights out" command in their area.

Another application of light scheduling control of networked light fixtures is scheduled dimming. For example, the lights could be scheduled to remain on during the "cleaning period" on a floor but at a reduced light level. Similarly, the load shedding function described above can be scheduled to occur at specific times.

Other Centralized Lighting Functions

In addition to load shedding and scheduling, other LAN-based lighting control functions can include global controls commissioning and energy use monitoring. These functions can be implemented from a central computer, saving hours of time otherwise spent on commissioning individual sensors in the workspace and installing individual energy monitoring devices throughout the building.

Summary

The integration of on-board sensors and LAN-based communications with workspace-specific direct-indirect light fixtures yields multiple benefits:

Maximum energy savings result from reducing the required number of fixtures by 50 percent or more. Only one fixture is required per workstation or private office up to 120 square feet.

The direct-indirect lighting distribution brightens all room surfaces resulting in a balanced luminous environment. Downlighting provides visually comfortable task lighting, and uplighting provides pleasant ambient lighting.

Personal dimming gives every user direct control over their workstation light level. The resulting ergonomic benefits—fewer complaints and higher productivity—may be difficult to quantify, but they can far outweigh the energy cost savings.

Energy costs are minimized due to integrated automatic controls—occupancy sensing, daylight dimming, and scheduling control—all without distraction to workers.

Load shedding provides maximum control over peak electricity demand and energy usage. This capability enables utility customers to take advantage of new electricity rates offered in the new age of deregulation.

Based on national-average installed costs and electricity rates, the typical payback period for a workspace-specific lighting and control system is in the range of three to five years.

Chapter 22— Total Metal Halide Pulse Start Systems Represent Significant Energy Savings for Lighting Installations

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Venture Lighting International

Abstract

A new series of interactive lamp-ballast systems under the generic name of "pulse start" offers significant performance improvements and energy savings over previously available metal halide options. But, among the numerous designs currently on the market, many are not true pulse start systems that incorporate all the advantages of this technology. This paper explains the important differences and the essential elements that must be present in a pulse start system to derive the full benefits and the reduced energy consumption provided by this technology. After reading this paper, the facility manager should understand how pulse start lamp and ballast construction differs from standard metal halide design and how these interactive changes represent a revolutionary departure for lighting applications.

Outline

I. Introduction: Metal Halide Lighting Basics

II. The Change to a System Approach

III. Ignitor Pulse Starting

IV. Formed Body Arc Tubes

V. Low Current Crest Factor Ballasts

VI. Open Fixture Designs

VII. Pulse Start Systems in New Installations

VIII. Pulse Start Systems for Retrofit Applications

  Advantages

  Case Study

IX. Summary

Introduction

Metal halide lamps are High Intensity Discharge (HID) lamps that produce intense white light. Originally designed in the 1960's for stadium lighting and other high wattage applications, they are available today in sizes ranging from 32 watts to 2000 watts. Metal halide lighting applications now constitute the fastest growing segment of the lighting market. Metal halide lamps are ideal for lighting large areas efficiently and are found in manufacturing areas, high bay areas, warehouses, parking lots, and numerous other commercial and industrial spaces. They offer excellent efficacies (lumens per watt), white light with excellent color rendering, compact size, and long life. All metal halide lamps, like other gas discharge lamps (mercury vapor, fluorescent, high pressure sodium and neon lights) require a ballast to operate them by creating the discharge in the lamp arc tube.

An arc discharge is essentially a sustained "lightning bolt." The role of the ballast is first to initiate the discharge and then to maintain a stable flow of electric current. The current serves to heat up the arc tube, and this heat ensures that sufficient metal halide molecules are vaporized into the discharge. The mechanism of light emission is entirely different from that which causes light to be emitted from a hot filament. Unlike a filament lamp which produces "continuum" spectra, a metal halide lamp provides a much more efficient "line" spectrum, emitting light in many discrete regions of the visible spectrum. It is this direct excitation of atoms to emit visible light that results in the high efficiency of these lamps, and substantially less heat is generated than in a regular incandescent filament lamp of the same wattage.

The "arc tube," is the heart of a metal halide lamp. A 32 watt arc tube has a chamber the size of a pea, and from this little source as much light is generated as a 4-foot-long fluorescent lamp. A 2000 watt sports lighting lamp has an arc tube the size of a banana enclosed in an outer bulb the size of a basketball. This single lamp generates as much light as nearly 120 standard 100-watt incandescent bulbs. The arc tube is made of fused silica (also referred to as "quartz") which is essentially melted sand. Although it looks just like glass, quartz has a very high melting point, and it is possible to melt many metals in quartz crucibles. The walls of this chamber typically reach about 1000°C in an operating arc tube. At the center of the discharge itself, the temperature may be as high as 5000°C, producing an intense and efficient emission of light.

When the arc tube is started, the heat from the electric arc discharge (or continuous spark) warms up the chamber and causes the mercury in the arc tube to vaporize, gradually building up pressure. This is the warm up phase; when the entire dose of mercury is vaporized, the lamp is said to be fully warmed up. An operating arc tube contains predominantly mercury vapor at high pressure, typically 4 to 20 atmospheres, with only a small partial pressure of the metal halide molecules. Yet it is the metal atoms that are responsible for most of the emitted light. Based on the type and quantity of different chemicals that are added, it is possible to obtain cool white, warm white or even daylight type color. A small amount of starting gas (typically argon and sometimes xenon) is also sealed in the chamber.

The Change to an Interactive System

Ballasts which operate metal halide lamps were originally designed in the 1960's and 70's. Ballast engineers were limited in making design changes because their new designs needed to be compatible with existing lamps. In turn, lamp designers could make only minor improvements because of the need for new lamps to operate on existing ballasts. While several new wattages have been added, "standard" lamps have changed very little over the past 30 years.

In the last few years, however, the metal halide lighting industry has turned to a systems approach. Lamps and ballasts are conceived and designed together to take advantage of interactive features and provide better performance and energy savings for the end user. This trend started with low wattage lamps introduced in the 1980's and early 90's. Now all major manufacturers produce some models of higher wattage lamps (150 to 450 watts) and compatible ballasts in a systems package that incorporates "pulse start" technology. Pulse start systems now offer attractive options for engineers designing lighting layouts for new spaces but are also worth considering as retrofit options for existing fixtures. No where is the impact as high as in indoor lighting for commercial and industrial areas. The wattage range is exactly right for lighting indoor spaces.

This technology is a major step forward in metal halide lighting. Pulse start system technology is the first true lighting advancement to be introduced in 30 years, and it is expected to replace standard metal halide lamps in 175, 250, 400 and 1000 watt products, which currently account for 70% of existing applications.

Nevertheless, a system classified as "pulse start" does not automatically mean that this system provides all the benefits associated with pulse start technology. These advances in lighting performance are achieved only as a result of newly engineered design features involving both lamp and ballast construction in an interactive lighting system.

Ignitor Pulse Starting

In designing ballasts for metal halide lamps, engineers have for years performed a delicate balancing act when specifying argon gas fill pressure in the arc tube chamber. Pressure too low created a build up of tungsten from the electrodes at each start that caused a light-absorbing film on the arc tube wall. Using higher fill pressures reduced the build up but made starting the lamps more difficult.

In the late 1960's and early 70's, engineers designed ballasts with exaggerated "peak" voltages to improve metal halide lamp starting. These ballasts are commonly referred to as "peak lead ballasts." The high peaks provided extra voltage to start the arc tube and allowed the lamp manufacturers to use slightly higher fill pressures. The traditional "standard" metal halide ballasts in use today all incorporate this peak, and since it is part of the ballast design, it cannot be turned off. It is in effect in the current waveform during steady state operation and causes electrode damage over the long term, contributing to lumen depreciation.

Pulse start systems address the starting problem by using a high voltage ignitor pulse to initiate the electric discharge. The old standard metal halide ballasts did not have such a pulse, instead they used a third electrode in the arc tube called a starter electrode. The electronic pulse in the new ignitor starts arc tubes even if the argon pressure is two to four times higher than in traditional arc tubes. The higher pressure results in less lumen degradation with each start and lamp designs that maintain their lumen output with less depreciation over time.

The separate ignitor used in pulse start technology provides a pulse that shuts off once the lamp has started. The lower current crest factor that is found in many of the newer pulse start ballasts results in a smoother, more benign current waveform for the operation of the lamp and reduces lumen depreciation. Lower current crest factor contributes to increased lumen maintenance because there is less stress on the electrodes from the higher currents.

The new ballasts can be slightly more expensive with the added ignitor, but given the advantages, those few dollars are well worth it. At 10 cents per kWh, a standard 400 watt lamp will use $900 of electric power over the life of the lamp (20,000 hours). These electricity costs are so much higher than the initial costs of lamps and ballasts. Even a 10% improvement in mean lumens translates to an $80 saving in power costs over the 20,000 hour life of the lamp. These savings can be realized, for example, by using 10% fewer fixtures or by using lamps of 10% lower wattage while still providing the same lumens or more. In fact, up to 20% improvement in mean lumens per watt (LPW) is possible with the best systems.

In a true pulse start system, a ballast with an ignitor and an arc tube with higher than standard fill pressure must be included. However, this is still a minimum lamp-ballast system that does not provide all the benefits of the total system; there are further advantages to be obtained when the complete pulse start technology involving new lamp design is installed.

Lamps with Formed Body Arc Tubes

As a consequence of this new ballast with ignitor starting, improvements could now be made in lamp design. For years, lamp designers had the ability to develop a more efficient arc chamber without the starter electrode required in standard arc tubes. The new arc chamber design needed the pulse start ballast to become a reality.

With these new pulse start ballast designs, there are now two types of arc tubes: (1) the new design formed body arc tubes which are ellipsoidal (or spherical) in shape with two "legs" on either side and (2) tubular bodies which are produced by pinching shut the two ends of a cylindrical piece of quartz. The new formed body arc tubes have only two electrodes, one at each end, thus eliminating the additional "starter" electrode at one end of the tubular pinched body arc tube. Figure 1 illustrates the difference.

Because they have only two main electrodes, the formed body arc tubes need the high voltage starter pulse from an ignitor to break down the gas between these electrodes. The ignitor, usually included in the ballast circuit, allows these arc tubes to be filled with a higher pressure of argon gas than the tubular bodies, a factor which improves long term performance.

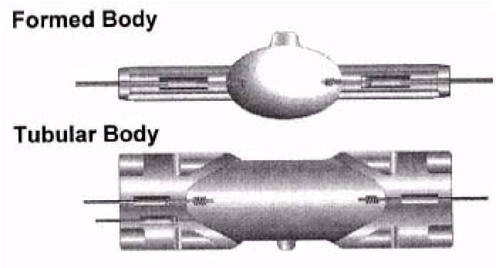


Figure 1
Two Kinds of Arc Tubes

Any ballast operating a metal halide lamp using an electronic high voltage pulse ignitor, typically 3000 to 4000 volts, would qualify as a pulse start system. However, a pulse start ignitor with an inferior ballast waveform does not provide the full benefits possible. And standard lamps, even when used on ballasts with ignitor starting, will not offer pulse start advantages. Pulse start systems are available without the new formed body arc tube but they provide improvements only in percent lumen maintenance without the gains in initial efficacy and color uniformity.

It is only the combination of pulse start ignitor ballasts with formed body arc tube lamps that can be designated as a true, total pulse start system providing the full benefits of this technology. These interactive systems offer the full gamut of benefits, including higher lumens, better lumen maintenance, improved color uniformity, faster warm-up and hot restrike, and improved ballast efficiency. The lumen maintenance chart (Figure 2) shown below compares the difference in lumen maintenance between the 320 watt pulse start lamp and the standard 400 watt lamp.

Ballast Options for Pulse Start Systems

Ignitor starting has instigated the development of more efficient ballasts in addition to the familiar Constant Wattage Autotransformer (CWA) ballasts. Three types of ballasts are available for pulse start systems: CWA, 277 volt reactor and regulated lag ballasts. In each, a high voltage ignitor provides the breakdown of the gases to jump start the arc. The outcome is more reliable cold starting, hot restrike in 50% less time, and reduced arc tube wall darkening. The end result is improved lumen maintenance and longer lamp life. Some reactor systems are almost twice as efficient as other ballasts and provide significant power cost savings in addition. Reactor ballasts operate on 277 volts without the step-up transformer or autotransformer that contributes to ballast losses.

Ballasts must also provide regulation, a factor that determines the extent to which lamp performance is affected by line voltage fluctuations. Although they are very

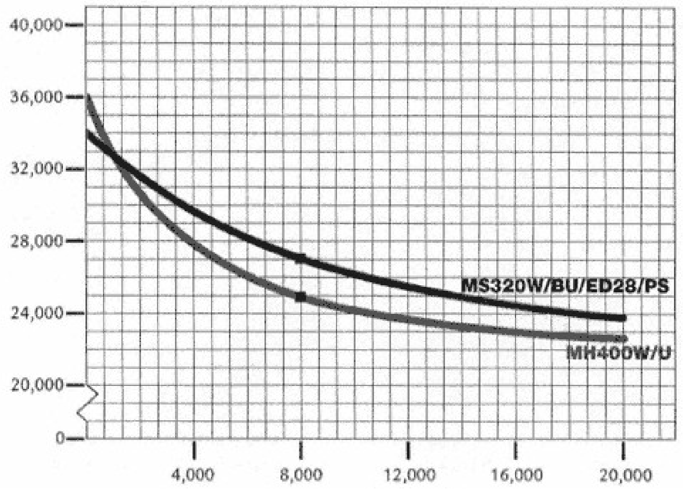


Figure 2

efficient, reactor ballasts offer poor regulation. A 5% drop in line voltage may lead to a 10% drop in light output. Regulated lag ballasts with pulse start ignitors offer very good regulation for metal halide lamps, although they are not as efficient as reactor ballasts. Particularly in continuous burn applications where lamps are turned off only once a week, a 400 watt pulse start system can provide up to 30,000 hours of lamp life.

The 277 volt reactor ballast has a lower current crest factor because there is very little distortion of the wave form. Pulse start reactor ballasts for use on 277 volt circuits reduce ballast losses about 50% by eliminating the need for voltage transformation. As an example, the 350 watt pulse start reactor ballast consumes only 30 watts while a standard 400 watt CWA ballast typically consumes about 60 watts.

Therefore, replacing a standard 400 watt unit with a 350 watt pulse start unit on a reactor system saves 50 watts in the lamp and 30 watts in the ballast for a total reduction in power consumption of 80 watts or 80/460 = 17%. Lumen output (initial) goes up by 6% and mean lumens (at the 8000 hour point) go up by 25%.

"Average Maintained Efficacy of System" ("AMES") is mean lumens divided by system watts. The table below lists system efficacies for the two systems discussed here. The improvement in Average Maintained Efficacy of System with the new pulse start system is seen in Figure 3 to be 51%!

Lamp	Ballast	System Watts	Initial Lumens	Mean Lumens (Lumens at 40% of life)	Average Maintained Efficacy of System (AMES) (mean lumens per system watt)	
350W Pulse Start	Controlled Current Reactor + Ignitor	380	38,000	31,500	**83 LPW**	**<--- 51% improvement**
400W Standard	CWA	460	36,000	25,200	**55 LPW**	

Figure 3
Average Maintained Efficiency of System 350w Pulse Start Vs. 400w Standard
Note: lamps assumed to burn vertically

The current crest factor is only 1.4, contributing to improved lumen maintenance. Additional improvements to the reactor ballast, called controlled current reactor by Venture Lighting, reduce the current draw during lamp starting and open circuit conditions compared to traditional reactor ballasts. Consequently, system energy savings can amount to over 25%. These ballasts are specified in 70% of new metal halide applications because of the improved lamp performance they provide in terms of longer life and better maintained lumens. The recent emergence of higher wattage (150W-450W) pulse start metal halide lamps in the North American market has presented a new opportunity to utilize reactor style ballasts.

Pulse start low current crest factor CWA ballasts yield additional benefits over standard CWA ballasts because of their improved current crest factor. These new designs all offer lower current crest factor down to 1.60 (compared to old technology 1.8 crest factor). The use of an ignitor allows quicker cold starting and faster hot restarts, a proven factor in longer lamp life and superior lumen maintenance.

Below are two plots showing the current being delivered to a lamp during operation by both a standard constant wattage autotransformer (CWA) ballast and a 277 volt reactor ballast. With the 277 volt reactor ballast, the ratio of the peak current to the average current delivered is approximately 1.4. The CWA ballast, on the other hand, shows a distorted current waveform in which this ratio is equal to around 1.8. The ratio of peak to average current is known as current crest factor as shown in Figure 4 below.

The regulated lag ballast offers the greatest level of control over lamp wattage fluctuations as a result of input line voltage variation. This ballast is larger and heavier than either the 277 volt reactor or the CWA, but is used in heavy industrial applications where users are concerned with the effect of voltage fluctuations on lamp life.

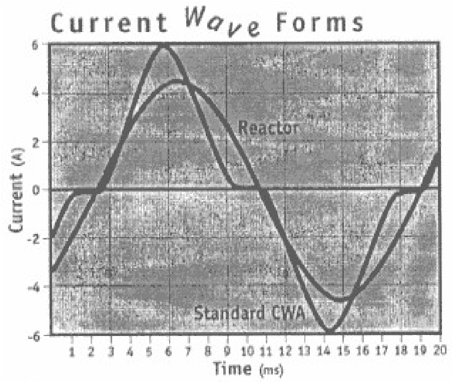


Figure 4

Open Fixture Lamp Technology

Because metal halide lamps operate at extremely high temperatures, standard metal halide lamps require enclosed fixtures due to the possibility of hazardous end-of-life arc tube rupture, causing arc tube and bulb glass fragments to fall from the fixture.

Longer operation of higher wattage metal halide lamps increases the likelihood of eventual end-of-life arc tube explosion. The hazard is even greater when lamps are burned seven days a week, 24 hours a day. With this burn cycle, the metal halide lighting industry recommends that lamps be shut down once a week for at least 15 minutes. This procedure is intended to assure that end-of-life lamp failure occurs passively at low pressure or by simply failing to re-ignite, and it should be done along with proper maintenance and group relamping before the end of rated lamp life. Nevertheless, it has not been proven that these steps eliminate nonpassive end-of-life rupture. As a result, new pulse start lamps specifically designed for open fixtures incorporate a shrouded arc tube, sometimes called a double-containment feature to enclose shattered particles. The compact design of the formed body arc tube easily allows the introduction of protective shrouds inside the envelope. The heavy glass shroud around the arc tube provides containment of hot arc particles should a non-passive arc tube failure occur, eliminating the need to enclose the fixture for safety reasons. The open fixture rating allows greater flexibility in design, lower fixture costs and improved maintained lumens. Fixture manufacturers can eliminate the glass lenses that reduce lighting efficiency due to light absorption and dirt accumulation and that create potentially higher operating temperatures. All lamps with an open rated shrouded arc tube can be operated continuously with no weekly shut-down required.

Due to the urgency of this issue, ANSI has taken the step of developing a test to determine if a lamp is safe for open fixture operation. This document (CDVC75(4/) 3918) is nearing the end of the approval process within the C784 ANSI subcommittee. In the ANSI test, arc tubes are artificially ruptured and must not cause cracks or fractures in the outer bulbs. At present, lamps designated "S" by ANSI are unshrouded and therefore do not pass the proposed test. Lamps designated "O" pass the ANSI test. Figure 5 below presents an overview of the differences in these two ratings.

"S" Rating	"O" Rating
No shroud or protective enclosure	Protective arc tube shroud
Must be operated ±15° of vertical	
Must be turned off 15 min. every week	Continuous operation, no shut-off required
Does not meet ANSI test for open rating	Meets ANSI criteria for open fixture use

Figure 5

Pulse Start for New Installations

Metal halide in general is the most energy-efficient source of white light in the world today. Metal halide lamps deliver more light with less energy usage compared to incandescent systems. They dramatically reduce fossil fuel consumption and in turn curb pollutant emissions. Long lasting metal halide lamps cut down solid wastes because relamping and lamp disposal are performed less often. State-of-the-art pulse start systems offer additional benefits in light quality along with reduced energy usage and lower operating costs. Initial installation is less costly because the increased light output and smaller lamp size reduce the number of fixtures needed to produce the required illumination. The complete metal halide pulse start system consisting of formed body arc tube lamps and low current crest factor ballasts with ignitor starting offers improved lumen maintenance, higher initial lumens, better color uniformity, faster warm-up and restrike and improved ballast efficiency. Figures 6 below compares the performance of nurse start systems in a number of wattages to standard metal halide pinched body lamps in terms of their light output and life. It shows pulse start systems that provide more light with the same energy use and pulse start systems that offer the same light with the highest energy savings.

A 320 watt pulse start system using a controlled current reactor ballast with ignitor starting offers significant savings per fixture when compared to 400 W probe start lamps using standard ballasts. Figure 7 illustrates the potential annual savings based on energy cost per kilowatt hours (kWh) and annual hours of use.

Retrofit Applications

Metal halide lamps are commonly used to retrofit incandescent, fluorescent and high pressure sodium lighting systems. Metal halide lamps produce light 3 to 5 times more efficiently than incandescent lamps. For an equivalent amount of energy, metal halide lamps produce five times the amount of light without the heat associated with incan-

Standard	Uni-Form® Pulse Start System	
	More Light/Same Energy	Same Light/Less Energy
MH 175 14000 Lumens 10000 Hours 80 LPW	MH 175/PS 17500 Lumens 15000 Hours 100 LPW	MH 150/PS 15000 Lumens 15000 Hours 100 LPW
MH 250 21000 Lumens 10000 Hours 84 LPW	MH 250/PS 26300 Lumens 15000 Hours (BU) 105 LPW	MH 200/PS 21000 Lumens 12000 Hours 105 LPW
MH 400 36000 Lumens 20000 Hours 90 LPW	MH 400/PS 44000 Lumens 20000 Hours (BU) 110 LPW	MH 320/PS 34000 Lumens 20000 Hours 106 LPW
MS 400/BU 40000 Lumens 20000 Hours 100 LPW		MH 350/PS 38000 Lumens 20000 Hours (V) 109 LPW

Figure 6
Pulse Start System Performance V. Standard Metal Halide

Energy Cost (¢/KWH)	Annual Cost Savings Per Fixture With Controlled Current Reactor Ballast - 0.115 kWs Saved				
0.14	$72.45	$88.55	$104.65	$120.75	$128.80
0.12	$62.10	$75.90	$ 89.70	$103.50	$110.40
0.10	$51.75	$63.25	$ 74.75	$ 86.25	**$ 92.00**
0.08	$41.40	$50.60	$ 59.80	$ 69.00	$ 73.60
0.04	$20.70	$25.30	$ 29.90	$ 34.50	$ 36.80
	4500	5500	6500	7500	8000
	Annual Hours of Use				

Figure 7

descent light. They emit a natural white light rather than the yellow light of high pressure sodium. Metal halide lamps are relatively unaffected by changes in ambient temperature, and they are available in a wide range of wattages and lumen packages for a variety of applications. These attributes afford the user more options in illumination levels, lighting design and system cost.

Many older lighting systems do not provide the illumination levels expected of current pulse start technology. When they are replaced with a pulse start system, dramatic benefits can be attained in higher light output as well as energy savings and heat reduction. Sometimes this upgrade can be accomplished using the existing fixture by adding a ballast, a new lamp and a replacement socket. This route can be more cost effective than whole fixture replacement, depending upon labor rates and time required for the retrofit.

A lighting system originally installed for a specific task can provide inadequate color rendering when the space is used for a different purpose. Replacing the yellow light of high pressure sodium with the white light of pulse start metal halide lamps can provide a better quality, more natural light. Unlike the low Color Rendering Index (CRI) of 22 provided by high pressure sodium lamps, pulse start lamps range in CRI from 65–70.

Simple lamp replacements are the easiest and lowest initial cost solutions to retrofit existing installations. More complex retrofits, involving changes in the lamp, ballast and sockets, require greater planning and technical competence, but can still be a good answer when the user wants to preserve the existing fixture. Pulse start systems using lamps with new formed body arc tubes which are designed to the same light center lengths as the old standard lamps permit the use of the same fixture and reflector without loss in fixture efficiency.

Installing a new pulse start system requires a new pulse start ballast. The best option is to remove the old ballast and install a new one. The reactor ballast is more efficient and provides a lower current crest factor. The replacement provides the full benefits of the new pulse start technology. A cost benefit analysis usually supports the ballast replacement.

Two attractive retrofit options are available. Facility managers can choose the same wattage ballast and lamp as the existing one and install a pulse start ballast and formed boy arc tube pulse start lamp that provides 10% to 20% higher lumens than standard lamps with less depreciation over time and no increase in energy usage. If the goal is to save energy rather than to achieve higher light levels, the second option is a lower wattage pulse start system which still provides the same light output as the standard system with significant energy savings.

Retrofit Case Study

In a successful retrofit project that achieved substantial energy savings, a chain of regional supermarkets switched from standard 400 watt metal halide lamps operating on CWA ballasts to a pulse start system. They were initially given a proposal by Venture Lighting International outlining the benefits to be achieved in energy savings using either a 320 watt pulse start lamp or a 350 watt pulse start lamp combined with a 277 volt reactor ballast. The 350 watt system provides more light for less energy than the 400 watt standard metal halide lamp. The 320 watt pulse start system offers the same light output as the 400 watt standard lamp but achieves maximum energy savings.

The chain decided to maximize its energy savings by installing Venture's 320 watt pulse start system. Combined with the 277 volt reactor ballast, the 320 watt lamp reduced system watts from 458 to 345, a total system savings of 113 watts per fixture. Each store was outfitted with 120 fixtures. Prior to the retrofit, the chain's annual energy cost for each store, based on an 80 hour burn cycle, was $42,678 @ .10/kWh. After the pulse start system installation, the annual energy cost per store was $32,148, a yearly savings of $10,530. Figure 8 illustrates the savings.

Summary

Pulse start metal halide technology is the first true lighting advancement to be introduced in 30 years, and it is expected to replace standard metal halide in 70% of existing applications. This technology is an interactive lampballast system approach to lighting installation that provides facility managers with increased options and attractive benefits in new and retrofit applications. The performance advantages to be gained from a true pulse start system include higher efficacy, greater energy efficiency, better color uniformity, faster warm-up and hot restrike, and longer life. Nevertheless, not all systems marketed under the name "pulse start" are true pulse start systems providing the full range of benefits. Facility managers need to be aware of the important differences and requirements when specifying a pulse start system for their installation. Only the combination of low current crest factor ballasts with high pulse ignitors and formed body arc tube lamps comprise a true, complete optimized pulse start system. The changes made in ballast design and arc chamber construction produce all the related benefits, including systems that produce more light using the same energy and systems that provide the same light output with maximum energy savings. Both options offer the lowest lifetime operating costs compared to traditional metal halide systems or incomplete systems offering only partial pulse start elements.

True Pulse Start System includes:

Pulse start ignitor

Low current crest factor ballast

Lamp with formed body arc tube

About the Author

Deborah Rogers directs technical marketing and sales for Venture Lighting International at their headquarters in Solon, Ohio. Deborah has spearheaded the marketing and sales of Venture's state-of-the-art metal halide Uni-Form® pulse start system. She has been guest speaker at numerous industry conferences and chapter meetings and has authored a number of technical articles on metal halide lighting. Deborah is a member of technical organizations including IESNA, NAESCO and EELA.

Payback Analysis	**Existing** 400W - M59 STD-CWA	**Proposed** 320W - PS 277V-Reactor
System Wattage	458	**345**
Fixture Count Per Location = 120 Usage Schedule (hours per year) *80 @ 24 Hr/Day= 8736* *40 @ 16 Hr/Day= 5824*		
Energy Cost per Year (@ .10/kWH) *(80 x Hr/ Yr x Watts x .001 x $0.10)+(40 x Hr/ Yr x Watts x .001 x $0.10)*	$42,678	**$32,148**
Proposed Savings per Year vs. Existing		**$10,530**
Payback Period Based on $7800 material cost *Deduct for Scheduled Lamp Replacement Cost - $3000*		**9 Months**
Payback Analysis based on Real Cost of $4800		**6 Months**

Figure 8

Chapter 23— A Case History of Lighting Upgrades for Tyson Foods

Kathy K. Peetz

Abstract

The following case history will describe the benefits achieved through the implementation of a lighting retrofit program. Tyson Foods Inc. partnered with Southern Company Energy Solutions, Inc. (Energy Solutions) to meet the goals set forth by both Tyson and the EPA under the Green Lights Program.

Introduction

As the world's largest poultry producer with 115 facilities in 17 states, Tyson Foods, Inc. handles 2.16 billion chickens annually. Achieving $7.5 billion in sales in 1998 Tyson currently employs approximately 65,000 people in the U.S., Mexico, and Canada. Tyson's facilities include 72 process plants, 52 hatcheries, 39 feed mills, and offices and operations that extend from Seguin, Texas to Jacksonville, Florida and Corydon, Indiana to Dawson, Georgia.

In 1997 Southern Company Energy Solutions, Inc., a subsidiary of the Southern Company, was approached to help offer solutions to standardize lighting equipment throughout Tyson's Process Plants. As the largest producer of electricity in the United States, Southern Company serves more than 3.7 million customers in the Southeast and around the world. By bringing the expertise and integrity of the Southern Company to Tyson's facilities, Energy Solutions maximized the potential and minimized the cost of the energy required for their critical operations.

The original projects began in 1996 with 17 complexes receiving lighting upgrades. Energy Solutions' initial involvement consisted of five (5) installations within the Southern Company operating territory. In 1998, Tyson awarded the full scope of the contract to Energy Solutions.

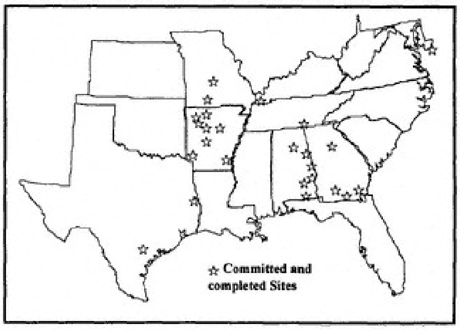


Figure 1
Tyson Processing Plants

Goals for Tyson Foods

A 30% reduction in lighting cost with overall energy savings of 2% of their total electrical consumption

Recycling of all lamps and ballasts as required by state and federal regulations to meet Green Lights and EPA requirements

Maintain light levels to customer and design specifications

Reduce product and maintenance cost

Use no upfront capital

Scope

Tyson's existing system consists of magnetic ballast with T12 lamp technology and probe start metal halides. Most fixtures are mounted over process equipment making repairs and maintenance difficult. The conditions in Tyson's process plants are damp and require constant cleaning. Using 800-PSI of water to wash down equipment on a daily basis, chemical solutions force their way into crevices causing extensive damage to sockets and wiring. As a result of routine exposure to high-pressure wash downs, lenses are susceptible to cracking and require frequent replacement. In one instance, a maintenance manager spent $18,000 annually in replacement of enclosed gasket lenses.

Solutions

Installation of specially designed fixtures to withstand the wet environment and high water pressure solved many of the maintenance issues. The fixtures were installed as plugins to facilitate removal for repair. As new fixtures were added, special stainless conduit and rubber cords were required to protect the integrity of the electrical system. As new electronic ballast and T8 lamps were installed, maintenance costs were deferred due to the new equipment. With warranties covering the materials and all defectives replaced by the manufacturer, each facility showed a decrease in lighting repairs. All materials were specified by Tyson to meet quality standards and maintain the energy savings required by the EPA. In an effort to regulate equipment purchasing, increase buying power of material, and consolidate vendors Tyson developed a single-source provider to satisfy a variety of needs.

Project Implementation

From start to finish, Energy Solutions controlled the sales process, project management and installation, material warranties and shared savings financing for each facility.

The process implemented by Energy Solutions is shown in the chart below:

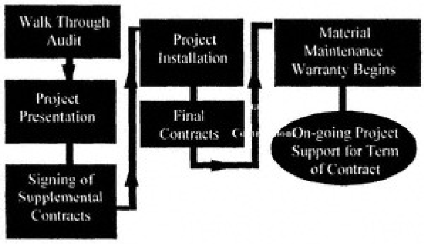


Figure 2
Project Flowchart

During the initial sales process an introduction of the program was presented to complex and plant managers. Upon survey approval, a team of engineers and project managers were sent to conduct audits and determine the condition of the existing lighting system, incorporating data such as light level requirements set by the USDA, color rendering index as well as maintenance of the system. During the course of the audits the team considered individual plant requests focusing on problems related to a specific facility.

With complete audit data, the existing fixture information was entered into a computer program designed specifically for Tyson. The customized program allowed Tyson to maximize maintenance and energy savings over the long term and develop their own maintenance and material cost realistic to their environment.

Tyson's goal consists of 100% participation from their facilities with the understanding that the level of opportunity may vary from plant to plant. The age and condition of each plant is considered when making assessments of the lighting systems. In final presentations, audit results defining energy and operational savings were made to a variety of Tyson personnel within each plant. Once contracts were signed the installation process began. Pre-construction meetings held with project managers, crew superintendents, and on-site personnel, were conducted to discuss safety requirements, work schedules and other details associated with project management. Scheduling within the parameters of Tyson's workload was the greatest challenge. Weekends and shutdowns were the only available times for lighting retrofits to be installed. The plant would close on late Friday and begin work again on Sunday afternoon. Energy Solutions had access during those few hours. During shut downs, the plant would have multiple contractors and equipment renovations scheduled for the same time. As each job is completed materials are supplied for the facility in order to cover any immediate failures. All EPA Green Lights paperwork is completed and submitted to document Tyson Foods participation in the national program

A warranty book is provided to the Parts Department in addition to a catalog, which includes cut sheets of each product with part numbers. Monthly calls are made to each facility to maintain a stock of materials to meet emergency needs.

The manufacturer material warranties include:

Fluorescent Electronic Ballast	5-years
Fluorescent T-8 Lamps	2-years
HID Pulse Start Metal Halide Ballast	5-years
HID Pulse Start Metal Halide Lamp	2-years

In addition to the manufacturer warranties, Energy Solutions maintains material replacement for the full term of the shared savings contract. These contract terms range from five to ten-years.

Summary

The installations, which began in 1997, have an expected completion in the year 2000. Currently 60% of the facilities are complete and represent an annual savings of 21,403,180 kWh. The chart below displays Energy Solutions' position in relation to Tyson's goals.

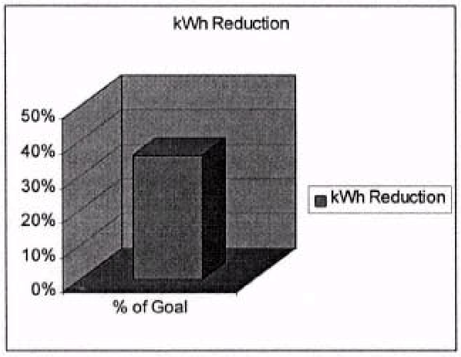
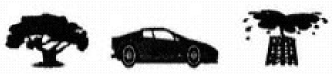


Figure 3
Current Achievements

Tyson's goal of achieving the savings numbers set forth continues to move forward. As each plant chooses to accept and implement the energy services project with Energy Solutions, the goal set forth by Tyson Foods, Inc. of 100 percent participation comes closer to a reality.

TABLE 1. ENVIRONMENTAL IMPACT



kWh Saved	CO_2 Acres of trees planted	CO_2 Cars removed	Energy Gallons of gasoline
21,403,180	6,204	3,032	1,945,744

Chapter 24— Hill Air Force Base Case Study New Lighting Technology Installation

John W. Adams, CLMC, LC
CES/Way International, Inc.

Abstract

Sulfur lighting is the first lighting technology breakthrough in recent history. The world's largest installation of sulfur lighting was implemented by CES/Way International, Inc. at Hill Air Force Base in Utah, where it is used in aircraft hangars dedicated to F16 and C130 aircraft maintenance and overhaul. This case study outlines the Department of Energy's pilot project criteria for the Hill application, discusses in detail how the technology was developed and applied at Hill, reports savings results and describes the benefits and new opportunities that this new lighting alternative brings to the industry and its clients.

Hollow Light Guide and Sulfur Lamp Background

In 1881, the first U.S. light pipe patent was proposed using a reflective coating inside a tube to reflect light from wall to wall and pipe it down the tube. Using conventional mirrors does not work well because mirrors are only about 95 percent reflective with the rest of the light lost by absorption.

Optical fibers composed of certain glasses or plastics can transport light much more efficiently, but are impractical for transporting large quantities of light. Large solid fibers or fiber bundles would be required. These bundles are heavy, difficult to install in many applications and exceedingly expensive. Fiber optics were successfully produced and patented in the 1970's.

The prism light guide was patented in 1981, 100 years after the first patent on piping light appeared and after a student at the University of British Columbia, Lorne Whitehead, recognized that prismatic materials in a hollow light guide could efficiently transport large quantities of light.

The first guides were constructed as rigid rectangular acrylic pipes with molded prisms, and each side of the 1/4 inch thick rigid panel was flat.

In 1983, 3M recognized that the macro-prism structure, which existed in these first thick-walled rigid panels, could be made as continuous film incorporating microscopic prisms with the same 90° geometry. This film, known as 3M™ Optical Lighting Film (OLF) was brought to market in 1989. With the typical losses due to absorption and transmission, the reflectance efficiency of OLF has been calculated as approaching 99 percent.

Using OLF, circular hollow light guides can be produced in a variety of sizes depending on the specific application. Based on the amount of light to be delivered and the distance it must be transported, tube diameters up to 10 inches or larger are routinely produced.

In 1970, Fusion Systems began development of an electrodeless, microwave-powered lamp for UV applications. Twenty years later, the sulfur lamp was invented.

By 1992, Fusion Lighting was incorporated with exclusive rights to all visible technology of the sulfur lamp. The first commercial sulfur lamp, Solar 1000®, was brought to market in 1994 and subsequently won several awards for technological innovation. The next generation sulfur lamp is today's Light Drive™ 1000, introduced in 1997.

Sulfur lamp development by Fusion Lighting was backed by the U.S. Department of Energy (DOE) and NASA, who were interested in attaining extreme technical data on the lamp relating to its potential for reduced energy use, color rendering quality, efficacy, lamp life and light delivery systems.

Each sulfur light bulb contains a small amount of sulfur and inert argon gas. When the sulfur is bombarded by focused microwave energy, it forms a plasma that glows very brightly, producing light containing all colors of the rainbow, closely matching that of the sun, but with very little heat or ultraviolet (UV) in the beam.

Each bulb, about the size of a golf ball, runs at 1425 watts producing approximately 135,000 lumens with a color rendering index of 79. Because there are no filaments or other metal components, it is possible that the bulb may never need replacement.

Sulfur lamps are an efficient, powerful, bright, full-spectral light source with many different indoor and outdoor uses.

The sulfur lamp can be used in a number of configurations. It can be used with reflectors for replacing high bay fixtures or with a hollow light guide commonly called a "light pipe", for illuminating large areas. In any configuration, the light emitted can be filtered, tinted, dimmed and reflected to meet precise lighting needs. Sulfur lamp technology is being utilized today in appropriate configurations across a wide range of applications in U.S. and Europe, including airport tarmac, aquarium, automobile assembly plant, cold storage facility, gas station, gymnasiums/sports facility, highway signage, museum, plant growth, postal sorting facility and a subway station.

The first DOE-sponsored applications of sulfur lamps in the U.S. are at the Smithsonian National Air and Space Museum and on the outside front canopy of DOE's Forrestall Building, both in Washington, D.C.

Case Study
Hill Air Force Base Application

Background

In 1996, DOE was looking for an aircraft hangar site in which to install a sulfur lighting demonstration project to illustrate the technology in a different application and help move it into the mainstream. They approached Andrews Air Force Base in Virginia with the idea of making the installation in the Presidential hangar for Air Force One. Andrews could not fund such a project, but Hill Air Force Base in Utah could because they were already in the midst of the first basewide, fence-to-fence energy systems upgrade ever undertaken by the military. CES/Way International, Inc. of Houston, Texas was implementing Hill's Energy Savings Performance Contract (ESPC). The Air Force suggested the sulfur lighting project be installed at Hill and CES/Way volunteered to support the project by using their lighting expertise to apply the new technology in a demonstration project to solve the base's low light problem.

Hill's original plan was to improve the quality of lighting in the low bay and hangar areas by doubling the number of lighting fixtures to reach the desired standard of 70 foot candles. Prior to the sulfur fusion lighting installation at HAFB, the existing mercury vapor and metal halide light fixtures produced very low light levels for the tasks performed in the hangars and low bays. For instance, in the low bays, fixtures mounted at 26 feet produced only 40–45 foot candles of light. In the high bays, 28–30 foot candles were produced by fixtures mounted at 45 feet. Needless to say, tremendous amount of task lighting was used to augment these poor light levels.

The DOE set criteria that had to be met by the pilot project. These were:

1. Must pay from savings

2. Must increase existing light levels

3. Must increase quality of light

What resulted at Hill AFB is the world's largest installation of the new sulfur lighting technology where it is used in aircraft hangars dedicated to F16 fighter and C130 cargo aircraft maintenance and overhaul.

Installation Overview and Challenges

Prior to beginning installation, a design team consisting of personnel from DOE, Fusion Lighting, Cooper Lighting, Ply-Light, 3M and CES/Way was assembled to develop the basic lighting concept.

It was agreed that light guides using Light Drive™ 1000 lamps would be used in the low bay area due to a mounting height requirement of 26 feet. Additional consideration had to be given to the task being performed, aircraft configuration and accessibility of the light sources for maintenance purposes.

Tightly spaced F-16 fighter aircraft are overhauled in the low bay area, so work occurred over and around the planes. Aircraft are parked in an overhaul dock for anywhere from 30 days to a full year and cannot be moved during that time period. The lighting system also had to be flexible enough to accommodate a change in aircraft should the mission change in the hangar.

All these considerations were met by installing light pipes and Light Drive™ 1000 lamps across the space. For maintenance, light sources were located over walk ways and drive ways so that no maintenance had to occur over aircraft. Should any change be made in the location or orientation of the docking station, the pattern of the light pipes would not have to be changed.

The light guides employed are ten-inch diameter tubes fabricated of multiple layers of plastic materials, with varying reflective and transmissive properties. Each ten-foot section of hollow light guide weighs approximately 30 pounds and are mounted on 16 foot centers. Forty-four (44) light pipes are installed, each being 105 feet long with a Fusion lamp module coupled to each pipe end.

In the large high bay hangars, a minimum mounting height of 45 feet was required by the Air Force to allow for work over and around three C-130 and two F-16 aircraft. Another consideration was to try to keep the same mounting points as the existing high bays to keep installation costs down.

Cooper Lighting designed a high bay fixture of metal refractor globes lined with glass to accommodate the Light Drive™ 1000 lamp. The new fixtures were installed in the same location as the old fixtures, so all design criteria were met.

In two of the four high bay hangars, replacement of the rigid conduit pendants up to 40 feet in length was necessary. This was accomplished by reaching over the docked aircraft to a height of 90 feet above the floor to make the installation.

Hill Air Force Base's sulfur fusion lighting retrofit reduced the number of fixtures in the low bay areas while increasing light levels to 70 foot candles using 88 sulfur lamps and 44 light pipes. In the hangars, the number of fixtures was maintained, but the lighting level was tripled. A total of 288 sulfur lamps was used.

Projected Savings

		Hill Air Force Base Bldg 225 Total Savings		Material Cost $997,462.40
Existing KW	New KW	Saved KW/MO	KW Savings	Energy Savings
1123.84	410.4	713.4	$48,542.46	$140,176.69
Existing KWH	New KWH	Saved KWH/YR	KWH Savings	Simple Payback
5,843,968.0	2,134,080.0	3,709,888.0	$91,634.23	7.12

Re-Lamping Results

Pacific Northwest National Laboratory undertook to assess the efficiency and performance of the system with the following findings:

Lighting Level

Compared to the high-intensity discharge systems they replaced, the sulfur lamps produces lighting levels that were 39%-47% higher in the low bay area and 130%-160% higher in the high bay area.

Energy Consumption

In comparison to an appropriately designed lighting system to achieve comparable lighting levels with metal halide lamps, sulfur lamps would consume 17% less energy in the low bay area and 37% less energy in the high bay area.

But due to inadequate pre-retrofit lighting, requirement to use pre-existing fixture locations which were closer than optimally placed and the addition of 32 more sulfur lamps to illuminate side and storage areas not previously lighted, energy consumption increase by 63% in the high bay area.

However, if all pre-retrofit lighting had been working and additional side lights had not been installed, high bay energy consumption would have increased by only 26% and still provide at least twice the light level.

Where sulfur light guides replace inefficient fixtures in the low bay area, energy consumption decreased by 42%.

The sulfur lamp retrofit must be viewed as a total package, not each section as a stand-alone.

Lighting Quality

Workers in the building reported being able to read samples of small type more easily after the sulfur lamp installation. They are better able to make out lettering on control panels as well as the colors of wiring—due not only to higher light levels, but also to excellent color rendering. Some workers were bothered by computer screen reflection, probably due to increased light levels.

Hill AFB Pilot Project Results Recap

The new lighting has been uniformly accepted by the aircraft workers.

Light levels and general distribution of light in the low-bay areas (light pipe installation) is much more uniform than the previous lighting system.

Light levels and general distribution of light in the high bay areas, traditional down-light fixture using the Fusion light source, has been dramatically improved. Light level readings have been increased from an average of 30 foot candles to 80+ foot candles.

Low bay area number of fixtures reduced while light levels increased

High bay number of fixtures retained but lighting level doubled

With a project of this nature, you cannot do too much planning!

The Hill Air Force Base sulfur fusion lighting retrofit is the first of its kind in a federal ESPC project. Its use and its implications for energy savings and lighting efficacy has far-reaching significance to lighting designers and engineers, public and private utilities, the military, government and private sector industries such as automobile manufacturing and aviation

Benefits of the Technology

Sulfur lighting offers the following advantages:

Improved visual performance with full color sun-like spectrum

Low operating costs due to energy efficiency

Lower cost of ownership over the lifetime of the lighting system

Minimal heat in light beam enabling wider choice of materials for use in optics

Minimal degradation of materials exposed to light—no UV filters needed for most applications

Improved control of light and greater light distribution efficiency

Much more light emitted over the life of the lighting system—100% at 60,000 hours

No observable color shifts over life of lamp—no need to match lamps or to relamp for color consistency

No drop-off in performance due to burning in an off-vertical position

More light faster with full light output in 20 seconds

Less lighting down time with hot restrike time of 5 minutes

Longer life due to no filaments or electrodes

Environmentally friendly due to no mercury—no risk of exposure to toxins in event of bulb failure and no additional disposal cost for spent lamps

Reduces energy and gives more control of lighting by dimming capability to 30%

Broad range of application across numerous markets

LIGHT DRIVE™ 1000 SPECIFICATIONS ELECTRICAL INPUTS

1425 Watts Input Power
200-240V, 50/60 Hz 1
277V, 60 Hz 1

PHYSICAL

Lamp Mass With Integral Electronic Power Supply 15.4 lbs.

OUTPUT

Total Luminous Flux	135,000 lumens
Correlated Color Temperature	6000 K
Color Rendering Index (R_3)	79
Average Luminance	19 Candela/Mm^2
Flicker (Max-Min)/Max	0*
X, Y Chromaticity Coordinate	0.3171, 0.397
S/P Ration	2.4

*As perceived by human vision

DESIGN LIFETIME

Lamp System Excluding Magnetron	60,000 Hours
Magnetron**	20,000 Hours

**Two magnetron replacement kits provided with each Light Drive™ 1000

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Chapter 25— Case Study: Energy Performance Projects at Federal Facilities

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Abstract

In recent years the surge in demand for energy services can be directly traced to the widening use and popularity of performance contracting. No market has shown more interest in, or need of, energy savings projects than the Federal sector. Considered as a single user the Federal Government purchases more energy than any other buyer in the United States, spending over $50 billion annually.

The Federal Government's desire to enter into performance style contracts is driven by shrinking budgets, deteriorating infrastructure and recently passed enabling legislation allowing governmental agencies, both military and civilian to enter into agreements structured on payments from savings. These factors have combined to produce an incredible potential for Government value and ESCO opportunity.

The following paper discusses two energy performance projects developed by Southern Company Energy Solutions, Inc. (SCES)at the Navy Supply Corps School and Robins Air Force Base. The first effort upgraded thermal systems at the Navy Supply Corps School in Athens, GA including boiler and chiller replacements. This project received the 1998 Energy User News Innovative Engineering Technology Award. The project at Robins AFB was developed as a full range energy system up-grade to five buildings. This effort resulted in substantially improved HVAC and lighting systems in over 1.2 million square feet of industrial facility.

Navy Supply Corps School

Athens, Georgia

Background

The campus that currently houses the Navy Supply Corps School (NSCS) was originally constructed in 1866 at the Normaltown School for Girls, located in north Athens, Georgia. The facility is comprised of 22 main buildings and operates year-round. The School provides training to all Naval and Marine Corps supply officers in basic and advanced logistics and supply applications. The school normally houses approximately 500 students and faculty.

Energy systems are maintained by a small, and self-sufficient, staff of military and civilian managers, technicians and mechanics. Heating loads are domestic hot water only with some boosting for kitchen and galley operations. There is no process hot water required on campus and there is no direct steam usage. Heating is provided by a district type system, each building supplied by a centrally located boiler plant and radial distribution piping system. Client buildings have steam-to-hot water converters, supplied by the district stem system, and a storage tank located in the mechanical room.

Likewise cooling loads are for space conditioning only and are provided locally at each of the buildings. Most of the newer/larger buildings have chiller systems; the older dormitories have through wall A/C units located in each room.

The energy project implemented at the NSCS is comprised of the three modules:

Replacement of fossil fuel fired boilers with high efficiency electric boilers

Removal of refrigeration units containing CFC based refrigerants or Ozone Depleting Substances (ODS)

Relamping the entire facility with high efficiency indoor and outdoor lighting.

Motivation

The prime driver for the project was the replacement of the central plant boilers. The three 200 hp fossil fuel fired boilers had been in service since 1955, and were 5 years past the end of useful life. The Navy was concerned that incremental maintenance and repair would not keep the system intact much longer and the units required replacement Funding, however, was not in the budget. The ultimate solution resulted in a bundling of all energy opportunities on-site might result in efficiency based savings that could be applied toward the boiler retrofit effort.

Further incentive for structuring this as an energy efficiency project comes in the form of Federal government guidance relating to energy usage in government facilities. Executive Order 12902 directs and requires all federal facilities to reduce their energy consumption by thirty percent (30%) by the year 2005, as compared with a 1985 baseline. It is important to note that the Navy was not motivated primarily by the efficiency aspects of the project, but rather used the EO format and direction as the basis for funding the infrastructure improvement.

Goals

The goal was to replace the central steam system. The primary constraint was to do it without capital investment Tying these two issues together was the contract structure. This structure was of particular importance in the project. While many organizations recognize the concept of energy savings contracting, relatively few projects have actually been done, or contracted for. Working through the technical aspects of the project and transforming them into a document suitable for government signature required the innovative NSCS team to try a unique approach to achieve their important goal.

Design Considerations

The NSCS is located on a stately red brick and oak campus. The main campus is over 100 years old and the Navy is very conscientious in maintaining appearance. While most construction work for the project was indoors, the removal of the storage tanks and routing of the electrical distribution lines required significant excavation and groundwork. All work was shielded by fencing during construction, and landscaped afterward. The new transformers were placed behind a privacy fence on the backside of the boiler-house.

The most positive impact was the removal of the combustion flue stack for the boiler-house during the installation of the electric boilers. This has contributed significantly to the appearance of the boiler house making it fit with the other buildings nearby.

Economic Issues

Economic considerations were paramount in this project and centered on two issues: project justification and financing. The initial go ahead on the project was based solely on development of economical justification of energy cost savings. The Navy clearly would not have proceeded with the project in this fashion had the economic analysis not justified the investment Secondly, project financing relied heavily on the economic analysis the project was developed on. Establishing energy costs, efficiency savings and investment budgets created a design basis allowing cash flow projections to be made and thus justify the contracts.

Innovative Aspects

The key innovation in this project was in bundling of the entire package, creating a portfolio project, with an acceptable technical result and a coherent cash flow strategy. In particular the following aspects can be considered innovative:

Real Time Pricing: The fossil fuel boilers had duel fuel capability—normally supplied with natural gas on an interruptible rate, switching to No. 2 fuel oil during interruptions. Electricity was supplied to the installation on the Georgia Power (GPCo) G10 rate, a traditional declining block with a demand ratchet. Through in depth knowledge of the suppliers rate structure, substantial savings were generated by moving to an electric boiler and taking advantage of Real Time Pricing (RTP), an incremental, or marginal cost type rate recently made available by GPCo. The essence of RTP is to incent electric customers to shift their load to off peak times—GPCo is a summer peaking utility and can offer electricity in the winter at very low rates. A winter loading system, such as electric boilers, is an excellent candidate to take advantage of a rate such as RTP.

Reducing demand (kW) during summer peak hours through the relamping project made further advantage of the rate tariff. This allowed the Navy to get credit of energy conserved at the summer (6.4 ¢/kWh), or peak rate, and add new load in the winter at the marginal (1.9 ¢/kWh), or off peak rate.

Loan Structuring: SCES has a core competency in serving Federal Government customers. Through this knowledge of the Federal budgetary requirements and funding cycles, financing was obtained that would allow the total flexibility in loan repayment. A customized loan was structured through a third party banking firm that provided the Navy with a Termination Schedule incorporating all of the time-cost-of-money variables enabling the customer to determine the loan status at any period.

This feature became very useful in the fall of 1998: the project was well underway, all contracts had been executed, and as the end of the federal fiscal year approached (30-September) the NSCS "found" $219,000 that had to be spent by year end or be lost. Within two days the Navy had contacted SCES, the contract was modified, and the money was committed. This resulted in the Navy's debt obligation decreasing by over three years on the life of the loan.

Speed of Delivery: The GSA AreaWide Utilities Contract was used to provide these services to the Navy. This contract vehicle allows the government and the contractor to negotiate for work scope items only with a majority of the legal and contractual issues not an issue. The resultant line was exceptional; for the speed in which the project was agreed to and completed. Initial scoping efforts started in February of 1997, the contract was signed in June, construction started in September, the boiler was in place and operations by mid-October, and all substantial work was complete by the last week of January.

Zero Change Orders: This contract was negotiated on a fixed price, defined scope basis. Very similar to a design/build in the commercial world. The project was put in place with zero contractor generated change-orders to the contract All modifications were made at the request of the customer, e.g. upgraded chemical addition system.

Project Statistics

The total project cost:	$1,083,335
Boiler Retrofit:	$724,260
Refrigeration:	$194,984
Relamp:	$164,091
Project Simple payback =	4.78 years
Return on Investment (ROI):	20.9%

Life Cycle Cost Model

A Life Cycle Cost Model (LCCID) was developed as a comparison of actual conditions extrapolated into the future, the *BaseCase,* versus the new configuration as it was installed, *Alternative 1*.

Find below a summary of the Models results:

	BaseCase (Dollars)	Alternative 1 (Dollars)
Construction Costs	392,316	1,061,787
Energy Costs	2,952,386	1,830,755
O&M Costs	2,812,532	671,391
Total Cost	6,157,230	3,563,933

LCCID Results

Alternative 1 is $2,593,297 less expensive, over its life, than BaseCase

Discounted Payback Period (DPP):	3.0
Savings to Investment Ratio (SIR):	4.9

Annual units of energy saved:

ECM	BaseCase (Mbtu)	Alternative 1 (Mbtu)	Savings (Mbtu)
Boiler	16,648	11,380	5,268
ODS	1,793	1,398	395
Relamp	4,116	2,440	1,676
Total	22,557	15,218	7,339

Operations & Maintenance Consideration

The gas fired boilers require a constant supervisory watch standing per Naval regulation, due to the combustion source provided by the open flame. Installation of the electric boilers enabled a much decreased watch standing because the energy source is an energized element with electronic breakering capacity.

Increased Boiler-house Space: The three gas fired boilers and associated steam and feedwater piping took up all floor space in the building. The new electric boilers along with their attendant switchgear take up the space of approximately one-half (1/2) the space on one boiler. The maintenance staff now has the use of free floor space roughly equal to that of a basketball court.

Robins Air Force Base

Warner Robins, Georgia

Background

The Robins AFB Energy Project most significantly distinguishes itself on the basis of its creation: a pure energy savings performance project. Robins AFB did not have a preconceived idea of the equipment or systems it needed to upgrade or replace, but rather, the Base simply wanted to avail itself of Federal programs allowing for facility and infrastructure improvements through energy savings payments. Robins AFB is a huge facility, one of the largest industrial sites in the Southeast, and as such Robins AFB recognizes significance of demand side management (DSM) programs.

Additionally, Robins, as many other DoD facilities, is under tremendous budgetary pressure. The result being money normally invested in facilities and building systems has been diverted to mission critical military spending. Robins AFB recognizes the seriousness of this situation and has latched onto the energy savings performance vehicle as a method of funding upgrades and improvements to the Base infrastructure in lieu of direct capital funding. The five building Project is intended to be a pilot program and additional projects are to be rolled out base-wide. Currently, Robins AFB has over 800 buildings and energy expenditure in excess of $15 million annually. The potential is significant.

Robins Energy Project Scope

Building	Size (sq.-ft)
125—Hangar	600,000
142—Plating Shop	62,000
158—Maintenance Shop	155,400
169—Gyro Shop	70,000
640—Avionics Repair	334,00
TOTAL	1,221,400

Motivation

As discussed above, the project format was intentionally broad, so as to be all encompassing, with significant room for creativity in development The primary goal was to affect as much energy efficiency improvement, in the candidate buildings, as economically possible. All energy systems, including: HVAC, controls, steam, lighting, compressed air, etc., were available for inclusion in the project.

Constraint

One significant financial constraint was encountered. The client stipulated that all dollar savings recognized must come from source energy only. Items such as operations and maintenance (O&M) savings, extended equipment life, etc. were not available for credit in the analysis.

The reason for this stipulation was two-fold: first, because of the way the Government segregates its funds, the Energy Engineer has authority to speak only to energy expenditures (his funded area). Items such as O&M are part of the Maintenance Zone budget, which the Energy Engineer has no authority to obligate. Secondly, given the pilot nature of the project, the Energy Engineer wanted to keep the savings calculation as defendable as possible. He felt that "non-hard" energy savings would be a red flag and may sink the Project.

Design Considerations

The Project was implemented on a design/build basis using commercial terms and specifications. Implementing a project in this fashion is a significant departure from the standard Military Construction (MilCon) process. A significant amount of time was devoted to educating the customer and getting them comfortable with a construction effort implemented without an up-front specification and design.

Economic Issues

Robins AFB, being a sophisticated energy user and purchaser, participates in several complex and interacting electricity rate tariff's, including: Real Time Pricing, Multiple Load Management, and Interruptible Service. Additionally, Robins has significant amount of on-site generation and is able to "shape" their load curve to minimize energy expenditure. Therefore, calculating the energy savings was a significant chore. A full DOE2 model was developed for each of the buildings; both baseline and post-installation configurations were modeled. These models were then converted into an 8760 hr/yr load profile and submitted to the serving utility, Georgia Power Company, for analysis. GPCo, using a rate calculator was able to accurately determine both KW and kWh savings and provide SCES with hard-dollar savings for each energy conservation measure.

Innovative Aspects

The key innovation in the Project was the method of bundling the entire energy package, creating a portfolio project with an acceptable technical result and a coherent cash flow strategy. Specifically, the following aspects can be considered innovative:

Project Development: The truly innovative aspect of the Project has its roots in the latitude the Air Force allowed SCES. The Project started from a "blank sheet of paper". There were no minimum equipment replacement items or pet projects. The only fixed criteria were the need for the Project to pay for itself in less than ten years. Given this freedom the developer, working hand-in-hand with the Energy

Engineer, was able to exploit all opportunities and develop a true portfolio project. Many small and marginal ECMs were combined into a large composite project meeting the financial guidelines.

Customer Relationship: Construction of the Project required a significant ESCO manpower presence on the Base. As a result of this interaction SCES has become a valuable part of the Robins Civil Engineering effort in an ongoing capacity. Specifically, SCES has been invited to locate a Project Developer on site and assist in a number of energy projects. Robins AFB has effectively increased its staff and resources without the cost of hiring permanent employees.

Speed of Delivery: The project timeline was exceptional for the speed in which the project was agreed to and completed. Initial scoping efforts started in spring of 1997, the contract was signed in July, design was completed by year's end and construction started in March. Total project turnover occurred in October of 1998, when the Air Force accepted all systems and equipment

Work Scope

All of the buildings in the project scope belong to the Air Force Material Command; whose mission is Program Depot Maintenance for all the aircraft Robins services. Client aircraft include: C-5A, C-130, C-141 and F16. Below is described each of the ECMs, and work activities included:

HVAC Upgrade

Air handling dampers, valves and actuators
Controls system calibration
Software setpoints
Piping and duct insulation
Air Handling Unit Coils

Steam System Tune-up

Valves
Insulation
Condensate receivers

Gas Fired Radiant Heating.

Currently installed steam heating systems are to be removed or disable as appropriate
Radiant heat to be installed in the high and low bays of Building 125
Install natural gas supply piping and metering systems

Motors

Premium efficiency motors to be installed in place of conventional motors

Relamp

Removal of conventional ballast and fluorescent lamps.
Cleaning of existing fixtures and lenses
Installation of electronic ballast and high efficiency fluorescent lamps in existing fixtures

Project Statistics

The total project cost:	$2,877,630
Project Simple payback =	6.08 years
Return on Investment (ROI):	16.4%

Life Cycle Cost Modeling

The cost and savings were modeled using the *Life Cycle Cost in Design for Windows* (LCCID) software, Version 1.5, Build 15, dated April, 1997.

The LCCID model was developed as a comparison of actual conditions extrapolated into the future, *The BaseCase,* versus the new configuration as it was installed, *The Alternative 1.* Find below a summary of the Models results:

	BaseCase (Dollars)	**Alternative 1** (Dollars)
Construction Costs	0	2,877,630
Annual Energy Costs		
Electricity	1,709,266	1,492,960
Gas	75,876	45,566
Fuel Oil	693,286	477,202
Water Savings	0	(10,163)
O&M Costs	0	0
Life Cycle Cost	$33,868,920	$30,053,860

LCCID Results:

Alternative 1 is $3,815,060 less expensive, over its life, than *Base Case*

Discounted Payback Period (DPP) =	7 years
Savings to Investment Ratio (SIR):	2.3

Annual units of energy saved

Source	**BaseCase Fuel Usage** (MBTU)	**Alternative 1 Fuel Usage** (MBTU)	**Savings** (MBTU)
Electric	128227	112000	16227
Natural Gas	199220	137127	62093
Fuel Oil	14156	8495	5661
Total	341,603	257,622	83,981

Operations & Maintenance Costs

While not allowed to take credit for O&M savings in the project analysis, significant savings did result from the upgraded equipment's reduction on the maintenance staff's duties. In particular, the installation of the infrared heating system in the Building 125 hangars virtually eliminated the need for steam supply to that building. Previously, Building 125 had been heated with conventional steam supplied air handling units. With the elimination of these AHUs, the maintenance staff was able to cease steam trap and condensate receiver maintenance work as well as all activities associated with the AHU coils, fans and motors. The infrared heaters are a very low maintenance due to their passive operation.

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Chapter 26—
Evaluation of Energy Consumption Factors at Army Forces Command Sites

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Abstract

Energy regulations prescribed by federal legislation and Executive Orders require federal facilities to reduce energy consumption per square foot of building floor space (hereinafter referred to as "energy intensity"). Prior regulations required energy intensity to be reduced by 10%, 20%, and 30% relative to a 1985 baseline by the years 1995, 2000, and 2005, respectively[1]. Executive Order 13123 recently extended the requirements to a 35% reduction by 2010 relative to 1985.

Based on 1998 energy consumption, FORSCOM energy intensity had dropped by 13.7% since 1985. Thus, FORSCOM met the 10% reduction required by 1995, but is far short of the 20%, 30%, and 35% reduction requirements established for 2000, 2005, and 2010, respectively.

Moderate success to date and concern about meeting future requirements prompted FORSCOM to initiate an evaluation of factors limiting site energy intensity improvement. The objectives of this assessment included:

1) Identifying the factors affecting energy intensity changes

2) Estimating the impact on energy intensity of these factors, and

3) Developing strategies for reducing energy intensity.

This paper reports on the methodology and results for Fort Hood, the first FORSCOM site to be evaluated.

Fort Hood Overview

Fort Hood, located 60 miles north of Austin, Texas adjacent to the City of Killeen, is one of 11 major installations within FORSCOM. The 340 square mile site is home to the 1st Calvary and 4th Infantry Divisions, several major Brigades and Groups, and many other military tenants. The total on-site population, including military and civilian personnel, and military family members, is approximately 75,000.

Fort Hood has over 4600 buildings totaling nearly 28 million square feet of floor space. Roughly one-half of these structures and one-third of the floor space is family housing. Unaccompanied personnel housing (i.e., barracks) account for another one-sixth of the total floor space. Office-type structures, maintenance, storage, and miscellaneous community facilities are the other major building categories.

Energy consumption at Fort Hood is dominated by electricity from a cost perspective; recent annual expenditures for electricity and natural gas have been approximately $20 million and $5 million, respectively. Total energy consumption has been relatively constant since 1985, but electricity use has

[1]Executive Orders 12759 and 12902; Energy Policy Act of 1992.

risen from about 35% of the total to a little more than half. Floor space has increased significantly since 1985, however, so energy intensity has dropped by about 16%, which is moderately better than for FORSCOM as a whole.

Analytical Approach

Energy intensity only normalizes for one factor affecting total energy use: total building square footage. By definition, changes in other factors affecting the demand for energy services or energy use have combined to produce the energy intensity metrics at each Fort, and for FORSCOM as a whole. These factors can be grouped into the following broad categories:

1) The demand for basic building energy services (heating, cooling, ventilating, lighting, service hot water, and plug loads).

2) Building envelope (e.g., windows, walls, roof) characteristics.

3) Building energy equipment (e.g., lighting, HVAC) characteristics.

4) Central energy equipment (e.g., boilers, chillers) characteristics.

5) Energy distribution equipment (e.g., steam, hot water, and chilled water lines) characteristics.

6) The demand for "process" services requiring energy (e.g., sewage, water, exterior lighting).

A generic site energy flow diagram (Figure 1) illustrates the relationship of these factors.

General Approach

The general approach was to identify the principal changes in energy use factors that explain the majority of changes in energy intensity since 1985. This includes factors that individually have caused energy intensity to decrease as well as those causing an increase. This approach segregates the impact of energy management strategies from external factors that are beyond the control of energy managers. Effective energy management strategies can be continued or initiated.

The approach examines changes in each of the energy use factor categories noted above. The impacts of changes in demand for energy services, building envelope characteristics, and building energy equipment characteristics were estimated by simulating energy use in several (~ 20) building prototypes representing the building stock as it existed in 1985 and comparing with the results for several building prototypes representing the stock in 1998. Changes in weather were incorporated into the analysis. Changes in plug loads were directly estimated based on prior studies of similar facilities. The secondary impact of changes in plug loads on heating and cooling demands were accounted for via building energy use simulations. The evaluation of central energy equipment looked specifically at changes in the type and efficiency of boilers, hot water generators, and chillers. Similarly, evaluation of changes in energy distribution equipment examined trends in the mix of central and distributed systems (e.g. central vs. distributed boilers) as well as changes in the efficiency of energy distribution equipment. Site records of building square footage were compared against central records to determine any discrepancies.

Specific Approach

The following specific steps were taken to conduct the evaluation:

1) Developed central energy plant, distribution system, building, and "process" characteristics that allowed simulation of total site energy use. "Process" services include exterior lighting, sewage, and water.

2) Used the Facility Energy Decision System (FEDS) [2] to simulate building energy use [1].

3) Developed spreadsheets to simulate central energy plant, distribution system, and "process" energy use.

4) Developed FEDS building characteristics for 20 representative building types that were used to represent all building energy loads.

5) Developed central energy plant, distribution system, and "process" characteristics to represent all non-building energy loads.

[2] FEDS is a user-friendly, Windows-based, menu-driven software program for assessing the energy efficiency resource potential of facilities ranging from single buildings to large federal installations.

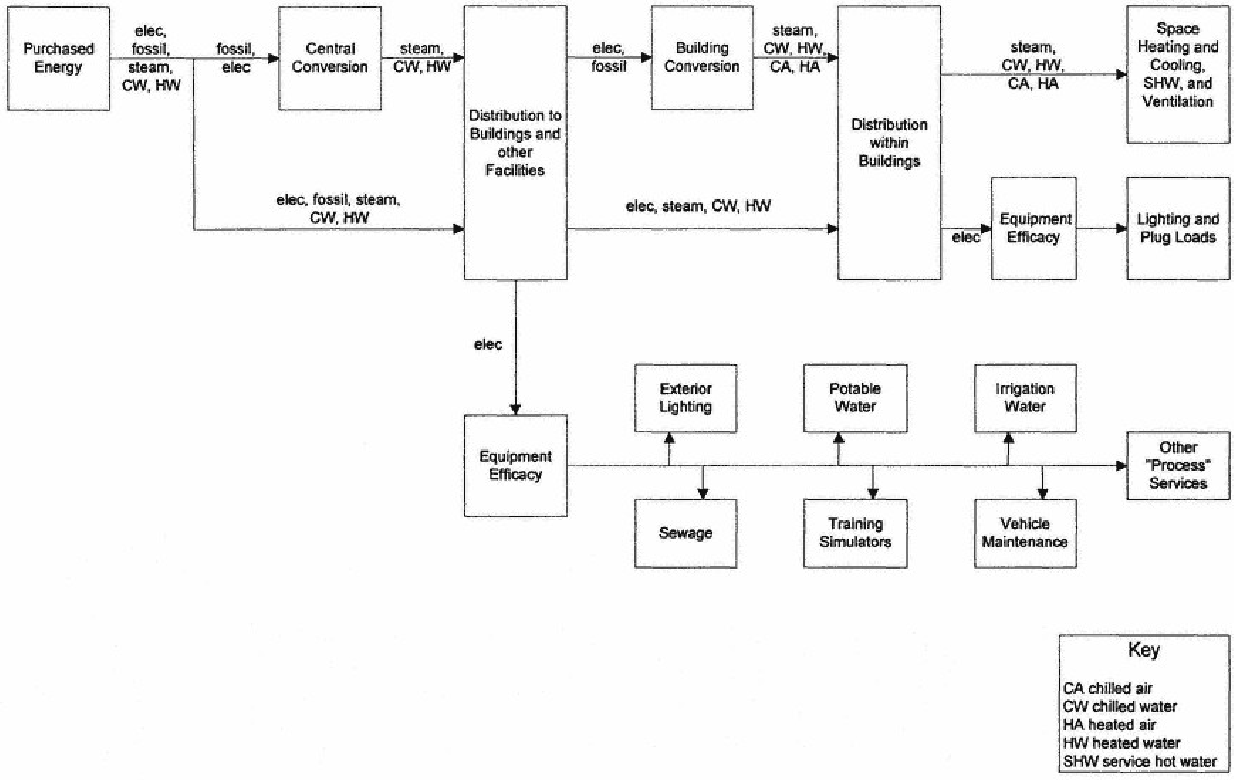

Figure 1
Generic Site Energy Flow Diagram

6) Developed characteristics for conditions existing in FY 1985 and FY 1998.

7) Adjusted characterizations until simulation results matched actual energy consumption and energy intensity in FY 1985 and FY 1998 reasonably well. Simulated results were calibrated to metered data for family housing, the hospital, and all other buildings.

8) Examined changes in energy system characteristics and external factors to identify those likely to have a significant impact on energy use and energy intensity.

9) Calculated the impact on energy use and energy intensity for the significant changes identified in item 8. The impact was calculated by setting the factors for 1998 back to 1985 conditions, with all other conditions held at 1998 conditions. (Note that the sum of the individual impacts calculated this way will not add up to the overall total impact due to interactive effects, but it does provide a good indication of relative importance.)

10) In general, the impact of changes were evaluated for the following moderately aggregated categories:

a) the extent of services provided, e.g., fraction of buildings cooled

b) the quality of service provided, e.g., the cooling temperature set point

c) building envelope

d) building distribution systems

e) building energy conversion systems

f) building personnel density

g) weather

h) central energy plant

i) exterior distribution systems

j) "processes"

11) Changes in the following and their impact on energy intensity were calculated to address specific factors identified during prior FORSCOM energy studies. Note that several of these items match or nearly match the categories listed in item 10.

a) office plug loads

b) domestic plug loads

c) exterior distribution efficiency

d) other changes in energy services (besides plug loads)

e) building envelope

f) building equipment

g) heat pumps

h) fuel switching

12) Compared the energy intensity of post- 1985 construction with that for pre-1986 construction.

13) Determined if there have been any changes in the official procedures for calculating energy intensity and calculated the impact, if any.

14) Determined what types of buildings and/or facilities can be excluded from the official energy intensity calculation and how these exclusions have been implemented at the site being evaluated.

15) Compared energy consumption and building square footage records at the site with central records for the same.

16) Identified any buildings that consume energy included in the site energy intensity calculation, but are not included in the square footage part of the site energy intensity calculation (e.g., temporary structures).

Results

The current listing of Ft. Hood real property maintained by the Army's Center for Public Works (CPW) was the primary basis for establishing the 1998 building stock. The real property database includes information on the age, type, and square footage for each building. This information was used to develop basic characteristics for the FEDS prototypes. The CPW real property data were similar to records kept by real property personnel at Fort Hood, but square footage totals for both were about 3% less than reported in RADDS[3].

Neither CPW nor Ft. Hood had electronic or paper copies of the 1985 real property database for Fort

[3] RADDS is the Army's central database for energy consumption and cost information. The acronym stands for the Redesigned Army DUERS Data System. In turn, DUERS stands for the Defense Utility Energy Reporting System.

Hood. A 1989 electronic database was obtained from CPW and paper records of building demolitions were obtained from Ft. Hood for the years after 1985. These two sources allowed the development of a 1985 real property database by deleting buildings constructed after 1985 and adding buildings demolished between 1985 and 1989 to the 1989 electronic database.

Fort Hood energy staff confirmed the correctness of RADDS energy use data and advised PNNL on buildings (e.g., schools, commissaries) that are supposed to be excluded from RADDS. No buildings were found to be included without their corresponding energy consumption or vice-versa. Discussions with CPW staff responsible for maintaining RADDS indicated no change in reporting rules between 1985 and 1998.

Evaluation of Historical Energy Use

Tables 1 and 2 present summary results from the FEDS simulation of energy consumption at Fort Hood compared to data reported in RADDS. Table 1 covers the entire Fort while Table 2 focuses on family housing. PNNL estimates of building area, energy consumption, and energy intensity were within 5% of the RADDS data for both 1985 and 1998. Given the uncertainties associated with many of the FEDS inputs and the expected accuracy of FEDS even with 100% certain inputs, these results were judged to form an adequate reference for examining the impact of changes in individual energy use factors. Further adjustment of the inputs would probably result in a better match, but would not likely have a substantial impact on the conclusions and recommendations presented below.

FEDS energy use estimates for 1985 and 1998 are broken out in Table 3. In both years, electricity and natural gas consumed within buildings accounts for nearly 90% of total energy consumption. The greater utilization of electricity and lesser utilization of natural gas are again evident, however. Electricity and natural gas inputs at central energy plants (CEPs) accounts for about 7% of the total, with an estimated 40% of this lost in distribution. "Process" electricity combines exterior lighting and pumping power. Electricity distribution losses were estimated to increase in proportion to end-use electricity consumption.

The FEDS results presented in Tables 1 and 2 were based on the actual weather in 1985 and 1998, respectively.

TABLE 1. COMPARISON OF FEDS AND RADDS DATA (TOTAL ENERGY CONSUMPTION)

	1985			1998		
	FEDS	**RADDS**	**FEDS/ RADDS**	**FEDS**	**RADDS**	**FEDS/ RADDS**
Building Area, ksf	23,503	23,449	1.00	26,958	27,832	0.97
Electricity, MBtu	989,074	986,476	1.00	1,317,453	1,385,340	0.95
Gas, MBtu	1,729,127	1,697,676	1.02	1,261,435	1,307,519	0.96
Electricity Intensity, MBtu/ksf	42.08	42.07	1.00	48.87	49.78	0.98
Gas Intensity, MBtu/ksf	73.57	72.51	1.01	46.79	46.98	1.00
Overall Intensity, MBtu/ksf	115.65	114.58	1.01	95.66	96.76	0.99

TABLE 2. COMPARISON OF FEDS AND RADDS DATA (FAMILY HOUSING ENERGY CONSUMPTION)

	1985			1998		
	FEDS	**RADDS**	**FEDS/ RADDS**	**FEDS**	**RADDS**	**FEDS/ RADDS**
Building Area, ksf	8648	8,222	1.05	9,611	9,192	1.05
Electricity, MBtu	278,668	269,050	1.04	336,016	321,351	1.05
Gas, MBtu	334,662	336,107	1.00	287,117	287,381	1.00
Electricity Intensity, MBtu/ksf	32.22	32.72	0.98	34.96	34.96	1.00
Gas Intensity, MBtu/ksf	38.70	40.88	0.95	29.87	31.26	0.96
Overall Intensity, MBtu/ksf	70.92	73.60	0.96	64.84	66.22	0.98

TABLE 3. FEDS COMPONENT ENERGY USE ESTIMATES

Component	**1985 MBtu/ksf**	**1998 MBtu/ksf**
Building Electricity	35.89	42.82
Building Natural Gas	67.59	42.08
CEP Electricity	2.03	1.67
CEP Natural Gas	5.98	4.72
Process Electricity	2.48	2.43
Electricity Distribution Losses	1.68	1.95
Total	115.65	95.66

Prior to investigating the impacts of other potentially controllable energy factors, energy consumption was simulated for 1985 and 1998 infrastructure characteristics with the weather for an average year. The weather-normalized results are shown in Table 4. The overall energy intensity increased by 0.64% in 1985 and 0.06% in 1998, so energy savings since 1985 associated with potentially controllable factors is probably understated by about 0.6%.

Table 5 presents the impact of changes in selected individual energy use factors on 1998 site energy intensities. The impacts were calculated by simulating energy use with FEDS with the assumption for the energy use factor being examined set equal to 1985 conditions (as if the energy use factor had not changed) while all other energy use factors remained at 1998 conditions. The results show that improvements to heating and cooling equipment efficiencies reduced energy intensity by 4.3% and 2.7%, respectively. Retrofit to double pane windows and the addition of storm windows in some family housing and barracks reduced energy intensity by 0.4% and 0.3%, respectively. On the other hand, Fort Hood's energy intensity suffered from increases in energy services provided. Increases in plug loads in barracks, family housing, and offices increased energy intensity by 0.8%, 1.8%, and 2.1%, respectively. In addition, an increase in the fraction of cooled building space increased energy intensity by 2.4%. Note that care must be taken when adding individual impacts together because of the interactive effects of some energy use factors.

TABLE 4. IMPACT OF WEATHER ON ENERGY INTENSITY

	Electricity, MBtu/ksf	Natural Gas, MBtu/ksf	Overall, MBtu/ksf
1985 actual weather	42.08	73.57	115.65
1985 average weather	41.42	74.98	116.40
1998 actual weather	48.87	46.79	95.66
1998 average weather	48.72	47.01	95.72

TABLE 5. SELECTED ENERGY USE FACTOR IMPACTS

Energy Use Factor	Impact on Site Energy Intensity
Heating Equipment Efficiency Improvement	Decrease by 4.3%
Cooling Equipment Efficiency Improvement	Decrease by 2.7%
Double Pane Windows in Family Housing	Decrease by 0.4%
Double Pane Windows in Barracks	Decrease by 0.3%
Barracks Plug Loads	Increase by 0.8%
Family Housing Plug Loads	Increase by 1.8%
Office Plug Loads	Increase by 2.1 %
Increased Fraction of Building Area Cooled	Increase by 2.4%

As indicated in Table 4, the overall energy intensity, adjusted for weather, has dropped from 116.4 in 1985 to 95.7 in 1998. Energy intensity varies significantly with building age, however. For the 1998 building stock, buildings constructed through 1985 have an average energy intensity of 103.9, while buildings constructed since 1985 have an average energy intensity of only 77.5. ***It would appear that change in the building stock, encompassing the construction of relatively efficient buildings and the demolition of less efficient buildings, has been the single most important change of an energy use factor since 1985.***

Evaluation of Retrofit Opportunities

FEDS was also used to identify cost-effective retrofits for each of the building sets evaluated at Fort Hood. Aggregated results for the entire Fort are presented in Table 6 by retrofit category. The results indicate that Fort Hood could cost-effectively reduce its current energy intensity by nearly 18%, or to about 78.5 MBtu/ksf. This analysis, consistent with the evaluation of historical energy use, is based on a combination of data collected while visiting Fort Hood and other assumptions inferred by FEDS based on facility age or assumed to match known energy consumption totals. Therefore, the underlying conditions supporting these proposed retrofits need to be verified by more detailed investigation in most cases. Exceptions are the use of more LED exit signs, compact fluorescent lighting, and T-8 fluorescent lighting, where the predominant use of inferior technology was evident from walking through representative buildings during the site visit.

TABLE 6. COST-EFFECTIVE RETROFITS AT FORT HOOD (BASED ON FEDS SIMULATION)

Retrofit Category	Investment, $M	Annual Savings, $M	Payback Period, Years	Net Present Value, $M	Annual Savings, MBtu	Reduction in Energy Intensity, %
Insulate Perimeter of Slab-On-Grade Foundations	2.85	0.33	8.8	2.00	53,790	2.08
Automatic Electric Dampers for Boilers	0.18	0.16	1.1	0.98	42,245	1.64
Space Heating Boiler and Furnace Replacements	0.83	0.18	4.6	0.90	32,818	1.27
Water Heating Boiler and Heater Replacements	0.37	0.39	1.0	4.35	49,447	1.92
Water Heater Insulation, Temperature Setback, Low-Flow Shower Heads, and Faucet Aerators	0.17	0.41	0.4	1.52	72,864	2.82
LED Exit Signs	4.00	0.58	6.9	4.18	18,768	0.73
Compact Fluorescents	3.88	0.79	4.9	13.47	48,516	1.88
T-8 Fluorescents	7.76	0.79	9.8	3.25	23,787	0.92
Roof Insulation	3.73	0.60	6.2	5.00	75,775	2.94
Window Coatings	4.96	0.76	6.5	0.96	38,517	1.49
Totals	28.73	5.00	5.8	36.62	456,527	17.69

Conclusions

1) The single biggest factor affecting energy intensity at Fort Hood is the construction of more energy efficient buildings since 1985. For the 1998 building stock, the energy intensity of post-1985 buildings was estimated to be 77.5 MBtu/ksf while the energy intensity of pre-1986 buildings was estimated to be 103.9 MBtu/ksf. Construction of new buildings and demolition of old buildings continues at Hood, which should continue to reduce site energy intensity.

2) Widespread replacement of building heating and cooling equipment and selected retrofit of single pane windows to double panes or the addition of storm windows has reduced energy intensity by about 8% since 1985. This trend is likely to continue as older, less efficient equipment is continuously replaced with new equipment that is more efficient.

3) Increases in plug loads in offices, barracks, and family housing, coupled with an increase in the fraction of building area cooled has increased energy intensity by about 7% since 1985. The trend of plug load increases is probably near its end; while more electric equipment is being used, concerns about plug loads are driving manufacturers to produce more efficient models. The net effect should be a leveling of the trend, perhaps even a slight decrease in annual average

load. Conversely, the fraction of building area cooled is expected to continue to climb.

4) No significant changes in energy intensity were found to be associated with a) the quality of energy service provided (e.g., space conditioning temperature set points), b) building energy distribution systems, c) exterior energy distribution systems, d) building occupancy or operating hours e) the use of heat pumps, or f) fuel switching (e.g., using electrically-driven vapor compression chillers instead of natural gas-fired absorption chillers).

5) Implementation of the cost-effective retrofits identified by FEDS (once they are field-verified) coupled with continued construction of energy efficient buildings and demolition of older, less efficient buildings should allow Fort Hood to reach its energy efficiency goals.

Recommendations

1) Serious consideration should be given to the cost-effective retrofits identified by FEDS. The building walk-throughs conducted by PNNL clearly identified significant opportunities for energy and dollar savings via implementation of LED exit signs, compact fluorescents, and T-8 fluorescents. Special attention should also be given to verifying the FEDS assumptions leading to the extremely short payback periods estimated for automatic electric dampers and various service hot water retrofits.

2) More insulation should be specified for new water heaters replacing failed units.

3) Screw-based compact fluorescent lamps should be installed in barracks desk lamps. New lamps should use pin-type fixtures to ensure continued energy savings. Free CFLs should also be provided to family housing tenants to ensure successful introduction and energy savings persistence.

4) Retrofit of T-12 fluorescent lamps should be accomplished via one or more of the following policies:

Require T-8 fixtures in all new construction

Require T-8 fixtures when T-12 fixtures fail

Require T-12 electronic ballasts when T-12 magnetic ballasts fail if replacement with a T-8 fixture is not feasible

5) Heat pumps should be seriously considered for family housing or other smaller buildings otherwise served by a combination of gas furnaces and DX cooling units, especially for new construction or when either the furnace, the cooling unit, or both are due for replacement.

6) The use of heat pumps would significantly reduce energy intensity; heating COPs would be relatively high in the Fort Hood climate. In addition, the incremental electricity consumed during the heating season would likely incur only relatively modest energy charges under the Fort's current rate structure.

7) Steam district heating systems are notoriously inefficient at many federal facilities, and our analysis suggests that Fort Hood is no different. Conversion of central steam systems serving four barracks complexes to building-level boilers (hot water generators) should be explored.

8) While significant energy and dollar savings appear achievable via the retrofits suggested by FEDS and/or the other recommendations noted above, the investment required is also significant. The energy team at Fort Hood will likely need support from FORSCOM and/or other organizations (e.g., ESPCs, utilities) to obtain the necessary funding.

References

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Chapter 27— Developing a Systems Integration Tool for Utility Data

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Abstract

The Facility Resource Energy Data (FRED) project first started in 1993 as a project team assessing the needs of the utility system at the U.S. Department of Energy's Hanford Site. It was decided that the amount of manual data entry and use of Lotus 1-2-3 spreadsheets (in DOS) was inadequate to continue producing Site electric bills. A tool was sought to integrate and control the stand-alone metering systems, analyze, and distribute utility-related data.

The team quickly realized that the number of meter points, diverse data streams, and redundant metering systems precluded the use of "off-the-shelf" utility management software. A systems integration tool was needed that could utilize existing software and add needed features without re-inventing existing ones. The solution was a systems integration tool called FRED.

FRED is really a suite of unique software modules and tools wrapped around existing software. In addition to its own features, FRED utilizes analysis and/or graphics from PCDAS data logger configuration, Adobe Acrobat™, Microsoft® Excel, Microsoft® Access, SRC's Metrix, and the Whole-Building Diagnostician (WBD). Having full control of the native code allows on-site programmers to make changes to the software when needed.

Various technical and organizational hurdles were encountered during FRED's implementation. Existing software was upgraded to communicate with FRED via DDE and OLE. Y2K compliance testing drained some of FRED's resources. Training was also needed to get the utility group's computer skills up-to-date. Each set of contractors at Hanford expressed different data needs. To meet these needs, FRED had to provide the greatest level of detail for those with in-depth needs as well as summary-level reports for the more casual user. The most difficult task was to get data producers, data users, and financial folks to accept this new way of doing things.

FRED's scope recently expanded to include an Internet-based module, with complete implementation occurring by the end of fiscal year 1999. The lessons learned during FRED's development will be useful to others who face similar problems, especially Federal sector sites.

Introduction

The U.S. Department of Energy's Hanford Site in Richland, Washington, once a nuclear weapons production center, is now dedicated to environmental cleanup of waste from its former mission and energy research. The Site consists of

[1] Pacific Northwest National Laboratory is operated by Battelle Memorial Institute for the U.S. Department of Energy under contract DE-AC06-76RLO 1830.

1,350 buildings scattered over 1,476 km^2 (570 mi^2). Many of the facilities are over 40 years old, and only recent history has seen an effort to install metering at the building level. Although one might presume that our predecessors were short-sighted to meter only the Site total, the metering met the needs at the time.

The history of metering at Hanford represents a path similar to other large, Federal facilities. Initially only total metering was provided, and additional meters were installed piece-meal over time. Thus, facilities are faced with a lack of either detailed energy data or an affective means of handling data from a variety of meter sources.

Today, the Energy Policy Act, Executive Order 12902, and Executive Order 13123 requires Federal facilities to reduce energy use. These orders dictate that facilities install more metering to document progress towards reduction goals and to better understand energy use at a facility. Additional trends in the Federal sector include a greater participation by sub-contractors, external organizations, and out-sourcing of activities to reduce costs. Each of these activities require more detailed energy data for cost reimbursement. Now with the cost justification for metering, we are seeing an explosion of metering points at Federal facilities.

With a renewed push for metering, facilities also experience a new problem—getting different metering systems to work together and provide accurate, reliable data in a timely fashion. Very few facilities have the luxury of purchasing complete turn-key automated metering systems. Therefore, facility managers are faced with the task of integrating, often outdated, metering equipment into an efficient data collection system.

The utility data tool developed for Hanford represent a solution to a set of problems that may also exist at other large Federal facilities.

Site Specifics

After 1998, the primary utility at the Hanford Site is electricity. To a lesser extent, steam, potable water, fuel oil, and vehicle fuels are available. The distribution of energy use by fuel type is shown in Table 1. Note that Hanford's coal plants, a major energy consumer, were retired in 1998.

TABLE 1. ENERGY USE BY FUEL TYPE

Fuel Type	FY 1996 Fuel Use, MBTUs
Electricity	3,739,420
Fuel Oil	243,187
Natural Gas	20,807
LPG/Propane	1,279
Coal	7,460,390
Gasoline	220,175
Diesel	1,248

Electrical Metering

In the early days, electrical metering existed only at the substation level. Metering was necessary because the electrical system wheeled power for Bonneville Power Administration (BPA). Routine electrical metering of buildings and processes began in earnest during the late 1970s. Many, but not all, facilities are currently metered. Facilities that aren't metered require loads to be distributed and/or estimated.

Hanford electrical service is provided by Hanford Electric Utilities, the City of Richland, Benton County Public Utility District (PUD), and Benton

TABLE 2. HANFORD ELECTRIC PROVIDERS

Provider	Meter Type	Count	Reporting Method
Hanford Electric Utilities	Automatic Data	283	Electronic Time-Series Data.
Hanford Electric Utilities	Manual Meters	531	Hand-held meter reader generated report.
City of Richland	Manual Meters (some automatic)	85	Monthly paper bills. Monthly electronic download.
Benton County PUD	Manual Meters	10	Monthly paper bills, yearly electronic data.
Benton County REA	Manual Meters	3	Monthly paper bills.

County Rural Electrification Association (REA). The Site contains approximately 912 electric meters, with about 5 new meters installed monthly. (see Table 2)

Hanford Electric Utilities operates two separate metering systems; manual meters and automatic data loggers. The manual meters are read monthly by a meter reader who enters the readings into a hand-held computer, which downloads these data to a database on a dedicated computer. The automatic meters are connected to electronic data loggers that communicate with a central computer nightly via shared phone lines. The data loggers were developed by Pacific Northwest National Laboratory for a large, regional end-use monitoring program in the mid-1980's and recycled for use by the Hanford's metering program. Each logger has analog and digital channels capable of recording time-series data for 16–32 metering points.

The two metering systems are pseudo-redundant—that is they partially overlap each other. The automatic meters were installed to supplement the poor quality and unreliability of manual meter readings. A complete switch to the automatic meters has never occurred because the communication mechanism, shared phone lines, is not completely reliable either. The incomplete overlap of metering systems, the unreliability of those systems, and the unmetered and estimated loads make the Hanford electric system a difficult one to monitor.

Water

Less than one dozen water meters are present on Site, located only at the main pump houses. Buildings served by Hanford utilities are not charged directly for water usage since building-level water usage is unavailable. Buildings served by the City of Richland are charged for actual use as shown on the monthly billing.

Steam

In 1998, the two coal plants providing space heating and process steam were replaced with smaller oil and natural gas boilers, installed and operated through an Energy Savings Performance Contract (ESPC). The ESPC contractor purchases natural gas from Cascade Natural Gas and produces steam for the Site. The ESPC project has produced a dramatic cost savings through reduced energy use.

Other

Several facilities use natural gas provided by Cascade Natural Gas. Fuel oil is also used in very small quantities. Fuel for vehicles is provided at two contractor run service stations and reported on a yearly basis.

The Problem

In 1993, with the growth in metering and downsizing within the Department of Energy, management began looking at the way utilities were metered, data processed, and reports generated. (Hadley, 1995) A study was commissioned to assess data needs and how they were addressed. A team representing the various contractors on Site, undertook the task of identifying options for a new data processing tool for Hanford.

The first criteria for a new tool, would be to reduce the number of manual tasks involved in collection, processing, and validation of utility data. The tool could also save manpower by providing an automated mechanism for responding to data requests. Secondly, the new tool would need to work with the current manual and automatic metering systems, to eliminate the cost of replacing those systems. Most importantly, the tool would need to handle Hanford's redundant metering systems, selecting data from the most accurate source, and allocating energy use or providing estimates where metering of facilities was incomplete.

These issues precluded the use of "off-the-shelf" utility management software. In 1993, the software simply didn't exist that could meet all of Hanford's requirements. The most sophisticated tools couldn't handle Hanford's "two meters on a single point, choose the best value." Even today's software (circa 1999), would require a great deal of customization and additional programming to handle Hanford's complex set of tasks and reports.

The decision was made to develop a systems integration tool that could utilize existing software without having to re-invent functionality currently existing in other software. The tool would need to automate data collection and validation tasks, handle redundant meter systems, and produce custom reports. It also had to be flexible and modular so features could be added directly applicable to different organizations. (Chvala, 1995) Developing

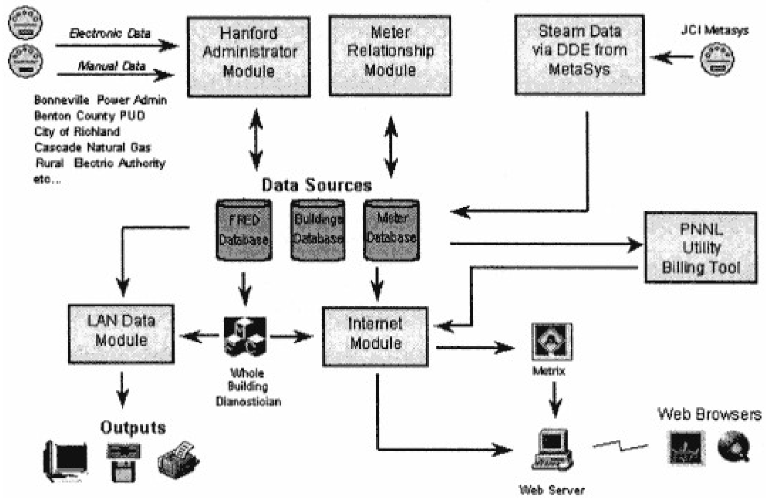

Figure 1
Simplified Fred Schematic

the tool in-house meant greater control over current and future development.

The Solution

The solution to Hanford's problem was found in a systems integration tool to provide pre- and post-processing of data from existing software, and manage other software modules with distinct functionality. Its goals were to be accessible to a large number of people on Site at no additional cost, have the ability to automate data tasks and reporting, be able to link to databases or import data stored on various servers, and be flexible to accommodate changing needs.

A development environment used for multi-media energy-related kiosks, Asymetrix Toolbook™, was selected as the development environment for Hanford's tool. Toolbook™ addressed the defined development goals allowing maximum flexibility and distribution at the lowest cost. It allowed programmers to utilize Microsoft® Windows® features like Dynamic Data Exchange (DDE), Object Linking and Embedding (OLE), and query databases using Structured Query Language (SQL) via Open Database Connectivity (ODBC) calls. Linking to databases across the Hanford Site ensures access to the most up-to-date data available. The tool's most important aspect is that it interacts with other software—the data logger configuration software, Microsoft® Excel, Microsoft® Access, and SRC's Metrix™.

Hanford's tool is named Facility Resource Energy Data (FRED). It is constructed of a series of interconnected modules, each performing a distinct task. Its modular nature allows new tasks or routines to be added as needed. Figure 1 shows a simplified schematic of the modules.

The Administrator Module and the Meter Relationship Module are designed for system administration tasks. The Administrator Module allows utility staff to manage the data collection, validation, billing, and reporting of utility data. The Meter Relationship Module maintains and tracks the meter relationship hierarchy, meter configuration information, and handles the important task of by generating usage equations used to determine energy use for buildings.

The Local Area Network (LAN) Data Module and the Internet Module provide utility data and reports to a wide range of users via the Intranet or the Hanford Local Area Network (HLAN). Both

TABLE 3. TEN OBSTACLES

	Problems	Difficulty	Solution	Type
1	Redundant Metering	"Off-the-shelf' software not applicable.	Hanford "virtual" meter denotes real-life manual and automatic meters.	Technical
2	Organizational Momentum	Difficulty moving from the way things have "always been done." Out-of-date computer equipment and skills.	New system built to look like the old way of doing things at discrete points. Upgraded equipment and skills.	Technical/ Management
3	Differing Contractors Needs	Some contractors want more detail, some less, others custom reports and analysis.	Build for the lowest level of detail and aggregate up. Modular nature of tool allows parties to add their own features.	Technical
4	Existing Software	Not efficient to reinvent existing tools.	Structured as a systems integration tool.	Technical
5	Steam Data	Unwillingness to provide data by ESPC contractor.	Only solution is contract modification. Lesson learned: "Write it in the contract."	Management
6	Providing Data Access	Data provided manually on request.	Data access provided free via Intranet or LAN.	Technical
7	Bill Reconciliation and Reporting	BPA data, wheeling power, billing, and reporting.	Reconcile all costs to BPA total cost and automate reporting.	Technical
8	Scope Creep	Development continually identified additional functionality or reports.	Manage scope creep and provide for contingencies.	Management
9	Software Implementation	Difficulties training, testing, and implementing.	Long development time and subcontractor facilitated implementation.	Technical
10	Year 2000 compliance	Difficult to test a complete set of inputs. Dependent on many providers of data whose systems could fail.	Construct complete set of dummy data and test for future years.	Technical

modules provide access to usage, cost, and various reports, while the LAN Data Module also includes a rate schedule analysis feature.

Additional modules have been added to accommodate unique needs. PNNL developed a Billing/Forecast Module focused on budgeting, financial tracking, and load forecasting. Another module is currently being tested that uses the Whole-Building Diagnostician (WBD), a building energy diagnostics model developed by PNNL, to provide on-going feedback of building operation to building managers.

System Requirements

FRED is designed to run on a Pentium personal computer running Microsoft® Windows95 or WindowsNT and must be connected to the HLAN. The runtime version can be distributed freely and no additional licensing is required. The only software requirement is that the users have access to Microsoft® Office which is provided by site license at Hanford. All other data and database functions are accomplished using ODBC links to databases on other Hanford servers from within the Windows environment. To access data using the Internet Module, the user needs an Internet connection and a browser such as Microsoft® Internet Explorer (version 3.0 or greater) or Netscape® Navigator (version 3.0 or greater).

Difficulties and Issues

Satisfying Hanford's needs didn't happen in quickly. Over three years, the tool's architecture changed several times to account for difficulties encountered during development. Table 3 lists the ten most difficult obstacles encountered during development. A detailed discussion of each obstacle and the developers' solution is provided for a better understanding of how the tool addressed Hanford's needs.

Problem 1—
Redundant Metering

The incomplete overlap of metering systems, the fact that neither is completely reliable, and the number of unmetered and estimated loads complicates the allocation of energy usage. Most utility management software packages expect a single meter on a single building, although some allow users to distribute loads to a group of buildings based on some criteria. However, none that we could find could take two meters, provide some checks to see which were the preferred, and determine if it fit historical trends.

To handle somewhat overlapping metering, a Hanford "virtual meter" was created to represent a metering point. Each point then could have various meters attached to it—manual, automatic, or both. When the Administrator Module collects these data, it checks the validity of all readings and selects the best value and records that value for the virtual meter. If the value is outside of an adjustable threshold or any other problem arises, it generates an error message, which a staff member must address and correct if necessary.

The Meter Relationship Module was developed to track the relationships between buildings and meters. Its main function is to allocate the energy use to the various buildings and other loads by linking to the electric line diagrams for the Site. The result is a usage equation for each building that determines electric usage. The equation can be a single meter, sum of several meters, subtraction of several meters, percentage split based on square footage, or a user-defined estimate. Figure 2 shows an example of the usage equations determined from the actual electrical line diagram. Each equation is saved in the database with an effective date, so that changes can be tracked over time.

Problem 2—
Organizational Momentum

Change, although inevitable, never comes easily. Shifting the organizational momentum to a new software tool and way of doing things proved difficult. In addition to the normal stresses of changing an organization's business paradigm, staff found themselves moving several generations forward in computer technology.

To facilitate acceptance, the software was designed with outputs and discrete points that mimic the steps that existed previously. Although the software could be designed to go directly from points A to D, going step-by-step from A to B to C to D provided a level of familiarity to the tool and allowed users to view the results of each step gaining confidence in the software.

The long development time for the software—three years—helped expose future users to the software and aided in its acceptance. The long development time also gave users the opportunity to improve their computer skills from DOS-based Lotus 1-2-3 era to Microsoft® Office and Windows. The software itself is very user friendly and graphically oriented. Only a few administrators need advanced computer skills to track down problems during data processing.

Problem 3—
Differing Contractor Needs

The Hanford Site is served by various contractors all of whom have different needs. Some want utility data by building, some by project or program, and others want a single total. In addition to utility data, PNNL wanted the fully burdened cost of energy (including overheads) to help manage declining budgets.

To meet a diverse set of needs, FRED was built for the highest level of detail, with tools to quickly aggregate these data. The modular nature of the tool also allowed users to pay for custom features or modules specific to their needs. The Billing/Forecast Module and the Internet Module were funded by organizations other than our prime funding source. As long as it's understood that all new modules, even though they are funded separately, become part of the suite of tools, the project as a whole benefits.

Problem 4—
Existing Software

Not many facilities have the luxury of replacing the entire metering infrastructure with new hardware and software that performs all system tasks. Developing a tool that worked with existing hardware and software was a necessity at Hanford. As a systems integration tool, controlling the existing data collection software was a low cost solution to extending the life of the metering systems without reinventing capabilities. The other unique feature was designing the software to work with other tools at the backend. By providing data and connections to existing software like SRC's Metrix™, advanced features can be utilized without having to build them from scratch. Links to other front end or backend software tools could easily be added as either modules or functions.

Problem 5—
Steam Data

When the coal plants were replaced with natural gas boilers, the ESPC contractor took over all purchases of natural gas and, in turn, provides steam to the Site. Time-series data are collected through an energy management and control system. The monthly figures for the first year were delivered six months after the year ended.

Unfortunately the ESPC contract did not clearly spell out the data requirements. The amount and timeliness of these data failed to meet the minimum of Hanford's quarterly reporting requirements. Building energy managers and engineers would also benefit from analysis of the time-series data to better understand their facilities. The ESPC contractor treats these data as business sensitive, even though they are collected in Hanford facilities.

The bottom line is to clearly define all requirements in the contract. Get the financial, contractual, and the engineering staff together and speaking the same language. Hanford found that the requirements for steam data from its ESPC contractor weren't clearly defined in the contract, and the only solution is to modify the existing contract.

Problem 6—
Providing Data Access

Providing access to utility data for building managers is the first step towards energy use accountability. Secondly, charging for energy use lower in the organizational structure will also encourage conservation. Even at Hanford, where facilities are fairly well metered, one contractor is proposing to lump all the energy charges in a "pool" for funding and pay for it through overhead accounts.

FRED's two data access modules allow users to access up-to-date utility information at the building level. Decisions of how utilities are billed are made at a higher level than this project.

Problem 7—
Bill Reconciliation and Reporting

Because of the structure of Hanford's electrical system some unique features were developed in FRED. First, Hanford Electric Utilities does not have a fixed electric rate it charges customers. The financial system dictates that all electric charges match exactly what BPA charges the Site each month. Therefore, site usage is computed, and charges are allocated so that the sum of all charges reconciles with the BPA charge. The result is a sliding rate that ranges from $0.01124/kWh to $0.03363/kWh for energy use and $2.441/kW and $1.806/kW for demand. FRED automatically computes the BPA charges, finds the usage for each load on Site, reconciles the charges, and determines what the electric rate is. Overhead charges for items such as operations and maintenance are added to these costs by the financial system in a later step.

The reporting requirements for the Site, specifically the quarterly report, provided an additional incentive for an automated tool. Energy cost and consumption must be reported quarterly in detail. The reports consist of a breakdown by fuel type, area, contractor, and use type (building, metered process, or vehicles). To construct the reports, the tool categorizes each load by use type during the billing process. These data feed into the quarterly report generation feature which also includes non-electric fuel inputs. The most difficult quarterly reports to generate compares current use to usage during the previous year and the 1985 base year. If the percent change is significant, a comment must be provided to explain the difference. For each entry, the tool provides suggested comments determined by frequency of occurrence in previous years. Users can select one of the recommend comments or provide a new one.

Problem 8—
Scope Creep

Scope creep, the gradual increase in expectations or deliverables, is a problem in most projects and should be actively managed. This project was no different. To combat scope creep, clearly define deliverables and provide for a reasonable number of contingencies. The long development time and redesigning of the tool was mainly caused by previously unidentified issues causing a reevaluation of the tool's architecture.

Problem 9—
Software Implementation

Hanford's tool presented a challenge to implement because of the complicated set of tasks that were replaced and the wide variety of reports generated. The tool went through several iterations in development, with future users having input into the tool's architecture at each step. The long development time provided additional familiarity which aided in its acceptance.

Testing of the software occurred both during the development stage by programmers and by utility personnel in parallel with current data processing procedures. The existing methods and FRED were operated simultaneously for approximately six months. Although this was longer than planned, it was necessary to work out software bugs and train utility personnel.

The software developers established a subcontract with an employee who had previously worked at Hanford and had intimate knowledge of utility operations. During the development stage, she acted as a project consultant, spending more time with the software developers than Hanford utility personnel could spare to help them understand utility operations. During software implementation, her good working relationships with existing utility employees helped facilitate software testing and implementation. She also represents a low-cost resource to Hanford Electric Utilities in the future to provide training or other assistance with the software.

***Problem 10—
Year 2000 Compliance***

Additional tests were required, because of the concern over computer failures in the year 2000. The tests were a significant task, requiring generating dummy input files and databases to simulate future data. The complete processing was performed on these data at significant dates. Hopefully this is a problem future projects won't have to face.

A tool like FRED, which utilizes other software packages, databases, and data input files, is in a vulnerable position. It is dependent on each piece to perform its specific task. The year 2000 compliance testing took into account each individual piece by contacting the company or developer of the tool. However, the number of interconnected pieces represents some increase in risk for the project. On a smaller scale, FRED is also dependent on each input file or database to remain the same. Small changes to input files will require some small changes in FRED.

Conclusions

Legislation passed in the last 5 to 10 years now provides cost justification for end-use metering of utilities. Rather than installing metering simply to meet requirements, facilities should utilize this metering to increase accountability for energy use. Where metering exists, facilities should take the higher road and discourage lumping energy costs into "pools." Rather, making individual organizations responsible for their energy costs and providing quick access to these data provide an effective tool to encourage energy reduction.

To handle these data, a custom application doesn't always make sense. Some Federal sites may be better served with an off-the-shelf utility data management package or by out-sourcing metering activities through an energy services company. All out-sourcing activities must be clearly defined by contract. Hanford found that the requirements for steam data from its ESPC contractor weren't clearly defined in its contract, and a solution has yet to be found. Certainly there are more options available than ever before and these should all be explored.

In Hanford's case, and many others, an in-house tool can provide the greatest flexibility and control for addressing specific problems. Experience at Hanford has shown that it's not necessary to replace or re-invent existing software. An architecture of systems integration allows the new tool to communicate with and control existing software. Viewing the tool as a suite of distinct modules can also help to fund development, where organizations only want to pay for functions that directly affect their tasks.

The lessons learned during FRED's development should be useful to others—especially large Federal facilities—who face similar problems.

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Chapter 28— ESPC Implementation at the National Animal Disease Center

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Abstract

The facilities at the United States Department of Agriculture, Agricultural Research Service, National Animal Disease Center (NADC), located in Ames, Iowa, support a scientific staff of approximately 230 persons conducting research on animal diseases with economic importance to the US livestock industry.

Annual energy consumption has been on the order of 520,000 Btu/sqft and annual energy expenditures exceed $1.5 million. The opportunities for energy and energy cost savings are significant and the Center is participating as an initial site for the DOE SuperESPC program. Preliminary ESCO proposals have identified more than $500,000 of annual cost savings, as well as improvements that will improve the comfort for building occupants and reliability of Center infrastructures. Anticipated ECMs include lighting, incinerator stack heat recovery, VAV retrofit and HVAC controls, air pump replacement, propane-air mixing stations, as well as back-up generation equipment, and a combustion turbine for co-generation. It is anticipated a delivery order will be issued for some or all of the proposed ECMs and implementation will begin during 1999.

From the perspective of a facility manager and engineer with recent experience, the paper will reflect upon the processes of identifying potential ECMs, development of project goals, working with an ESCO and contracting specialists, evaluating technical proposals and ESCO proposed ECMs, consideration of M&V approaches, developing agency management support, and working with the ESCO during construction installation. Positive and negative aspects of the process will be reported in order to help prepare facility managers to implement successful ESPC projects at Federal facilities.

Background

The USDA National Animal Disease Center conducts research on animal diseases that affect the US livestock industry. The facilities typically house cattle, pigs, sheep, and poultry with a variety of animal diseases; including research on zoonotic diseases that are transmissible to humans, and diseases transmissible to animals in the surrounding community. The facility design incorporates a number of means and measures to protect staff and the public from potential exposure to disease agents, including high-efficiency air filtration, use of steam sterilizers for solid wastes exiting the laboratories, heat sterilization of wastewater, and incineration of animal carcasses and biohazard wastes. The Center animal care program also adheres to laboratory animal care standards requiring total environmental control and 100% fresh air ventilation rates of 10–15 changes per hour.

The unique Center features for conducting research within biocontainment require significant energy and utility expenditures in order to be completed in a safe manner. The projected FY-2000 utility budget is $1.6 million, about 8% of the total Center research budget and nearly 1/3 of the cost to operate and maintain the Center facilities. In recent years, the ARS budget process identifies facility operating costs as indirect research costs taken off the top of the research allocations, which has increased some research staff interest in energy conservation since they realize savings could be utilized by the Center research programs.

The Center was designed in 1957 and occupied in 1961. The facilities include approximately 80 buildings, totaling approximately 450,000 sqft on a 320 acre site. The major laboratory and animal containment facilities are served by a central boiler/chiller plant. Other than replacement of chillers, extension of central chilled & hot heating water to a group of animal buildings, and an upgrade of an animal carcass incinerator in the 1980s, no significant modernization, mechanization, or energy conservation improvement projects have been implemented.

Center Energy Conservation Potential

The Center, like many facilities, focuses primary management attention to its mission and supporting research programs. Management staff are trained in veterinary medicine and the biological sciences, and while there has been a general recognition that the facility is energy intensive by nature, limited management or engineering attention has been applied to investigating Center energy efficiency and potential energy conservation savings.

The Center engineering unit began to investigate energy efficiency and utility operating costs in the mid-1990s. One of the first steps was to compare Center energy utilization with other research facilities. An Energy Utilization Index (EUI) for the Center was calculated by dividing the total Center energy consumption by the total square footage. Figure 1, 1995 EUI, illustrates the Center EUI in comparison with other types of facilities for Fiscal Year 1995 (data from DOE, FEMP website). As demonstrated by the figure, the Center EUI is about double the EUI for health care facilities, and additionally on the order of 3 to 4 times the average for other ARS research facilities. However, the numbers cannot be directly compared since the Center energy uses for waste and wastewater sterilization, incinerators, and the additional 100% fresh air necessary to comply with animal care & agency ventilation requirements, are not typical of other facilities. In reality, there are no other like facilities for direct comparison. Keeping these factors in mind, and considering that the energy efficiency of the ventilation and decontamination systems could be improved, and the very limited energy conservation measures implemented, it appears the EPAct and Executive Order goals should be attainable.

Review of the Center utility costs also identified several areas for additional investigation. Review of energy billings found that the Center power factor has been dropping over the years and utility cost penalties were approaching $20,000 annually. The Center is supplied with both firm and interruptible natural gas services. While the boilers and incinerators are on the interruptible service since they are backed up by fuel oil, a number of smaller buildings are served directly with firm gas. The natural gas cost differential for the firm gas (exclusive of supply/transport options) has been about $25,000 per year. The Center is also served by utility-owned standby generators (40 yrs old) in a substation on the site. This arrangement limits the Center electric rate options to a firm commercial time-of-day rate with an "Excess Facilities" charge for the standby generators of approximately $30,000 per year. Additionally, utility metering is limited to a single electric meter and natural gas meters in the utility substation for the Center.

Using the preliminary information, a group of energy conservation projects were identified and the implementation costs were estimated. Just concentrating on the main facilities (no ECMs were considered for facilities that need to be replaced), the needs were estimated to be $3 to $4 million. These projects are in addition to lighting retrofits and small projects initiated with operating funds.

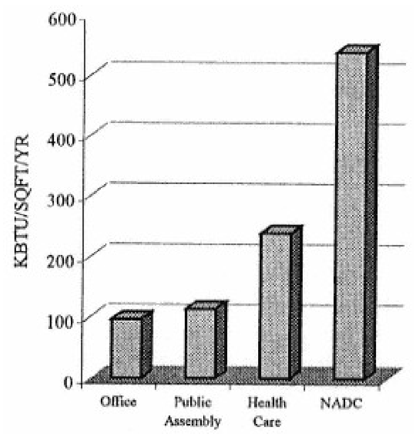

Figure 1
1995 Eui

Within ARS, energy conservation improvement funding is budgeted along with regular Repair & Maintenance activities. The Center has consistently exceeded the Agency's minimum budget for R&M, but continues to fall behind the R&M needs of the research programs where changes are being implemented at an increasing pace. The $500,000 budget for Center R&M contracts is allocated for critical research needs and therefore R&M funding is available for only a few small ECMs. The limited ECMs implemented have been directed to expansion of the central computer-based building management system and purchase of electric submetering hardware. Implementation of significant energy conservation measures will require external or special funding.

Energy Savings Performance Contracting

Following passage of the 1992 Energy Policy Act and subsequent Executive Orders, the Center engineer participated in DOE Federal Energy Management Program (FEMP) training on Energy Savings Performance Contracting

(ESPC) in 1995. An initial vision for the scope of ECMs was developed which included HVAC improvements for the Administration Building, metering in major buildings, a steam trap maintenance program, power factor correction, back-up fuel for firm natural gas facilities, and control upgrades. It was estimated these improvements would require an investment of $1.5 million and would generate about $250,000 in annual savings. Contracting assistance to initiate an ESPC was investigated, but in all practicality, the Agency did not have personnel adequately trained for development of a site-specific ESPC and a DOE regional SuperESPC was not yet available.

Following the DOE training, a SavEnergy Audit was funded by DOE for the NADC Administration Building. The audit documented the potential savings, but also served to maintain contact with the DOE regional office and the Center was invited to participate as an initial site for the DOE Midwest Region SuperESPC in 1997. Under the interagency agreement covering participation as an initial site, ARS receives technical and contracting support, and has agreed to negotiate an ESPC delivery order with one of the successful Energy Service Companies (ESCO). DOE energy engineers provided technical assistance to develop a Site Data Package (SDP) for a number of Center ECMs and the Center engineer participated in the technical evaluation process for the regional SuperESPC solicitation.

Delivery Order Status

Following DOE's award of ESPC contracts with multiple ESCOs, the Center selected one of the ESCOs for the NADC project. Selection was based on the technical approach and evaluation of site-specific ECMs demonstrated in the regional ESPC proposal. The Site Data Package and required ECM list from the regional solicitation was revised to eliminate ECMs that did not appear to be practical and issued as an RFP to the ESCO, who was then allowed to perform site analysis. Regular technical discussions with the ESCO and government contracting team have been conducted to maintain open communication and provide feedback to the ESCO in development of their proposal. At the close of ESCO investigation and technical discussions, the RFP was amended to update the project requirements in writing.

The revised SDP identified site areas/ECMs that would not be considered due to biocontainment requirements or planned maintenance, but also allowed the ESCO to investigate and propose additional ECMs. While this latitude appears to have been beneficial to the overall project, in technical discussion it became clear the ESCO would be proposing additional ECMs that would more than double the anticipated implementation cost and project term. This raised concern from the Agency facility division (FD) and financial management personnel. FD was concerned that improvements included in the ESPC project would not be repaid for buildings that should be demolished or remodeled in a tentative modernization plan, and financial management questioned the practicality of an extended financial management commitment for M&V on a project that would not provide significant budgetary benefit for a number of years. Discussion of these issues resulted in several months of delay while the ESCO was awaiting direction for the formal proposal scope. The ESCO has been allowed to propose the additional scope of ECMs, however it will be necessary for the government evaluation team to address these issues in detail when the proposal is evaluated and during final negotiation.

If the additional ECMs are accepted, and based on very preliminary calculations, the project implementation cost would be roughly $6 million and would generate roughly $600,000 of annual energy cost savings. Additional information may be available at the WEEC paper presentation. The project team is working to issue a delivery order in the fall of 1999 with anticipation that implementation would be fully completed in the first half of FY-200 1.

Anticipated ESCO Proposal

One of the key ESPC projects for the Center engineer was improvements to the Administration Building. The building has very poor temperature control for both heating and cooling, and poor lighting fixtures and distribution. Current lighting distribution includes up to 12, 34W florescent lamps per office/desk space. Conditioned air is directed from wall registers along the ceiling in the offices causing drafts and resulting in a number of occupants placing electric heaters under their desks. Additionally, the number of temperature control zones are not adequate to satisfy occupant needs and some of the electric heaters are used year-around. The proposed project for this building would convert the HVAC system to VAV by installing modulating VAV outlet registers and temperature sensors in each office, modulate zone temperatures, install an ASD on the supply fan, and program the temperature system controls. Additionally a new suspended ceiling would be installed to support the new supply registers and new lighting fixtures, which would be significantly reduced in number and would be more optimally located to serve the occupants.

Although a significant portion of the energy cost savings for this building could be achieved without the suspended ceiling, modulating registers, individual room temperature sensors, and new lighting fixtures, the original scope for this project has been retained at the insistence of the Center engineer. Reasons include that this building generates a significant portion of temperature control service calls, the morale and comfort of the administrative staff is important, and improvements to the administrative facilities would be dead last on the priority order of any Agency modernization or R&M funding. An ESPC would be the only likely manner funding could be obtained to make energy conservation and environmental control improvements to the building. The building is also one of the few buildings on the site where visitation is not restricted by biosafety protocols. Therefore this building could be used to showcase to the Agency and other Federal facilities how ESPC projects could benefit facility conditions that affect employees, as well as produce energy savings.

In addition to addressing the required ECMs, it is anticipated the ESCO will propose new ECMs for ventilation air heat recovery for the main laboratory building, preheating combustion air for the incinerators, and a co-generation ECM. The co-gen ECM would install a nominal 1,000 KW natural gas-fired combustion turbine (CT) electric generator with heat recovery boiler, and a new nominal 1,800 KW diesel standby generator. The CT would be operated as base-load producing electricity and up to 8,000 lbs/hr of steam for heating and sterilization use. An additional boiler section would produce additional steam as required and at a greater efficiency that the existing outdated boilers. The economic viability of this ECM stems from the combination of the CT and standby generator, which will provide greater total generating capacity than the current peak electrical load. This will allow the Center to switch from firm to interruptible electric rates, which cuts the electric demand charges in half; thereby cutting the electric rate by roughly 1/4 as well as eliminating the current "Excess Facilities" charges ($2,433/mo) for the current 40 year-old generators owned by the utility provider. This combination also increases the standby capacity as compared to the utility-owned generators (about 2/3 the current peak demand) and the Center will no longer be required to curtail some operations in the event of an electrical curtailment or emergency power outage. Other benefits include improved reliability of steam generation and standby electrical services with new equipment, and reduced future capital expenditures for replacement boilers and standby generation equipment.

However, the proposal significantly increases the cost and term for the entire project (initial implementation cost is anticipated to be double the total implementation costs for all the other ECMs)—and indirectly affects the economic viability of nearly all other ECMs since the price of electricity will be reduced if the co-gen project is implemented.

Experiences and Lessons Learned

The general acceptance of the ESPC financing approach in facility management and the use of the established DOE SuperESPC master contracts will make implementation of delivery orders easier in the future. However, for the short term facility engineers and managers need to be prepared for several stumbling blocks that may delay or kill project implementation.

Educated Facility Advocate

Facility managers must recognize that ESPCs will require considerable preparation, analysis, negotiation, implementation, and monitoring time. Each project needs a facility advocate who can commit significant time to the project, and even better if the advocate has a deep-rooted belief in the principles of ESPC and a clear vision of the site needs and objectives. The advocate will also be most effective if he/she has technical energy engineering and government contracting training. The advocate needs to be able to see the project through, including administrative support for travel as necessary, and possess both patience and endurance. In all likelihood, an ESPC will not become implemented without this advocate.

Administrative Support

A facility manager considering an ESPC needs to determine the level of administrative/contracting support early in the project development. If local contracting authority or expertise is not available, the manager may need to meet with the appropriate Agency officials to learn their ESPC training and experience, tolerance for perceived risk, and enthusiasm for ESPC financing before planning starts. Strong administrative and contracting commitment should be obtained before any Agency's first ESPC project is initiated.

It also may be necessary to coordinate the efforts of more than one section within an Agency to implement a project. For example, within ARS a procurement/contracting section handles ESPCs since they look more like a service contract than a construction contract. But the ESPC implements facility improvements which would normally be managed by a Facilities Division (FD). Several persons in the procurement section are trained in ESPC contracting, but are not familiar with and do not have the authority to deal with facility issues; and therefore look to FD for technical support. However, FD has no persons trained in ESPCs (or energy management), has their own overflowing workload priorities, and FD simply does not have the time or professional resources to provide adequate technical support. For the NADC project, the worst scenario played out when the financial management person responsible for Congressional notification of the ESPC project asked FD a question about the project and FD responded that the project should not be implemented since Center modernization would be demolishing the Center buildings before the ESPC could be paid off. This lack of internal Agency communication delayed providing guidance to the ESCO for several months and required several reports and trips to headquarters to discuss and demonstrate that the project scope had been planned with modernization in mind and the two projects were compatible and being coordinated.

Implementation of an ESPC requires a senior Agency official to send a notification letter to Congress at least 30 days before a contract is awarded. Be assured this official will want to be fully informed about the project in preparation for any questions that may return after the notification is sent to Congress. If he/she is not familiar with how ESPCs work, it is likely the project team will need to prepare not only the project materials, but general training on the ESPC authorizing legislation and the mechanics of the process. If possible, seek assistance from DOE representatives to inform this official.

If the Agency official is also a financial administrator, be aware that an ESPC may not generate much enthusiasm since there will likely be small short term cost savings for the Agency budget and it is probable that the full financial benefit would not be realized for a number of years. When it is easier not to act or say no, just being the right thing to do will not likely be an adequate justification for this official. Be sure to identify the indirect benefits such as increased equipment reliability, reduced maintenance and operation costs, reduced future capital expenditures, less demand on limited financial resources, etc. One of the reasons for Congressional notification is that Congress is supposed to allocate funding to cancel the financial obligation to the ESCO in the event a federal program cut affects the ESPC project site. Agency financial officials will likely be very skeptical that Congress will actually provide the cancellation funding and will be concerned that Agency appropriations would have to be diverted from programs to cover potential cancellation costs.

Agency administrators also need to recognize that prolonged procurement processes wear on the patience and enthusiasm of site advocates. If the procurement process is lengthy, there may be times when it appears to the site advocate that he/she is getting nowhere, hitting their head against a solid wall so to speak. Isolation at a site can be a lonely feeling that may erode the confidence, enthusiasm, and ultimately the productivity of the site advocate.

Technical Support

Energy engineering expertise will be absolutely required for implementation of an ESPC. A mechanical engineering background would be helpful, but a more specific energy engineering training is usually necessary to effectively communicate with the ESCO and to evaluate the proposal. If in-house expertise and time is not available, then arrange for DOE or independent technical assistance. In the case of SuperESPCs, the cost for DOE technical assistance can be repaid from the savings. The ESPC experience these technical sources will bring to the project will be valuable in avoiding difficulties during the term of the project. It is not practical or realistic to rely on the ESCO for significant technical guidance.

Contracting Support

The ideal project team would match the project requirements with technical and contracting experience and expertise. Where this is not practical, it may be appropriate to plan the project scope to match the skills of the project team. Working with an ESCO requires significant and detailed communication during the project assessment phase and the ESCO approaches a partner-like open relationship with the contracting official. This is somewhat contrary to the adversarial nature of typical competitive bidding processes and some contracting officials may have difficulty dealing in this manner.

It is also recognized that being first is not always easiest, and initiating an ESPC within an Agency where several ESPCs have been implemented and policies & procedures have been established may enhance the implementation of successful projects.

Setting the Project Scope

It is important that the site review potential ECMs and determine which projects would be important and beneficial to the facility. Goals and expectations should also be developed in advance of discussions with an ESCO. Use walk-through energy audits or utility-supplier assistance to gather data.

ESPC financing can be very flexible to accomplish site improvement goals that are related to energy conservation. Consider projects that improve employee comfort or working conditions, lighting distribution improvements, and projects that change how maintenance and operating costs are funded. Also consider aggregating ECMs with short term payback with ECMs with longer payback in order to accomplish projects that would not be considered independently. The administration building HVAC and lighting improvements at NADC is such an example. Installation of the new suspended ceiling requires an investment where there is no payback, but combined with the site power factor correction, other HVAC improvements, and site and building lighting retrofits, the entire package will meet the selection criteria set for the project.

Preparations for ESCO Meeting

In preparation for the first meeting with the ESCO, the NADC project team gathered detailed information about the site and felt well prepared. However, it soon became clear the ESCO preferred to do their own analysis, and the project team was not prepared for the more basic ESCO questions; such as:

1) Which ECMs are really required vs wanted if determined to be financially viable? What are the site priorities and what measures will determine their ranking?

2) What are the site energy & energy cost saving goals?

3) What maximum contract term/length would be acceptable?

4) What ECMs/projects would not be acceptable?

5) What maintenance costs will be required to be paid from the savings?

6) What confidence/risk is acceptable to the site with regard to stipulation vs measurement of savings?

7) For each ECM type, what M&V approaches would be acceptable?

8) Will the site accept an increase in scope if the ESCO identifies additional economically viable ECMs?

When working with an ESCO, it is in the interest of both parties to fully share site information and decision-making criteria. Remember that the government ultimately pays for the ESCO investigation cost over the contract term and there is no sense in allowing the ESCO to reinvestigate what is already known. Similarly, if there are political or practical reasons why a particular ECM would or would not be considered, make it known up front.

If simple payback will be used to help determine economic feasibility of specific ECMs, define how it will be calculated (include investigation and M&V costs in the total cost). When establishing an acceptable contract term, keep in mind that the financed term will be 2–3 times the simple payback. Also keep in mind the EPAct goals/requirements to implement all energy and water conservation projects with a payback of 10 years or less.

Cash Flow

When planning the terms of an ESPC there are several options that significantly affect the cash flow and the term of the project. For simplification, ESPC financing can be compared to a home mortgage; the greater the initial investment/loan amount and/or the less the monthly/annual repayment, the longer the contract term will be. The longer the term, the more interest costs the government will incur.

One method to reduce the ESCO's initial investment is to apply any utility rebates to the project. The site should investigate utility supplier rebate/DSM programs, determine when the payment will be made, and the technical transfer details to apply the rebate to the project.

Maintenance costs for the new ESCO-owned equipment is often paid by the contract, however it must be remembered that the maximum government payment will be the documented savings and any payments for maintenance included in the ESPC will be deducted from the savings that is used to repay the implementation investment. Payment for maintenance costs will therefore lengthen the contract term and increase the total financing cost to the government. The site should consider to what extent it would be comfortable repairing and maintaining ESCO-owned equipment since it may be more cost effective for the site to complete the maintenance services with in-house forces or to directly contract for maintenance.

Product warranty and equipment life also plays into this decision. If the ESCO installs equipment with an anticipated life of 10 years and the contract term is 15 years, the ESCO will include the replacement cost in the initial investment cost to be financed by the site. If the site determines to assume the maintenance/repair costs, the site will fund the replacement from operating funds in the year the actual replacement occurs. Another method to minimize site risk would be for the ESCO to purchase extended warranties on high cost equipment items.

ESCO proposals will often include operating cost savings. Each site needs to determine if and/or what operating costs will be real. Material cost savings where the ECM converts to longer life lamps and ballasts may be real and can be documented, however, the associated labor cost savings may not be realized unless the site reduces the labor force accordingly. If the site reassigns the labor to other tasks, there will be no net savings to the site and the site operating costs will in effect be increased by the amount paid to the ESCO for operating cost "savings."

The energy cost escalation rate will also be a issue to be negotiated with the ESCO and reflects that the ESPC will produce units of energy savings, but the price for the energy will vary and will likely increase in the future. Acceptance of an escallation rate will increase the payments to the contractor to compensate for the price increase and the annual site utility/ESPC budget needs to anticipate this cost increase. Since it is unknown what utility prices will be in the future, the DOE published escallation rate is often used as a guide.

Measurement & Verification Plan

An annual balancing and verification of energy savings is necessary and required for ESPCs. A written plan will be required and should fully document the measurement and calculation methods that will be used to verify savings. The site should also plan for how the annual verification will be completed—what records need to be kept, who will be responsible, what level of skills will be available, and what training will be needed. When determining the M&V approach that sets the annual verification procedures, keep the level of staffing and staffing skills that will likely be available over the contract term in mind.

When determining the M&V requirements for each ECM the site should be aware the ESCO will include the cost to develop the documentation and annual verification in the proposal. These costs are paid off the top of the energy savings before the savings are applied to the installation costs. Sites need to keep in mind that the ESPC is not a research project where detailed energy consumption data needs to be measured, and it is not a full employment program for the site or energy engineer.

Metering itself does not generate any savings and should be minimized unless necessary for the project energy consumption verification. If submetering is desired to assist the site in management of other energy costs, it may be more cost effective to use operating or R&M funds rather than financing the submetering through the ESPC project.

Stipulation of issues such as hours of operation or stipulation of future savings based on baseline and one-time installed measurements should be strongly considered. Consider the cost to complete detailed modeling and measurements with the potential savings in mind. At NADC, for example, the cost to measure the entire administration building energy consumption and develop modeling to adjust for weather and occupancy energy consumption makes it impractical to determine the HVAC cooling cost savings related to the reduced cooling load of the new lighting systems. It is anticipated the lighting hours will be stipulated and before/after installation measurements will be used to stipulate the wattage savings for this ECM and the relatively small savings for reduced cooling load will be neglected from the measured and documented savings.

Recommendations

The most successful Energy Savings Performance Contract projects will be at Federal sites where both location technical experience and energy management training as well as ESPC contracting experience and training is maximized. Facility managers considering ESPC projects need to investigate the level and skills of administrative, technical, and contracting expertise available. If technical expertise and time is not available, plan to obtain these services from DOE or other independent sources. Investigation of administrative support should include consideration of the training and experience with ESPCs at the Agency level where Congressional notification will be issued.

Considerable pre-planning should take place where the site identifies its energy saving priorities and goals, determines how maintenance, operating, utility rebates, & energy escalation costs will be addressed, and determine acceptable approaches for measurement and verification, contract term, and ESCO identified ECMs.

Anticipate open, partner-like communication with the ESCO during their site investigation and baseline measurement period. The site advocate needs to be involved in all the details, have patience/stamina, and be deeply committed to the project. When evaluating proposals, factor the indirect benefits such as equipment reliability and future capital improvement cost reductions into the decision-making process.

Agencies need to keep in mind that an ESPC is simply a financing means for facility improvements that generate energy savings. M&V plans need to be simple enough that they can be continued for the life of the project without unnecessary paperwork. The M&V plan SHOULD NOT create a research project on energy conservation or guarantee the need for a site energy engineer.

As ESPCs are implemented at more Federal locations, their popularity will increase and the ease of implementation will improve. Issuance of the most recent Executive Order will further encourage Agency administrators to become trained and consider wider-spread use of ESPCs. Facility managers and engineers need to become aware of the benefits of ESPC financing and become trained and knowledgeable in order to fully realize the benefits of Energy Savings Performance Contracting financing.

The NADC ESPC project has required a significant effort on the part of the Center engineer and staff, which has resulted in a detailed understanding of the ESPC process, and site energy requirements and saving opportunities. The Center remains confident in the ESPC approach and that a successful project will be implemented.

Biography

Dennis L. Jones has been chief engineer and facility manager at the USDA, ARS, National Animal Disease Center for the past 7 years and has responsibility for maintenance and operation of research facilities with a staff of 40 and an annual budget in excess of $4.5 million.

Jones received BS and MS degrees in Agricultural Engineering from Iowa State University with a minor in Energy Engineering and his MS thesis documented performance of an integrated solar collector for a swine nursery.

Dennis Jones has been a registered professional engineer for more than 20 years and a Senior Member of AEE since 1992. His previous professional experience has included work for a livestock equipment manufacturer, a general contractor, manager of a university ag experiment station engineering service, and three years in a consulting engineering practice.

Chapter 29— HVAC and Controls Retrofit of a Manufacturing Plant

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Abstract

This article discusses the design and installation of a 3600-ton central plant and 750,000 cfm air-side system in a Texas manufacturing facility originally cooled by a legion of split-system units

Outline

Introduction

This article discusses the retrofit of The Trane Company's manufacturing plant in Tyler, Tex., which employs over 3000 people and operates year round. An average of 2000 residential, outdoor, air-cooled condensing/compressor units are manufactured each day with output varying with demand. The article will describe the system and general design and installation conditions of a 3600-ton central plant and a 750,000 cfm air-side system with a focus on the air-side systems and controls as well as present central plant and chilled water distribution designs.

Design Challenges

The original manufacturing plant was built by General Electric in the 1950s and was approximately 300,000 sq ft. Over the years, additional manufacturing buildings were added, and with attached office, engineering, testing, R&D, and shipping functions, the total floor area grew to 925,000 sq ft—750,000 sq ft of which was redone to include air conditioned space. The new chillers were sized to accommodate the remaining space, which will be retrofitted in the future.

The HVAC challenges in the plant were poor indoor air quality (IAQ) caused by paint fumes and oil mist generated by manufacturing processes; little or no outside air except by infiltration; warm and humid indoor conditions; and inefficient, high-maintenance systems lacking a cooling capacity.

The manufacturing plant was originally air conditioned with split-system direct expansion (DX) units that had proliferated to a total of 450 3-, 5-, and 10-ton units and a sea of condensers on the roof. The capacity of the units had gradually diminished to the point that the plant was tempered but not able to maintain normal comfort ranges. The units could maintain a 10 to 15 F temperature drop across the evaporator coils with little or no dehumidification of the air. This lack of dehumidification and sensible cooling capacity was due to a build-up of oil mist and particulate on the cooling coils over the years. This build-up could not be cleaned without damaging the aluminum cooling coil fins.

Maintenance personnel were challenged with the continual maintenance of failed compressors, controls, condenser fans, evaporator coil refrigerant leakage, and evaporator fan failures. Finding the units that were not operating and maintaining filters required constant attention. The owner estimated that $200,000 per year in maintenance savings would result from replacing the DX units with a central chiller plant.

Cooling Loads

The plant cooling loads were calculated based upon exterior skin loads, manufacturing process equipment, lights, and workers, which required from 0.75 to 1.5 cfm per sq ft. Manufacturing processes and their resultant cooling loads change over time; consequently, the new air handlers and distribution systems were designed with flexibility in mind. A minimum of 1 cfm per sq ft in most areas and 1.5 cfm per sq ft in low bay, heavy equipment areas (not readily moved in the future) were provided in the design of the units and ductwork distribution systems. The heating load of the skin calculated to 10 Btu per sq ft; the outside air load is 10 Btu per sq ft; and the interior loads, lights, workers, and processes summed to 25 Btu per sq ft. Because the interior loads exceed the skin and outside air loads, heating equipment was not provided in the new system.

Air Handler Design

The air handler concept for this project required maintaining the existing systems in service, the minimal disruption of manufacturing processes, and minimizing construction work after hours and on weekends. Thirty new air handling units (AHUs) were installed, ranging from 8000 to 42,000 cfm air supply capacity. The majority of the units have a capacity of 30,000 cfm. Twenty-three rooftop units and seven indoor units were installed.

The original design concept for the AHUs was to provide supply and return/relief fans. When value engineered, they were changed to supply-fan-only units with relief (for economizer) air provided by through-wall prop fans distributed throughout the building. This decision saved over $400,000 in first-cost equipment and electrical services.

The air handlers are constant volume, chilled water, cooling-only units. The units are double-wall construction featuring draw-thru design with single, isolated base centrifugal fans. The outside air intake dampers are divided into minimum outside air dampers and economizer air dampers. These units serve high bay, 25 to 60 ft clear-to-structure, open manufacturing areas with some mezzanine manufacturing lower ceiling areas.

Approximately 40 percent of the plant area is dedicated to manufacturing processes which generate high oil mist. Oil mist plating or settlement accumulates on building surfaces and can cause equipment degradation. It can decrease lighting performance. Most importantly, oil mist, along with paint fumes, impact indoor air quality. Clearly, there was a need to remove as much of the mist as possible.

We recommended that the owner retain an outside air quality consultant to test the airborne particle size and concentration of the oil mist, then make recommendations for the air handler filters. The ambient air sampling measurement results indicated an average particle size of 1 to 2 microns. Metal filters collect particles by impact or impingement in the 10 micron and larger size with little effectiveness on this smaller size particle. The consultant recommended 65 percent, 12 in. pleated (extended surface) rigid filters with non-woven, non-oil wetting (clogging) media. Based upon measured particle densities, the expected life of these filters is six to nine months before loading to 11/2 in. wg pressure drop. By analyzing the oil mist, $225,000 first-cost savings were realized by avoiding the metal filters. The metal filters cost $0.30 per cfm while the filters used cost $0.10 per cfm.

The new air handlers and filters have been operating for five months; the plant environment is significantly improved; and filter life is as anticipated. No pre-filters were installed on the 65 percent filters. With the extended media surface and size of oil particulate, it was decided that 30 percent pre-filters would not significantly extend the life of the 65 percent filters or justify the fan energy expended through pressure drop in the pre-filters. Where oil mist was not being generated in the plant, 30 percent efficiency filters were used. Air pressure drop across the filters is monitored by both the DDC controls system and filter pressure differential gauges mounted on the unit.

Air Distribution

The plant had split-system air handlers mounted on columns in half the areas. These units had a short discharge gooseneck duct discharging into the plant. Other areas utilized small tonnage, horizontal-mounted fans and DX evaporator units installed in catwalks. These units had supply ductwork with overhead distribution out into the plant area below. Return ducts were not utilized for either type of system. In all cases, roof-mounted compressor and condensing units with connecting refrigerant piping were installed in close proximity to provide cooling. A separate system of outside makeup air with or without cooling capacity had been installed—ducted to each horizontal air handler or discharged directly overhead into the space served.

The existing plant ductwork was re-used as much as possible to minimize interruption of manufacturing and control costs. The outside air makeup ductwork was used in one building to supply air to the distribution system of each 5- or 10-ton horizontal unit removed.

In other areas of the plant, extensive distribution ductwork was installed where individual, vertical air handlers had been column-mounted with spot cooling. The new ductwork was installed to maintain floor clearances with drops and supplies located where needed to maintain even distribution of air at the work level on the floors.

Insulation of the new ductwork is flexible, external wrap, 2-in. glass fiber and was limited to vertical drops of ductwork from the rooftop air handlers and 10 ft of horizontal duct from the main. With building pressurization control minimizing infiltration of warm humid air from outside and the new air handlers ability to control humidity in the plant, we felt there existed very little potential for moisture condensation on the supply ductwork.

If condensation did occur, those areas of ductwork could be insulated on an as-needed basis. This would save a significant amount of first-cost expenditures where the insulation probably wasn't needed. Distribution ductwork near loading docks and in proximity to large building doors to the outside were insulated. After operating through the summer, no additional insulation was needed. In some instances, condensation formed on the face of the supply diffuser but did not drip on the floor.

The air distribution system design attempted to deliver air to the occupied zone and utilize stratification within the plant, while working around the high bay storage and rack areas. The plant had numerous spot cooling fans; these were left in place to assist with the distribution of air and maintain mixing within the low bay areas and spaces having a high density of workers.

The outside air for the building is brought in at each air handler, approximately 10 percent or 80,000 cfm total for the plant. Exhaust or relief of this air is designed to occur in the oil mist generating areas, thus controlling air movement from clean to dirty areas in the plant.

Controls

The plant utilized direct digital controls (DDC), and each air handler has a stand-alone, local control panel (also known as a programmable control module or PCM). The PCMs are monitored and can be reprogrammed from the central plant controls system.

An ARCNET local area network (LAN) was used to connect the air handler-mounted PCMs through twisted pair wire in a bus configuration. The bus then connects to an ARCNET hub. Two hubs located in the plant collect the LAN bus cable. The loops for the rooftop units feed through twisted pair wire to their respective hubs. The hubs in turn are connected to the central plant through shielded coaxial cable.

Basic alarm reporting functions include filter pressure drop, set point cooling control, leaving air temperature, and fan failure (both filter differential and CTs on the power are monitored and alarmed). The chilled water control valve position is indicated on the air handler graphics along with return air temperature, mixed air temperature, outside air dampers, leaving air temperatures, and fan status.

The air handler cooling coils are split into two equal active coil sections with individual control valves modulating chilled water flow to the coil. The lower coil control valve sequences to full open before the upper coil valve is enabled. This sequence of operation allows full de-humidification from the active coil while the other cooling coil modulates to maintain leaving air set point conditions. This feature is most needed when the outside air temperature is below 85 F and the relative humidity levels are higher than 65 percent. Data from the air handlers are logged at 4 pm every day. Parameters include:

Return air temperature

Mixed air temperature

Discharge air temperature

Control valve output—calling for 75 percent open

Control valve actual position

Alarm status on filters

Data trends record the history of operation and can be referenced when investigating IAQ or comfort complaints from the factory. The trends are inspected and graphed each day. Thus far, graphical comparison has led to the discovery of plugged control valves (debris in lines) and an economizer allowing 100 percent outside air when not called for.

The chilled water control valves sequence or modulate to adjust the leaving air temperature condition based upon return air temperature. A return air thermostat located in each AHU senses the space temperature. Individual space temperature sensors were not installed.

Each air handler will go into economizer mode when its return air temperature is 5 F warmer than the outside air temperature. Each unit modulates the outside air economizer damper to maintain leaving air temperature. As mentioned earlier, no building relief dampers are installed in the units. Relief of the economizer makeup air is accomplished by building fans. The controls system senses building static pressure and activates up to 44 relief fans (totaling up to 400,000 cfm) as required to maintain the building slightly positive with respect to the outside. Existing process systems exhaust 60,000 cfm of air continuously.

Design winter conditions are 23 F outside air temperature. Each unit has a freeze stat protecting the chilled water coil. This shuts off the supply fan and opens the chilled water valves to maintain circulation through the cooling coils. The chilled water distribution piping is on the roof and exposed to the atmosphere.

Air handlers at the end of major pipe loops have three-way control valves installed to maintain minimum pump flow requirements—30 percent of one pump or 650 gpm. This insures that the loop water is kept cold. If the chilled water was not circulated to the end of pipe runs, the water would warm to ambient conditions, require time to cool down, and cycle the pipe through expansion and contraction.

When ambient temperatures drop to below 35 F, one control valve in each air handler opens to 50 percent flow, and the central plant pumps operate to circulate water through the piping system. Whether the air handlers are running or not, the building's heat maintains the chilled water loop by heat transfer from the air through the cooling coils to the water piping loop.

The controls for the variable flow chilled water system are set to maintain a differential pressure of 20 psi across the supply and return chilled water piping. The control sensing points for this pressure are where the pipes leave the central plant and are at two-thirds the distance out into the system. Since water is incompressible, either location should adequately control; however, controls were installed at both locations to test this theory. Also, the controls system will be programmed to adjust pump speed to maintain flow in the system in response to the air handlers' worst case call for chilled water. This could result in additional pump energy savings.

Startup and commissioning of the controls system was performed on the fly. The air handling units and the chiller system were operating wide open, while the controls system hardware and software were being installed. The air handlers were brought on-line as soon as the chilled water piping and power were available. Different areas of the plant were placed on the system as work progressed.

Chilled Water Plant Design

The chilled water plant consists of four 900-ton water-cooled centrifugal chillers, four draw-through cooling towers, four condenser water pumps, and three chilled water primary pumps.

The sizing of the chillers was based upon a 2700-ton plant load, a 500-ton future load in the office areas (to be converted to chilled water at a later date), and 300-ton growth for either manufacturing or data processing. The chiller selection was based upon yearly simulations of load profiles, efficiency versus first cost, and minimizing overall plant kw per ton-hr energy usage.

The design selected is a variable flow, primary pumping system with series flow through two chillers. The design chilled water temperature out of the plant is 40 F supply, 60 F return. Air handler cooling coils were selected with a 20 F temperature drop. This 20 F chilled water temperature design is accomplished by flowing chilled water through two chillers, piped in series. The upstream chiller is designed for a temperature drop of 60 to 49 F, while the downstream chiller is designed for 49 F entering and 40 F leaving temperatures. As indicated in Fig. 1, each chiller can operate independently of the other and can maintain the 20 F temperature drop in the system.

A 10 F chilled water differential through a chiller would require 2.4 gpm flow per ton of cooling capacity. By flowing serially through the chillers, two chillers share this 2.4 gpm and essentially flow 1.2 gpm per ton-hr produced. When one chiller is operating, it can operate at 1.2 gpm per ton and produce the full chilled water temperature drop of 20 F. The chiller evaporators are a two-pass design, which significantly reduces the chilled water pressure drop at maximum and minimum flow. A two-position bypass valve and a two-position isolation valve in the chiller interconnecting piping allows either chiller to operate without flow through the other chiller. State-of-the-art microprocessor controls and their continuous monitoring and adjustment of the chiller operating parameters ensure the reliability of this variable flow design.

The combination of chillers operating in series and variable flow primary pumping will save $50,000 per year in pumping energy costs—compared to a conventional approach utilizing parallel flow, constant volume primary with variable flow secondary, and a 10 F change chilled water temperature. Estimated first-cost savings of $60,000 were realized by not installing primary constant volume pumps to circulate water through the chillers.

The chillers utilize HCFC-123 refrigerant, with the lead chiller efficiency rated at 0.50 kw per ton. The lag chiller is rated at 0.57 kw per ton, with an average efficiency of 0.53 kw per ton when operating in series. The chiller efficiencies are at condenser water temperatures of 85 F entering and 95 F leaving.

As indicated in Fig. 2, the chiller efficiency improves (kw per ton decreases) in the range of 60 to 80 percent load to 0.47 kw per ton for the lead chiller. Further reducing the condenser water to 57.5 F when ambient conditions allow provides a kw per ton efficiency of 0.35 at part-load. The DDC control system is programmed to optimize total plant kw per ton as real-time operating experience with part-load conditions and the availability of colder condenser water from the cooling towers. The lower limit of the condenser water entering temperature for this chiller is 57.5 f.

The building load (chilled water usage and calculated cooling tons required) is measured by a turbine flow meter as the chilled water leaves the central plant. The air handling (load side) flow control is predominately controlled by two-way valves. The plant's cooling load is calculated by measuring gpm flow and temperature differential between the chilled water system's supply and return. The building automation system brings chillers on-line based upon load.

Cooling Tower Design

Four induced-draft, cross-flow cooling towers were installed with two common basins each serving a pair of towers. The towers are constructed entirely of stainless steel with PVC fill. The additional cost of the stainless steel construction was justified based upon life expectancy of the towers matching that of the chiller plant—which is more than 20 years. The tower fans are two-speed, four total. Operation at half speed offers one-eighth power consumption with 50 percent heat rejection capacity.

Four centrifugal pumps serve the towers in constant volume fashion through a common piping header; the pumps were sized for each chiller's condenser water flow. A condenser water pump is activated as each chiller is started. When only one or two pumps are running (one or two chillers needed), the distribution supply to the third and fourth set of tower cells is isolated, and flow from one or two condenser pumps is restricted to the first two (of four) cooling tower hot decks.

Chilled Water Pumping

Three primary variable volume chilled water pumps perform the chilled water pumping. One pump operates per pair of chillers; the third is a standby pump. A variable speed drive on each pump varies the flow through the chillers from 100 to 50 percent based upon the pressure differential measured in the supply and return chiller piping system.

The chilled water distribution system is mounted on the roof, varying in size from 16 to 6 in. diameter, and totals 1.1 miles of pipe. The longest straight run of pipe is 600 ft in length. The building's pipe and water mass require 1000 ton-hr of chilled water to cool down to operating temperature. The system contains 8600 gal of water in the piping.

All of the distribution piping was installed on the roof, and the runs are supported at 15 ft on center. Pipe chosen was Schedule 30 steel. The piping was mounted on the roof to avoid working within the plant and interfering with plant operations. Additionally, the rooftop enabled easy access for installation. Working on the flat roof instead of 60 ft high scaffolding increased productivity significantly and reduced trade-labor costs for pipe fitters, insulators, and riggers.

Piping design challenges included mounting 40 F chilled water piping on the roof in a hot, humid climate and managing expansion and contraction of piping from ambient temperatures that could reach 110 F when the water was not circulated through the chillers and cooled to 40 F.

Various pipe-joining methods were evaluated: welding, mechanical pipe grooves, flanged, and rolled grooves with lighter wall pipe. Welding pipe on the roof was discounted because it was labor-intensive, could damage the roof membrane, and posed a fire threat to the roof insulation. Rolled groove pipe joint did not have the pull-apart resistance provided by the cut groove joints. Flanged joints offered no benefit over other methods of pipe joining while significantly increasing the labor and material costs.

Mechanical pipe grooves were chosen due to ease of installation, pre-fabrication at grade, pull-apart resistance, and the joints' ability to sustain 1/8 in. pipe movement per joint. Movement occurs as contraction when chilled water cools the pipe. With random-length pipes averaging 21 ft in length, the required movement per joint was 1/16 in., resulting in a safety factor of two. The pipe essentially free floats on the roof, with lateral movement restrained by the pipe supports and linear contraction/expansion of the pipe accommodated at each pipe joint. The existing structure did not have the capacity to restrain pipe movement resulting from a 600 ft length of pipe, if welded joints were used.

Cellular glass rigid pipe insulation with an aluminum jacket was chosen over less expensive glass fiber insulation and PVC jacketing. This system cost an additional $50,000. The performance of the system over the life of the installation, however, was the major consideration. Other deciding factors were:

The vapor barrier provided by the closed cell rigid insulation, which is essentially continuous through the depth or thickness of the insulation.

The rigidity of the insulation as a backer for the aluminum jacket provides greater resistance to mechanical damage.

The weathering characteristics (longer life) of aluminum jacketing versus PVC jacketing.

Energy Performance

The design of this project anticipated a reduction in cooling energy from 2.2 to 1.1 kw per ton-hr. The chiller plant was brought on line in the middle of May 1998, while the work progressed with the full-plant cooling,

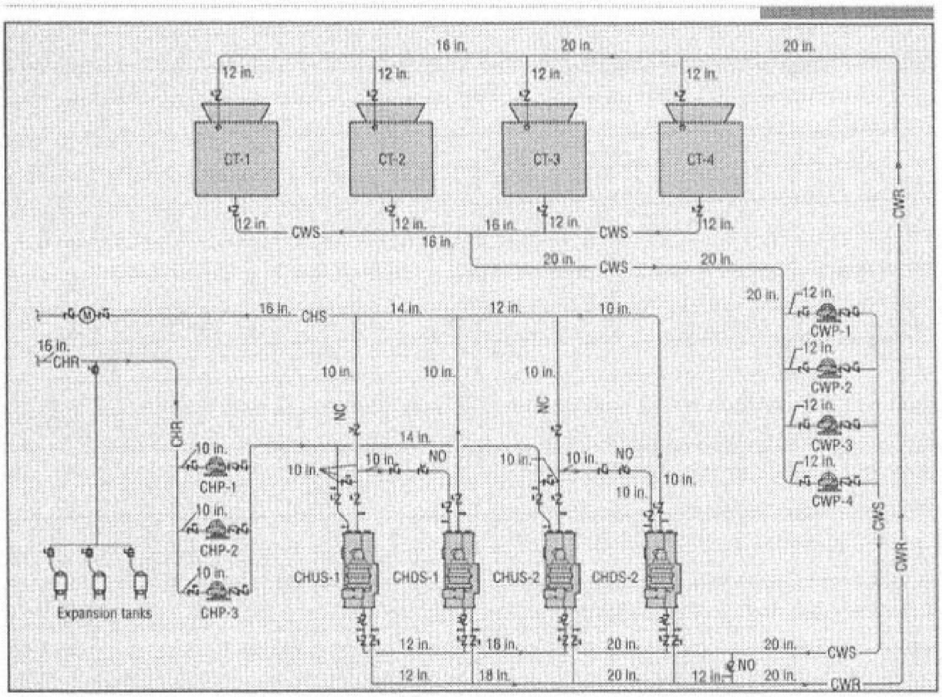

Figure 1
Schematic Diagram of Chilled Water Flow through Chillers.

which was completed by the end of June. This summer was the second hottest Texas summer on record, during which the chiller plant operated on two chillers until mid-morning when a third was required on line. The maximum cooling tonnage was measured at 2200 tons, which occurred in mid-afternoon. Evaluation of the actual energy savings versus the anticipated savings has not been completed yet. It will be difficult to quantify the actual savings because the level of comfort, i.e., temperature control in the plant, has improved significantly, in addition to the indoor air quality.

Summary

The environmental comfort and indoor air quality of the plant were noticeably improved over the performance of the system replaced. Savings of electrical energy are anticipated to be approximately $800,000 per year. And, with utility company incentives, the investment should be paid back in less than 10 years.

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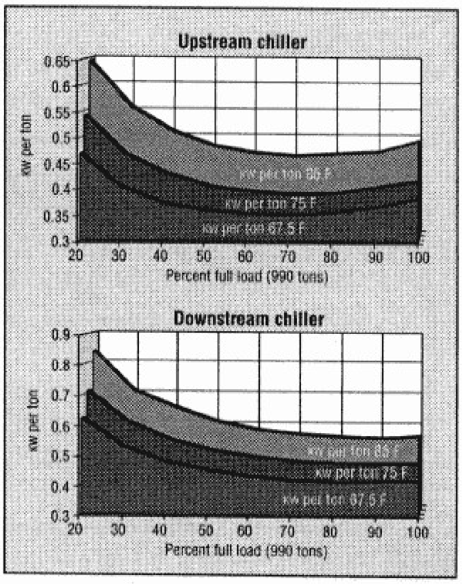

Figure 2
Chiller Efficiencies At Lower Condenser Water Temperatures for
Upstream and Downstream Chillers under Part-Load Conditions.

Chapter 30— Naval Hospital Retrofit for Comfort, Control, and Energy Efficiency

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Abstract

A project to replace the HVAC control systems of a large US Navy hospital in Southern California with new digital controls is currently in the early stages of construction. The project is part of the hospital's plan to minimize energy consumption, optimize its HVAC equipment and systems, and reduce operating costs. The HVAC controls upgrade project design also included automation and monitoring of the operations of the central steam and cogeneration power plant serving the facility as well as planning for testing and balancing to minimize disruption of hospital operations through the phased implementation of the control system renovations. The project is part of the Navy's multi-base, area-wide energy management initiative.

Outline

Introduction

The Need to Reduce Energy Consumption and Operating Costs

The Need to Replace HVAC Controls

Challenges of Renovations in a Hospital During Ongoing Operations

Hospital-specific HVAC Controls and Monitoring

Energy Management System Procurement

Conclusion

Introduction

The US Navy, a major presence in the San Diego area, has embarked on a challenging program, which is led by the Public Works Center to implement a multi-base, area-wide Energy Management Systems (EMS) program in San Diego. The objectives of the program entail centralizing utility monitoring, minimizing energy consumption, and optimizing the use of a reduced labor force for operation and maintenance. This presentation will describe a part of this effort: replacing the heating, ventilating, and air conditioning (HVAC) control systems at the Naval Medical Center with new digital controls and Energy Management.

The Need to Reduce Energy Consumption and Operating Costs

The Naval Medical Center in San Diego is the largest military medical facility in the world. The multi-building facility, with well over one million square feet, was completed in the mid-1980s. Increasing pressure in the military to reduce costs led to the reduction of operating personnel and the outsourcing of the maintenance activities at this facility.

The hospital was designed with pneumatic central and terminal HVAC controls and with limited centralized equipment monitoring.

The central utility, co-generation plant (see Figure 1) provides all the building utilities for the hospital as well as a portion of the electric power requirements. (Five years ago the hospital was purchasing only 60–75% of its electricity.) The central chiller plant consists of three 850-ton chillers, two of which are centrifugal type and the third is a steam absorption unit used for base loading. Each of the plant's three gas-fired 800 kW turbine generators has a dedicated 6000 lb/hr heat recovery boiler. The steam from the heat recovery boilers is used primarily to run the absorption chiller. The plant has plans to replace one of the centrifugal chillers with a second absorption unit. There are also three dual-fuel, fire tube boilers, each with a design capacity of 17,500 lb/hr, one utilized year round.

The central plant was originally designed with a computer monitoring system to calculate the thermal efficiency of the steam/electric co-generation system. Unfortunately, the system subcontractor went out of business during the final stages of construction as the programming was being completed, and the energy management system software was never implemented. The operation of the central plant chilled water, steam generation, electrical cogeneration, hospital central utilities and systems, and the plant performance (efficiency) calculations, required for the Federal Energy Regulatory Commission's (FERC) Co-generation Facility Qualification, have therefore been performed manually since the beginning of plant operations.

In 1995, Public Works Center commissioned an operational study of the medical facility's HVAC systems as part of the plans to extend the Navy's San Diego area-wide EMS to the hospital. The study found that the most of the 69 supply air fans (and associated return and exhaust fans) were running continuously without any automated or manual setback, delivering over 1.2 million cubic feet per minute of conditioned air into the medical facility. This single finding was the major justification for an EMS to schedule equipment operation.

The study also found other justifications for central plant operations monitoring such as the fact that all the steam condensate returns to the central plant was being dumped because of contamination. The study recommended installing conductivity cells at the points of steam condensate collection in the hospital to try to isolate contamination sources early. Another energy-related finding was that the economizer controls of most supply of air systems were not operating.

One of the emphases of the study was to clearly identify energy-related from non-energy-related savings associated with the replacement of HVAC controls with a direct digital control (DDC) system.

Non-energy related savings would result from cost avoidance by better monitoring of equipment operation through the installation of vibration sensors for fans and motors, monitoring of the instrument air supply to HVAC controllers, and filter-loading monitoring. Monitoring of the electrical substations and associated switchgear also fell in this category. A life-cost analysis was performed using the energy- and non-energy-related recommendations presented, and, after applying a savings-to-investment-ratio limit provided by the Navy, the project to design a new EMS and the replacement of HVAC controls began.

The Need to Replace HVAC Controls

As part of the EMS design, a survey of the existing conditions of the variable air volume (VAV) systems was also conducted.

The survey found that none of the 300 VAV air terminal boxes (out of a total of 1,450 VAV boxes in the entire hospital) was operating within their original design parameters. The Navy therefore decided to include the replacement of the pneumatic terminal controls with new DDC controllers. The hospital facilities personnel's indication that the pneumatic controllers on the air handling fans were not operating as specified resulted in the decision to replace the central HVAC controls in addition to the planned EMS HVAC equipment monitoring and control functions. New air monitoring stations will be installed to improve the flow tracking ability of the central variable air systems.

The VAV air terminal box study also recommended the replacement of existing central VAV fan inlet vane controls on critical air handlers with variable speed drives. This recommendation was in line with the results of an independent energy audit performed by the San Diego electric utility.

Once the scope of the HVAC control renovation project design was accepted based on a favorable payback period (the simple payback for the VAV box controls alone is under two years), the most challenging phase of the design got underway. This entailed planning a phased renovation of the ventilation and environmental controls on this fully operational medical facility to minimize operational disruptions.

Challenges of Renovations in a Hospital During Ongoing Operations

The challenge of scheduling the HVAC control renovations with the more than 100 departments at the hospital was coordinated by the facility operations engineers with hospital administrators. Floor plans were prepared showing all areas and references to their associated HVAC equipment (see Figure 2).

Renovation schedules were also prepared for all areas (see Figure 3). The schedules differentiated between testing and balancing and commissioning activities. Equipment data tables were also prepared listing each HVAC piece of equipment and their associated areas served, type of equipment, and references to specified commissioning procedures (see Figure 4).

It is expected that by the time of the actual renovation work, there will be modifications to the renovation schedules due to area and department reassignments. But the format will be valuable to the successful implementation with minimum disruptions to medical activities.

Hospital-Specific HVAC Controls and Monitoring

A critical item in the operation of hospital HVAC was identified by facilities personnel as maintaining pressurization in specific rooms for patient isolation. Post-operation isolation requires the room to be positive to its surrounding spaces while infectious isolation requires the room to be negative to the surroundings.

The original hospital design made provisions for turning isolation rooms from positively to negatively pressurized and vice versa. At the time of the EMS design survey, however, these pneumatic controls were abandoned and the rooms were fixed in one mode. Facilities and medical personnel identified specific isolation rounds, all with buffer zone air locks, and differential pressure sensors were included in the design (see Figure 5). The EMS design included local alarm panels at nursing stations. The users can only change the pressurization mode by modifying the air terminal box controllers CFM setpoints.

Another requirement specific to the operation of the hospital was the need for monitoring medical central utilities, such as the vacuum and compressed air systems, for medical and dental use. The EMS design also included alarms for domestic, hot water and drinking water systems.

Energy Management System Procurement

The EMS configuration is shown in Figure 6. The system will consist of stand-alone digital controllers performing specific control functions but tied into a dedicated EMS local area network (LAN). The data transmission media for the LAN will be fiber optic cable. The fiber optic cable will run through ductbanks for the high voltage power distribution between buildings.

The EMS design integrated the hospital supervisory monitoring and control functions into the existing power plant control room. The EMS central monitoring and control server for the hospital will be connected to the Navy San Diego EMS area-wide network using existing high-speed communication lines between naval facilities.

A challenging issue in the development of the procurement specification for the EMS was the need to include realistic performance and experience requirements in order to prevent the fate of the original central plant EMS and, at the same time, maintain an open, competitive environment. As a result, the contract was awarded to an experienced nationally known HVAC control system supplier with a large and stable presence in the San Diego area. The system was procured with the assistance of the local electric utility company.

Conclusion

The system under construction covers only the core hospital buildings. The Navy will procure the EMS for the central plant under a separate contract and will use PLC hardware and EMS software specifically designed for power plant operations. The operating sequences included in the EMS design for central plant equipment and systems were derived from interviews of operating personnel and have captured years of specific operating experience for this facility.

The EMS design has provided the Navy with a clear definition of the functions that should be automated and monitored to successfully operate this large and complex facility with a reduced labor force and to meet the challenges of energy usage optimization and operational readiness.

About the Author

Mr. Rios has more than 20 years of experience in the design of automation, instrumentation, and control systems for pharmaceutical, biotechnology, and laboratory facilities. His background encompasses the design, technical evaluation, configuration, start-up and system validation support of industrial process control systems as well as utilities and building automation systems. He has also been involved in the design and engineering of facility energy management and control systems and SCADA systems for electric utilities, mass transit and campus utility distribution applications.

At Kling Lindquist, he is responsible for the development of HVAC building automation and control system design and interfacing with other engineering disciplines to integrate HVAC systems with facility design.

Mr. Rios is a registered Professional Engineer in Pennsylvania. He holds a Bachelor of Science degree in Mechanical Engineering from Northeastern University and a Master of Science degree in Engineering Management from Drexel University.

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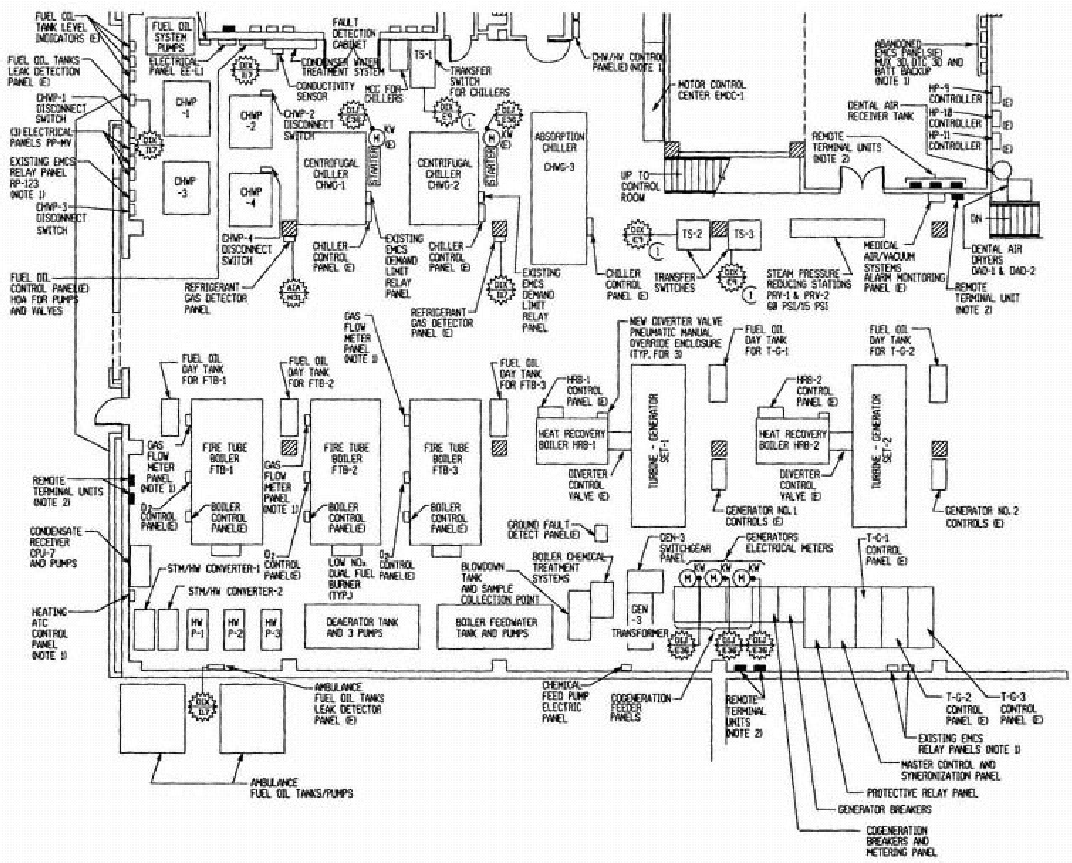

Figure 1
Central Plant Layout

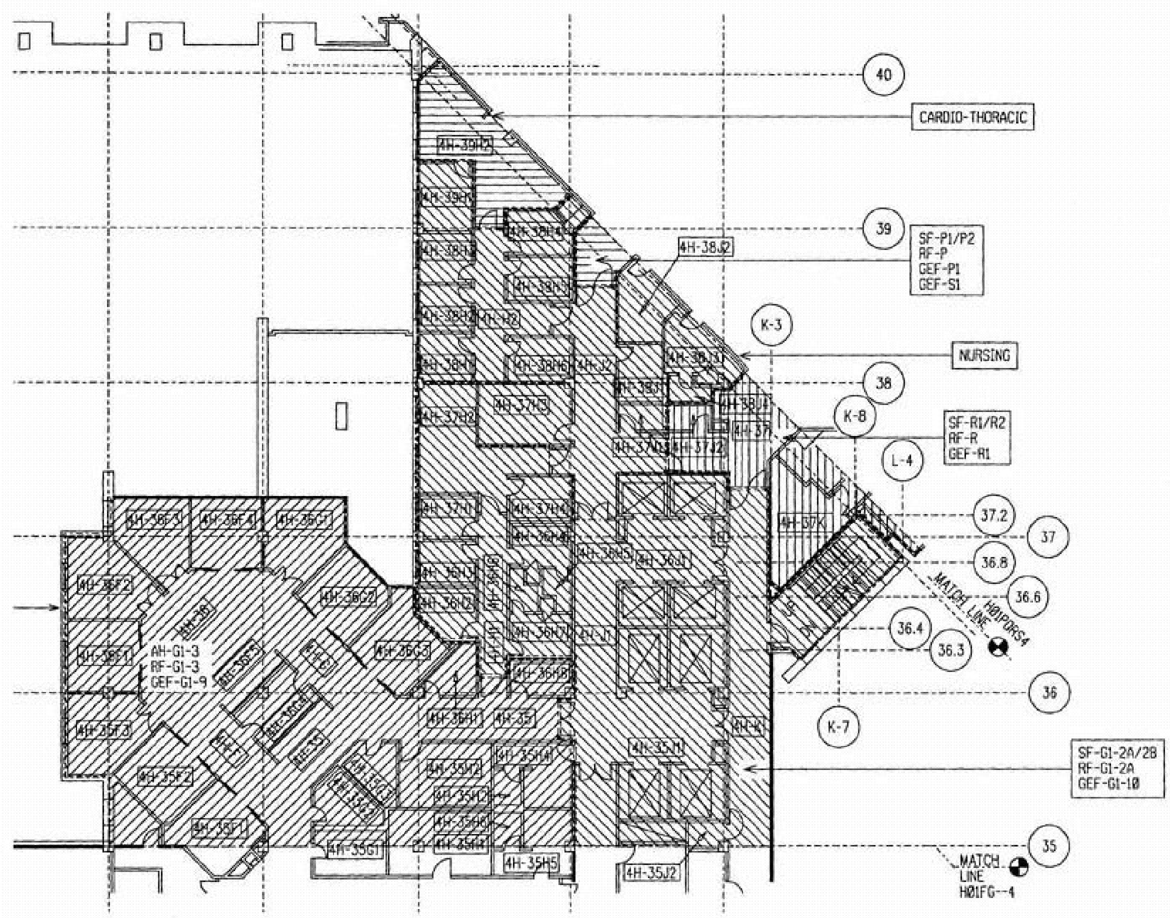

Figure 2
Typical Testing and Balancing Floor Plan

HOURLY SCHEDULE

DEPARTMENT NAME	OPERATIONAL HOURS		AVAILABLE WORK HOURS																							
			0100	0200	0300	0400	0500	0600	0700	0800	0900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400
(CID) CLINICAL INVESTIGATION	1600-0700	TAB							0700--									1600								
		COMM							0700													2000--				
MATERIAL MANAGEMENT	1600-0700	TAB							0700--									1600								
		COMM							0700													2000--				
(CID) NAVY EXCHANGE	1600-0700	TAB							0700--									1600								
		COMM							0700													2000--				
YMCA	1600-0700	TAB							0700--									1600								
		COMM							0700													2000--				
RED CROSS	1600-0700	TAB							0700--									1600								
		COMM							0700													2000--				
MORGUE		TAB																								
		COMM																								
VOLUNTEER FUNCTIONS		TAB																								
		COMM																								
MacDONALD'S		TAB																								
		COMM																								
PATIO		TAB																								
		COMM																								
SUPPLY CLERKS		TAB																								
		COMM																								
MEDICAL PHOTOGRAPHY		TAB																								
		COMM																								

THIS SCHEDULE IS PREPARED FOR INFORMATION ONLY.
WORK SCHEDULE TO BE SUBMITTED BY THE CONTRACTOR, APPROVED AND COORDINATED BY THE GOVERNMENT.

Figure 3
Tab/Commissioning Work Schedule

EQUIPMENT DATA			
EQUIPMENT INDENTIFICATION	OTHER AREAS SERVED - SEE DWG. REFERENCED	TYPE OF EQUIPMENT	COMMISSIONING REF. SECTION 15995 AND APPENDICES AS NOTED
SF-E1-1A/1B RF-E1-1A	HØ1DE--G HØ1DE--1 HØ1DE--2 HØ1FGN-1 HØ1FG--2	AIR HANDLING UNIT	A.4 AND B.4
GEF-E1-6	HØ1DE--G HØ1DE--1 HØ1DE--2 HØ1FGN-1 HØ1FG--2	EXHAUST FAN	A.1Ø AND B.1Ø
GEF-E1-7 GEF-E1-8	HØ1DE--G	EXHAUST FAN	A.1Ø AND B.1Ø
SF-E1-3A/3B RF-E1-3A	HØ1DE--G HØ1FGN-1 HØ1DE--1 HØ1FG--2 HØ1DE--2 HØ1FG--4 HØ1DE--4	AIR HANDLING UNIT	A.4 AND B.4
GEF-E1-1Ø	HØ1DE--G HØ1FGN-1 HØ1DE--1 HØ1FG--2 HØ1DE--2 HØ1FG--4 HØ1DE--4	EXHAUST FAN	A.1Ø AND B.1Ø
SF-G1-1A/1B RF-G1-1A	HØ1FG--2 HØ1FG--3 HØ1FG--4 HØ1H---G HØ1H---2	AIR HANDLING UNIT	A.4 AND B.4
FEF-G1-2 FEF-G1-4 FEF-G1-5 FEF-G1-6 GEF-G1-5 GEF-G1-6 GEF-G1-7	HØ1H---G	EXHAUST FAN	A.1Ø AND B.1Ø
GEF-G1-8	HØ1FG--2 HØ1FG--3 HØ1FG--4 HØ1H---G HØ1H---2	EXHAUST FAN	A.1Ø AND B.1Ø
SF-G1-2A/2B RF-G1-2A	HØ1S---G HØ1FG--3 HØ1PQRS1 HØ1FG--4 HØ1PQRS2 HØ1H---G HØ1PQRS3 HØ1H---1 HØ1PQRS4 HØ1H---2 HØ1PQRS5 HØ1H---3 HØ1FGN-1 HØ1H---4 HØ1FG--2 HØ1H---5	AIR HANDLING UNIT	A.4 AND B.4
GEF-G1-1Ø	HØ1S---G HØ1FG--3 HØ1PQRS1 HØ1FG--4 HØ1PQRS2 HØ1H---G HØ1PQRS3 HØ1H---1 HØ1PQRS4 HØ1H---2 HØ1FGN-1 HØ1H---3 HØ1FG--2 HØ1H---4	EXHAUST FAN	A.1Ø AND B.1Ø
KEF-PRG-1	HØ1H---G	EXHAUST FAN	A.1Ø AND B.1Ø
AH-GG-1		AIR HANDLING UNIT	A.3 AND B.3
FEF-G1-1		EXHAUST FAN	A.1Ø AND B.1Ø
CPU-6		CONDENSATE PUMP	A.12 AND B.12

Figure 4
Testing and Balance Equipment Data

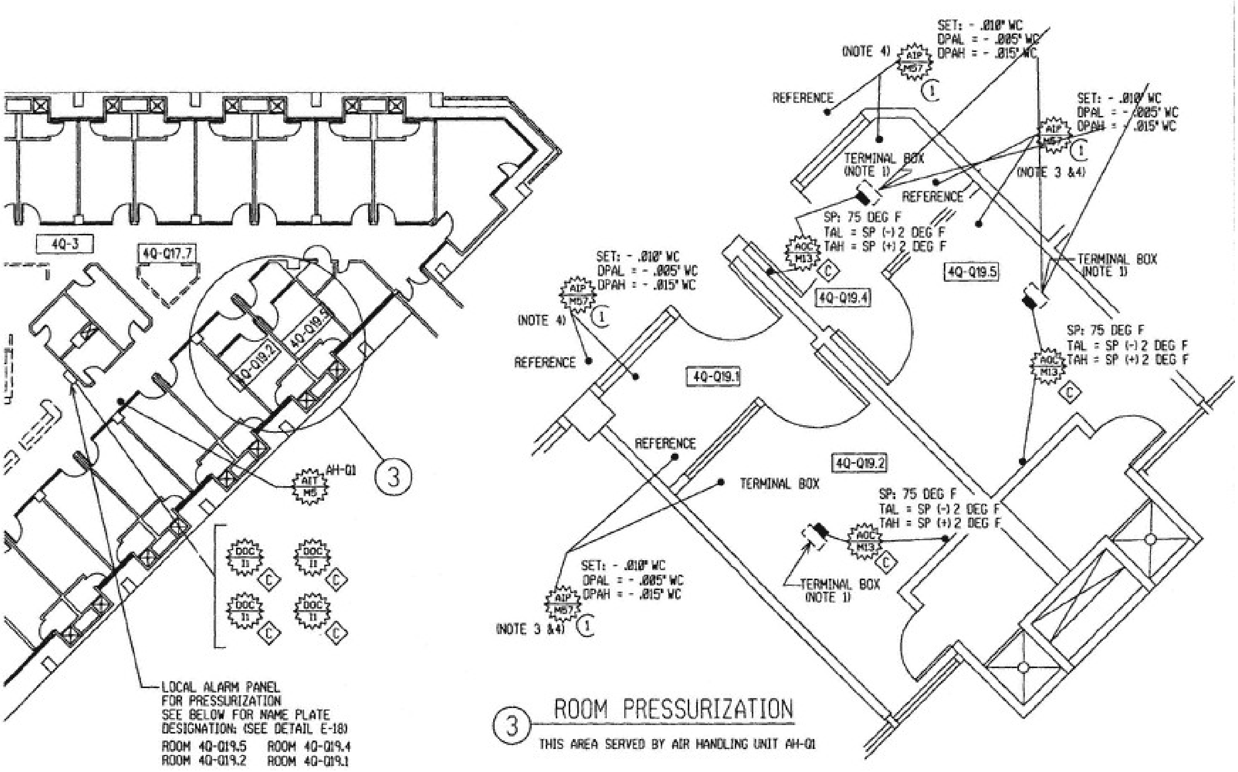

Figure 5
Isolation Room Hvac Control Renovations

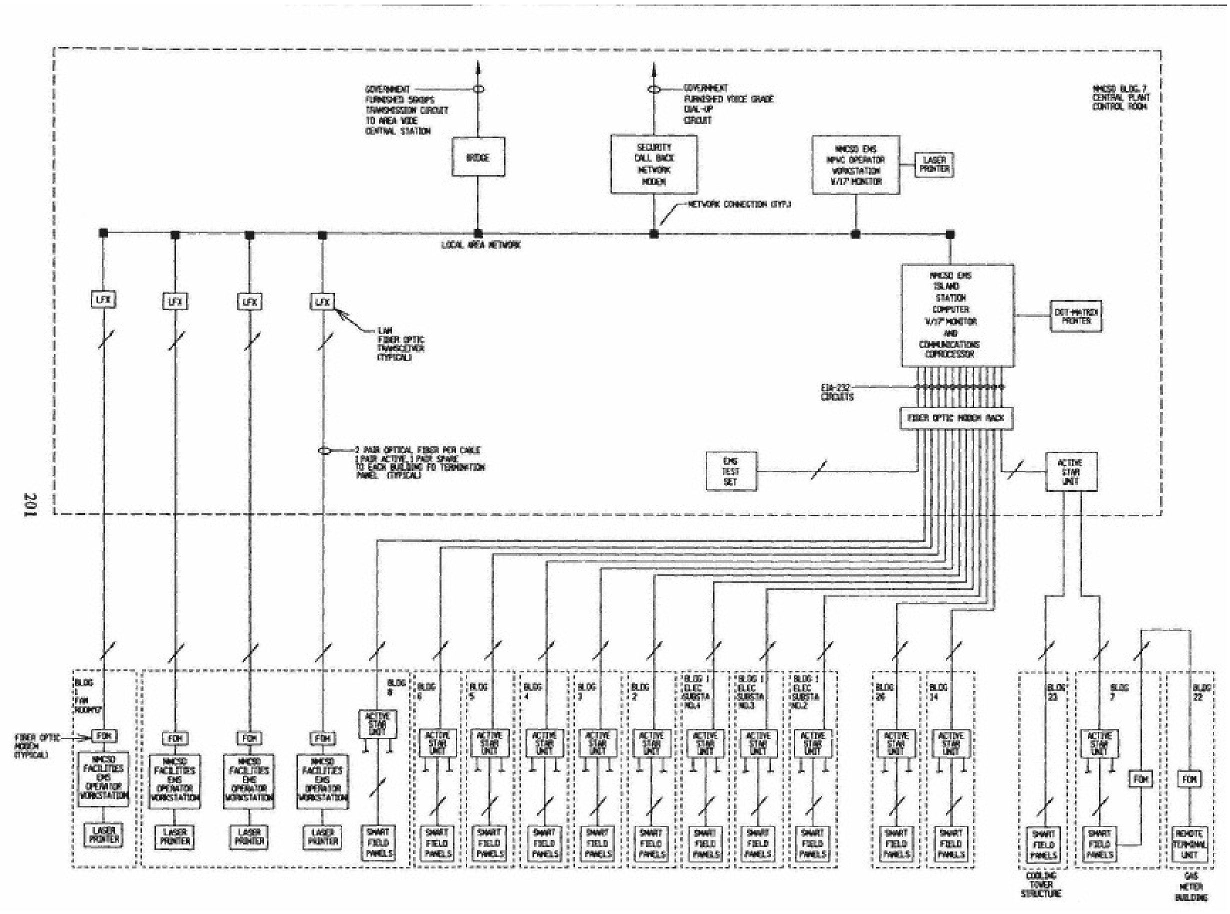

Figure 6
Ems Network Diagram

Chapter 31—
Reducing Electrical Utility Costs with Thermal Energy Storage

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Abstract

The electric utility rate structure for most commercial buildings include three components. One of these components is a charge for electric power demand. In the summer, the demand charge can be more than half of the total monthly energy cost. If the peak electric power demand is reduced at a facility, the electric utility costs will be reduced dramatically. This can be accomplished with thermal energy storage.

Thermal energy storage is a load shifting technique that operates the cooling equipment during low power demand periods. The stored cooling is then used when the facility is approaching the peak electric power demand for the billing month. Partial storage can be used to lower the peak power demand by allowing some of the cooling equipment to be shut off. Full storage may provide additional savings by turning all of the cooling equipment off.

There are two basic types of thermal energy storage in use today. Chilled water storage involves a large tank connected into the chilled water distribution system. Ice storage demands much less space for tanks but requires a more complicated control system and specialized equipment.

Designing a cooling system that includes thermal energy storage increases the possible configurations to consider. Selecting the most economical proportions of cooling equipment capacity and storage size requires knowledge of the peak cooling load and the building cooling load profile. An energy analysis can be done to determine the most economical system.

This paper addresses the energy cost advantages of thermal chilled water storage, types of thermal energy storage, sizing methods, and other design considerations. The available choices for thermal energy storage are explained including the benefits and disadvantages of each.

Electrical Rate Structures

Most commercial rate structures have three basic components:

Customer Charge or Meter Charge: Constant monthly charge.

Consumption Charge: Charge for consumption of energy (per kWh)

Power Demand Charge: Charge for the peak power demand (per kW peak per month).

Although many rate structures are more complicated with varying consumption rates and ratchets, most rate structures can be modeled by the energy engineer with these three basic elements.

An occasional rate structure includes time-of-use rates or seasonal rate changes. With time-of-use rate structures, the utility company is attempting to discourage the use of energy or a high peak demand during the times when the utility is at its peak. With seasonal rate structures, where the consumption rate is lower in the winter months, the utility is attempting to encourage the use of electricity for comfort heating.

For the energy engineer to determine the economical feasibility of an energy conservation measure (ECM), the consumption and demand charges must be known. The ECM will not effect any monthly customer chares and only the incremental decrease in electrical energy cost is needed to determine the savings.

Peak Power Demand

For many facilities, the peak power demand charges contribute to a large portion of the annual energy costs. For these facilities, reducing the monthly peak demand can result in significant reduction in the annual energy costs.

To provide an example of the cost contribution of power demand on the electrical energy costs, the energy profile and cost for a facility will be used. This facility is an office building located in the northeastern United States. The building is open during normal weekday business hours and parts of the building are occupied on the weekend.

Since the building is unoccupied at night and during most of the weekends, the lights and HVAC electrical consumption is reduced except during the weekday business hours.

As you will see in figure 1, the summer electrical power demand profile indicates a large disparity between day and night. In the winter months, the interior zone cooling load is met with an air side economizer and the afternoon peak is not as significant.

The utility rate structure for the facility contains an incremental energy consumption charge of $0.034 per kWh. There is also a monthly charge for demand of $18.34 per kW of peak power demand. There is no ratchet clause or time-of-use schedule.

Generally speaking, the consumption charge is average for this type of facility. However, the charge for peak power demand is higher than in most areas of the country.

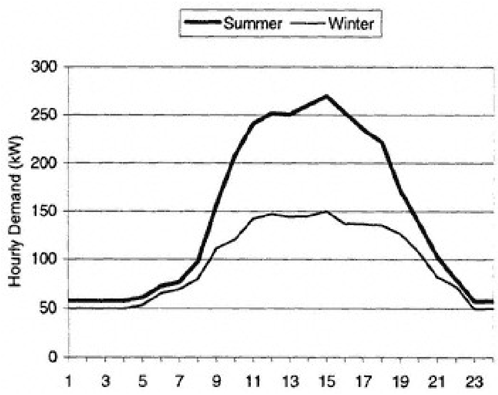

Figure 1
Electrical Demand Profile

As deregulation of the electric power industry comes into existence, the utility companies will be competing for the customers that have a level load profile. Since this facility has such a high peak power demand relative to the consumption, electric providers will be less willing to compete to serve this customer. Thermal energy storage can be used to lower the peak power demand, reduce the annual electrical energy cost, and position the owner for obtaining a more favorable rate structure in the future.

Thermal Storage

Thermal energy storage presents an opportunity to level the power demand profile by shifting the power load. This is accomplished by operating all or part of the cooling systems (or heating systems) during the off-peak hours and storing the cooling capacity for use when the building is approaching the month's peak power demand.

There are two approaches to sizing thermal energy storage systems:

Partial Storage: The stored cooling is used to supplement the cooling equipment during the peak periods. The cooling equipment is either under-sized or not run at full capacity.

Full Storage: The cooling equipment is shut off during the peak periods and the cooling load is fully met from storage.

To determine the most cost-effective thermal energy storage ECM, an energy and economic analysis of each should be accomplished. There are several considerations that should be considered before proceeding:

1. Will the existing cooling equipment be utilized?

An old centrifugal chiller is probably not capable of generating the low temperature water that is required to build ice for storage. However, old centrifugal chillers can be operated at their peak efficiency at all times if chilled water storage is used. Also, since the cooling equipment operation is being moved off-peak, the economic benefits replacing old equipment with high-efficiency equipment are reduced.

The primary operating time for the cooling equipment will be moved to times when the ambient conditions are cooler. With the decrease in cooling tower or condenser fan energy and lower compressor lift, the overall energy efficiency for both air-cooled and water-cooled equipment.

2. Is the cooling plant required to be sized for the maximum cooling demand?

For new construction or cooling equipment replacements, the installed equipment can be sized to the daily load and not the peak cooling load. The peak summer cooling demand, which may only occur one day per year, can be met by the thermal energy storage. For example, 50 tons from the chiller and 50 tons from storage can cool a building with a 100-ton peak load. The 50-ton chiller will then operate all hours to meet the off-peak cooling requirements and replenish the storage.

3. Is physical space available for the energy storage?

If space is limited, partial storage may only be possible or storage may be limited to sensible plus latent storage.

4. Is an alternative fuel a better choice than thermal storage to reduce electric power demand?

If the cost of natural gas is low, absorption or an engine driven centrifugal may be a better alternative for reducing the peak power demand. Also, a hybrid plant which uses electric source cooling during off-peak and gas source cooling during the day can reduce the electric power demand peak. This approach can be analyzed as an alternate energy conservation measure.

Sizing Thermal Storage

The cooling load profile for one day during the summer needs to be determined to begin the sizing of the storage. This can be obtained by measurement or can be estimated from computer modeling.

If there is an existing energy management system within the facility, the cooling plant delivery may have been monitored during the latest peak cooling period. In most facilities, the highest cooling load of the facility is less than the installed cooling capacity so the existing equipment size should not be used as a short cut to proper sizing.

For older facilities built before the information age when personal computers were not prevalent, the maximum cooling requirements of the facility may be greater than the installed capacity. Be careful not to underestimate capability of a new cooling system to provide adequate cooling which the facility has not had before. This may eliminate all of the projected savings.

If no cooling load profile is available, a computer model of the facility can be created to estimate the daily cooling load profile. There are several modeling programs in use throughout the industry that can be used. Develop the model for the existing equipment and calibrate using historical energy data.

In the previously described example, the building cooling load profile was estimated using a computer model. Several other ECMs were being considered for the building and the profile after implementation of other ECMs was used for the thermal energy storage calculations. The summer and autumn cooling load profiles are presented in figure 2.

Once the load profile is determined, the peak cooling load and daily cooling requirements can be used to determine the minimum storage size and cooling equipment size. (Of course, the actual size installed should be above this size.)

Partial Thermal Storage

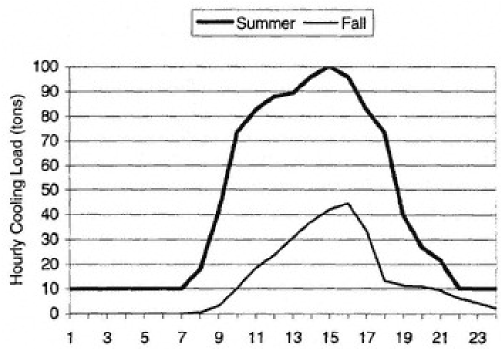

Figure 2
Cooling Load Profile

For partial thermal energy storage, the cooling equipment is sized to run 24-hours a day at full capacity during the peak summer day.

$$q = \frac{Q\text{, ton-hours/day}}{24\text{, hrs/day}}\text{, tons}$$

q = Cooling Equipment Capacity
Q = Peak Summer Daily Load

With this equipment size, the cooling equipment will operate at full capacity all day. When the building load is less than the cooling capacity, the excess will be stored. When the building load requirement is above the cooling capacity, the balance is drawn from the storage.

To determine the amount of storage required, the profile must be used. Several iterations may be necessary to obtain the minimum size that will meet the peak cooling load and allow enough excess cooling capacity to replenish the storage.

In this simplified example, the cooling equipment is sized to run continuously throughout the day and night during the peak cooling of the summer. The storage is sized to supplement the cooling equipment and meet the peak load in the afternoon. The storage is then replenished during the evening and night.

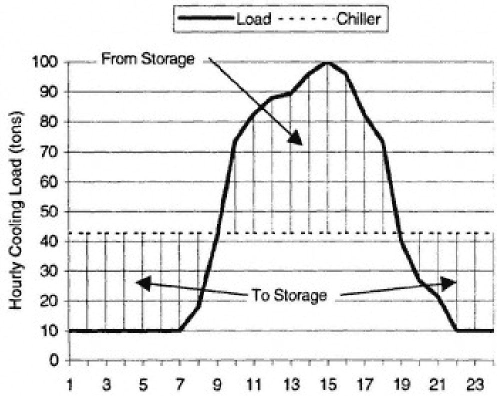

Figure 3
Partial Storage Profile

As shown in figure 3, the example office building is an excellent candidate for partial thermal energy storage. The cooling equipment capacity during the peak of the summer can be reduced to 43 tons when the peak cooling demand is 100 tons. The cooling system contribution to the monthly electrical demand charge will be significantly reduced.

The thermal energy storage capacity required is determined by the amount of cooling load shifted to off-peak times. For this example, 402 ton-hours of thermal energy storage are required to meet the peak summer cooling requirements.

To determine the annual energy cost savings, all months of the year need to be considered individually. During the months when the cooling load is less than the annual peak, the storage will be replenished before early morning. Since the afternoon load will be less than in the peak of summer, much more of the cooling load can be burdened on the storage capacity. However, during the winter months when the cooling equipment is not utilized, there will be no savings from thermal energy storage.

Full Thermal Storage

Since the example office building has such a drastic peak cooling demand load profile, the opportunity to completely eliminate the cooling equipment contribution to the monthly demand peak is possible. This can be accomplished by shifting the entire cooling production to the off-peak hours with full thermal energy storage.

To determine the needed capacity for the cooling equipment and the storage requirements for full thermal energy storage requires knowledge of the electrical power demand profile and the cooling equipment's contribution. For the office building, a breakdown of the electric power demand profile was determined from the computer model and is shown in figure 4. Full thermal energy storage will be used to eliminate the cooling equipment power from the monthly electric power demand.

To take full advantage of the thermal energy storage, the cooling equipment needs to be shut down or limited when the building is approaching the peak power demand for the month. During the occupied hours when the lights and fans are operating, as shown on figure 2, the total cooling requirements are 625 ton-hours. Therefore, this is the requirement for the storage capacity.

The cooling equipment needs to generate the entire days cooling during the hours when the lights and fans are off. From figure 2, the entire peak day uses 1029 ton-hours. The cooling equipment will operate between 9:00 p.m. and 6:00 a.m., 9 hours, at full load to replenish the storage and meet the night load. Also, there is no time-of-use schedule in the rate structure so the operation of the chiller in the off-hours may cause a demand peak.

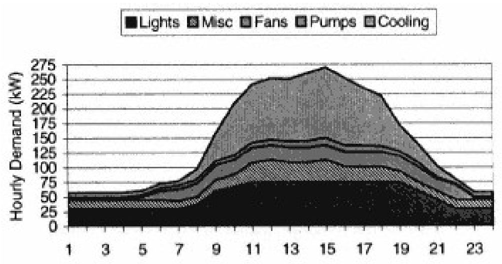

Figure 4
Baseline Electrical Demand

Several iterations will be necessary to estimate the optimum size of the chiller.

Using these values, the new electric power demand profile can be regenerated. Assumptions should be made of the full load efficiency of the chiller during the hours of operation and the storage temperature being used. Figure 5 shows the electrical demand profile after thermal energy storage.

This example is for a 90-ton chiller with capabilities for demand limiting. A direct digital control system should also be included to monitor the building power demand peak and limit the chiller power to avoid setting the peak demand for the month.

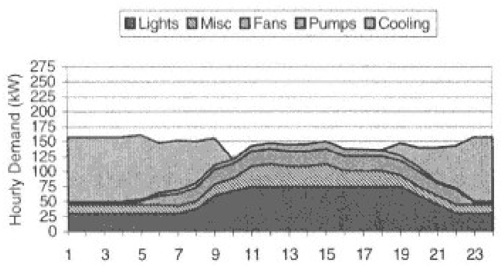

Figure 5
Partial Storage Electrical Demand

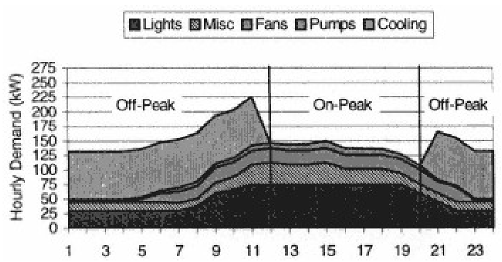

Figure 6
Time-of-use Demand

As you can see, the peak power demand is reduced from 270 kW to 161 kW during the peak summer month. Of course, the savings for the other months of the year will not be as high since the existing chiller contribution is not as much. For savings estimating purposes, the peak power demand of the remaining months of the year will be no higher than 161 kW (unless winter heat is electric).

If the rate structure includes time-of-use or a time-of-use rate structure is available, the installed chiller capacity can be smaller. For the example building, the time-of-use structure allowed for peak power demand recording from noon to 9 p.m. during the summer months. This allows the chiller to operate at full load during the off-peak hours without demand limiting.

Figure 6 shows the demand profile for the time-of-use application. The billed peak power demand is recorded in the afternoon only and is reduced to 150 kW. The chiller capacity is also reduced to 70 tons.

Since the storage is now only required during the on-peak times, the storage size is reduced from 943 ton-hours to 661 ton-hours for full storage capacity and a time-of-use rate schedule.

Thermal Energy Storage Types

There are several manufacturers that market thermal energy storage equipment for the commercial and industrial HVAC industry. The types of thermal storage can be classified as two types:

1. Sensible Only: Thermal storage is stored as sensible heat only.

2. Sensible and Latent: The medium, typically water, is frozen and melted during the storage process. The latent heat from the phase to minimize the physical storage size.

The type of thermal energy storage that is best for the facility can be determined by looking back to the original questions. If the existing cooling equipment is going to be utilized, the equipment may not be capable of generating the low temperatures required for latent storage. If physical size of the storage is a concern, utilizing sensible and latent storage may be the only option.

Sensible Only Energy Storage

The simplest thermal energy storage configuration is when sensible only storage is used. This is typically accomplished by storing chilled water at the normal operating temperature. The control system complexity is also not a concern since adding thermal energy storage can be accomplished without drastically changing and complicating the control system.

Adding chilled water storage to chilled water plants with conventional primary and secondary pumping system is accomplished by adding a storage vessel to the de-coupler pipe. The excess flow from the chillers that is not required by the secondary loop normally flows through the de-coupler (or bypass) pipe back to the chiller and the chiller unloads. By adding a storage tank to the de-coupler pipe, the excess flow is added to the bottom of the tank and warmer water at the top of the tank is returned to the chiller. When the primary flow is less than the secondary flow, the stored chilled water is withdrawn from the tank and warm return water is returned to the top of the tank. This system schematic is shown in figure 7.

The chilled water at the bottom and the warm water at the top of the tank are separated by stratification. The boundary area between the two temperatures is called a thermocline. The differential temperature between the design chilled water return and the chiller delivery temperature determines the volume of storage required. Volume must also be allowed for the thermocline. The greater the aspect ratio between height and diameter, the less volume is required for the thermocline.

Use the following formula to calculate the storage volume required. For estimating storage tank size, assume 15% to 20% additional for the thermocline.

$$\text{Volume (gal)} = 1440 * \text{Capacity (Ton-Hr)} \div dT$$

Where dT = temperature difference (°F)

Advantages:

Utilize Existing Equipment: Existing equipment is utilized at the original design operating temperatures. No modification is necessary.

Simple Controls: Adding storage to a primary-secondary pumping chilled water plant only requires modification of the start and stop sequencing. For most installations, either by design or choice, the lag chillers are started manually. With this thermal energy storage configuration, the lag chillers may no longer be required.

Chiller Efficiency Increase: The overall operating efficiency of an existing chiller will be increased with this type of storage and configuration. As the tank is being replenished, the load on the chiller is at design where older centrifugal chillers are most efficient. The chiller will continue to operate at full load until the storage is fully charged. Since a greater percentage of the operation will be at night when ambient temperatures are lower, the cooling tower will be more efficient and condenser water temperatures can be reduced further increasing the overall efficiency of the cooling equipment.

Disadvantages:

Physical Size: The space requirement for chilled water storage is much greater than sensible plus latent storage. However, if required for fire protection on-site storage of water can be utilized for thermal energy storage.

Existing Problems: Since the storage capacity is dependent upon the differential chilled water temperature, the return water temperature from the building can be a disadvantage. If the facility has some three-way valves, inefficient air handling unit cooling coils, or constant flow process loads, the return water temperature can be lower than design. The chilled water storage tank capacity will be reduced if the stored water is replaced with colder than desired return water.

Capacity Increase: If additional storage capacity is required, the volume of storage is not easily changed. It may be possible to lower the chilled water supply temperature from the cooling equipment and add blending valves to increase the storage capacity.

Latent and Sensible Storage

It takes 8.34 Btus to cool one gallon of water by 1 °F. It takes 1,962 Btus to freeze one gallon of water. It takes 4.47 Btus to cool that gallon of ice by 1 °F. Therefore, cooling one gallon of water from 34°F to ice at 31°F takes 1974.8 Btus of energy. The heat required to melt the ice is the same as freezing the ice.

Because of the latent heat of phase change, physical space requirements are much less. When compared to chilled water storage at a differential temperature of 20°F, ice thermal energy storage requires 8% of the storage volume. This can be significant when physical space is an issue.

There are several methods of building and using an ice inventory. Some require specialized equipment and carry sophisticated maintenance requirements. Some examples:

Ice on Coil: Probably the most common method. A water and glycol mixture is cooled below 32°F

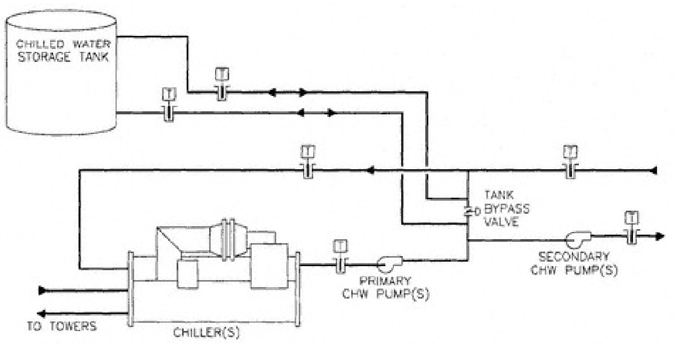

Figure 7
Chilled Water Storage

and pumped through coils in a storage vessel filled with water. The water freezes on the coils. To use the storage, water pumped through the coils thereby cooling the fluid and melting the ice.

Ice Cube: Similar to ice-on-coil, this method involves a water and glycol mixture that flows through a storage vessel. In the storage vessel are small containers filled with water that freeze.

Ice Harvesting: Chilled water flows over the evaporator plates of the refrigeration machine and ice forms on the plates. When the ice thickness is sufficient, hot gas run through the plates causes the ice sheet to separate and fall into a storage tank under the machine. This system involves no glycol since the flow of chilled water directly frozen. The equipment can also be operated as a chiller.

Ice Slurry: As with ice harvesting, a glycol solution is not required. Ice particles are formed and exist in suspension within the storage tank. The ice crystals are formed by specialized cooling equipment.

Although some of the equipment can be more complicated to maintain, the specialized systems are generally more energy efficient is developing the ice for latent storage.

Figure 8 shows a typical application for sensible plus latent thermal energy storage. In the example, ice storage tanks and a water/glycol solution are used. The solution is separated from the building chilled water system by a water-to-water heat exchanger.

When the ice build is activated, the chiller operates at full capacity and the solution is pumped through the ice storage tanks. The solution is bypassed around the heat exchanger through a control valve to maintain the building loop temperature when the ice build mode is active. As the temperature of the water stored in the tanks drops, the chilled water discharge temperature from the chiller continues to fall. When all of the water in the storage tanks is frozen, the ice build mode is complete and the chiller returns to normal operation.

When necessary to reduce the building peak power demand or when additional cooling is required beyond the capacity of the chiller, a portion of the water/glycol solution is run through the storage tanks. This melts the ice and eventually raises the storage water temperature.

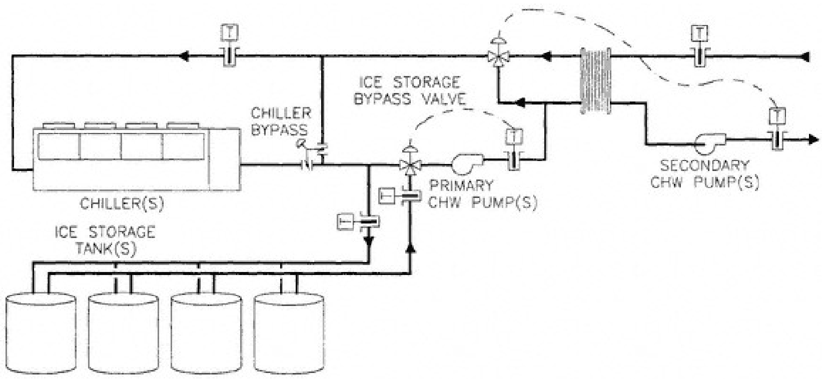

Figure 8
Ice Storage

Advantages:

Physical Size: The physical size of the storage is less than 10% of chilled water storage.

Low Temperature: The chilled water system can be designed for a lower design temperature supply and higher differential temperature to reduce the distribution flow and pumping power requirements.

Low Temperature Air: With the lowered chilled water supply temperature, the air handling units can be designed for low temperature air. This can be used to reduce the fan power and lower building relative humidity levels.

Expandable: If additional energy storage is required with ice storage tanks, additional capacity can be added with incremental addition of tanks. This advantage is not as easy with specialized sensible plus latent thermal energy storage equipment.

Disadvantages:

Specialized Equipment: To obtain latent thermal energy storage, water must be changed to ice. The existing equipment located in a facility may not be capable of the low temperature discharge or may not be energy efficient at low delivery temperature. Specialized ice making equipment may also be used.

Loss of Efficiency: The compressor lift in a refrigeration system determines the compressor power and the equipment energy efficiency. With lower discharge temperatures, this lift is higher and the efficiency decreases. However, if the equipment. is run at night with lower ambient and condensing temperatures, the efficiency loss may be negligible.

Complex Controls: Especially with ice harvesting and slurry systems, nonstandard equipment is required. Also, ice storage requires a more complex sequence of operation for the chilled water plant. Although possible with DDC controls, complexity is a disadvantage. These issues can be included in the economic feasibility as an increase in maintenance cost for the savings analysis.

System Example

For the example office building, thermal energy storage was considered for an energy conservation measure (ECM). The existing system included an air-cooled reciprocating chiller serving half of the building and a packaged rooftop unit serving the other. A computer model of the building, after other ECMs are in place, was developed to estimate the savings from different models of thermal energy storage.

Since physical space was an issue, chilled water storage was disregarded in favor of sensible and latent thermal energy storage with ice-on-coil storage tanks. Partial storage and full storage were considered as separate ECMs.

To recap the previously presented values in this example:

Electrical Costs (monthly):
Consumption = $ 0.034 per kWh
Demand = $ 18.34 per peak kW
Time-of-use rate structure is available

Peak Cooling (July):
Peak cooling demand = 100 tons
Profile for cooling in Figure 2
Some cooling required at night.

Baseline Electrical Energy Costs

	kWh	kW	Cost
Jan	86,764	146	$ 5,628
Feb	78,527	146	$ 5,348
Mar	87,646	165	$ 6,006
Apr	85,291	213	$ 6,806
May	100,189	246	$ 7,918
Jun	109,181	254	$ 8,371
Jul	120,214	262	$ 8,892
Aug	109,835	257	$ 8,448
Sep	97,890	249	$ 7,895
Oct	88,331	212	$ 6,891
Nov	84,597	166	$ 5,921
Dec	86,758	163	$ 5,939
TOTAL	1,135,223	2,479	$ 84,062

Partial Thermal Energy Storage:
Chiller Capacity = 43 tons
Storage Size = 402 ton-hrs

Partial TES Electrical Energy Costs

	kWh	kW	Cost
Jan	65,843	131	$ 4,641
Feb	59,868	131	$ 4,438
Mar	66,054	136	$ 4,740
Apr	63,130	154	$ 4,971
May	73,025	203	$ 6,206
Jun	78,175	223	$ 6,748
Jul	81,765	229	$ 6,980
Aug	78,254	217	$ 6,640
Sep	70,078	202	$ 6,087
Oct	65,093	152	$ 5,001
Nov	62,704	134	$ 4,589
Dec	65,126	134	$ 4,672
TOTAL	829,115	2,046	$ 65,714

Full Thermal Energy Storage:
Chiller capacity = 70 tons
Storage Size = 661 ton-hrs
(Change to time-of-use rate structure.)

Full TES Electrical Energy Costs

	kWh	kW	Cost
Jan	62,493	134	$ 4,582
Feb	56,671	131	$ 4,329
Mar	63,441	136	$ 4,651
Apr	62,217	158	$ 5,013
May	75,285	155	$ 5,402
Jun	77,972	152	$ 5,439
Jul	81,952	152	$ 5,574
Aug	77,748	152	$ 5,431
Sep	72,522	155	$ 5,308
Oct	64,143	157	$ 5,060
Nov	60,762	137	$ 4,578
Dec	62,290	135	$ 4,594
TOTAL	817,496	1,754	$ 59,963

Energy Cost Savings:
Partial Energy Storage = $ 18, 348/year
Full Energy Storage = $ 24,099/year

Partial to Full adds $ 5,751/year

In this example, the additional savings from adding capacity to obtain full thermal energy storage are small when compared to the savings from partial storage. Therefore, the incremental installed cost for the additional storage capacity and chiller cost was found not to be economically justifiable. However, the chiller installed for this project was sized at 75 tons to insure cooling availability. This allowed for additional savings during the mild cooling season where the system could be operated as a full thermal energy storage system.

Since cooling is necessary during all hours, the system was designed to provide chilled water to the building while the storage was being replenished. This is accomplished by blending the sub-cooled water delivered to the ice storage tank to maintain the chilled water supply temperature. This could also be accomplished with a water-to-water heat exchanger as shown in figure 8.

Summary

With the approaching deregulation of the electric utility industry there will be competition to provide electrical power to consumers. Since each competing provider will have a finite capacity to deliver power, an electrical consumer that uses a high amount of energy (kWh) and has a low peak power demand (kW) will be a targeted customer. Thermal energy storage can be used to modify the power load profile of a facility.

Thermal energy storage can be accomplished in many ways. Chilled water storage can be applied to nearly any existing chilled water plant as long as there is adequate space for a large storage tank. Where physical space has a premium value, using sensible and latent storage can reduce the required space for thermal energy storage. Latent storage of water and ice can be achieved with specialized equipment and more complex controls.

With thermal energy storage, electrical energy (kWh) may not be reduced but there may be a significant reduction in the annual cost of electricity by reducing the demand cost.

In the theoretical future of electrical utility deregulation, a facility with a proven level power load profile will be able to negotiate the lowest possible electrical rates for the lowest overall cost. As deregulation approaches the theoretical, thermal energy storage will become more common in new construction and system upgrades.

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Profile

Mr. Ward has been a mechanical engineer in the heating and air conditioning field since 1982. Twelve of these years have been in the temperature controls and energy management industry serving as design engineer, project manager, technician, and operations manager. He has extensive experience in the application of mechanical systems and automatic temperature controls to obtain the most reliable and energy efficient operation of heating and air conditioning equipment. With Mechanical Professional Services, Inc., an operating company of Limbach Constructors, Mr. Ward applies this experience by providing energy analysis and design assistance for existing and new mechanical systems for both new designs and performance contracting.

Education

The Ohio State University, 1982

Bachelor of Science in Mechanical

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Certification

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Chapter 32— Steam System Optimization: A Case Study

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Abstract

The steam system optimization (generation, distribution, use and condensate return) offers a large opportunity for action to comply with the new levels of energy efficiency standards. Superior design and improved maintenance practices are the two main sources of savings in steam systems. Increased competition no longer permits an industry to survive with energy waste that could be eliminated.

This paper highlights the study findings of the steam system in a plant from the Food industry. The steam system operates with an annual budget of $1.9 million. Normal steam demand ranges between 80,000 to 85,000 lb/hr.

The steam system analysis identified energy savings worth $270,000 per year. The optimization measures were in two categories:

No cost/low cost optimizations that can be done through a better maintenance and improved operating condition

Major improvements that require a significant investment, and includes the modification of the process and major equipment.

Introduction

Nearly half of industrial energy is used to generate steam. Improving steam system efficiency will contribute significantly to the profitability for every plant. There are proven energy savings techniques that capture significant energy saving benefits upon implementation. Some of them are industry wide, others are specific for each industry.

Steam systems consist of several components such as:

Steam generation

Steam distribution

Steam usage

Condensate collection and return

A comprehensive steam system optimization addresses these interrelated areas, identifies the problems, and recommend all necessary corrective measures to eliminate them.

Overview of the Site Steam System

This paper discusses the steam system of a typical Food industry plant in the USA.

Steam Load and Cost:

ABC Plant spends over $1,920,000 for steam generation (fuel, water, electricity and chemicals) every year. During 1997, steam generation averaged from 80,000 to 85,000 lbs/hr. At the end of 1997, with the commissioning of a new process reactor, the steam consumption will be increased by 7,000 lb/hr. The steam cost, excluding labor, as calculated by ABC Plant engineers, varies between $3.00 and $4.08 per 1000 lb depending on the condensate disposition (see TABLE 1).

TABLE 1. STEAM COST

Steam Cost Based on Condensate Disposition	$/1000 lb
100% Condensate Return	$3.00
Steam Injected to Process	$3.28
20% Condensate Return	$3.86
Condensate to Sewer	$4.08

Steam Generation

ABC Plant has two (2) boilers to meet its steam demand. Both boilers are natural gas and waste fuel fired, with the capacity of 150,000 lb/hr and 70,000 lbs/hr at 165 psig and 370°F. At normal operating conditions they work at average steam output respectively of 80,000 lb/hr and of 10,000 lb/hr (stand-by). There are meters available to measure steam and natural gas flow, flue gas stack temperature, excess O_2, pressures and other important parameters controlling the combustion and boiler operation. TABLE 2 shows the readings for June 10th, 1998 that are used for further calculations.

By the end of 1998, a new natural gas fired boiler with the capacity of 30,000 lb/hr at 600 psig will be installed to serve the needs of the new process reactor. It will operate at 7000 lb/hr and will back-up the other boiler during annual shutdowns.

TABLE 2. STACK GAS AND AIR TEMPERATURES

Date	Stack Gas to Atmosphere* (SGA)	Air to Main Burners* (AMB)	Stack Gas to Air Heater* (SGH)
10-Jun	370	500	740
	320	436	627
	365	464	698
	340	457	665
	325	428	615
	341	461	704
Average	344	458	675

* Location of the measurements see in Figure 1.

Steam Distribution System and Utilization

Steam is generated at 165 psig and distributed at 165 psig and 35 psig. In the buildings pressure reducing stations and temperature regulated valves additionally reduce and control the pressure to the required levels for different consumers.

ABC Plant utilizes steam in two ways:

indirect use, returning the condensate after process heating, hot water generation and comfort heating.

direct use in XXX moisturizers, XXX steamers, XXX water tanks, XXX process and Deaerator.

The following differentiation of the average steam consumption by area is established.

Medium Pressure

(MP) Steam (165 psig)	Building	Average Flow Lb./hr
1. X	15, 16	15,000
2. XX	16, 17, 18	30,000
3. XXX	18, 19, 20, 20A, 22	20,000
4. XXXX	10	20,000

Low Pressure (LP) Steam System (35 psig)

The 35 psig steam system is used for building air space heating throughout the plant, HVAC systems and in the Deaerator.

Steam distribution lines are predominantly accessible and insulated.

There are about 360 steam traps in the whole complex. The average steam trap age is 10 years. Improper steam trapping, applications and piping practices were observed during the visit. More detailed data and comments about the steam traps and their performance were provided in a separate steam trap report.

Condensate return

Condensate recovery is about 20%, due to a large percentage of the total steam load used for direct injection. Obvious wastes of condensate were observed during the visit. The drainage of hot condensate, due to condensate return system problems, is one of the main concerns of plant personnel.

At the ABC Plant, condensate from the whole plant is collected at a Central Condensate Receiver (CCR) in the basement of Buildings 15 and 16. All the condensate return lines discharge to a common header above the CCR. It also collects the make-up water (MUW) for the Boiler after the heat recovery of the XX waste water and the boiler blowdown. An 8" vent maintains the tank at atmospheric pressure. Through electrical pumps the mix of condensate and MUW is routed to the Deaerator, and then to the Boiler.

The Medium Pressure Condensate (CM) and Low Pressure condensate (CL) is either returned by direct discharge (steam traps) to the CCR or through pumps from the farthest points of the plant (Nitrogen and Mix XX areas). The MP steam users working in a modulated pressure control were identified as the most difficult part of the system to return condensate to the CCR.

Savings Opportunities

A thorough review of the system confirmed there are energy saving potentials in the boiler system, steam distribution system and in the condensate return system. The following paragraphs highlight 8 energy savings opportunities identified at the site and describe the measures proposed to realize these savings.

1—
Install Economizer in the Boiler Stack to Recover the Heat from Flue Gases

To recover the heat from the flue gases, ABC Plant has installed an air preheater in the boiler stack. During the study, the boiler was operating at an average load of 80,000 lbs/h, with 7.3% oxygen and 340°F stack temperature. A forced draft (FD) fan supplies the combustion air to the air preheater, and then to the boiler. The ambient air is preheated from ambient temperature to 460°F, while the flue gases are cooled by more than 360°F. Although there is heat recovery, the flue gas temperature is higher than optimum and shows a possibility for further heat recovery.

One of the most effective ways to recover energy from flue gases is to use an economizer to preheat the lower temperature water (make-up water) going into the boiler. At 165 psig, the temperature of the steam and water in the boiler is about 370°F and each pound of water needs 290 BTU/lb to reach the boiling point.

Hot flue gases contain a lot of wasted energy. It is beneficial to put this energy back into the boiler with the heat recovery equipment. Preheating the incoming feedwater to the Deaerator (after the CCR) in an economizer will improve the boiler efficiency. Since economizers are fairly expensive, they must be justified by a high level of boiler utilization. Once installed, they are usually trouble-free and require little maintenance.

It was proposed to install an economizer in the stack of the boilers to recover a portion of the heat that is carried away by the flue gases leaving the stack. For proposed modifications see FIGURE 1.

Installing an economizer will result in an annual fuel saving up to $72,900. The saving calculations are based on the average stack gas temperature (340°F) recorded by ABC Plant personnel and 85,000 lb/h steam load.

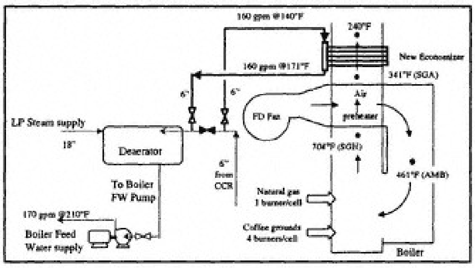

Figure 1
Heat Recovery of the Flue Gases

The resulting increase of boiler efficiency will reduce the fuel consumption by 26,130 mcf per year and the total carbon emissions by 442 tons per year.

Total investment cost for materials and labor is expected to be less than $182,000 and the pay back period for this project will be less than 2.5 years.

2—
Install Vent Condenser to the Deaerator

Site observations identified steam loss through the Deaerator vent, which is designed to release the non-condensable vapors. As informed by the operating personnel and measured by the gages, the Deaerator pressure is normally maintained at 3–4 psig. Even at normal operating conditions considerable steam will escape. Installing a vent condenser can recover this escaping steam, still allowing the non-condensable vapors to escape. There is no measurement of flash vapors and steam escaping through the vent, however reliable estimations of the steam flow is used to size the vent condenser.

It is proposed to install a vent condenser at the top of the Deaerator. The proposed scheme is shown in Figure 2.

The proposed vent condenser will be cooled by incoming mixed treated MUW and condensate from the Central Condensate Receiver before it enters the Deaerator. The savings estimations for the vent condenser are based on 330 lbs/hr of steam, while the vent condenser may be designed to handle up to 660 lb/hr of steam under upset conditions. Recovered condensate from the vent condenser will flow down to Deaerator by gravity.

Reduced pressure and recovery of vent steam at the Deaerator will save in fuel, water and chemicals totally $10,400 annually.

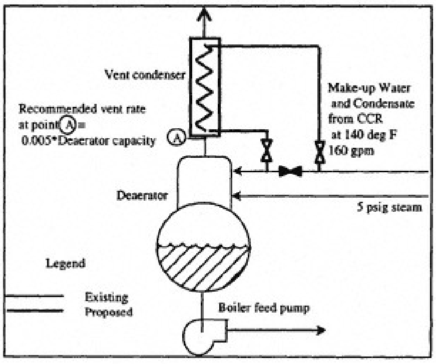

Figure 2
Proposed Heat Recovery at the Deaerator

Recovering the vented steam will reduce fuel consumption by 3140 mcf per year and will reduce the total carbon emissions by 53 tons per year.

Saving water by increasing the condensate return will lead to reduction in raw water consumption by 350,000 gal per year.

Total investment cost for materials and labor will be less than $ 18,000. The simple payback period is less than 2 years.

3—
Quench the Flash in the Central Condensate Receiver Vent

Survey observations identified considerable steam loss through the CCR vent, which is designed to release the flash steam from the Receiver and to maintain atmospheric pressure.

Discussion with operating personnel confirmed problems with the CCR and excessive pressure and steam CCR venting. Recently a new arrangement of the condensate return lines was established. A large header collects the condensate from the incoming return lines and the MUW enters the CCR next to the header inlet. This arrangement helps to absorb some of the heat from the flash steam, but a considerable amount escapes through the vent. At normal operating conditions, greater than a 5 foot plum was observed.

It is proposed to minimize losses due to vented flash steam by quenching it with make-up water. The proposed modification is shown in FIGURE 3.

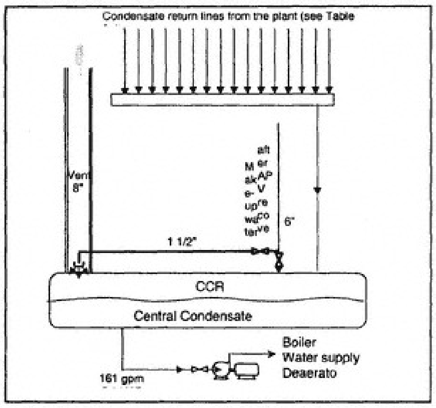

Figure 3
Quenching Flash Steam in Central Condensate Receiver

Recovery of vented flash steam at the CRR will save fuel, water and chemicals equaling up to $10,900 annually. The savings estimations are based on flash steam velocity of 8 fps through the 8" vent (375 lb/hr of steam).

Recovering the heat of vented flash steam will reduce the fuel consumption by 3500 mcf per year and the total carbon emissions by 59 tons per year.

Saving water by increasing the condensate return will lead to decrease in raw water consumption by 390,000 gal per year.

Total investment cost for materials and labor will be less than $ 3,000. The simple payback period is less than 4 months.

4—
Recover Heat from Cooling in Air Compressors

Four Compressors (2 Joys and 2 Suns) supply more than 3000 cfm of compressed air at 90 psig to the plant. They are installed at the ground floor of building # 23 and operate continuously throughout the year. These are 2-stage compressors with an oil cooler, an inter-cooler and an after cooler. At present, circulating cooling water recovers heat from the above coolers and rejects it to atmosphere through a cooling tower. Only one of the compressors (Joy #1) consumes approximately 115 gpm of cooling water. The cooling water enters these heat exchangers at 87°F and leaves at 108–114°F. ABC Plant personnel had a big concern about the oil cooler performance at higher ambient temperatures. The set point for shutdown of the compressors is 140°F and the oil temperature reached 136–140°F during the survey.

Trouble free compressor operation is ensured when required temperatures are maintained in the coolers. Their performance is highly affected by scaling problems at the jackets. At present, circulating cooling water that flows through the heat exchanger is chemically treated for hardness. Hence, no scaling problems are experienced. However, at present, the cooling tower rejects 11,000 million Btu of heat annually from this compressor alone, while make-up water is heated using steam in the Deaerator. Steam system efficiency can be improved by matching this heat rejection with a suitable heating need. However, the matching need to recover the compressors heat rejection should use chemically treated water and should be in continuous service. ABC Plant boilers and process consume cold make-up water at an average rate of 220 gpm throughout the year. Softened water is the best quality treated water and chances of scaling are negligible. Make-up water from the softening plant is available at ambient temperature. In addition to the recovery of the heat that is rejected to atmosphere, this method of cooling will assure the unimpeded work of the compressors. Furthermore, scaling problems are minimal in once through cooling water systems.

It is proposed to preheat the soft water from the Softeners, by passing it through the oil coolers and part of inter-coolers and after-coolers of air compressors. Accordingly, a 6" soft water supply line and an insulated 6" return line will be provided from softeners to the compressor building to recover this heat. These two lines will be tied-in parallel to the existing circulating water line. This configuration will allow ABC Plant to revert back to the existing circulating cooling water system in case of an emergency. Since soft water is passed through the coolers of the compressor, a chance of scaling is negligible. Suitable check valves and correct changeover sequence will prevent cooling tower water contamination of the boiler feed water system.

There is no special equipment involved and no interference with any heat recovery process is anticipated due to the proposed modifications. The suggested modifications are shown in FIGURE 4.

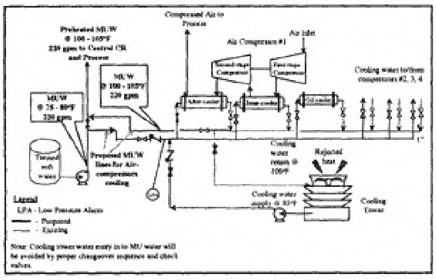

Figure 4
Heat Recovery From Compressor Cooling

Recovering heat that is rejected at present to atmosphere will save 21,000 million BTU annually. This will save fuel in the boilers and reduce the cooling tower load considerably while the compressor reliability is maintained, if not improved. At 80% boiler efficiency and 1997 fuel costs, this will save ABC Plant $57,300 annually.

Recovering the heat from compressor cooling will reduce the fuel consumption by 20,500 mcf per year and reduce the total carbon emissions by 346 tons per year.

Total estimated investment to implement the proposed modifications will be $62,000 and the investment can be recovered in 1.1 year.

5—
Optimize Condensate Return System at XX Area

The predominant problem throughout the facility is the condensate return system. Considerable condensate draining is required, combined with venting steam at the CCR tank.

Many steam and condensate system inadequacies were observed, including incorrect and missing drainage of supply lines, misapplications, inappropriate sizing and condensate removal from heat exchange equipment. This leads to drainage problems, condensate flooding and energy/performance losses as equipment became damaged (water-hammered and/or corroded), which reduces efficiency and requires increased manpower for maintenance.

XX area uses MP and LP steam for the process. The LP steam is supplied to the Moisturizers (#1 to #4) for Hot water heat exchangers (HE's) and for direct steam injection. All other process users are MP steam users. All heat exchangers (process heating) are on-demand systems using steam modulating pressure control valves to control steam pressure and temperature. During no-load conditions, steam flow is reduced to zero. This modulating steam pressure causes drainage problem with the heat exchangers because the systems are not trapped properly. The above systems are not efficient and are maintenance intensive.

In wintertime, comfort heating equipment uses LP steam. It is reduced through a PRV at the 5th floor of bldg. #20.

Problems in returning the condensate and operating the equipment forced the plant personnel to open the by-pass and bleed valves, and to drain the condensate to the floor. At modulated steam pressure supply, the steam trap can not respond immediately to the process requirements as the motive force for every steam trap is pressure differential. At start-up, low inlet pressure prevents drain traps from functioning properly. Live steam from failed steam traps in the condensate return system further restricts the steam trap function as the back pressure increases and makes the pressure differential even smaller. If drain valves are not opened, the obstructed condensate creates back-pressure problems, leaks and safety relief valves discharges (FIGURE 5).

Several problems were observed and noted about the improper operation and installation of the condensate return system in this area:

- No air vents are installed at heat exchangers and steam traps. This decreases heat transfer efficiency, lowers the process speed and creates opportunities for air locks, which prevents the condensate removal.

- No differentiation between low and medium pressure condensate return is established in the original design of the system

- No separate return of modulated and constant pressure condensate. This allows the discharged higher pressure condensate to create back pressure for the traps operating at lower pressure. This keeps them from working properly

- Pipes and return lines are unreasonably restricted or undersized

Energy efficiency of steam supply and condensate return system depends on the effective usage of steam traps, air vents and properly sized and piped condensate return lines.

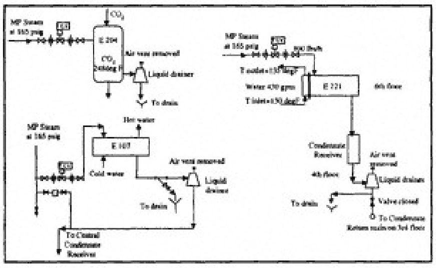

Figure 5
Existing Piping

Properly sized and installed condensate return lines assure reliable operation of the main process equipment and maximum amount of returned condensate.

Maximizing condensate return to the boilers reduces the quantity of make-up water, as well as, the amount of chemicals for water treatment. Also condensate contains valuable energy and by returning it, it reduces the fuel burnt in the boiler.

To rectify the condensate return problems, it was proposed:

1. To facilitate the condensate return where there is lower steam supply pressure, it is proposed to install steam driven pump (pumping trap) after each separate heat exchanger ahead of the existing steam trap. An equalizing line will equal the pressure in the Pumping trap and the CR. If receiver is not available a new one should be installed. This will assure the condensate return and the back-pressure will not affect the work of the heat exchanger.

2. To remove the air from the system air vents have to be installed at the Steam traps and at the Heat exchangers. To prevent vacuum formation vacuum breakers have to be installed. The existing steam trap will handle the condensate when the inlet steam pressure is higher than the back pressure in the condensate return lines and will stop the steam from flowing through the pump trap. FIGURE 6 is an illustration of the modifications proposed in 1. and 2.

3. To use the heat in high pressure condensate it is proposed to install a Flash tank in the middle of line CL-5123, right after the tie-in of line CL-3309 (E-215 condensate return). It will collect the condensate from several heat exchangers. The flash steam has to be routed to LP steam header to steam users with continuous operation, such as the HE for the moisturizers and the direct steam injection. Other potential users of LP steam are the Concentration Tank, TK-112 and the Hot Water HE. During winter, it will be used in the comfort heating equipment. Anther option for summer time use of flash steam is to be routed to the CCR and to condense, while preheating the MUW. FIGURE 7 is an illustration of the proposed modification.

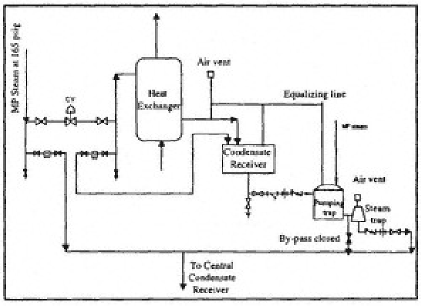

Figure 6
Proposed Condensate Removal From
He Working Under Modulated Pressure

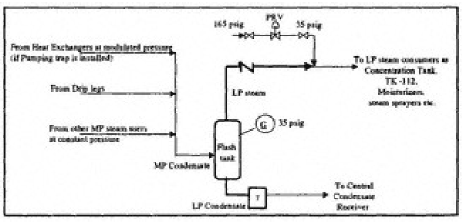

Figure 7
Mp Condensate Flash Steam Usage

Implementing the above recommendations will save ABC Plant minimum $74,300 annually. Separation of the high temperature condensate will prevent thermal shock in the pipes and will create a safe working environment. It will improve the system reliability and will reduce maintenance costs.

Improving the condensate return system will decrease fuel consumption by 12,270 mcf per year and will reduce the total carbon emissions by 207 tons per year.

Increasing the condensate return will decrease raw water consumption by 5,890,000 gal per year.

The required investment to implement the proposed modifications is estimated to be $137,000. The pay-back will be less than 2 years.

6—
Prevent Thermal Shock in Aquachem and Nitrogen Areas

At present, in the Aquachem area, condensate from two HEs (outside) is returned through Pumping Traps and discharged to the Nitrogen tank to evaporate the Nitrogen. The pumping traps will discharge the condensate to the condensate return line when the inlet pressure is lower than the condensate return pressure. In the same tank steam is directly injected at low pressure. A PRV reduces the pressure from 160 to 60 psig. A drip leg from the main line also discharges in the tank. The temperature in the tank is maintained at 145°F. The condensate is collected through an overflow pipe, which is routed to condensate collection tank and pumped with an electrical pump to the condensate return header and further to the CCR (see FIGURE 8). Water hammer occurs in the return line after the pump. The condensate is drained from the receiver to the sewer.

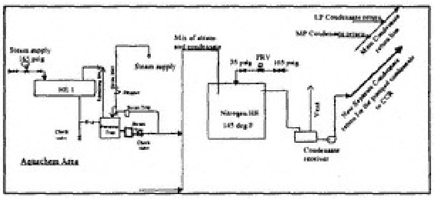

Figure 8
Existing Condensate Return

Thermal shock is a term that describes the interference between fluids with different pressures and temperatures. When condensate at steam supply pressure passes through the trap and enters the condensate header at lower pressure, flash steam is released. One pound of steam occupies more than 1500 times the volume of a pound of water. When the flash steam mixes with cold condensate it collapses. However, when the flash steam collapses, water is accelerated into the resulting vacuum from all directions. Water hammer results from the collapse of this trapped steam. The localized sudden reduction in pressure caused by the collapse of the steam bubbles has a tendency to chip out pipe and tube interiors. Oxide layers that otherwise would resist further corrosion are removed, resulting in accelerated corrosion. Over a period of time, this repeated stress and wear on the pipe would weaken it to a point of rupture.

It is proposed to:

1. Install steam traps after the Pumping trap at the outside HE. This will prevent the steam from blowing through the Pump trap when the inlet pressure is higher than the condensate return pressure.

2. Reroute the pumped condensate (140°F) in a separate 2" line to the CCR to prevent water hammer by mixing cold and hot condensate. This will also help the discharge of the steam traps in the building because there won't be any back pressure created from the electrical pump.

FIGURE 9 reflects the above recommendations.

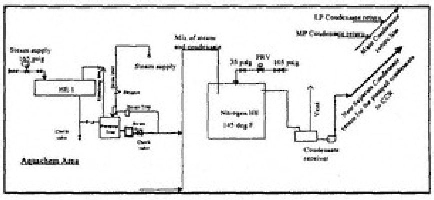

Figure 9
Proposed Condensate Return Modifications

Implementing the above listed recommendation will save ABC Plant $4,300 yearly. It will also improve the system reliability and safety, and will reduce maintenance costs.

Improved condensate return system will reduce fuel consumption by 255 mcf per year and reduce the total carbon emissions by 4 tons per year.

Improving the condensate return system will lead to a decrease in raw water consumption by 520,000 gal per year.

Total investment to implement the above listed recommendation will be $15,000. The pay-back will be less than 3.5 years.

7—
Recover the Flash Steam from X's Heat Exchangers

At present, in Building 18, four (4) HEs continuously heat fresh water from 115°F to 335°F. Three of them are operating while the fourth is on stand-by. The fresh water flow is 30 gpm through each heat exchanger. Each heat exchanger consists of two separate shell & tube heat exchangers with common steam control valve and separate steam traps. The condensate is returned directly to the CCR. The heat content of the high-pressure condensate is not used at present and the flash steam is vented through the vent of the CCR. See existing arrangement in FIGURE 10.

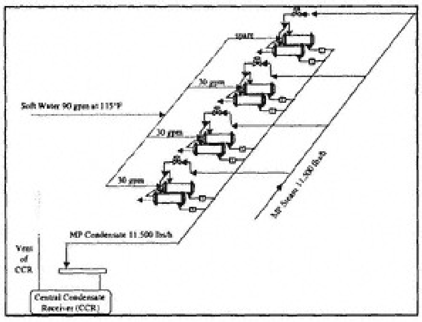

Figure 10
Existing Arrangement at Heat Exchangers

It is proposed to rearrange the condensate return system in a way that the MP condensate can be used. The flash steam from it will preheat the incoming fresh water. This will decrease the steam flow through the PRVs and reduce the consumption of MP steam. To implement this proposal the existing system will not be disturbed. A new heat exchanger will be installed on the common water supply line ahead of the four existing HE and a flash tank at the condensate discharge side downstream of the existing steam traps. The HE will use 15 psig flash steam from 165 psig condensate. A new 3" pipe originating from the flash tank will supply the LP steam to the new HE. Safety drain traps will be installed on the HE's outlet to assure proper drainage at start-up operation. See proposed modifications in FIGURE 11.

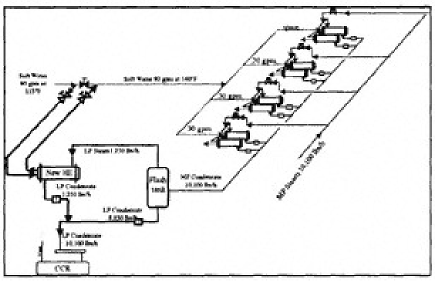

Figure 11
Proposed Heat Recovery at Heat Exchangers

Implementing the above recommendation will benefit ABC Plant with savings of $28,700 annually.

Improving the condensate return system and using the flash steam from MP condensate will reduce the fuel consumption by 10,270 mcf per year and the total carbon emissions by 173 tons per year.

Total investment to implement the above listed recommendation will be $51,000 and the pay-back periods is less than 1.8 years.

8—
Recover Pressure (Energy) Instead of Reducing Steam Pressure Through PRV

The deaerator consumes LP steam year round, at average load of 5,000 lb/hr. All the steam is reduced from 165 psig to 35 psig through a pressure-reducing valve (PRV), while an existing steam turbine driven feed water pump is abandoned. Due to high maintenance cost and operational problems, this pump has not been in use for more than 10 years.

Reducing steam pressure through PRV wastes useful available energy. When steam flow through a PRV is small and fluctuating, recovering mechanical energy may not be economically feasible. However the Deaerator needs about 5,000 lb/hr steam constantly throughout the year.

It is possible to utilize the pressure (energy) available in steam to drive the existing pump, that will reduce electrical consumption. An advantage of this is the simplicity of replacing one standby electrical motor, without disturbing any of the existing arrangement. Also, the present system will turn on when steam flow drops, and this will be a smooth transition. One pump can be replaced with the proposed steam turbine and the necessary steam line tie-in connections. The steam turbine will work as a parallel drive to the existing feed water pumps. This pump is located one level below the present PRV and the 165 and 35 psig steam headers. It will be in service continuously. The configuration for the turbine drive installation is shown in FIGURE 12.

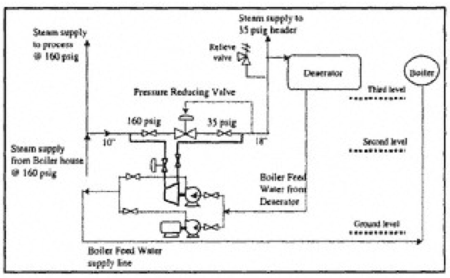

Figure 12
Steam Turbine Drive To Bfw Pump

The power available by reducing an average of 5000 lb/h will be in the range of 70 hp. The recovered pressure (energy) from steam is expected to save $10,800 annually.

When the LP steam usage is reduced, due to the future improvements in the Deaerator and condensate recovery systems, the benefits are expected to decrease if the Deaerator is the single user of LP steam. This saving opportunity should be considered after identification of other LP steam users (additionally to the Deaerator). This consideration will assure the required steam load for the pump drive and the constant head at the pump discharge even when the Deaerator LP consumption changes.

Then utilizing the pressure (energy) available in this steam is technically and economically feasible, but not recommended at this stage of the study.

Conclusion

The ABC plant has a potential to **capture $270,000** in annual energy savings by implementing the above eight recommendations.

These recommendations require no major process modification. Some of them could be implemented through periodic maintenance program. The others requiring new equipment can be done during the plant turn-around.

Optimization of steam system by the implementing the above recommendations will also **reduce the total carbon emission** to the environment with **1284 tons** annually.

References

1. 1997 Operating data from client's Food Processing facilities

2. Turner, Wayne C., *Energy Management Handbook,* 1992.

3. Armstrong International Inc., *Steam Conservation Guidelines for Condensate Drainage,* Handbook N-101, 1994.

Chapter 33— Energy Evaluation of a Potable Water Treatment Plant Using Disolved Air Flotation

Sean F. Anderson, CEM, CPE

Introduction:
Site Information

The Root Reservoir Treatment Plant is located on Reservoir Road in Lenox, Massachusetts. Lenox is located 150 miles north of New York City and 100 miles west of Boston. It is a small community of 5,600 full time residents and grows to a part time summer community of over 9,000 due to the unique nearby vacation attractions including, Tanglewood Music Center and the Normal Rockwell Museum. The large fluctuation between summer and winter populations requires the drinking water treatment facility to be flexible.

Plant Information

The Lenox drinking water plant utilizes dissolved air flotation with filtration (DAFF) technology. It also incorporates sand filtration to provide high quality finished water. This process replaces conventional sedimentation and conventional filtration systems. DAFF systems have shorter process times, lower space requirements, reduced sludge volumes, lower operation costs, and the capital costs are usually far lower than that of conventional systems. The treatment plant was constructed in 1993 utilizing components designed by the Krofta Engineering Corporation. It is designed to treat 1.6 million gallons per day (mgd). The actual flows are between 0.5 to 1 mgd. Due to the excellent design of the plant only 1 hour per day is required for operator supervision. The plant's control system operates the process continually. An operator visits the site for about 1–2 hours per day, five days per week. The operator verifies readings, completes laboratory testing, performs general housekeeping and verifies that the plant is in good working order. The entire treatment process can be monitored from the town's Public Works office, which is over 4 miles away.

The Town of Lenox estimates that 82% of the population (or 4,600 people) is serviced by town water. The remaining 1,000 people are serviced by private wells. The Town charges a fee of $3.00 per 1000 gallons of water that each household uses. As of January 1st, 1999, the Town of Lenox is charged $0.0793128 per kilowatt-hour for electricity from Western Massachusetts Electric Company. The Root Reservoir Treatment Plant produced 258.0 and 259.2 million gallons (MG) in 1997 and 1998, respectively. The plant utilizes a dissolved air flotation technique that requires coagulation chemicals. The chemicals used are 8.3% liquid alum ($Al_2(SO_4)_3$ + H_2O), and poly aluminum chloride ($Al_{13}(OH)_{20}(SO_4)_2Cl_{15}$), referred to as PAC.

Raw Water Overview

The Root Reservoir Treatment Plant consists of two identical 18-foot diameter Krofta SASF-18 units. The two units are housed in a building located on Reservoir Road in Lenox, Massachusetts. The treatment plant draws water from the Root Reservoir system. The reservoir consists of Upper Root (elevation of 1487-feet) and Lower Root (elevation of 1456-feet), which has a combined capacity of 169 million gallons. Most of the water from the watershed drains into the Upper Reservoir, which overflows into the Lower Reservoir. Raw water can be drawn from either location but is primarily drawn from Lower Reservoir. The reservoir is located in the Lenox Mountain Brook Watershed and was acquired by the Lenox Water Company in 1891. The watershed consists of 780 acres and is located along Lenox's western boarder of Richmond. The area has a safe yield of 0.73 million gallons per year following the New England Watershed Area/Dependable Yield Curve.

Typically, the quality of the raw water is quite high. Most times of the year the raw water is relatively easy to treat. During these times liquid alum ($A1_2(SO_4)_3$ + H_2O) is used as a coagulant. Occasionally, the liquid alum does not work effectively. Therefore, a coagulant of poly aluminum chloride ($Al_{13}(OH)_{20}(SO_4)_2Cl_{15}$) is used. Poly aluminum chloride is used when the alkalinity and temperature are low. Typically this occurs during the cold winter months. Normally, the raw water turbidity is less than 2.0 nephelometric turbidity units (NTU), while the quality required by the State for the finished water is <0.5 NTU. However, the goal of the plant is a quality of <0.1 NTU, which the plant is capable of reaching. The alkalinity ranges from 45 to 62 mg/l. The treatment plant has an average turbidity removal efficiency of over 91%.

Basic Process Overview

Water is drawn from the reservoir and treated in one of the two 18-foot Krofta units. Coagulation chemicals are added to the raw water before it enters the units. Dissolved air is introduced into the raw water and the tiny micro-bubbles float the solids to the surface where a spiral scoop removes the sludge. (The sludge, at about 2% solids content, is sent to the sludge well. From there, it is pumped to a dewatering pond where it freezes over the cold winter months. The freeze/thaw cycle stabilizes the sludge and further aids in dewatering. Once enough sludge has accumulated, the dry cake is dug out with heavy equipment and disposed of by the Town.) The treated water in the clarifier travels downward through a sand filter, which is designed to filter out any impurities that were not removed by the flotation process. After passing through the sand filter, the finished water travels into a clearwell. The finished water from the clearwell is disinfected with chlorine and is sent to the distribution system of the Town of Lenox.

Treatment Process

Raw water is drawn from the Lower Root Reservoir through a 10-inch pipeline into the treatment facility. Coagulation chemicals, which aid in coagulation, are added in the 10-inch line through a chemical injection nozzle. The chemical is feed into the 10-inch raw water main by one of four 0.25 HP chemical metering pumps. The chemicals are stored in three 3,000-gallon cylindrical tanks located on-site. One of two chemicals are added, either alum or PAlCl. The 10-inch line splits into two 6-inch lines that supply each 18-foot diameter unit. Two units are utilized for the purpose of redundancy since the total flow required is far less than the design flow of the plant. The 6-inch chemically treated raw water enters a central mixing tank, called the flocculation tank. The 6-inch pipeline splits into two 4-inch lines. These lines are connected to two nozzles that are positioned to cause a swirling motion as the water is discharged into the central mixing tank. From the central mixing tank, the water rises upward which gently mixes the solution of raw water and coagulant thus increasing floc formation. The flocculated water flows from the flocculation tank into the outer flotation zone by passing below a circular baffle that separates the two tanks.

Aerated water is distributed through the distribution pipe, or ring, into the floatation tank. The rapid pressure drop occurs at the globe valve feeding the ring. Once the dissolved air comes out of solution, the aerated water resembles a white milky white substance. The air dissolving tube (ADT) generates the high-pressure aerated water. This is accomplished by injecting compressed air into the tube along with water. The water to be aerated can either come from the raw water inlet or, more commonly from the first filtrate water from the clearwell. Tiny microbubbles in the aerated water attach to the floc and "floats" the suspended impurities to the surface. The floating sludge material is scooped off the surface by a spiral scoop, which discharges the sludge directly into a 6-inch pipeline and then into an 8-inch pipeline and on to the sludge well. All wetted parts, including the spiral scoop, are constructed from 304 stainless steel. The spiral scoop has a larger diameter on the outer end than the inner end. This allows sludge to flow towards the center and eventually to the sludge well. The sludge scoop and backwash components are mounted on a rotating carriage that travels around the outer edge of the unit. The rotating carriage contains the backwash pump, the spiral scoop, and the drive motor and related equipment. Two wheels ride on the top edge of the clarifier wall and support the outer end of the carriage while it pivots in the center on a bearing.

The bottom of the sand flotation unit is composed of three equal sections. Each section contains it's own sealed clearwell which is positioned below seven sand filtration beds (cells) whose depth is 12 inches and has an average filter flow of 2.5 gpm per square foot. The total filter area is 203 square feet and the filter media has a grain size of 0.35 to 0.45 millimeters. Nozzles prevent the sand from traveling from the filter bed into the clearwell. Each clearwell compartment has a 6-inch outlet with a 6-inch filtered pipeline and a valve. The valve is used to isolate the sand filter beds over a clearwell compartment for backwashing or to direct filtered water to the plant clearwell. The pipelines from the three clearwells connect together to a common 6-inch pipeline that discharges to the plant clearwell.

The purpose of the backwash cycle is to remove the materials that have been entrapped in the filter media from the treatment process. Backwashing is accomplished by a backwash pump and hood. The hood is lowered over the cell to be cleaned and the pump draws water upwards from the clearwell, into the cell. The impurities entrapped in the media are removed.

Most mechanical systems in the Root Reservoir Treatment Plant are monitored by a direct digital control system (DDC). The DDC systems have the ability to trend and record data at key points in the process. The system has the capability to send an alarm to an operator miles away in the event a malfunction occurs. Programmable logic controllers (PLC) control the plant. The PLCs are very flexible, accurate easy to operate. This results in a plant with excellent process control, excellent reliability and very little required oversight.

Backwashing

Backwashing is required to ensure proper operation of the treatment plant. This is accomplished by a single suction pump mounted on the rotary carriage. A filter bed can only be backwashed when the backwash hood covers the top of the filter bed. The backwash hood is mounted on the bottom of the rotating carriage and travels down to the filter media surface by two pneumatic cylinders.

Finished water is taken from the clearwell below the cell to be cleaned and passed through the filter media. The backwash flow expands the sand and re-suspends the entrapped solids. The backwash water is high in solids content and it contains carryover of sand that was removed from the media. By passing the backwash water through a sand separator, the sand is returned to the bed and the clarified 'dirty' water is sent to be either retreated or to the sludge well.

During a backwash cycle, the rotating carriage stops above the pie-shaped filter sector that is to be cleaned. A proximity switch signals the carriage to stop directly above the cell to be cleaned (backwashed). Each pie-shaped cell contains 13.18 square feet of filter area. Pneumatic cylinders allow the pie-shaped 304 stainless steel backwash hood to drop from its storage area, below the carriage, to the surface of the filter media. Once the hood is in place, a watertight seal is formed over a particular sand filter cell. Then the backwash pump is energized and draws finished water from the clearwell and uniformly through the filter media. The clean water flushes out material entrapped in the media. The backwash flow per cell is 265 gpm, while the maximum design flow of the filter bed for backwashing is 20 gpm per square foot. The backwash water, which is high in solids content, travels into a centrifugal sand separator to remove any sand that may have been removed from the bed during the backwash process. As the backwash water enters the sand separator it is directed in a circular flow and accelerated. This circular motion allows the clarified water to discharge from the separator at the top, and the sand settles to the bottom of the unit. The sand is allowed to return to the filter bed and the backwash water is sent to either the flotation tank (to be treated again) or to the sludge well. Primarily, the backwash water is sent to the floatation tank because the solids content is relatively low.

The backwash frequency is variable because timers dictate the duration of the key component operation times such as the interval between backwashes and the duration of the backwash pump operation. Currently, the backwash pump timer is set to be energized for 45 seconds. Once the timer signals that the backwash procedure is complete; the pump is de-energized, the settling timer begins to ensure the sand has settled, the hood is retracted upwards, and the carriage moves over the next cell to backwashed.

Originally, the interval of the cells to be backwashed was set during the initial startup of the plant in 1993 and very little has been done to alter the order in which cells are cleaned. Currently, each of the seven cells in section one (#1) is cleaned. The carriage passes over all seven cells of section two (#2), to section three (#3) where all seven cells are cleaned. Once all of section three (#3) is cleaned, the carriage passes over section one (#1) to section two (#2) where all seven cells in section two (#2) are cleaned. A closer examination of the finished water quality verses backwash frequency should be done in order to determine what the appropriate backwash interval should be. The best backwash interval would be the shortest time that the components operate, while still providing high quality finished water.

The control system of the treatment plant was designed using programmable logic controllers (PLC). The PLCs have the ability to incorporate feedback control loops, which can signal other operations. For example, if a set point is reached or a limit exceeded, the PLC will create and alarm or perform another operation. The system can be configured to summons an operator in the event of a malfunction or open valves in the event of a high level alarm. In addition, the PLCs can be used as timers. By adjusting a keypad on the control panel, a signal will be sent to an electrical relay that will control the duration of operation of a particular electrical component. For example, an operator sets the time that the backwash pump should be on. The PLC sends a signal to the relay that controls the backwash pump power supply. The circuit is closed and power is applied to the pump only for the set time in the PLC. Once the timer has expired, the PLC no longer sends a signal to the motor relay, thus the backwash pump is de-energized and shuts off. See TABLE 1 for important timer values.

TABLE 1. Current Timer Settings at the Plant

Timer	Duration (minutes)
Backwash Pump "ON"	0:45
Sand Settle Time	0:30
Carriage Move Time (cell to cell)[a]	0:30
Carriage Move Time (skipping a section)[a]	3:34

[a] This is not a timer, it is a function of the speed of the carriage drive motor.

By adjusting the timer values from their current values to lower values, energy can be saved. TABLE 2 shows the current total 'ON' time for the mechanical components for one complete cycle of the treatment unit. Currently, one cycle is 46 minutes long and is defined as the total time it takes for the rotating carriage and backwash system to clean cell one (#1) of section one (#1), through the entire filter bed, and back to cell one (#1) of section (#1). Each unit completes 31.3 cycles per 24 hour period.

TABLE 2. Current 'ON' Times of Mechanical Systems

Mechanical System	Duration	Quantity
Scoop Drive	9.95 hr/d	2
Backwash Pump	8.2 hr/d	2
Carriage Drive	9.95 hr/d	2
Chemical Pump	24 hr/d	1
Air Compressor	2 hr/d	1
ADT Pump	24 hr/d	2
Sludge Pump	0.25 hr/d	1
Wet Well Pump	1.2 hr/d	1
Low Lift Pump	24 hr/d	1
High Lift Pump	24 hr/d	1
Chlorine Pony Pump	24 hr/d	1
Dehumidifiers	23 hr/d	6
Main Lighting	10 hr/week	12
Office Lighting	10 hr/week	12
Low Lift Lighting	1.7 hr/week	8
High Lift Lighting	1.7 hr/week	8
Clearwell Lighting	1.7 hr/week	34
Air Compressor Lighting	1.7 hr/week	20
Chlorine Room Lighting	1 hr/week	1
Outside Lighting	60 hr/week	4
Hot Water Boiler	5 hr/week	1
Fans	0 hr/week	2
Heaters	4.6 hr/week	6

Energy Audit

An energy audit serves the purpose of identifying where a building or plant uses energy and identifies energy conservation opportunities. There are three main types of audits that range from simple to complex. These are the *walk-through,* the *mini-audit* and the *maxi-audit.* The walk-through is the least costly and time-consuming. It involves walking through the plant to identify major areas of energy consumption and conservation. The second is a mini-audit where preliminary tests are performed and readings are taken. The final is the maxi-audit where detailed data is collected over a period of time. This evaluates how much energy is used for each function such as lighting, process, HVAC, etc. A maxi-audit was performed on the Root Reservoir Treatment Plant over a two-month period in November and December 1998.

Calculations

The simple calculations used to determine kilowatt-hours (kWh) and the electrical costs are shown below. Equation 1-1 is used in determining the amount of kilowatts consumed by a motor. Equation 1-2 is used to determine the electrical cost of a motor, while equation 1-3 is used to determine lighting electrical costs.

Kilowatt-hour=amperage*voltage*√3(for 3 phases)/1000*hours operating 1-1

Electrical cost=amperage*voltage*√3/1000*hours operating*$per kWh 1-2

Electrical cost=# of fixtures*watts/1000*hours operating*$per kWh 1-3

Data Collection

Readings were taken during the normal operation of the treatment plant so that the values would be representative. The procedure for gathering the electrical data was simple. First, all mechanical devices were itemized and cataloged in a database (see appendix). Information about the applied voltage, motor efficiency, quantity of items, horsepower, power phase, and full load amperage were obtained from a variety of sources including the operation and maintenance manual (O & M), nameplate data and operator interviews. The most important data gathered was the actual amperage drawn and the duration of power supplied.

The amperage values were gathered by utilizing a Fluke 32 clamp meter. The procedure was to remove the electrical splice box cover to reveal the electrical connections. While the electrical device was running at a normal load, the clamp meter was placed on each of the current-carrying conductors. A value was recorded for each of the three legs and the actual amperage was determined.

Preventative maintenance (PM) is an important part of every mechanical system. It not only insures the proper operation of a device; it increases the life of the device by addressing maintenance issues *before* they pose a critical problem. A preventative maintenance program may cost some money initially, but will always save money in the long run. Electrical PM is no exception. While taking amperage readings, an electrical PM inspection was performed. The inspection concentrated on a number of key points. One point of interest was to determine that all three current-carrying conductors (legs) were drawing similar amperages. If one leg was drawing far greater amperage than the other two, it can be a signal that a failure is likely to occur in that particular leg. In addition, excess heat is generated as more amperage passes through a conductor. This heat can be significant and presents a fire hazard in the plant. While each electrical splice box cover was removed, a visual inspection was performed. Care was taken to inspect for cracked or damaged insulation, bare conductors poking out of the wirenuts, proper tightness of the wirenuts on the conductor ends, and burnt spots or signs of arcing on the internal area of the connection box. It is important to note that the Root Reservoir Treatment Plant was in excellent electrical condition and the inspection revealed no problems to report. However, a periodic inspection of the electrical splice connections, circuit breaker lugs, transformer connections and switchgear components is strongly recommended.

The duration of power supplied to the unit was the last important item to be determined. By utilizing a chronograph from Timex, the duration of operation was recorded. Devices are controlled by either timers, float switches, limit switches, or proximity switches. Calculations were completed to determine the total 'ON' time of a device so that the electrical costs could be determined. Please refer back to TABLE 2 for 'ON' times for the mechanical equipment.

Energy uses were divided into three major areas for review. The areas are the clarifier operation, backwash cycle, and the building consumption (including lighting systems, HVAC systems, and miscellaneous devices).

Clarifier Operation

The clarifier operation consists of a number of components running in conjunction with each other for the process to work correctly. This not only includes the devices on the clarifier, but also the related devices and support systems. TABLE 3 shows the devices that operate during normal clarifier operation. Please note that the air compressor is required for the ADT system as well as for the pneumatic power for the hood.

Backwash Cycle

The backwash cycle includes a 5 horsepower pump, and two pneumatic cylinders for the hood operation. TABLE 4 shows the current energy usage of the backwash cycle.

Building Systems

One area that should not be neglected when performing an energy audit is the energy consumption of the building systems including lighting and heating, ventilation and air-conditioning (HVAC). Items plugged into outlets, like power tools, vacuums, personal workstation computers, personal radios, should not be overlooked in larger plants. However, due to the relative small size of the Root Reservoir Treatment Plant, these miscellaneous users of power can be considered negligible.

TABLE 3. Energy Consumption of Clarifier (2 Units)

Mechanical System	Duration	Quantity	kWh/yr	Cost/yr
Scoop Drive	9.95 hr/d	2	8,680	$688
Carriage Drive	9.95 hr/d	2	8,680	$688
ADT Pump	24 hr/d	2	155,642	$12,345
Chemical Pump	24 hr/d	1	410	$33
Air Compressor[a]	1.7 hr/d	1	5,537	$439
Sludge Pump	0.25 hr/d	1	603	$48
Wet Well Pump	1.2 hr/d	1	732	$57
Low Lift Pump[b]	24 hr/d	1	41,877	$3,321
High Lift Pump[b]	24 hr/d	1	221,947	$17,603
Chlorine Pony Pump[c]	24 hr/d	1	11,865	$941
Total Clarifier Cost per Year:				**$36,163**

[a] It is estimated that 85% of air compressor operation is for the ADT system.

[b] Low and high lift pumps are required due to the elevation of the water treatment plant versus the distribution system.

[c] Chlorination is located on-site. Often found separately located at typical treatment plants.

TABLE 4. Energy Consumption of Backwash Cycle (2 Units)

Mechanical System	Duration	Quantity	kWh/yr	Cost/yr
Backwash Pump	8.2 hr/d	2	19,078	$1,513
Air Compressor[a]	0.3 hr/d	1	977	$78
Total Backwash Cost per Year:				**$1,591**

[a] It is estimated that 15% of air compressor operation is for the hood's pneumatic power.

Lighting

Lighting can represent a large consumer of electricity in an industrial plant. It is also worthy of noting that lighting systems are the easiest to develop energy conservation programs. A simple rule of thumb, "when you leave an area . . . turn the lights out". One note of caution, saving energy is not more important than providing a safe working environment. emergency and safety lighting is important and should not be reduced to save money. TABLE 5 shows the lighting consumption costs of the Root Reservoir Plant.

TABLE 5. Energy Consumption of Lighting Systems

Area	Duration	Quantity	kWh/yr	Cost per year
Main Lighting	10 hr/wk	12	1,560	$124
Office Lighting	11 hr/wk	12	275	$22
Low Lift Lighting	1.7 hr/wk	8	28	$2
High Lift Lighting	1.7 hr/wk	8	57	$5
Clearwell Lighting	1.7 hr/wk	34	120	$10
Air Comp. Lighting	1.7 hr/wk	20	71	$6
Chlorine Lighting	1.0 hr/wk	1	6	$1
Outside Lighting	60 hr/wk	4	2,652	$211
Total Lighting Cost per Year:				**$381**

Heating, Ventalation and Air-Conditioning

Heating, ventilation and air-conditioning (HVAC) is an area that typically uses two sources of energy. Primarily, electrical energy is used for fans and control systems and a second energy source is used for fuel, such as coal, natural gas, oil or propane. Propane is used for a heating supply of the root Reservoir Treatment Plant. (This energy audit does not include the propane used for heating, as the amount used is very small.) Occasionally electrical energy is used for a heat source but is normally prohibitive in industrial plants due to the high cost of electricity. TABLE 6 shows the HVAC consumption costs of the Root Reservoir Treatment Plant.

TABLE 6. Energy Consumption of HVAC Systems

Area	Duration	Quantity	kWh/yr	Cost per year
Hot Water Boiler	5 hr/wk	1	1,170	$93
Fans	0 hr/wk	2	0	$0
Heaters	4.6 hr/wk	6	442	$35
Dehumidifiers	23 hr/d	6	10,039	$796
Total HVAC Cost (electrical) per Year:				**$924**

Results

The total electrical energy consumption of the Root Reservoir Treatment Plant is shown on TABLE 7.

TABLE 7. Total Energy Consumption of the Treatment Plant

Area	Total kWh/yr	Cost per year
Clarifier Operation	456,950	$36,241
Backwash Cycle	20,060	$1,591
Lighting Systems	4,769	$381
HVAC	11,651	$924
Total Electrical Energy Costs per Year:		**$39,059**

The energy profile for the Root Reservoir Treatment Plant is 93% used for the clarifier operations, 4% is used for the backwash cycles of the sand filter beds, 2% is used for HVAC systems, and 1% is used for lighting purposes. In terms of energy conservation, the clarifier operation represents the largest potential for cost savings due to its high energy usage but all areas will be reviewed to find the potential conservation projects.

The Root Reservoir Treatment Plant is provided electricity by Western Massachusetts Electric Company (WMECO), a subsidiary of Northeast Utilities. The total electrical bill for 19989 was $37,153. Please note the discrepancy between the calculated annual electric costs and the actual. The small error of 5.1% is due to estimations of "ON" times, and variances in loads which occur throughout the entire year. The only way to reduced the error to zero is to gather data over the period of one full year. In addition, the calculations assumed that both units ran together at 100% load. The treatment plant ran at about 56% capacity for 1998. (The plant is designed to treat 584 MG (1.6 mgd) per year and in 1998. only 259.2 MG were treated.) Therefore, the actual electrical consumption would be less than the calculated consumption. However, the valued determined by calculations are proportional. Meaning that the relative amounts are the same.

Conservation Recommendations

Energy management is the key to conservation. By identifying where the plant uses energy then a closer look can be taken to identify the areas for conservation. Obviously, the largest users of electricity represent the greatest possibility for conservation thus the greatest cost savings. However, it should be noted that all areas should be reviewed to determine all available energy conservation opportunities. The recommendations for conservation programs can include mechanical retrofits, employee education or the installation of some type of electronic control system. The program must be feasible, cost effective, economical, and realistic to implement.

Clarifier Operation

The greatest user of electricity in the Root Reservoir Treatment Plant is the operation of the clarifier and its related components. 93% ($36,241) of the electricity used at the facility is used in the clarifier operation. The major users are the high lift pump (49%), the ADT pump (35%), and the low lift pump (9%). The annual electrical cost per year is $17,603 for the high lift pump, $12,345 for the ADT pump, and $3,321 for the low lift pump. The remaining components including the chlorine pony pump, the scoop drive and the carriage drive represent less than 2–3% of the total usage. Therefore, no substantial conservation measures will be examined for these components.

Recommendations for conservation measures will concentrate on the high lift pump, the ADT pump, and the low lift pump.

High Lift Pump

The high lift pump transfers the treated finished water from the treatment plant clearwell to the town's distribution system. It pumps 24 hour per day and is required for normal operation. One recommendation is to replace this aging pump's motor with a high efficiency motor. A high efficiency motor is a new generation design, requiring less energy than that of a conventional motor. One drawback is that this type of motor costs 30% more than a conventional motor. The efficiency of the lead pump's motor was unable to be determined due to the age of the Lincoln 40 horsepower unit. If the old Lincoln motor were replaced with a new, high efficiency motor, a savings would result in decreased electrical consumption. A safe estimation would be a savings of 10% with a high efficiency motor which would result in an annual savings of **$1,760.**

In order for a retrofit to be economical, economic analyses must be reviewed. A simple and easy calculation to determine if a project should be undertaken is *simple payback period* calculation. The payback period is the time required to recover the capital investment out of the earnings or savings. This is simply computed as the initial investment divided by the after tax savings. See equation 1–5.

$$\text{Payback Period} = \frac{\text{initial investment}}{\text{after tax savings}} \qquad 1\text{-}5$$

Therefore, if the parts and labor of the retrofit cost $1,760 and the annual savings were $1,760 per year, then the payback period would be one year. Factors like deprecation or tax regulations are not considered in this simple economic analysis.

ADT Pump

The ADT pump requires 35% of the electricity for the clarifier operation. The ADT system generates aerated water by passing compressed air and water through a contact tube where the air is dissolved in the liquid. This design requires two mechanical components, the pump and air compressor. It is estimated that 85% of the load to the air compressor is to provide the ADT system with compressed air. If another technology could be utilized, savings would result from the decreased electrical consumption of the air compressor *and* ADT pump.

The ADT system represents a unique energy conservation area. Newer technologies have been developed to produce aerated water that may save significant energy. Historically, these systems could not generate bubbles of the correct size to be effective in DAF systems. Many companies currently on the market sell aeration systems that range from passive air introduction systems like venturi nozzles and eductors to specially configured pumping systems.

If a new technology could be used that did not require compressed air, then the resulting savings would be the current compressor load to the ADT system. This results in annual savings of **$439.** In addition, if a passive air introduction system were used, the pumping requirement would be less. Depending on the manufacturer's specifications, a saving perhaps 15–20% of the current electrical consumption could be realized. 15% savings of the ADT pump consumption would result in savings of **$1,852.**

Low Lift Pump

The low lift pump transfers finished water from the plant's clearwell to the high lift pump station. Initially, the pumping system was not properly designed. The town performed a retrofit of one of the pumps. A 15 horsepower unit replaced one of the two original 5 horsepower pump motors. It was determined that the new pump was too powerful for the required flows. Therefore, the existing 5 horsepower pump is still used.

One recommendation is to retrofit the pump so that it pumps less water. One way to accomplish this is by throttling down the output valve. The motor however would still require the normal amperage to operate so no electrical savings would result. To realize savings, the diameter of the impeller of the centrifugal pump must be reduced, thus decreasing the flow produced. The motor would require fewer amps to operate and electrical savings would be realized. In order for this to be feasible, the pump curve supplied by the manufacturer and the flow range of the pump must be known. Reducing the diameter of the impeller requires machining in a lathe. Typically, for a 15 horsepower motor, a reduction of impeller diameter would result in an amperage decrease of between 2–5 amps. Assuming a 3.5 amperage drop, and because The unit runs 24 hours per day, 365 days per year, and assuming a 3.5 amperage drop, results in an annual electrical saving of **$1,937.**

Backwash Cycle

The backwash cycle represents 4% ($1,591) of the total electrical energy consumed at the Root Reservoir Treatment Plant. The energy profile of the backwash components shows that 95% of the electrical energy is used for the backwash pump.

The major user of electricity is the backwash pump. By adjusting the timer so that the unit is on for a shorter duration, an electrical cost saving can be realized. It should be noted that this timer value should not be arbitrarily lowered. The most appropriate backwash interval would be the shortest time, while still providing high quality finished water. However, the following demonstrates that even a 5-second reduction in timer duration can save money. If the current "ON" timer is set for 45 seconds and it is energized 21 times per cycle, and 31.3 cycles per day, then the total "ON" time per day is 8.22 hours. By adjusting the timers from 45 seconds to 40 seconds, results in an "ON" time per day of 7.3 hours. This results in 55.2 fewer minutes of the pump being energized, and thus annual cost savings of **$83.** This value is not significant but it should be noted that this would be a procedural change, and would require no capital cost.

Building

The building systems 3% ($1,305) of the total electrical energy consumed at the Root Reservoir Treatment Plant. Although this is a small value, conservation measures can still save money.

Lighting

Typically in the United States, lighting accounts for 20% of industry's electrical consumption. The facility's lighting costs is less than 1% and is far below the national average. Therefore, there are few conservation opportunities in the lighting area. However, the areas *where* the lighting serves is a point for discussion.

The area of concern is the outside lighting which represents 57% ($211) of the building systems electrical usage. Typically outside lighting serves three purposes; architectural lighting (for aesthetic purposes), safety lighting for workers (to prevent falls or attacks), and security lighting (to illuminate the area to prevent illegal acts). These reasons are each valid for a variety of locations but they may not be necessary in this particular location. The plant is deep in an isolated area. No unauthorized individuals are allowed in the vicinity of the building. The building was not designed to be beautiful from the exterior, so the architectural lighting is of no concern. Next, workers are only on-site during the daylight hours so safety lighting at night is of no concern. Finally, security lighting is of no real significance due to the isolated location of the plant. Therefore, it is recommended that all exterior lights be removed while a single light, wired to a motion sensor, is left to illuminate the entrance door. The reason for this is that occasionally an operator may have to report to the building late at night to address an alarm condition. The motion sensor will come on when the operator approaches and will provide illumination of the doorway while still conserving energy. The cost of the motion sensor is around $30. The annual savings from the disconnected lights would be **$186.** The payback period of this recommendation would be 0.08 years (29 days).

HVAC

Heating, ventilation and air-condition systems represent only 2% ($924) of the facility's electrical consumption and 43% of the building system's electrical consumption. The HVAC systems in the plant are relatively new and efficient. Therefore, no appreciable energy conservation measures can be recommended for the heating system that would be cost effective. However 86% of the HVAC energy consumption is consumed for dehumidification.

Dehumidification equipment was not installed during the initial construction. Portable dehumidifiers are used throughout the plant. Currently, $796 per year is spent to dehumidify the air at the facility. This is required all year round due to the differences in temperatures of the ground, water in pipes, and the air. Moisture in the air condenses on the pipes (due to the cold water temperature) or on the walls (due to the lower ground temperature) and the resulting condensation drips on the floor and equipment. Rust on equipment and moisture in electrical control components can lead to a shorter equipment life. By dehumidifying the air, the resulting condensation is lowered and the moisture problems with equipment alleviated.

A recommendation for dehumidifying the air in the facility is to install a dehumidifying coil in the air-handling unit (AHU) that services the lower area of the treatment plant. This would require a coil, a small refrigeration unit, and drains to be installed. The most expensive device is the refrigeration unit, while the entire project may cost between $800-$1500. This project may not seem cost effective when simply analyzing the electrical costs. However once maintenance costs, shorter equipment life, and costs due to downtime are factored in, the project may be feasible. If the capital costs of the refrigeration unit, the coil, and the drainage systems were ignored, the annual savings would be **$796.** Obviously, the capital cost cannot be ignored, however, after the break-even point of the project was reached, the savings would be realized.

Conservation Results

TABLE 8 shows the results of the energy conservation recommendations. The total savings of $7,053 could be realized if the energy conservation recommendations were implemented. The savings represent an 18.1% reduction in operating costs.

TABLE 8. Energy Conservation Recommendation Results

Area	Type	Total Annual Savings
High Efficiency High Lift Pump	Retrofit	$1,760
No Compressed Air for ADT	Retrofit	$439
ADT Pump Savings	Retrofit	$1,852
Low Lift Pump Impeller	Retrofit	$1,937
Backwash Pump Timer Adjust	Program	$83
Outside Lighting Program	Retrofit	$186
Dehumidification System	Retrofit	$796
Total Energy Conservation Recommendation Results:		**$7,053**

Current Production Costs

Current the production costs in terms of electrical energy usage is defined as the cost to the Town of Lenox to produce 1000 gallons of finished water. It has been calculated that the electrical costs for the facility in 1998 was $39,059. The plant produced 259.2 million gallons in 1998. Therefore, the production cost is **$0.1507** per 1000 gallons produced.

Current Margin

The Town charges $3.00 per 1000 gallons each household consumes, while is costs them $0.1507 per 1000 gallons produced. Therefore, the Root Reservoir Treatment Plant had a margin of $738,541 (income of $777,600–operation cost of $39,059). It should be noted that the margin indicated does not take in account additional costs of labor, chemicals, sludge disposal, vehicles, preventative maintenance, distribution system maintenance, spare parts, taxes or municipal bonds.

Potential Production Costs

If all of the recommended energy conservation programs were implemented, savings of $7,053 would be realized. Therefore, the potential operation costs would be $32,006 ($39,059–$7,053) and the potential production costs would be **$0.1235** per 1000 gallons produced.

Potential Margin

The potential margin of the Root Reservoir Treatment Plant would be $745,594 (income of $777,600–operational cost of $32,006) if the recommended energy conservation measures were implemented.

Conclusions

The Root Reservoir Treatment Plant in the Town of Lenox, Massachusetts is capable of treating 1.6 mgd using a dissolved air flotation with filtration (DAFF) technology designed by Krofta Engineering Corporation.

The treatment operation is divided into four areas for discussion; the clarifier operation, the backwash cycle, HVAC systems, and lighting systems. In 1998, the clarifier used $36,241 in electricity costs that represented 93% of the total facility consumption. The backwash cycle uses $1,591 in electricity costs that represent 4% of the total facility consumption. The HVAC system uses $924 in electricity costs that represent 2% of the total facility consumption. While the lighting system uses $381 in electricity costs, that represents 1% of the total facility consumption.

In 1998, the Root Reservoir Treatment Plant used 501,142 kilowatts of electricity that cost $39,059. The Town of Lenox was charged $0.0793128 per kWh in 1998. It produced 259.2 MG of finished water for a town of 5,600 people who are charged $3.00 per 1000 gallons that each household consumes.

Energy conservation measures were recommended that would provide cost savings of $7,053 that would reduce the operation costs by 18.1%. The current production cost is $0.1507 per 1000 gallons of finished water produced. If the all of the estimated benefits of the conservation recommendations were followed and implemented, the potential production cost would be $0.1235 per 1000 gallons produced.

About the Author

Mr. Sean Anderson currently is employed as a Project Engineer at Groundwater & Environmental Services, Inc. (GES) in Windsor, Connecticut. GES provides environmental consulting and remediation services to petroleum, manufacturing, and specialized industries, as well as to government agencies.

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Chapter 34— Minimizing Risks with Performance Contracting Projects—A Customer Checklist

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Overview

Performance Contracting (PC) is the process of providing guaranteed facility improvements that typically require no upfront capital. Since the savings generated from this process pay for the costs of the improvements, these types of projects are fiscally attractive. This is especially true for owners or entities that have very little or no capital to finance much needed improvements. Ensuring success with a Performance Contract is however an ongoing process starting with the company selection, through project design, implementation and contract maintenance. As the number of companies offering these type of services is increasing everyday, and their approach, track record, and offerings vary, a client is challenged with asking a lot of questions en route to selecting and maintaining the right partner.

All aspects of a PC agreement are defined in a contract. Understanding this contract is the client's biggest challenge. A typical contract has five separate sections dealing with 1) Contract Terms & Condition, 2) Scope of Work, 3) Performance Guarantee, 4) Baseline, Measurement & Verification, and 5) Financial Analysis. Complying with all the stated objectives of the contract and ensuring that the financial and performance guarantees are met requires considerable effort on both the Energy Service Company (ESCO) and the client.

This paper will provide simple checklists for each aspect of the PC process starting with the qualification process. The checklist will detail questions that can provide tremendous insight on a company, their approach to the business, specific details about your project, and their long term commitment to your project. As the contract is the legal document that binds the ESCO to a project, this paper will provide detailed checklists for each of the five sections of the contract to ensure that all aspects of the contract are well understood and agreed by both parties. This is the only means to achieve a long-term successful partnership!

Qualification

The first and foremost step to a successful performance contract is selecting a company that is qualified and has the proven track record in performance contracts. This is critical, as you are just about to launch into an agreement that could be 10 to 25 years long. The following checklist is designed to help with the qualification process and should be filled out for every company that you are evaluating. A score card for each company will bring out their strengths and weaknesses. Keep in mind that this is only a sample of the questions you can ask, and a more specific list can be utilized for your particular facility or specific situation.

Dedicated Business Unit

Age of Company

Total Annual Sales

Annual Performance Contracting Sales

Years Offering Performance Contracting Services

Total Performance Contracts

Performance Contracts in your Region

Performance Contracts in your Vertical Market

Accredited by NAESCO (National Association of Energy Service Companies)

Location of Office to Manage Project

Ability to Service Installed Equipment

PC Projects Canceled in the last 5 years and their Reasons

% of PC Projects not meeting Guarantee

Total Worldwide Employees

Employees Dedicated to PC

Certified Energy Managers

Professional Engineers

Firm providing Guarantee, ESCO or 3rd party?

Ability to Bond 100% of the project

Portfolio of Service Offerings

Project References

Ability to Implement Energy Awareness and Education Program

Ability to Provide Supply Side Services

Contract Terms & Conditions

The most important aspect of any performance contract as is with any legal contract is understanding the information contained within the contract. As a potential customer about to sign a multi-million dollar contract, it is imperative that the terms and conditions of the contract be clearly understood. As the information you need is described in various parts of the contract and not all in one single page, it is important to take the time to read the contract in detail. It is always recommended to have your attorney review the contract. The following checklist will help simplify the details of the contract.

Get the ESCO to explain the terms of the contract

What is the length of the performance contract?

When does the contract start?

What is the installation time frame?

When does the guarantee start?

When does the 1st payment occur?

When does the service and/or monitoring contract start?

What is the term of the annual service and/or monitoring contract?

What happens when the project installation time frame is not met?

Is the contract price guaranteed?

Are taxes and all fees included in the contract price?

What is the overall project warranty?

Does the contract insurance coverage meet your requirements?

Does the contract explain how possible disputes will be addressed?

Has your attorney reviewed the contract?

What are the responsibilities of the customer and the ESCO?

Scope of Work

Being the heart of the project, the scope must be well defined and clearly established so that all parties understand it. The following checklist will ensure that the scope is provided in detail and the work to be performed will be done in an efficient manner.

Is the scope of work provided in detail?

Does the scope follow all pertinent codes and regulations?

Is the scope of the project in line with your facility goals and objectives?

Has the project been fully designed?

Will stamped drawings be provided for the project?

Is a dedicated project manager assigned to the job?

When will the work be performed?

Has a detailed project work schedule been provided?

What interruptions will it cause your facility?

Is a performance and payment bond included in the project?

Who will issue the permits on the project?

What are the access and space requirements of the project?

How many subcontractors will be used on the job?

Will any part of the work require customer to shift or stop normal business activity?

Does the scope include cleanup of hazardous materials such as PCBs?

What training will be provided as part of the performance contract?

Is a customer employee required on-site during project installation?

Is an energy awareness or education program included as part of this project?

What are the owner's operation and maintenance requirements?

Performance (Savings) Guarantee

As the savings or performance is guaranteed as a result of a performance contract, the terms of the guarantee should be clearly spelled out, including what is guaranteed, clauses for shortfalls, and excess savings. The checklist below is designed to provide clarifications on guarantees.

Who provides the guarantee? ESCO or 3rd party?

What is the length of the guarantee?

Is there a guaranteed savings bond on the project?

What is the projected total annual savings?

What is the guaranteed total annual savings?

What is the breakdown of energy and non-energy (operational) cost savings?

What is the breakdown of savings by energy and unit type?

Is the non-energy savings guaranteed?

Is installation savings guaranteed?

What happens when a savings shortfall occurs in any year?

What happens when excess savings occur?

Can excess savings be carried forward?

Can excess savings in future year be used to offset past shortfalls?

Is there a clause for shared savings? If so, what is the breakdown?

Does the shared savings occur when the savings exceed projected or guaranteed savings?

What conditions will void the guarantee?

Baseline, Measurement & Verification (M&V)

Savings cannot be verified without first identifying a baseline for comparison. Although there are different ways of measuring and verifying savings and performance, it is important to use the method that is best understood and accepted by the involved parties. The checklist below will aid in asking the right questions when dealing with baselines and M&V.

What is the baseline year for comparison?

How was the baseline derived?

What parameters were utilized to arrive at the baseline—sq. ft, hours of operation, # occupants, weather, production output, etc.

How will savings be verified and what methodology will be utilized?

Will the M&V methods comply with the International Measurement & Verification Protocol?

What changes to the facility constitute an adjustment to the baseline?

How will adjustments be made?

What utility rates will be used to calculate savings?

What happens if utility rates increase or decrease?

How were operational cost savings derived?

Is an annual escalation utilized for savings?

How often will savings be reported and reconciled?

Is a 3rd party verification included in the contract?

Financial Analysis

This section typically details the contract amount and payment terms, but does not always include a cashflow which details the yearly payment and savings profile. This is a vital component of a performance contract, as the savings generated each year should offset the payment and service costs. Even if the details of the financial analysis are not all included in the contract, an owner should obtain the following information for their particular project, as it will have a net economic impact on the project.

Total Project Cost

Term of the Agreement

Nominal Interest Rate

Effective Interest Rate

Length of Construction Period

Loan Buydown Amount

Amount of Project Rebate

Type of Financing

Payment Frequency

Payment in Advance or Arrears

Equal or Graduated Payments

Date of 1st Payment

Total Project Savings

Total Project Payments

Net Project Cashflow

Project Payback

Net Present Value

Return on Investment

Internal Rate of Return

Summary

Performance Contracting is an excellent means of achieving both energy efficiency and much needed facility improvements through guaranteed results. Though the Performance Contractor assumes the majority of the risks associated with a project, a customer is tasked with several critical components in implementing a successful project. This starts with selecting the right long-term partner with whom the customer achieves their facility goals and objectives through a team approach. A good relationship is critical as this partnership is built on trust and understanding and unless the parties are comfortable with each other, the long-term success of the project could be in jeopardy.

The contract is the legal binding agreement between a customer and a performance contractor. A thorough understanding of the various terms and conditions, along with details of project scope, performance or savings guaranteed, method of establishing and verifying these savings, and financial impact can be obtained by asking the right questions. As you are in the process of signing or endorsing a multi-year, potentially multi-million performance contract, asking the right questions can help you minimize risks, and select and maintain the right long term partner to achieve your facilities' objectives through the implementation of a performance contract. Guaranteed!

Chapter 35— The Energy Star® Solution: A New Standard in Energy Upgrade Analysis

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NOTE: The views expressed in this paper are those of the project principals, Coriolana Simon of EPA and Lindsay Audin, president of Energywiz, Inc. They do not necessarily reflect the views of the US Environmental Protection Agency.

Abstract

To present opportunities for whole-building upgrades, the US Environmental Protection Agency's (EPA) Energy Star Buildings (ESB) program is developing a performance specification for energy auditing. By following this standardized protocol, such enhanced audits will be approved as "Energy Star Solutions."

The Energy Star Solution process follows an approach of "approving, adapting, or enhancing" existing auditing tools and formats, and then combining them to form a co-ordinated and complete package. In creating this set of standards, market research was conducted on the concept, on current auditing procedures, and on integration with related federal programs. To ensure a market-based perspective, a peer review panel of industry experts has been convened. In phase one preliminary design, protocols were developed for approving existing auditing tools. Phase two calls for the Solution process to be developed in draft form and presented to a wide array of stakeholders in the energy marketplace for two purposes: 1) to solicit input and secure commitments of support and 2) to establish an organizational framework for the subsequent stages of project development.

The principal feature of the Energy Star Solution is the integrated analysis of energy use, wherein interactions among building systems are examined, rather than looking only at single systems or components. This permits more realistic portrayal of potential savings of both cost and energy. By more clearly demonstrating how energy savings can improve any customer's energy bottom line, the Energy Star Solution will encourage implementation of profitable energy efficiency measures (EEMs). Such results will increase the perceived value of the audit process, while reducing the perceived risk in energy efficiency investment. This will be accomplished by highlighting energy efficiency opportunities as a business plan, according to the customer's own financial parameters. At the same time, by its unique inclusion of CO_2 mitigation calculations, the Energy Star Solution will help EPA toward its goals of reducing greenhouse gas emissions.

As a new tool for the evolving energy industry, the Energy Star Solution is being designed to:

- help standardize the way energy audits are performed
- bring energy customers greater value and less risk
- give energy service providers a more comprehensive product offering
- add to EPA's climate protection initiative.

The Energy Star Solution seeks to augment the value of energy auditing in the new millennium.

Making a Stronger Case for Energy Efficiency

Energy efficiency technologies for buildings are well known, and the benefits of a well planned facility energy strategy have been promoted for years. So why haven't more buildings been made energy efficient? Some feel that the case for energy efficiency has often not been made in a sufficiently compelling way to building owners and managers. To help correct this situation, the US Environmental Protection Agency (EPA) is developing a standardized energy upgrade analysis process that offers a convincing presentation of energy savings.

Why an Energy Auditing Standard?

In the past, the essential instrument leading to savings has been, in one form or another, an analysis of the ways energy is used—and could be saved—in an existing building. Such analyses have been called "energy audits," "technical assistance studies," "feasibility studies," "energy assessments," or "energy upgrade proposals." All recommend specific changes to equipment and/or operating procedures and indicate the economic value of such changes.

By focusing on single systems or components instead of whole buildings, energy audits have often overlooked how energy efficiency measures (EEMs) work together or with other energy-related building systems. Taking account of these *interactions* between and among EEMs is critical for an accurate analysis of energy use—and therefore, an accurate depiction of potential cost savings. Ignoring them can result in overestimation of savings, and/or operational problems.

Traditionally, the results of energy efficiency audits have been presented as a list of individual measures, each showing installation cost and payback period, ordered from the shortest to the longest. This practice encourages customers to pick and choose among what may be unrelated EEMs, often "cherry picking" the easiest measures with the quickest paybacks. A truer picture of potential savings is derived by *integrating* the measures—that is, by analyzing the cost and savings from carrying out a defined set of measures simultaneously.

"Integration" of EEMs is slightly different from *"cascading,"* an earlier approach that was required under the Department of Energy's (DOE) Institutional Conservation Program (ICP). "Cascading" means examining, in a suggested order based on payback and practicality, the cost of doing one measure, then a second measure assuming the first had already been done, then a third measure, assuming the first two had been done, and so on. Ideally, an *integrated* package would include the full list of cascaded measures instead of looking at each one individually.

Over the 25 or more years that energy audits have been performed, their range of quality and completeness has widened. In the '80's and early '90's, efforts to reduce imported oil fostered federal grants to states for energy upgrades in institutional buildings, accompanied by the first standards defining an acceptable level of analysis. When utilities became involved in energy efficiency by offering rebates and free energy audits, the number of audits—and auditors—increased dramatically. Vendors trying to sell energy efficient products also got into the audit business—though the results were often little more than refined sales promotions.

Missing the Mark on Savings

Many energy customers upgraded their facilities with new equipment but were often disappointed with the results. Too many conflicting and exaggerated claims were made, and too little guidance was available to help discern the best approach. Unsophisticated analyses failed to account for interactions between systems, yielding inflated savings assumptions and occasionally resulting in lost productivity and/or comfort. Some new installations were too complicated for untrained building maintenance personnel and were disconnected or ripped out. A few such "horror stories" were sufficient to convince many facility personnel that there was too little value in energy savings to risk their careers. Very little effort was devoted to measuring and verifying (M&V) the savings from EEMs.

The end result has been a skeptical attitude toward energy efficiency, with many building managers waiting for a new product to develop a longer track record, or simply avoiding involvement with energy efficiency altogether. When energy prices leveled off and began to drop, sales got even tougher. Deregulation has misled some into thinking that prices will drop so far that there is little need to even consider investing in energy upgrades.

While few vendors are willing to provide numbers, many would agree that most energy audits end up gracing a bookshelf or recycling bin, instead of serving as the basis for an upgrade.

The Need for a New Approach

Experience has shown that investing in energy upgrades can, if done properly, provide an excellent rate of return. If such proposals became more persuasive to energy customers, more energy savings would result. Just as the UL and Good Housekeeping labels were instrumental in securing the acceptability of many new products, some form of independent standard, accompanied by a recognized symbol, is needed to attain a level of acceptability for energy upgrades.

To upgrade the nearly 80 billion square feet of commercial space[1] in this country, an approach is needed that provides standardized, integrated, whole-building energy analyses that improve on today's often minimal audits. Such an improved procedure, backed up with independent oversight, would convince energy customers to invest in energy efficiency and help maximize delivered energy savings.

EPA's Energy Star Solution (E☆S) is that new approach.

What's the E☆S All about?

The E☆S Process Defined

In pursuit of such higher quality, whole-building upgrades, EPA's Energy Star Buildings program[2] recently initiated development of this innovative approach for enhanced energy upgrade analyses. This offering is not another piece of software, nor is it a service that performs energy audits. Rather, the Energy Star Solution project is creating ***a set of standards and supporting documents for energy upgrade***

analysis whose goal is to make convincingly clear the magnitude and likelihood of savings expected from such installations. Any energy upgrade analysis that follows EPA's standard and bears the Energy Star logo will be known as an "Energy Star Solution."

Essential components of the Energy Star Solution process include:

- an energy auditing performance specification, with a report template
- a vendors' guide for using the spec to produce an Energy Star Solution
- a consumers' manual to simplify handling the energy upgrade process

Designing the Spec

Development of the E☆S spec. The goal of this effort is to offer guidance and examples for users of the spec so that they may economically pursue higher quality energy upgrade analyses.

What's New/Different

Market research by the E☆S project is drawing on the best existing individual tools and procedures and shaping them into a performance specification, approving, adapting, or enhancing them as appropriate to yield one consistent, comprehensive approach.

Much of the value of the E☆S process lies in the following enhancements, many of which are missing from most of today's energy upgrade analyses:

- an emphasis on energy efficiency as a business opportunity to be treated like a business plan
- a standardized—and more complete—auditing procedure centered around the interaction of energy efficiency measures (EEMs)
- an integrated package of suggested measures, fitting the customer's financial criteria, shown as both a single proposal and as a cascaded list of EEMs
- recommendations and costing for M&V to be built into the design for each EEM as a way to ensure and quantify real savings
- benchmarking with the new EPA Label for Buildings tool[3]
- use of the Energy Star logo as a quality mark on E☆S reports
- a more precise depiction of the value of CO_2 reductions due to energy upgrades for possible future sale through emissions trading[4]
- quality assurance through spot checks by an independent third party and a systematic and standardized approach to training of energy auditors.

Emphasis on a Business Plan Approach

Central to the E☆S's approach is the emphasis on dollars first, BTUs second. In its opening pages, an E☆S report will highlight energy efficiency opportunities as a business plan—not an engineering task—based on financial parameters chosen by the customer, not the vendor. While offering the familiar context of simple payback, an E☆S takes customers a step further in their economic understanding of energy efficiency as an internal "profit center" by also offering a variety of other financial criteria and a probability curve for savings.

As part of an E☆S pre-audit interview, for example, a customer's financial parameters will be reviewed to ensure that his goals and desires are explored. Would life-cycle costing or a cash flow analysis over a 10-year period help him understand and sell the upgrade to his senior management? Is there a funding limit that cannot be exceeded, regardless of payback? Are there measures that must be taken (e.g., chiller replacement) for non-energy reasons?

Another part of an E☆S financial presentation shows the probability and range of payback for a specified group of measures, taking into account such variables as weather. Most business decisions today involve some analysis of risk so that it may be appropriately managed. An E☆S will offer a simple curve (using existing PC-based software) that shows how calculated savings could change due to conditions such as a warmer winter or uncertainty over burn hours for lighting. The result will be a more credible portrayal of likely savings or rate-of-return in the sophisticated manner to which CEOs are accustomed.[5]

Such financial presentation reduces customers' perceived risk of investing in energy efficiency while increasing their perceived value of the audit process. At the same time, this approach benefits vendors by turning more of their audits into actual projects and providing a unique edge over their competitors.

Market Focus and Market Support

From the beginning, the E☆S process in their own facilities. While it could also be applied to individual residences and industrial facilities, the simplicity of the former and the complexity of the latter often make other tools more appropriate.

Since the E☆S is offered to the marketplace. To that end, an independent Peer Review Board of energy experts was assembled and has been participating in developing the process.

Faced by budget constraints at EPA, the E☆S needs champions from many quarters of the energy marketplace. Assistance is therefore being sought from three key groups:

state energy agencies, particularly those with System Benefit Charge funds to disburse

non-profit organizations whose mission is to promote energy efficiency

other federal agencies involved with energy efficiency and standard-setting.

The types of support being sought include endorsements and promotion, funding for specific tasks, in-kind services (such as originating content through in-house staff), and eventual adoption as a standard for energy analyses sponsored by those groups.

As the E☆S concept develops a firm market-based foundation, the following tasks will be pursued:

final development of the spec and other technical features

field testing on real buildings

marketing

training design

quality control methods

program maintenance

feedback, evaluation, and revision.

A Solution for the Future

Turning a diverging set of trends and a history of uncodified practice in energy auditing into a credible standard the market will trust is not an easy task. With the commitment and participation of the energy community as partners in its development, the Energy Star Solution will guide the energy efficiency industry toward a true market transformation. It is thus poised to become the new standard for energy upgrade analysis in the market of tomorrow.

References

1. Energy Star Buildings is EPA's voluntary energy efficiency program for commercial and industrial buildings, focusing on "pollution prevention at a profit." Program participants follow this overall approach to upgrading their buildings:

develop baselines

forecast savings through energy upgrade analysis

secure funding

carry out integrated upgrades

promote the success of the resulting savings

The ESB integrated strategy for optimizing upgrades highlights system interactions and calls for:

Green Lights (lighting upgrades)

building tune-up ("recommissioning")

other load reductions

fan system upgrades

heating and cooling system upgrades.

2. This information is derived from DOE's Commercial Building Energy Consumption Survey (CBECS), 1994.

3. The Energy Star Label for Buildings may be awarded for excellence in energy performance to buildings that score 75 or higher on a scale from 1 to 100 with the Energy Star benchmarking tool. For more information, go to www.epa.gov/buildinglabel.

4. Prior carbon mitigation efforts used average power plant emissions, defined by the ten federal regions or state boundaries. Greater precision is obtained, according to EPA's Acid Rain Division, by utilizing the marginal

emission rates based on the dispatching of peaking generation units as defined by the boundaries of reliability councils established by the North American Electricity Reliability Council (NERC).

5. A recent (January, 1999) article in *Engineered Systems* magazine demonstrated how Crystal Ball, an Excel add-on by Decisioneering Corp., may be used to develop such a curve. Such tools are commonly used by energy marketing firms to assess and manage risk in pricing.

SECTION 2—
ENERGY SERVICE & POWER MARKETING

Chapter 36—
Key Considerations for Successful Financing of Energy Projects

Michael T. Frawley

The Importance of a Financing Strategy

Today, many organizations are evaluating the viability of implementing energy projects. As these evaluations are taking place, one key variable that is often overlooked in the early stages is the financing. A strategy for financing a project needs to be developed early on in the evaluation process to ensure that the project can clear the hurdles set by the organization's decision makers. Despite the fact that the majority of energy projects are worthwhile, the lack of proper financing is very often the reason why they fail to be implemented.

For an organization sponsoring an energy project, a great deal of thought needs to be given to how the project will ultimately get funded. The key to successfully financing an energy project is careful research and preparation in presenting the project to the organization's decision makers. If the organization's project sponsor (i.e., the person(s) initiating the project) is able to demonstrate that they have done their homework, it is more likely that the energy project will receive the attention that it deserves. This means researching the organization's financial resources and requirements, and the various financing options available so that this information can be translated into a well-packaged project financing proposal and presentation that speaks the language of the decision makers and clearly demonstrates the project's benefits to the organization.

Understanding the Organization's Financial Position

There are a number of key considerations that need to be researched in preparing the project financing proposal and presentation. The first and most important step in this research phase is determining the organization's current financial situation. If this can be accomplished early on in the process, a means can be found by which an energy project can be funded.

It is important to recognize that organizations vary in terms of their financial position. Knowing where a particular organization stands in its financial position can provide a roadmap to financing the project. For example, some organizations are strapped for cash, while others have plenty of cash available. Some have a high debt position, while others are debt free. An evaluation should be made early on to determine which financial profile the organization meets. This can easily be achieved by reviewing the organization's annual financial statements and talking with the organization's finance staff. Business documents, such as annual business plans, can also offer insight into other possible capital expenditures that may impact the financial position of the organization.

Once the organization's financial position is determined, financing options can be evaluated and recommended that best meet the organization's resources. For example, organizations with plenty of cash on hand may simply fund the energy project outright, while organizations that have little cash or place a stiff premium on the cost of internal money may opt for an off-balance sheet structure. For organizations that have little cash but low debt structures, financing the project through a lease from a third party may be the optimal solution.

Understanding the Organization's Financial Requirements

Before choosing the financing mechanism to recommend for the energy project, it is also important to understand what the organization's financial requirements are in terms of payback, internal rate of return, and hurdle rate. These are common screening tools used by organizations to determine the most attractive projects to fund. These requirements will vary from organization to organization. For example, organizations that compete in capital intensive industries place a high cost on internal money and, therefore, require a quick payback and a high internal rate of return for its projects. This situation can differ in organizations that have a lower cost of capital and, therefore, lower financial requirements for projects. A discussion with the finance department can shed some light on these financial screening tools and the organization's requirements.

A strong understanding of the organization's financial requirements is critical since, very often, projects compete with one another in the capital budgeting process. Within this process, projects are most often ranked based on the financial criteria discussed above. Projects are typically ranked by financial return and are then approved and funded in order from the best to the worst until capital dollars have been depleted. This method often leaves many projects without financing. An interview with finance staff may provide insight into a project's ability to compete in this process.

Some energy projects, although an attractive investment, may not receive financing because they do not meet the requirement that they be related to the organization's core business. Therefore, it is imperative that a project recommendation addresses the financial benefits of the project in the form of reduced energy costs, which translate into profit for the organization.

Knowing an organization's financial requirements early on in the process can save time, effort, and money in creating a project that is fundable. Knowing upfront the financial constraints of an organization can provide insight into how the project needs to be positioned.

Understanding the Available Financing Options for the Project

The best way to determine the optimal financing option to propose for an energy project is by becoming familiar with the various benefits and disadvantages of the various financing approaches available. The following provides a brief overview of these options.

The first financing option to evaluate for a project is internal cash reserves. A cash purchase is the cheapest approach for an organization to utilize to fund an energy project since the organization is not paying for risk associated with credit and performance that is inherent in third-party financing. Also, all project benefits (e.g., project cash flows) are immediately available. With the majority of organizations, however, cash is not in abundance and the project must compete in the capital budgeting process.

If cash is unavailable, the next logical question to be considered is whether or not the organization can finance the project through a third-party financier. An important consideration will be the organization's willingness to assume additional debt. This is also referred to as the balance sheet impact. A balance sheet shows an organization's assets and how those assets are financed through equity and/or liabilities (debt). An on-balance sheet financing simply means that the project would create a liability on the balance sheet and increase the organization's debt. An off-balance sheet financing would avoid this impact and create an expense in the organization's profit and loss statement.

Should an organization have a willingness to take on debt, a loan or capital lease can be arranged for the energy project. The strategy for this structure would be to extend the term to allow the savings to equal or exceed the cost of the loan or lease payments. The loan would typically have broad collateral in the organization's assets, while a lease's collateral would be specific to the project equipment. Under these structures, an organization would own the equipment and title would pass at the end of the finance term. The organization is obligated for the full loan or lease amount. These vehicles work well when an organization is comfortable with the risks of the project and can accept the on-balance sheet obligation. For nonprofit organizations, the availability of tax-exempt leases can be a very attractive alternative due to the low interest rates that they provide.

If cash is unavailable and on-balance sheet financing is unattractive, a third strategy would be to have an energy services company ("ESCo") provide the financing in exchange for a service contract. Under this scenario, the ESCo would be paid a negotiated amount based on the energy cost savings produced from the project. This performance-based project financing has become especially popular in the Federal marketplace where the government keeps all of the savings that exceed the agreed upon savings amount. In the case of a savings shortfall, the Government would pay based only on the amount that has been saved.

A quick guide to assist in determining the best financing mechanism to recommend in the energy project proposal is to answer the following series of questions:

1) Is the project able to compete for capital dollars, and, if so, within what time period?

2) If not, or the time period for competition is too long, is your organization comfortable with taking on additional debt?

3) If not, is the organization interested in off-balance sheet financing through an ESCo?

The key point to remember is the importance of determining the organization's financial situation and requirements before the energy project proposal is presented to the financial executives as each method of financing carries different costs and offers different benefits to an organization.

Understanding the Project Decision Makers

Another strategy used by individuals who have implemented successful energy projects is to package the project financing proposal in a way that their organization's upper management is accustomed to seeing it. The information should be presented in an organized format that is easy to follow and, ultimately, relates the project to its positive impact on the organization's bottom line. Ideally, the strategy should be to position the project as an internal profit center. This is important because, although the project could bring some significant energy infrastructure improvements, finance executives will be more concerned with its impact on profits.

In addition, the more the project's sponsor can speak the language of the financial executives, the more credible the project will appear. Therefore, the project's sponsor should become familiar with key financial terminology and models (e.g., payback, internal rate of return and net present value). Information on these and other related financing concepts are readily available in finance textbooks or via the Internet, and most models are already pre-programmed into the major spreadsheet software packages.

Case studies highlighting energy upgrade project success stories can also create impact during the presentation and address some of the concerns that a CFO may have in terms of project risks and benefits. Case studies demonstrating the value of energy project implementation should be readily available from an ESCo or other energy project developer.

Summary

It has been shown that an energy project can provide significant benefits to an organization in terms of improved efficiency, reduced energy costs, and a positive impact on the bottom line. It is the responsibility of the project's sponsor to move the project from conception to approval by the organization's decision makers. By doing the appropriate homework upfront, it is possible to elicit excitement and approval for the project and set the standards for energy project presentations, making it easier for similar projects to get approved for financing in the future.

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ABB Energy Capital provides innovative financing for energy , environmental, and other mid-sized project financing opportunities. The company offers a comprehensive portfolio of financial products and services, specializing in performance-based project financing.

Chapter 37— David and Goliath Revisited

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Abstract

This paper describes the conflict between a small independent energy services company (ESCO), Sherber Associates, Inc., against a large utility company that simultaneously administered a rebate program that the small ESCO depended on, and that also owned an unregulated ESCO that competed directly against the small independent ESCO. Efforts to negotiate failed and this dispute wound up in litigation. When regulators allow utility companies to run high dollar rebate programs and own unregulated ESCO subsidiaries that also compete against independent ESCOs for these rebate dollars, a conflict of interest is established that can lead to predatory behavior by the utility company.

Introduction

In 1992, with the prospect of electric deregulation looming, Public Service Electric & Gas Co. (PSE&G) formed Public Service Conservation Resources Corporation (PSCRC) as an unregulated subsidiary. According to Public Service Enterprise Group's (PSEG—the parent holding company of PSE&G and PSCRC) 1993 annual report, PSCRC was formed to develop "the marketing and managing of demand side management products . . . providing the potential to produce good returns for PSCRC". Thus, PSCRC's charter set it up to directly compete with independent ESCOs such as my company. It also clearly put PSE&G, PSCRC's corporate parent, in a conflict of interest by owning an unregulated ESCO and administering the Standard Offer rebate program that the competitors of PSE&G's unregulated subsidiary ESCO such as my company depended upon.

Energis Resources was formed in December 1996 for much the same purposes as a subsidiary of PSEG (the parent holding company), and PSCRC's operations were folded into Energis. In January 1998, Energis was renamed Public Service Energy Technologies (PSET). Incidentally, both Energis and PSET had their offices in Edison Township, New Jersey.

On March 27, 1997, my company, Sherber Associates, Inc., an independent energy services company, entered into an energy performance contract with the Edison Township (NJ) Board of Education to provide energy conservation measures (Edison Board of Education Contract). According to the Edison Board of Education Contract, Sherber Associates was to install energy efficient lighting fixtures in all eighteen of their school buildings, replace ten pieces of rooftop HVAC equipment and install ten hot water heaters to permit boilers to be shut down in the fall and spring. This will be referred to as the Edison Schools Project.

Sherber Associates arranged for the financing of the project, and qualified the project for Standard Offer 2 (SO2) rebate payments. We expected to retain a percentage of the SO2 payments as its administrative fee for invoicing PSE&G for the monthly rebates earned by the project, and the balance of the SO2 payments would be given to the Edison Board of Education upon receipt from PSE&G.

Sherber Associates proposed to perform the work in two phases. The first phase was pursuant to contract number 21268-001, and consisted of lighting retrofits for of the five largest school buildings. This will be referred to as the First Edison Schools Contract. The First Edison Schools Contract was drafted by PSE&G. The work for the First PSE&G Contract was successfully and timely completed.

On June 26, 1997, Sherber Associates submitted the second phase of the Edison Schools Project for contract processing by PSE&G. The second phase consisted of lighting measures for the rest of the school buildings and a maintenance building, and all the HVAC measures. The proposal by Sherber Associates for the second phase of the Edison Schools Project contained all the necessary information and met all the requirements for a SO2 project. Sherber Associates is informed based on past experience with PSE&G that in the ordinary course, it was

PSE&G's practice to accept qualified projects such as the Edison Schools Project in a matter of a few days since these involve boilerplate contracts that were authored by PSE&G. The second phase of the Edison Schools Project was planned to be completed before the end of the summer recess, so that work could be performed on a continuous basis while the buildings were not in use.

PSE&G's "Heightened Level of Scrutiny" Halts our Project and other ESCO Projects

In early June 1997 PSE&G stopped signing Standard Offer 2 contracts. However, they did not tell us they had done this at the time they initiated this action. So that when we submitted our Second Edison Schools contract this moratorium had been in place for several weeks. We believe they were obligated to do under the existing contracts we had with them since it was clearly a change in the program.

Indeed, when I later mentioned this to one of their managers following a meeting in December 1997, he told me that PSE&G's DSM staff had been ordered by in-house counsel not to tell us that they were they were not signing any more S02 contracts at the time they did this. Before starting my company I had worked in management for a Fortune 20 company and had worked very closely with in-house counsel on a number of projects. Based on my experience, it is highly unlikely that in-house counsel would have issued such an order without the consent or orders from senior management at PSE&G.

On July 1, 1997, I called PSE&G's DSM Department to inquire as to the status of the project proposal he had submitted to PSE&G on June 26, 1997 and also set up the pre-implementation audits that PSE&G required as a condition of approving the project. During that phone conversation with their DSM resource acquisition manager he told me that PSE&G was signing no new Standard Offer 2 contracts (such as the one I hand-delivered on June 26, 1997). He also said that a "senior vice-president" at PSE&G had ordered them (the PSE&G DSM Department) a month before not to sign any new Standard Offer 2 contracts.

Nor were we the only ones impacted. We heard through one of our suppliers that a hundred million-dollar renovation at Newark Airport was also delayed by PSE&G's moratorium on sighing new SO2 contracts. Many other ESCOs had their projects halted, too.

The NJBPU staff began receiving complaints from energy service companies such as Sherber Associates starting on June 18, 1997. The NJBPU staff then notified PSE&G by letter dated June 23, 1997, that in the NJBPU's Staff's opinion the unilateral discontinuance of Standard Offer 2 was in violation of the NJBPU's December 29, 1995 Order, Docket No. EE9508063.

According to the NJBPU, PSE&G told them in writing by a letter from a Mr. Delany, PSE&G's Vice President and Corporate Rate Counsel, dated June 27, 1997 that they had not suspended the Standard Offer 2 program but instead were applying a "heightened level of scrutiny" to the pending S02 contracts that they were in fact not signing. This was a week before the PSE&G DSM resource acquisition manager told me on the phone that he had been ordered not to sign any more SO2 contracts.

A Formal Complaint and Request for Formal Hearing dated July 9, 1997, was filed with the NJBPU on July 10, 1997, on behalf of a number of ESCOs, including my firm, by SYCOM, another ESCO. The SYCOM complaint alleged that PSE&G had effectively suspended the Standard Offer 2 rebate program in violation of the NJBPU's December 29, 1995 Order.

NJBPU Rules PSE&G to have Violated Its Order Establishing Standard Offer 2

The New Jersey Board of Public Utilities (NJBPU) heard the SYCOM Complaint on July 30, 1997. In a written ruling issued on August 18, 1997, the NJBPU ruled that PSE&G's actions were unwarranted and a violation of the NJBPU's December 29, 1995 Order establishing the Standard Offer 2 Rebate Program. It ordered PSE&G to sign all pending Standard Offer 2 contracts within five days.

More Problems Develop

Even before the July 30, 1997 hearing before the NJPBU we believe that PSE&G realized they were going to lose so they started signing contracts again. But it is interesting how they went about this. They dated our contract July 14, 1997, but did not send it to us until July 23, 1997. Because we couldn't start construction until we had our buildings audited and we could not set up audits until we had an executed contract we could not even make audit appointments until July 24, 1997. Because of PSE&G' s illegal SO2 moratorium, their auditors were also backed up so we could not get our first school in the Second Edison Schools contract audited until August 8, 1997.

Thus, a project that should have finished construction by Labor Day was not substantially completed until the end of October 1997. We incurred additional costs because we had to finish most of the work on evening shift at differential after the school year had started. I had to keep my construction manager, my trailers and myself in the field two more months than I had planned. This delay, just from the construction interfered with our ability to bid on two million-dollar municipal projects that we had a good chance to win.

At the same time PSE&G's audit contractor, CMC, was taking too long to complete its paperwork and billing disks that we needed to prepare S02 invoices. We also found mistakes that their auditors had made which short-changed our customer and which they wouldn't admit, even in the face of photographic evidence.

Attempts to Negotiate Are Futile

In an attempt to resolve many of the disputed issues between us and PSE&G I asked if we could negotiate face to face at their offices in Newark. A negotiating meeting took place on December 3, 1997 at PSE&G's offices in Newark. Unfortunately, the PSE&G personnel at the meeting simply stonewalled at the meeting.

During the meeting I brought up this issue of the July 7, 1997 letter that the DSM contracts manager had sent to me attempting to unilaterally relieve PSE&G of its obligations to pay multiple invoices or facilities within thirty days. The PSE&G DSM contracts manager responded that if I did not accept that change PSE&G would take up to six months to pay our rebate invoices.

State Regulators Are Indifferent, or Worse

Early in 1998, after the failure to resolve many of what we felt were a number of meritorious disputes with PSE&G or its audit contractor, Conservation Management Corp. (CMC), we sent a series of letters to the staff of the NJBPU asking their assistance. Our letters described in great detail the dispute items we had with PSE&G and their audit contractor. Our letters in several instances included photographic proof documenting our position concerning our disputes on errors we alleged that PSE&G's auditors had committed which shortchanged our customer and us.

We asked for, and were able to arrange, a meeting at the NJBPU's offices in Newark on April 22, 1998, with representatives of PSE&G, my company and its attorney, and a staff member of the NJBPU.

At the very beginning of the meeting the NJBPU staff member told me that he had not read any of the half dozen or so letters I had sent to the NJBPU describing the disputes we had had with PSE&G leading up to this meeting. He said that he could only stay for two hours, at the end of which time the meeting was over. What was worse, was that this staff member had told me in a previous phone conversation that his view of the Standard Offer Program was, "Its their (PSE&G's) program, and we (the NJBPU) let them run it as they want".

So, we had to waste precious time rearguing points that we had made and substantiated previously by letter. The NJBPU staff member was not very sympathetic and indeed at several points even parroted word for word PSE&G's position even before we had a chance to respond to PSE&G's arguments.

During this meeting, I brought up the issue of PSE&G's July 7, 1997 letter to me in which they unilaterally attempted to relieve themselves of the obligation to pay our invoices within thirty days if we submitted invoices for multiple invoices or facilities. After bringing this issue up again, the PSE&G DSM contracts manager once again reiterated his threat to take up to six months paying our rebate invoices if we did not accept it. As events later unfolded, he made good on that threat.

We did achieve what I thought was an agreement with PSE&G regarding what they required in order for them to approve our new rooftop HVAC units and gas-fired hot water heaters. To avoid any misunderstandings I confirmed it twice verbally at the end of the meeting and then we sent PSE&G and the NJBPU a confirmation memo and asked them to write us with any disagreements of our account of the agreement we reached. They did not send any correspondence disagreeing with our account of the meeting and this agreement.

PSE&G Retaliates Following the Meeting with the NJBPU

In accordance with our April 22nd agreement on the HVAC equipment we installed I sent PSE&G a package with all seven items we had agreed to. PSE&G has never disputed that all seven of the agreed upon items were in the package. Instead, PSE&G continued to refuse to accept our HVAC equipment site plan and demanded additional information that was not part of the April 22nd agreement we had arrived at in the NJBPU's offices.

We tried to comply with PSE&G's additional information requests and they either rejected our additional documentation or asked for even more documentation that was not part of the April 22nd agreement.

So we had high efficiency HVAC and hot water heater equipment that we had installed in the fall of 1997, and had been delivering real energy savings since then that PSE&G was refusing to accept or pay rebates for. PSE&G refused repeated verbal and written requests to even inspect this equipment.

Then, PSE&G had the nerve to send us a series of default notices which didn't specify what the defaults were or what remedies they sought.

At the same time PSE&G simply stopped paying our rebate invoices after the April 22, 1998 meeting at the NJBPU's offices. For the first few months they invented wholly pretextual reasons to deny payment of a few invoices.

On July 10, 1998 several invoices we had submitted to PSE&G for payment were returned. Each invoice packet contained a letter stating the invoices could not be processed because there was no billing disk submitted with the invoice backup. This was not the first time PSE&G had returned several invoices for lack of a billing disk. My former office manager told me that she always checked that each invoice packet has a billing disk before they were sent out. However, what was remarkable about this instance was that the so-called missing diskette was clipped to PSE&G's cover letter stating that they were returning the invoices because there was no billing disk attached.

On July 17, 1998 PSE&G sent letters to us concerning our billing package for two of the Edison schools for the months of October through December 1997. They claimed that there was "Disk error. Some points were missing. . . " Yet, the letter did not specify which points were missing which was very suspicious. My office manager and I opened the files and were not able to find any errors or any of the missing points that PSE&G claimed were missing. These letters were also incorrectly addressed which delayed their delivery to us. We had by this time sent a separate official notice via certified mail to PSE&G back on June 19th with our correct address which PSE&G obviously disregarded.

We then resubmitted this billing package to PSE&G on July 20, 1998. We did not receive payment until November 5, 1998, nearly four months later, following the issuance of the Order to Show Cause. In the meantime, PSE&G did not notify us of any other errors on these billing disks. This nearly four-month time to payment by PSE&G was significantly beyond the thirty-day payment or error notification requirements of all three contracts.

By this time this kind of behavior by PSE&G was the subject of in-house joke. We called it the "excuse of the month club". It seemed that every month PSE&G came up with another sham excuse not to pay our invoices.

After we corrected the "errors" in our allegedly defective invoices and sent them back this time we didn't hear anything. We figured they had run out of sham excuses. They simply did not pay our invoices and did not even return them with new error messages within the thirty days required by their own contract.

They were also deliberately using the wrong address in time-critical correspondence we sent to them. In several instances this materially delayed our receipt of important notices from PSE&G. At first we gave them the benefit of the doubt and excused it to error. But even after we repeatedly notified them of this error they continued to send time-critical notices to the wrong address. In a revealing conversation my office manager had with one of the PSE&G employees he admitted that someone at their end had whited out our address and written in the wrong address.

"We're Having Too Much Fun"

With PSE&G refusing to pay our past-due rebate invoices the situation became dire for our company. We decided to take advantage of legislative hearings on the pending deregulation of the electric markets in New Jersey to apply some political pressure on PSE&G to stop harassing us and start honoring their contractual obligations to us.

On September 16, 1998, I testified before the New Jersey Assembly Democratic Task Force on Energy Deregulation in Deptford, NJ about many of PSE&G's bad acts against us including the unwarranted refusal to accept our HVAC and hot water heater equipment and their refusal without explanation to pay tens of thousands of dollars of our rebate invoices. There were two representatives of PSE&G at this hearing. Later in the hearing these two PSE&G representatives also provided testimony.

The PSE&G representatives in their remarks claimed they were not aware of PSE&G's actions against my company and our customers such as the Edison Board of Education. They promised the legislators a response to our allegations against PSE&G within two weeks. A month later I called the office of one of the members of this task force and found out that PSE&G had not provided their promised response.

After the hearing, a very revealing conversation took place. One of my attorneys, Bill Potter, and I went up to the front of the meeting room. At the same time the two PSE&G representatives came to the front of the room in front of the dais. Mr. Potter asked them if they knew what PSE&G was doing to my company. One of them admitted a passing familiarity of what PSE&G was doing to us (and the Edison Board of Education), contrary to what he told the legislative task force. Mr. Potter then asked the PSE&G representatives if we could just work things out. One of the two PSE&G representatives then put his arm around me and said, "Why would we want to do that, we're having too much fun".

On September 23, 1998, a week after my testimony before the NJ Assembly Task Force on Electric Deregulation PSE&G sent me a notice of default threatening to terminate our Second Edison Schools Contract. The September 23rd letter did not comply with the requirements of the contract for a notice of default. It did not specify what the default was or specify a cure. Instead it simply demanded the termination of the contract. Could this have been connected with my testimony the week before?

If the Second PSE&G Contract had been terminated, Sherber Associates and the Edison Board of Education would be denied the benefit of the ten years of SO2 payments remaining under the contract. PSE&G and its ratepayers, however, would have continued to enjoy the benefit of the energy savings that they had bargained for and which the Edison Board of Education and Sherber Associates had borne the cost of. Termination of the Second Edison Schools Contract would have caused Sherber Associates to default on its contract with the Edison Board of Education and probably driven us out of business.

PSE&G was aware of this since it had required a copy of our contract with the Edison Board of Education as a condition of executing a Standard Offer contract with us.

We believe that it is only because we eventually took this matter to court that PSE&G was prevented from making good on its bad-faith threat to terminate our Second Edison Schools contract 21268-002.

On Friday, October 9, 1998 we held a phone conference with PSE&G as a last ditch effort to resolve the dispute before we resorted to litigation.

During this phone conference, PSE&G's DSM contracts manager freely admitted that he had held up paying our invoices "to bring us to the table". We viewed that, given his past behavior, as a euphemism for attempting to bring us to our knees.

The PSE&G DSM contracts manager tried to blame us for their deliberate failure to pay our invoices. He claimed that our invoices were faulty because they had an extra blank column. We pointed out to him that they had never notified us of this so-called deficiency, and the contract that PSE&G wrote stated that they were clearly obligated to notify us within 30 days of any errors or deficiencies in our invoices or the invoices were deemed correct and payment due within 30 days of invoice receipt by PSE&G. They clearly did not do this.

The months of frustration from dealing with PSE&G's stonewalling and the financial damage we had suffered from non-payment of our rebate invoices and legal fees in dealing with PSE&G led to my office manager's resignation the following Monday, October 12, 1998 after the October 9th conference call.

Attempts to Negotiate Are Futile:
Litigation Is Commenced

When PSE&G did not honor its commitment from the October 9th phone conference to pay the past-due rebates within five business days we filed a lawsuit in Middlesex County Superior on November 4, 1998. When we filed suit, our records showed PSE&G past due on over $100 thousand to us. Some of our invoices were more than six months past due. For a small company such as ours that was a tremendous amount of money and it had adversely affected our operations by then.

On the very first day of the lawsuit, in a hearing in front of the senior assignment judge, an Order to Show Cause was issued against PSE&G compelling them to pay within twenty days all of the rebate invoices that they did not contest. According to my attorney, it is extremely difficult and rare to get a judge to issue such an order at the very beginning of a case. When such a court order is issued it means that the judge has found no dispute of the key facts and that irreparable harm had been done to my company. The court order also required PSE&G to explain within twenty days why they weren't paying any of the remaining outstanding invoices we had sent to them.

PSE&G Engages in a Delay and Bleed Defense

As part of PSE&G's defense, they included a sworn affidavit from their DSM contracts manager which among things claimed that their delay in paying us was due to our invoicing errors and that my company was the only one having invoicing problems. This flew in the face of what I had heard from other ESCOs and other parties that prepared Standard Offer invoices for PSE&G. Indeed, after I showed the November 3, 1998 affidavit to an executive from another ESCO, upon reviewing it he said of it, "This is perjury".

Following a December hearing before the judge in this case we scheduled a settlement meeting for January 6, 1998 at PSE&G's offices in Newark. After we made a fair amount of progress in settling many of the disputed issues it was agreed that a follow-up meeting would be held to attempt to conclude the negotiations. Due to a short deadline RFQ that came out I asked my attorney to reschedule the original follow up meeting. For two weeks my attorney tried in vain to reach his in-house counterpart at PSE&G, who did not return my attorney's calls or give any indication whatsoever of any difficulty or impossible issues in our negotiations.

Finally, at the end of the two weeks we received a notice from the PSE&G attorney that he was filing a motion with the Court in which he claimed that negotiations had broken down and that he was motioning for the case to be transferred to the NJBPU. Mind you, PSE&G was the party that walked away from the negotiating table without explanation. The Court heard this motion to transfer, and on March 19, 1999 quickly rejected it.

However, this clearly indicated that the January 6th meeting which lasted approximately four hours and took over six hours of drive time for me just to get to and from was simply a bad faith attempt by PSE&G to waste my time and my attorney's time.

Shortly thereafter, PSE&G filed another frivolous motion requesting a case management meeting. This too, was rejected. But, it succeeded in wasting more time and money.

On March 22, 1999, we served PSE&G with our interrogatories. Under the Rules of Civil Procedure PSE&G had sixty days to respond. Shortly before their sixty days was up PSE&G's attorney asked for a thirty-day extension which we granted.

When the thirty-day extension for the interrogatories we requested from PSE&G was up my attorney made repeated calls to his counterpart representing PSE&G, that were not returned. Finally, he got through to the PSE&G attorney. The PSE&G attorney made some bogus claims about how difficult the interrogatory requests were but then committed to deliver them by July 30, 1999 when this paper was submitted for publication.

Mind you, PSE&G's interrogatories on us were far more widespread than were our requests to them, to the point of being harassing. PSE&G asked us for every document having anything to do with this case. My small company with one full-time employee by this point was able to produce all 25,000 pages of documents that PSE&G requested in nine boxes that I personally packed. It took me approximately a week to pack and organize all of these documents. After we took the documents to the printers for numbering and copying, PSE&G refused to pay for it which they were obligated to do under the Rules of Civil Procedure. This indicated to me that the PSE&G attorneys were, in bad faith, attempting to abuse the document requests and the discovery process, much as their colleagues had abused the Standard Offer program to harass and delay us, and waste as much of my time as possible.

PSET Posts a $14 Million Loss for 1998

In 1998, the first year we know that PSE&G broke separately the financial performance of its unregulated ESCO subsidiary, PSET, it recorded a loss of approximately $14 million. At the same time we have heard through the industry grapevine that there was significant turnover among PSET's personnel due to poor morale and operating results.

PSE&G'S Behavior and the Costs of Litigation Have Done Irreparable Harm to Our Business

There is an old curse that goes, "May you have a just lawsuit". What it means is that someone had to work you over and do grievous harm to you before you have a just case. Then your opponent can abuse the (inherent patience, procedures and costs of the) legal system in order to work you over some more. Going into this case I did not have a romantic, idealized view of the litigation that my company would engage in to protect our rights and assets against PSE&G. I knew that it would be expensive, time-consuming, and frustrating. And that was with a strong case, too.

But, I felt we had no choice given that to do nothing would have meant that we would have wound up breaching our agreements with out customers, which would have the end of our small business.

Still, my firm has paid a heavy price for this fight. I lost a very capable office manager. The legal fees have seriously hurt my company's finances. The vast amounts of time prosecuting this case have hindered my ability to market my firm's services. On several municipal jobs where we submitted statements of qualification they asked if we were involved in any litigation. So we had to disclose details of this matter. Having to disclose that you are a small company involved in litigation can scare customers and thus may have hurt our chances of winning several major jobs, even though we are clearly capable of doing the work as was evidenced by our Edison Public Schools project being written up as a case study by both Energy User News and Engineered Systems magazines.

Conclusions and Lessons Learned

1—
For the Regulators

Federal and state regulators who allow utility companies to run substantial rebate programs and own unregulated energy service companies are inviting dangerous conflicts of interest that can result in the kind of anti-competitive, abusive behavior that PSE&G exhibited against our company. Even PSE&G's own consultant, the Wisconsin Energy Conservation Corporation (WECC), in a study that was financed by PSE&G, concluded that PSE&G should not continue to run a rebate program (and an unregulated ESCO at the same time) when it said in it's summary:

> "Regulatory redirection and initiatives, including the promotion of a statewide SO (Standard Offer) program administered by a non-utility independent administrator, would capture an important opportunity, that will otherwise be lost, for contributing to the BPU's and the State of New Jersey's goals of increased energy efficiency and the development of a competitive energy industry in New Jersey".

That is startling language from a consultant that was hired by PSE&G to evaluate PSE&G's own handling of the Standard Offer program.

2—
For the Independent ESCOs

If you operate in a state where the utility company administers a substantially sized rebate program and owns one or more unregulated ESCOs be very careful, document everything, and have a good attorney ready. The temptation for the utility company to abuse its stewardship of the rebate program in order to hinder competitors of its own ESCO may be too much for it to resist.

If the utility company administering your rebate program acts like PSE&G did against us and others obviously treat it like any other commercial dispute and try to negotiate with them, if possible. You may even want to show them this paper and ask them if this is the kind of industry publicity they would like.

If negotiation fails, understand that litigation will be more painful, more time consuming and more expensive than you can possibly imagine. Litigation should be the very last resort of an ESCO in dispute with a utility. Your attorney can and will spend money far faster than you can make it—and I happen to like my both of my attorneys, too. However, if you understand this, are thoroughly prepared and have the intestinal fortitude to go through with it you can win. Like many wars, it may be a costly victory. But like many wars, sometimes you have circumstances forced upon you that you can't control and have to make the best of them. Also as in many wars you may be dealing with an adversary (like PSE&G) that is either acting irrationally or has badly miscalculated the situation and in particular your ability and willingness to fight back.

3—
For the Utility Companies

Engaging in the kind of behavior that PSE&G engaged in against our company is not only immoral, unethical and illegal, it doesn't even make good business sense either. At the time of the writing of this article this matter was well along in litigation and the key facts of the case were beyond dispute. Indeed, the issues of whether or not PSE&G had acted improperly in delaying the execution of the second Edison Schools contract, and in not timely paying our rebate invoices have already been determined as matters of fact by the NJBPU and a Superior Court judge, respectively.

PSE&G likely faces the prospect of writing us a large check as part of a settlement or a jury verdict. While PURPA allows PSE&G to pass on to the ratepayers much of its legal costs, it does not cover the amount of that check they may have to write to us or the value of the time of their staff while it is tied up in litigation.

Neither is it good public relations for the utility company as the deregulation of the electric markets is about to occur to engage in this type of behavior. At this point good public relations are more important than they ever have been for utility companies.

Utility companies should rethink whether they should even be in the energy services business. The vast majority of utility-owned ESCOs are losing money, and have lost money almost continuously since they were owned or started by their utility companies. According to PSE&G's own web site, PSE&G's own ESCO, PSET lost $14 million in 1998. So how did PSE&G's behavior that has been described in this paper benefited PSE&G?

Most business consultants talk about the core competencies of businesses being far more critical to their success in a market, as opposed to the size or the connections of their corporate parent. In our experience as an ESCO, the core competencies that we have seen leading to success in the ESCO business are excellence in customer focus and customer service, engineering excellence, low overhead, being a time-based competitor, strict accountability, and hiring and retaining above average people. How many public utilities given all of the years of regulated non-competitive operation can honestly say they have most, if any of these core competencies? An ex-utility friend of mine put it best when he said that if you work for a utility company in order to make a dollar, you expense it. That approach won't get you far in the ESCO business, even with a billion-dollar parent.

DAVID VS. GOLIATH REVISITED

	1500 B.C.	1999 A.D
Goliath:	6.5 ft. tall	$6.5 Billion in revenues
	Heavy armor	Multi-billion dollar balance sheet Legal bills paid by ratepayers
	Backed up with an army	Has an army of lobbyists, attorneys, and sympathetic regulators
David:	A good sling	Slinging an opponent is illegal
	Backed up with an army	Very small company and a law firm
The Fight:	Over in a few minutes	Disputes and litigation have gone on for more than two years, and the battle is far from over
	Cost David a stone or two	Has cost tens of thousands of dollars in legal fees, millions in lost business

Chapter 38— Leveraging Knowledge: Transferring Energy Services to New Markets

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Abstract

In newly competitive energy markets long-term customer commitments will be sought and gained from value-added energy services. The concept of selling energy services rather than a regulated commodity is part of an emergent "sustainable development" paradigm which requires transformation of corporate and consumer cultures. Information systems and knowledge management will be central to transferring new energy services concepts and capabilities. Global energy companies will accelerate change as they create collaborations which deploy their information technology based knowledge management systems.

keywords: energy-services, energy technology transfer, utility market transformation, knowledge managment

Introduction

Can energy services technology be successfully transferred to new markets in developing countries? This question is of concern on a global scale: the rate at which new technologies are deployed will be a major factor determining whether countries and the world as a whole can achieve sustainable growth paths.[1] It is also of concern on a microeconomic level: what strategies will be effective at matching supply of our services to demand or, perhaps better, at creating demand for our particular type of supply. In this paper we identify trends which are shaping the mechanics and institutions of markets for energy services. From these trends we draw some tentative conclusions about how the energy service business will be practiced and its technology transferred.

At one level transferring energy services technology refers to how technologies such as process alterations and new hardware are deployed by end users.[2] In so far as end users are continually evaluating their technology options, factor prices, plant age, and so forth, they will eventually make the investments which improve their (economic) efficiency.[3] An energy services model seeks to influence and speed this decision process via entrepreneurship and project development savvy. An energy services company (esco) identifies and promotes a project, develops financing, and implements. Under a performance contract, a revenue stream is constructed of avoided energy costs, sufficient to provide the required returns for all parties. While the model seems to be about projects, what underlies it is knowledge about technology operations and energy futures.

A market transformation model shifts the focus away from the esco entrepreneur, to collaborations and procurement programs which consciously seek to kickstart markets for new technologies.[4] The individual project disappears within an initiative aimed at impacting a product's market segment, development and production gear-up. Programs use features such as product competitions and incentives to retailers. The key role is that of a knowledge-based catalyst—a role played, typically, by a national research lab, an industry r&d institute, sometimes a utility itself—which has the knowledge resources to identify technology and market parameters and the communication skills to bring together the various parties—producers, distributors, procurement agencies, and end-users.

At another level, transferring energy services technology refers to getting knowledge into the hands of those who will promote and develop projects.[5] This kind of transfer is especially relevant at the early phases of market development: creating a "cadre of extension agents" will promote faster passage through the bottom of the innovation diffusion S-curve. Development agencies have begun encouraging esco's to undertake this process. Even more than with market transformation, this process requires effective sharing of information and knowledge amongst a network of participants.

The argument of this paper is that networked information and knowledge sharing are key to esco practice, especially for new markets. Organizations that understand this and form their business practices, collaborations, and customer offers around it will be successful. Global entities are best positioned to create and manage systems which will facilitate this—and conversely forming such systems may be at the heart of "going global". Local players will be strongly motivated to become part of such networks. Specialists will need to plug their skills into such networks. Comprehending the information technology will open the doorway to participating in the markets. And the more widespread the participation, the more will energy markets be transformed.

World News

Emerging Markets

The long term growth of energy demand lies in the developing countries. Both population and per capita energy use are increasing faster than in the mature markets of the developed world. Infrastructure of all types is much less energy efficient and is generally in need of replacement and expansion (even though there are still major gains to be made in transforming advanced country infrastructures, such as the giant step to renewables).[6]

But the decades of technology transfer by direct government action financed by multilateral development institutions are largely over. The World Bank has shifted its emphasis from development funding to policy reforms which aim to "get prices right", privatize overgrown public sectors, open markets to international flows of private capital and direct investment.

Such liberalization has allowed contradiction to emerge between the long and the short term. Even though growth and technology transfer are projected for the long-term, market conditions are no longer controlled to provide a stable environment in the short-term. The recent wave of foreign exchange devaluations called the "asian flu" has seriously damaged existing private foreign investment in many emerging market power sectors and halted new flows.[7] Dollar (or mark or yen) denominated investments are subjected to devalued returns (revenues) in the local currency. The recommended short-term strategy for internationals trying to stay in these markets for the long haul is to find projects which enhance local positions with limited investment exposure.

Sustainability

The development paradigm at the middle of the twentieth century focused on creating industrial infrastructure for transfer to national monopolies. Large projects were underwritten and risk assumed by international institutions. Government ownership without a clear burden of risk encouraged the pursuit of social goals through price subsidies and employment practices, which contributed significantly to eventual public sector fiscal crises.

At the entry to the 21st century, driven by global environmental concerns, we see this state-based industrial paradigm, having served its basic purpose, giving way to an alternative development model of "sustainability". A new paradigm brings with it a new "technology cluster". For the energy sector, sustainability means technologies for

- cleaner fuels and renewable sources
- process alterations for high efficiency and low emissions
- improved process monitoring and control
- new vehicle designs and transportation systems
- product design for low material use and reusability
- recycling, re-use, and industrial ecology developments

Some of these changes apply to central power stations but in general the implication is greater emphasis on end-use characteristics. End-users become a more active part of the energy sector rather than passive consumers. There will be many participants making independent decisions, in markets influenced, but not directed, by public sector rules and incentives.

Competition & Globalization

In the developed world deregulation of the utility industry has led to a wave of mergers and aquisitions. Through consolidation a class of global corporations is emerging, geared to competition and replacing the structure of local regulated monopolies. In the developing countries, debt crises of the 1980's along with free-market ideology of the 1990's has led to restructuring of the public sector—privatizing the national monopolies created for infrastructure development by sale to international consortia of private investors, often led by the new global utilities.

Opening markets brings new entrants. A precursor to full competition, independent power producers (IPP's) became a significant part of the utility industry during the 1980's. They brought to the market relatively small, state-of-the-art plants and altered basic industry concepts of how power resources could be procured. Still more radical was an expanded concept of demand-side management. Under regulatory mandate and incentivizing, utilities procured blocks of "negawatts"—guaranteed energy conservation—demonstrating that end-users and third-party service providers could be structured into the market to provide power via utilization of technologies for improved end-use efficiency.

With competition, most advanced in the United States, energy consumers are seen to be changing from generally passive to active. Major consumers, no longer captive, have new-found market power. The trend is for large usrs to strategically analyze their energy use and plan their purchasing, to seek specific services, to shop among various suppliers. To serve these customers and to aggregate smaller ones, specialist brokers and marketers have emerged. Options multiply as the many players make offers, develop new products, create rate and service packages etc.

Connectivity and Global Networks

Connectivity is expected. The complex of computers, telecommunications, and the internet are an essential part of up-to-date business infrastructure. It is a marker of what is world-class. Multinational corporations tie their operations together this way. International agencies such as UNESCO are tracking and promoting the growth of this informational nexus. In the developed world markets are now created and commerce conducted in virtual space.

Transformation of Utilities to an Energy Services Model

The transition from sales to service will be an enormous culture shock . . . It will involve the addition of service oriented marketing practices to more traditional technologically driven corporate practices. The conglomerates of the twenty first century will be built upon the remains of corporations unable to make this transition[8]

Utilities, which have traditionally been producers and distributors of an energy commodity under regulated monopoly conditions, are in the process of re-visioning their business.[9] A trend of esco ownership by utilities is well established, providing a means of experimenting with new services in response to deregulation in home markets. The energy services model will shift from tangential to central in utility practice as competitive markets evolve.[10] While one might argue that knowledge was always embodied in every kilowatt sold, in a services model knowledge moves to the forefront of marketing and sales as packages are tailored for market segments and even specific end-users. The shift to a new business model will be a culture shock to organizations accustomed to regulated service in spatially defined and protected markets.

While initial entry into developing markets may be via power plant projects or privatizations, globalizing utilities will use their knowledge of coordinating energy supply, distribution, and on-site services to expand and solidify their share of local energy markets.

Bundling and Creating New Kinds of Products

In seeking long term customer commitments under competitive conditions, bundling energy services will be a significant part of strategy. Methods of energy performance contracting will be integrated into utility marketing as a way to add customer value and differentiate product. In differentiating its product, the utility shows that it provides more than an energy commodity. Added value comes from expertise in managing energy and related resources. Talk of becoming former customers' "energy partner", of providing "total solutions" is now rampant. While fast becoming a new orthodoxy of rhetoric, the practice will let a thousand flowers bloom, many in forms yet unimagined.

The offer of creatively financed new equipment can certainly hook a customer. But besides plant upgrading and process alteration projects, the utility can re-direct its resources to offer new kinds of products, modeled after products from the financial services industry, such as

strategic planning for energy procurement

energy risk management and annuity plans

information and expertise sourcing and best practice reference

energy cost reporting, data warehousing and analysis

software interface to other business systems

linking customers for industrial ecology developments

Capitalizing Distributed Resources

Partnerships in their customers' plant operations will lead utility operations and accounting systems to encompass improved efficiency, on-site generation, and alternative energy sources. Such distributed resources will greatly reduce the "lumpiness" of a utility's investment pattern and thus allow a lower risk investment strategy in competing for market share. Once this is fully realized as a strategic advantage, on-site project investments will become part of a utility's corporate finance on the same footing as traditional plant equipment for the generating base.

Metering, Billing and Data Warehousing

Systems to aggregate site data will be necessary for this business model. Existing SCADA and metering technologies will be evolved in this direction, integrating with automated process and building control systems and GIS (geographical information system) tools already used for grid and pipeline management. What we now see as separate metering and verification for esco projects will be combined into unitary billing, broken out analogously to an investment portfolio statement. In the investment field, simplicity of investment and ease of tracking ongoing results are promoted as competitive advantage. Moreover, warehousing customers' energy use data can be used to considerable competitive advantage. Through creative "data mining"—making recommendations based on use patterns, in designing win-win rate structures, and so forth—the incumbent supplier can strengthen its relationship.

Participating in Wider Markets

With data aggregated, it becomes possible for on-site projects to be brought into emissions markets. Under present (unaggregated) arrangements most on-site projects are too small to cost-effectively participate. Thus the expansion of utility services, on the one hand, enables these markets to operate more efficiently and, on the other, enables a benefit to be shared between the enduser and the utility. The benefit, of course, is an incentive to further clean energy production.

Building an Information System

Following the model of other globalized industries, the industry leaders will increasingly become "wired" corporations, using information and communication technology to integrate their internal processes, expertise resources and linkages to external partners, allies, and collaborators.[11] A schematic representation as shown in Figure 1 can help put things in perspective. The information system serves as a network channel and also as a means of organizing knowledge. We can assume that the new global utilities have an abundance of knowledge resources but if inaccessible they are without value. So creating the information system framework is a form of corporate resource mining.

The communication backbone would be developed in joint venture with an international telecom and internet provider. The utility becomes a "content-provider". Since communications providers earn revenue based on traffic and users are drawn by content, good content providers are ever-more valuable and worthy of investment. Negotiating this fundamental relationship needs to be a priority item.

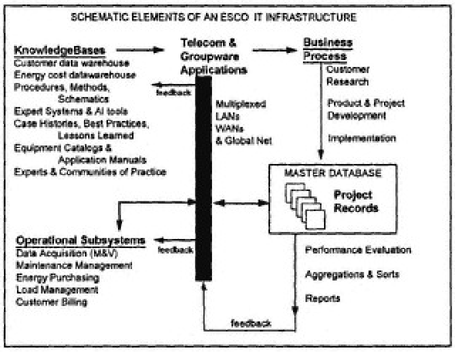

Figure 1

Realizing that the new business model is information-based leads to learning lessons from the information industry.[12] First and foremost is that the same technology/system should be used for many markets. This spreads the development investment across consumers differentiated by geography, market segments, and time of adoption. Early and later adopters provide "legs" which extend an information product's lifetime. Adapting the technology for a wide variety of users implies "versioning" of features, capabilities, and distinct levels of access, associated with differential pricing. Extending product life implies update releases, a function with tactical dimensions in meeting competitor challenges.

Customer lock-in, another information product concept, approximates the energy marketer's goal of securing long-term purchase agreements. Lock-in starts with acclimating the customer to a user-interface and operating environment which meets needs without unnecessary complication. It continues with tailoring features and information, to such features as personalized on-line research support and links to on-line energy markets. The more comprehensive is the energy-related environment, the more functions the customer will perform in it and the higher his or her perceived switching costs. Getting users to learn how to use the information system is itself a vital piece of technology transfer.

Reaching Out into New Markets

Students of technology diffusion find that acceptance of innovation follows an S-shaped pattern, as shown in Figure 2. Communication has been identified as the key to the process, starting with early adopters motivated and inclined to experiment who then initiate the spread of positive messages through their social networks; an increasing density of communication accelerates the rate of acceptance until the community (or market) is saturated.[13]

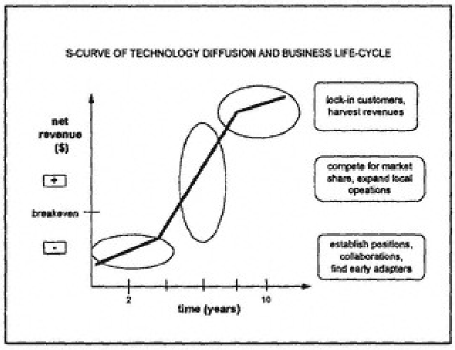

Figure 2

We can anticipate that this pattern will apply to changes in the energy business at several levels. First there is the transformation of utility business by adoption of an energy services model, presently at the early acceptance phase in developed countries but hardly yet exported to emerging markets. As part of this change comes the more specific adoption of information technologies as a way of linking global utilities to local ones, and these collaborations to service providers and to end-users. This step should be viewed as the spread of an enabling technology—in and of itself it does not change energy-producing or energy-using systems. Such change comes only when utilities and customer collaborations put in place new processes and equipment, which are the final level of innovation. It is the scope and pace of this final level which impacts the world environmental situation. Acceptance of the enabling technologies opens the door to a potentially cascading series of new applications in distributed generation and end-use efficiency. Thus the S-Curve shown as Figure 2 should be understood as a simplification of what will actually be a family of such upward curves as new applications are generated.

The information/knowledge system provides a way of projecting intent and capabilities into a new market and provides a framework for access and interactivity. Focused marketing will help identify early adopters, so a plan based on market segmentation should be tied to system release, licensing and pilot efforts. Advertising, news releases, surveys, seminars and workshops are traditional means of releasing information. On-line conferences add Web networking to this repertoire. The sponsor is able to review wide-ranging comment which provides market insight and contacts. Conferences can spawn on-line communities of knowledge. International agencies have shown interest in this type of interactive mechanism as a means of spreading and transferring knowledge, learning, and sharing information.

But only a broader transformation of understandings throughout the society will hasten the upturn from early acceptance to widespread participation. Corporate environmental responsibility initiative grew in developed countries only when such concerns were pressed by the public. Another lesson from the information and network industries is where needs are only dimly perceived by customers to build the market rather than to narrowly pursue market share. This means promoting the new possibilities, heightening interest, involvement, and access, developing a communicative network and collaborations beyond specific short-term customer opportunities. A new local competence base is needed to support growth. Understanding these issues leads to various forms of engagement with societal institutions:

Universities and Research Institutes: promote environmental studies, endow faculty positions, provide on-line technical resources, internship opportunities and career paths

Non-Governmental Organizations: support specific project initiatives, attend community meetings, offer on-line technical resources, speakers and seminars

Professional and Industry Associations: create special certification programs, offer speakers and seminars, participate in trade shows, support with corporate memberships

Government Agencies and Local Governments: propose win-win projects, support pilots and demonstrations, provide on-line technical resources for new energy extension services and associated professional training, provide best-practice references for regulations and programmatic incentives

This kind of market development effort goes beyond normal marketing, beyond segmentation and customer strategies. Brand-name recognition will follow.

Conclusion

A little crystal-ball gazing suggests how the game will be played.

Competition by value-added services to end users—energy services model of utility business

Transfer of energy services technology cluster by newly emergent global utilities

IT capabilities created in joint venture with telecom/internet service provider

Knowledge management for information access and sharing across global network

Creation of local partnerships and collaborations, utilizing global information system as keystone

Giant, consolidated utilities are already becoming a major force in global capital flows. We suggest that their accepting an energy-services based business model and deploying information technology based systems can make them also a major force in global knowledge flows. Information and knowledge sharing will strongly impact the rate of technological change ("leapfrogging") and resource use as energy markets in developing countries are transformed.

References

1. An economic analysis of this issue is provided by Duchin and Lange The Future of the Environment Oxford Press 1994 using an input-output world model. Under their assumptions about the rate and extent of efficiency change in various sectors, the CO_2 abatement goals of the Rio/Kyoto Conventions will not be met.

2. Such improvements in technology are subsumed by economists under "technical progress" as opposed to increased inputs of labor and/or capital. "Knowledge" has an ambiguous status in the traditional (Cobb-Douglas) production function. The human capital school (see especially by G. Becker) treat knowledge as an attribute of human capital as it is trained and educated. Others categorize it as an element of "the residual" which accounts for growth over and above what can be accounted for by labor and capital inputs.

3. Economic efficiency will encompass energy efficiency in so far as energy is fully priced (ie- without subsidy) and even more so if taxed to account for externalities.

4. For a recent summary see Scott, M., Parker, G. and Currie, J. "How to Build Markets for Energy-Efficient Technologies" Strategic Planning for Energy and the Environment v. 18 no. 4 1999

5. Recent technical economics has begun to treat knowledge creation, focusing on the R&D process. See the literature on endogenous growth such as P. Romer or M. Scott. There has been less economic attention to the spread and use of existing knowledge, such as we are primarily discussing in this paper. Japan's astounding growth and that of other East Asian "tigers" are probably suggestive here. Their skill has been in adopting and commercializing technologies not creating them. See also the discussion of R&D by C.I. Jones Introduction to Economic Growth 1998

6. This is recognized in the idea of "joint implementation" of CO_2 emissions abatement where a developed country uses its capital to buy a more cost-effective abatement project in a developing country.

7. A. Streicher "The Future of the Global Power Industry" HaglerBailly Perspectives v.1 issue 3 1998

8. Laudis and Graedel "Manufacturing" in D. Richards and G. Pearson The Ecology of Industry National Academy Press 1998

9. Re-visioning and re-inventing are a widely discussed theme in popular social science of the 1990's. Perhaps the best known and most accessible development of this theme for business is G.Hamel and C. K. Prahalad Competing for the Future Harvard Business School Press 1994

10. See C.Flavin and N.Lenssen. "Reshaping the Power Industry" in L.Brown et al State of the World 1994 Worldwatch Institute/Norton1994 for a fuller discussion of utility industry events and trends since the 1970's and the shift towards an energy services model. The de-regulation of an industry typically leads to a phase of commoditization and pure price competition as new entrants attack previously protected players. For this reason it appeared that utility deregulation would lead to market dominance by lowest cost sources, particularly coal, wheeled regionally. Initially utilities "stripped down" inessentials such as mandated energy service programs, to gird themselves for price wars. But this phase was short, perhaps because of short-term supply constraints (it takes about 10 years to site, permit, and build a new coal plant) and the large number of existing players (not everyone can be a cost-leader). Instead, the majors have begun competing on the basis of "value-added". See, for example, "The Billion-Dollar Battle" Energy Manager v. 2 no.1 January 1999. Also see E. Smeloff and P. Asmus Reinventing Utilities: Competition, Citizen Action, and Clean Power Island Press 1997 for case studies of utilities adopting integrated resource responses to deregulation.

11. See Bartlett and Ghoshal Managing Across Borders Harvard Business School Press 1989

12. The most accessible treatment is C.Shapiro and H.Varian Information Rules: a Strategic Guide to the Network Economy Harvard Business School Press 1999

13. Rogers, E. Diffusion of Innovations Free Press 1995 (4th edition)

Chapter 39— Serving Smaller Customers

By Daniel S. Waintroob

Abstract

Thirty five percent of all commercial space is occupied by small businesses, and 98 percent of all commercial buildings in the United States are less than 100,000 square feet. Because owners and occupants in the small business sector are less informed and less energy efficient than those in the large facility sector, opportunities for substantial gains in energy efficiency exist. Yet, this market is largely ignored by the energy service industry mostly because of high transaction costs typically associated with developing a project. There are, however, substantial opportunities to reduce these costs and effectively serve smaller customers by employing many of the techniques now effectively used in other industries, including targeted marketing, adjustments, standardization and automation of routine business and engineering functions, and using new marketing channels to reach customers.

The author will describe Aspen's OPUS™ (Optimal Power Use Service) and how it enables energy services companies to reach smaller customers. Included in the paper will be descriptions of the process, case studies, and a pro forma business analysis. Attendees will be able to assess whether a small business strategy should be part of their service portfolio.

Introduction

As described in the Abstract the vast majority of commercial energy users are smaller customers. However, they also represent a significant portion of the energy consumption in the U.S. While it is not the purpose of this paper to provide a detailed market analysis, it is interesting to note that the United States Department of Energy's Energy Information Administration—Sales and Revenues (1995) put the commercial electric sales market at approximately $66 billion out of the total of $207 billion. From the perspective of the author this represents a largely untapped market in that Energy Service Companies (ESCO's) generally devote their efforts to the largest customers.

This has not been an illogical choice on their part given that the sales and other transaction costs in performance contracting have traditionally required large energy savings to justify these costs. Lead identification, marketing, site engineering, contract negotiations and financing required significant up front expenditures on the ESCO's part. However, it is also interesting to note that the largest customers are also the most sophisticated about their energy decisions and, therefore, require a very significant and often competitive sales effort.

In Aspen's energy auditing experiences[1] over the past few years, smaller customers often had very good cost-effective opportunities to upgrade their energy systems. However, follow-up surveys have indicated that only a small portion of these opportunities were being implemented. These surveys generally indicated that these measures were not implemented often due to a lack of time and/or expertise.

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[1] Aspen Systems provides energy auditing services on behalf of electric utilities, ESCO's and other agencies. In the past five years, we have audited 2,500 commercial facilities.

These needs align themselves very well with the types of *turn key* services that ESCO's traditionally provide. The challenge is to reduce the transaction costs such that mutually profitable opportunities can be exploited. Hence, Aspen designed its OPUS—(Optimal Power Use Service) to address these concerns significantly expand the market available to ESCO's and other ventures.

The OPUS Design

The key feature to the OPUS approach is to provide, as an *owner's agent,* the commercial client with soup-to-nuts support in energy efficiency projects. That is the service provider does not take title to the equipment or directly finance the equipment; but otherwise provides the same services that an ESCO traditionally provides. Namely, the OPUS service consists of the following elements:

Lead Identification and Marketing

Site Survey & Energy Optimization Report

Vendor Solicitation

Bid Evaluation & Contract Assistance

Financial Assistance

Implementation Support & Post Implementation Support

The key to cost-effectiveness in this approach is that OPUS approaches the market as a program rather than a series of one-on-one transactions. Therefore, a number of steps have been taken to simplify, automate, and preapprove many of the processes. These elements are described below:

Lead Identification and Marketing

This is a market that lends itself to aggregated approaches that use organizations that are already working with these customers. As an example, we are currently conducting a pilot, under the auspices of the U.S. DOE's Rebuild America Program and EPA Energy Star Small business program, in the Chowan/Roanake area of North Carolina. In this effort a community-based organization is handling the customer recruitment and energy analyses. In Wisconsin, our efforts are under the umbrella of the State of Wisconsin's Focus On Energy Effort. In both instances, program design features were made to specially match the needs of the sponsoring organizations.

Site Survey/Energy Optimization Report

Aspen's experiences with energy auditing led it to develop a report writing tool that extracted data from commercially available audit tools and then allowed it to make a customer report that presented the information needed to go forward:

1. An Executive Summary which includes a summary of all the recommended measures, sorted by building and then by payback;

2. An End-Use Summary which reflects energy use by equipment type for each building

3. Billing history analyses;

4. Detailed narratives of each type of upgrade opportunity;

5. Opportunities considered but not recommended without further investigation or those considered that are small and worth implementing but not worth a full write-up;

6. Equipment inventories and operating schedules;

7. Facility descriptions; and

8. Application-specific comments for individual measures, as appropriate

9. Project Specifications

10. Statement of Work

11. List of prequalified vendors:

12. Application for Financing

In selecting the recommendations, we seek to create a package that will allow the costs of the OPUS service to including with the financing of the measures be slightly cash positive.

Vendor Selection

The key to the OPUS approach is to use pre-qualified vendors. Therefore, in advance to an OPUS program roll out interested a Request for Qualifications is sent out and interested vendors are screened. To help control costs standardized bid forms are used, the vendor agrees to follow-up inspections and a dispute resolution process.

Bid Evaluation/Contract Assistance

Once the customer decides to proceed with the project an Invitation to Bid is sent to the pre-qualified vendors. The OPUS service provider would review the bids with the customer and then provide the go-ahead to the vendor or vendors the customer approves. A standardized contract form is used.

Financial Assistance

As part of the project at least one interest lender is identified. This lender will pre-approve the financing to a ceiling amount based on a standardized load application. In North Carolina, for example, if the loan is less than $25,000 a simple application is required. If it is above $25,000 financial statements are required. In any case, the concept is to make access to financing as seamless as possible.

Implementation and Post Implementation Support

In this phase Aspen acts as the owner's representative by sending a field engineer to the facility to:

Verify that the installation meets specifications

Insure predicted energy savings

Update the vendor list of contractors performing work of the highest quality and value

In summary OPUS is designed to reduce transaction costs by standardizing processes, leveraging off of local resources, aggregating resources and using computerized tools to the maximum extent possible. The program is designed to overcome the customer barriers of lack of time and lack of knowledge to produce projects that are cost-effective for them.

Experiences to Date

The OPUS concept is a new one and at the time of this writing two projects are underway that will have results that can be shared with the audience when the WEEC meets.

The first is under the Auspices of the State of Wisconsin's Focus on Energy Program. Under a subcontract with Delta Technologies and the Wisconsin Department of Administration—Aspen has launched a program directed toward commercial businesses. In addition, the state has a program directed toward municipal governments. Under this program we are using pre-existing lists of vendors obtained from state agencies and local utilities. We are currently recruiting customers. A key feature of this program is use support from the U.S. Department of Energy's Rebuild America Program. In Wisconsin interested municipalities and other agencies would sign a Memo of Understanding agreeing to develop an energy action plan. This will enable the program to continue beyond Aspen's contract period.

In North Carolina with support from the Rebuild America Program and U.S. EPA's Energy Star Small Business program. Aspen has initiated a program that operates under the name, Wraparound℠ and uses local organization; CADA that has been trained in the system. Several local lenders have agreed to participate and customer recruitment is underway.

About the Author

Daniel S. Waintroob, Group Manager of Energy Services for Aspen Systems Corporation headquartered in Rockville, Maryland. He has more than 25 years of hands-on experience in applying information system solutions to help energy companies meet their strategic and tactical goals. Mr. Waintroob is an expert in developing and using consumer energy utilization data as well, rapidly designing and implementing projects. He has addressed an extensive range of issues, from energy supply policy for the New England region, to a strategic information system plan for an African electric company, to home weatherization and low-income fuel assistance. He has been involved with the start-up of two energy service companies, and recently completed a business process review of three ESCOs in China.

He may be contacted at 301-519-6634 or by e-mail at dwaintroob@aspensys.com.

For more information on the discussed programs contact/call:

1-888-STAR-YES for the Energy Star® Small Business program,

1-800-DOE-EREC for the Rebuild America program, and

1-800-762-7077 for the Wisconsin Focus on Energy program.

Chapter 40— "It's Not Just about Price"—The Total Energy Solutions Approach

22nd World Energy Engineering Congress
October 22, 1999
Presenter: William Leahy—Manager—Technical Support Services Select
Energy, a Northeast Utilities company

Now that states have begun the task of restructuring the electric industry, many customers are voicing their disappointment about the lack of significant savings in their energy bill from deregulation legislation. The reasons the promised savings are not being realized typically fall into three categories;

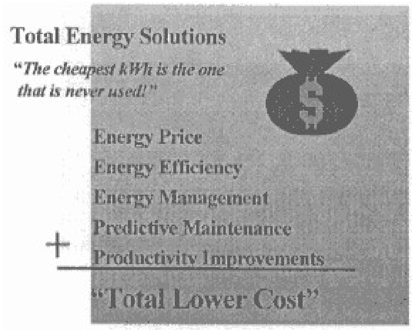
1. Cumbersome, unbundled rates granting local distribution companies (LDCs) with significant recovery of stranded investments,

2. Below market standard offers or default service, providing energy at prices even or below the current open market and

3. Complex rules of engagement for power brokers and energy marketers making it difficult for them to successfully compete with the *Home Team.*

All three of these reasons have reduced the anticipated savings many businesses expected from open competition. But don't fret, significant savings are still achievable when you couple energy price reductions from deregulation with the tried and true savings available from implementing energy efficiency and load management improvements. The bundling an energy commodity with energy services has become the banner for an emerging group of power marketers willing to customize power proposals that address the customer's individual energy use issues.

Facility managers have begun to recognize that the extra attention they are receiving from these power marketers has brought rise to a different approach—one that has significant potential to lower their bills and improve their profitability. This approach has been categorized as the **Total Energy Solutions** approach to reducing energy costs.



Energy services companies that offer both energy and related energy products offer an alternative over the pure energy commodity brokers. They offer an integrated approach that provides the customer with both competitively priced energy commodity, for all fuels, combined with a full line of energy solutions aimed at the customer's specific energy needs.

The **Total Energy Solutions** provider might offer a full portfolio of customized products that fall into five categories:

Commodity Sales with customized contract terms and pricing for electric, gas, and oil

Information Services including; energy auditing, metering and sub-metering, energy accounting and management software, engineering design, strategic planning, aggregation services and procurement services

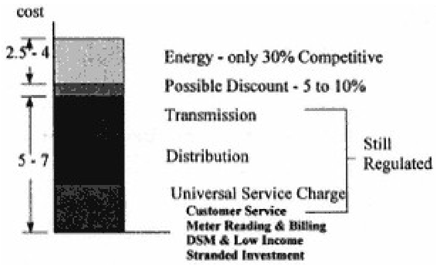
Operations and Maintenance Services; predictive maintenance, power quality diagnostics and solutions, equipment operations and maintenance.

Equipment installations, design/build, project management, process improvements, and waste reductions.

Financing Services including; leasing, guaranteed savings and performance contracting,

The fact is that in most cases, there is a far greater cost savings potential in reducing the amount of energy consumed in a facility than can be achieved by negotiating a more favorable energy charge on your electric bill. In most states, the energy component of the unbundled electric bill only represents 30% of the total bill. Also the potential benefits to a company's bottom line from improvements made through demand management, productivity improvements and waste reduction will far out-way commodity cost savings from deregulation.

Restructured Rates



You might think that the LDCs have already been offering products and services, and at prices often significantly "subsidized" by utility rates. True, LDC sponsored Demand Side Management (DSM) programs with rebates and incentives have been around for years, and many businesses have participated. But these programs are typically technology focused, and may or may not address the real energy and productivity opportunities available within a specific facility. Also, these funds are often difficult to access when the solution required is custom in nature and not an "off the shelf" technology.

The role of utility incentive programs is to influence the market by changing what is considered "state of the art." Once the standard is changed, the subsidy is removed. Their goal is usually not to address the needs of individual customers. **Total Energy Solutions** providers look beyond specific technologies and start with developing a knowledge of the customer's facility.

But aren't all power brokers the same?

The idea that energy price is the only issue for customers, and that all power brokers and energy marketers are the same is like saying "One Size Fits All." In the electric marketplace, like all other markets, customers have different needs. Some businesses, with energy professionals in-house, are fully capable of addressing the potential energy savings opportunities within their facilities. They may only be interested in procuring the cheapest commodity available. The only variables might be the term of the contract. But many businesses do not have these sophisticated in-house resources.

Many business managers understand that to achieve the full potential of saving opportunities within their facility, they require specialized professional help. They recognize that there are companies in the marketplace that can deliver the whole package in an integrated way. Call it "One Stop Shopping. " We have seen this in nearly all industries that have deregulated. There is always room for marketing companies willing to accommodate customers with different needs. Some customers shop price, some reliability, some convenience, some added value and some a combination of the four. More than likely the electric industry will follow this model and provide for true differentiation between suppliers in the marketplace based on meeting the needs and buying habits of a variety of customers.

The **Total Energy Solutions** provider is not limited to the commonly held, regulator-approved DSM technologies. They are open and equipped to address any energy related opportunities to improve the way businesses use energy. With many companies, reducing staffing and energy budgets, and many others considering outsourcing, there are numerous options for getting the most from your energy dollar.

What are the areas of improvement most often requested?

Products and Services

- Energy efficiency improvements
  - Audits and engineering studies
  - Lighting, HVAC, motors and drives, controls and compressed air
- Load management
  - Improved load factor
  - Peak shaving
  - Load shifting
- Power Quality
  - Power factor improvements
  - UPS, surge protection
  - Back-up generators
- Metering and Billing options
  - Real time data from the utility meter
  - Sub-metering with Web site access
- Energy Accounting software tools
  - Bill error checking
  - Most beneficial rate review
- Energy procurement assistance
  - Load aggregation
  - Load modeling
- Electrical Equipment Testing & Servicing
- Cogeneration
- Fuel Diversity Options
- Predictive Maintenance
- Productivity and Process Improvements
- Production Waste Minimization
- Project Management
- Strategic Planning

Is this just theory, or does this approach really work? Let's review some examples:

A manufacturer in Massachusetts secured an electric energy rate 7% lower that default services by installing a natural gas driven air compressor which improved his load factor from under 60% to over 70%. He was also able to improve his gas rate by moving from a seasonal rate to a twelve month rate. The waste heat recovery from the engine driven compressor reduced gas consumption to a coating process as well. The installation had a 14 month payback.

A postal processing center found that they not only cut their electric use by 10% when the facility was modernized with a high efficient lighting system but they also experiences dramatic productivity improvements. Without realizing it, the workers increased processing output by 20%. The lighting system had a 3 year payback from energy reduction; however, if the increased productivity is factored in, the payback is under one year.

A metals manufacturing plant with a 10 MW load was unable to command a competitive energy commodity price due to their 45% load factor. A study of their load interval data revealed that if they could schedule the 30 minute cycles on their largest forging presses not to overlap, they could reduce the demand charge from the LDC by 3 MW, improve their load factor to over 60%, get a commodity price under standard offer, all without sacrificing production.

A web based energy reporting system tied to the utility meter and a series of submeters provided near real-time data to a local waste water treatment plant, aiding them in scheduling discretionary processes and maintenance procedures so as not to impact the plants current excellent load factor. A predictive maintenance program utilizing thermography and vibration analysis provides information for the ordering of parts and efficient scheduling of pump maintenance in the off-peak hours

A national account customer was looking to get a favorable energy price for his multiple facilities within a geographic area. He was able to use the same software product capable of aggregating his loads to also identify billing errors, and most beneficial rates. In addition, management reports from the system identified high use facilities in need of energy audits and efficiency improvements. Savings from building improvements and rate adjustments outweighed the discount created by bidding the commodity.

These are just a few examples of the real energy and cost savings achievable when an integrated approach is taken to energy cost reduction. The answer is not just getting the cheapest commodity price. The answer is to seek a **Total Energy Solution.**

Chapter 41— Minimizing Risk in Energy Project Financing

Gregg E. Haggart

Abstract

In order to meet the needs of commercial and industrial customers, energy services providers are required to undertake a more active role in the development, financing, ownership and management of energy-related projects. This article focuses on the key business points that should be included in an Energy Services Agreement between an energy services provider and its customer. The emphasis is on what a project lender requires in this agreement and on the key points that minimize the risks to the energy services provider.

Commercial/Industrial Market

Developing and implementing energy-related projects in the commercial and industrial marketplace can be very challenging. In the private sector, energy projects no matter how worthwhile, compete for limited capital resources. Even companies with plenty of cash on hand will scrutinize a project to ensure that it meets their payback, internal rates of return and hurdle rates. Companies that compete in capital intensive industries place an even higher cost on internal monies, meaning that the economic payback must be quicker and the hurdle rates higher. In this highly competitive environment, all projects, not just energy projects, are ranked by financial return and then funded from best to worst. This creates a situation where many otherwise "good" energy projects simply do not get done. It does not matter whether the customer funds the project with cash or debt, if the company's balance sheet is impacted, there will be competition for funding.

Off-Balance Sheet Solution

To circumvent these financial issues, many energy services providers are including the financing as part of the energy project. Using this approach, the energy services provider and the customer enter into a long-term servicing agreement, under which the energy services provider constructs the project utilizing third-party financing that is repaid either from the savings generated or from the purchase of the output (e.g., chilled water, steam) by the customer. Typically, these projects are design/build and provide a "turn-key" solution to the customer, including ongoing operations and maintenance support from the energy services provider to ensure the long-term success of the project. In most cases, there is also ongoing measurement and verification to document the actual energy consumption.

The most unique aspect of this type of agreement is the favorable accounting treatment received by the customer. Because the agreement between the energy services provider and customer is for services and not a lease or sale of equipment, the transaction is treated as an operating expense, rather than a capital expense or debt obligation, making it off-balance sheet to the customer. The importance of this accounting treatment cannot be overstated. In many cases the difference between an engineering study that sits on a shelf and one that gets implemented is the financial impact the project will have on the customer. The more an energy services provider understands about the customer's financial requirements, the greater the likelihood that an energy project will be implemented.

There are two general models that utilize this off-balance sheet structure; shared savings and asset monetization. The flow of services and money related to this structure is shown in Figure 1.

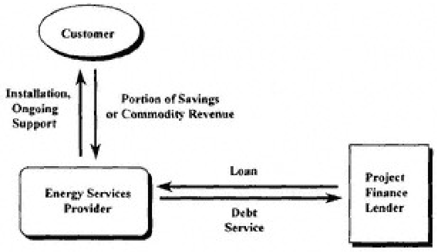


Figure 1
Project Financing

Shared Savings

With the shared savings structure, the energy services provider installs the energy efficiency measures utilizing third-party financing and agrees to share with the customer the savings generated as a result of the project. The length of the agreement and the amount of the savings split, while negotiable, is typically driven by the economics of the project. This is because the energy services provider needs his share of the savings to repay the loan used to finance the equipment, cover the ongoing operations and maintenance expenses, as well as make an appropriate profit. At the end of the contract term, ownership of the energy assets (e.g., lights, HVAC equipment, controls, etc.) are transferred to the customer. This shared savings model has been used successfully for many years even by tax-exempt customers such as schools, hospitals and municipalities.

Asset Monetization

Another structure gaining popularity, is called asset monetization, which is very similar to the shared savings structure. This outsourcing of the customer's energy assets is the natural evolution of the trend to outsource non-core support services such as facilities, custodial and food service. Another important factor in the growing acceptance of asset monetization is the deregulation of the electric industry. In order to remain competitive, many energy services providers are integrating the sale of energy into the agreement to create a bundled offering.

Asset monetization involves the acquisition of the customer's energy-producing assets (e.g., chillers, boilers) by the energy services provider who will own, operate and maintain those assets. In return, the customer agrees to buy back the output or commodity (e.g., chilled water, steam) from the energy services provider. This revenue stream from the output purchased by the customer is used to pay for the project and make an appropriate profit.

Benefits

Shared savings and asset monetization are popular financial structures for commercial and industrial customers because they free up the capital, manpower and other internal resources normally required in the operation of non-core business functions. Risk is minimized as well since with this performance-based structure, the customer only pays for services delivered. If there is a disruption of service, there may be no payment due. Perhaps most importantly, because the customer and the energy services provider are entering into a servicing agreement, the customer's capital is not utilized and there is no debt obligation. Therefore, there is no impact to the customer's balance sheet. The agreement to share savings or pay for the output becomes an operating expense similar to telephone service or electricity. With an off-balance sheet solution, there is essentially no Internal Rate of Return hurdle to overcome, the Return on Assets is improved and the customer can focus on the benefits of the project, not just the economics.

There are benefits to the energy services provider as well. If the project is structured in a manner attractive to a project lender, an energy services provider may receive funding for up to 100% of the cost of the project. Many lenders will even assume the performance risk of the project and fund the project non-recourse to the energy services provider. This means that the lender can only look to the project and its assets for repayment of the loan. In order to receive such favorable lending terms, there are certain key elements that a lender looks for within the agreement between the energy services provider and the customer.

The Energy Services Agreement

The Energy Services Agreement (ESA) is the controlling document in this transaction between the energy services provider and the customer. Because the energy services provider is not selling capital equipment as a part of the transaction, but rather providing a service that involves equipment, this transaction differs substantially from other performance contracting documents. There are several key elements that must be included in the ESA to minimize the risk to the energy services provider and make the project attractive to a potential project finance lender. These elements are outlined below.

Term of Agreement

The term of the contract is driven primarily by the economics of the project and is usually negotiated between the energy services provider and the customer. The factors that affect the payback of the project, such as project cost, savings generated (or output purchased) and interest rates, likewise have an impact on the length of the contract. This is because the energy services provider must recover his costs and make a profit, which most likely will take a number of years. But there are other factors that should be considered as well. Because the energy services provider and the project lender are looking to the long-term performance of the project for repayment, it is important that the equipment perform for at least as long as the term of the agreement. For this reason, the agreement should be no longer than 90% of the expected life of the equipment. (The energy services provider and the lender should also be interested in how the equipment will be serviced and maintained, including warranties and insurance.) In addition to the above considerations, most lenders will not want to see terms greater than 10 to 15 years.

Take or Pay Provision

Another key element of the ESA is the take or pay provision. This provision stipulates the minimum amount of savings to be credited to the energy services provider or the minimum amount of the commodity that must be purchased (i.e., taken) by the customer over a period of time. While the actual amounts may fluctuate according to the formulas in the ESA, there should always be a negotiated minimum take. The importance of this minimum take is critical to a lender for it assures the lender that there will always be enough revenue generated from the project to service the debt. Without a minimum take or pay provision, a lender is greatly exposed to performance risk and will underwrite the project accordingly.

Fuel Rate Risk

During the term of the agreement there will likely be fluctuations in the price of energy consumed. These fluctuations can affect both the cost of the commodity purchased for asset monetization projects, and the energy savings calculations in the case of shared savings agreements. Although forward rate locks are sometimes purchased, the cost can be prohibitively high. The most common way to handle this fuel rate risk is to structure a pass-through to the customer that allows the energy costs to be increased or decreased on a periodic basis to reflect actual rate changes. Another method of minimizing rate risk is to negotiate floors and/or ceilings on the rate adjustment to protect against this fluctuation. Like the take or pay provision, this rate pass-through or floor, helps to limit the amount of risk to the energy services provider and project lender.

Termination Charges

Termination charges are very important to both the energy services provider and the lender, both of whom look to the long-term performance of the project for repayment. If there are no termination charges and agreement is terminated early, there will be an unpaid principal balance on the loan. Likewise, the energy services provider may have amortized some of the project costs over the term of the agreement and may need to recover these costs. For this reason, if the ESA has a provision to allow the customer to terminate before the end of the term, such as an option to purchase, then a termination schedule should be included. This schedule outlines the outstanding principal balance and other ancillary costs that must be repaid by the customer. Absent this provision, neither the energy services provider nor the lender can be assured of recovering their costs.

Defaults & Remedies

Because these agreements are based on performance it is important to outline when a party is not performing and what can be done about it. Typically, if the customer has notified the energy services provider that he is in default as per the ESA, there is a period of time allowed the energy services provider to cure the default. Likewise, the project lender should be notified at the same time to ensure that the energy services provider cures the default or be given the opportunity to cure the default himself. If the customer is in default, the lender may take possession of the equipment and termination charges may be applied. Just like the energy services provider and customer, the lender is very interested in the continued long-term performance of the project.

Summary

While commercial and industrial customers are requiring energy services providers to undertake a more active role in the development, ownership and operation of energy-related projects, this does not necessarily equate to more risk for the energy services provider. Properly structured, an energy service provider can deliver a project that meets the customer's energy and financial requirements and shifts much of the risk to the customer and project lender. The key is in creating a compelling financial reason for the project to be implemented.

Chapter 42— Load Shaping: A Critical End Use Response to Electric Utility Deregulation

John L. King III, P.E.

Introduction

In the early days of what has now evolved into the practice of Energy Management, we experienced a proliferation of various "energy conservation" activities, aimed at simply reducing the amount of energy consumed in a given facility. These activities targeted any and all forms of purchased energy (electricity, natural gas, fuel oil, steam, etc.), with the primary goal being to reduce costs by purchasing less of these energy "commodities." This approach led many facility managers to cultivate a "less is better" philosophy. One problem with this approach, now well documented, is that in many cases the comfort of the human occupants of buildings was compromised. We all remember the days of 68 degrees F in winter and 78 degrees F in summer, as well as the exacerbation of IAQ problems which accompanied excessive reductions in outside air undertaken in the name of energy conservation.

Another problem born of this view of energy as simply a commodity to be purchased is that it often resulted in the placing of too much emphasis on the common units of measurement by which facility managers tracked their purchases: gallons of fuel oil, therms of natural gas, pounds of steam and kilowatt-hours of electricity. By thinking of each form of purchased energy as a commodity to be tracked by some convenient unit of measure, the significance of the DEMAND portion of the electric bills of a great many facility was often lost in the shuffle. With different rates at different times of day, purchased fuel charges and various other mysterious charges and riders, it has been and still is often seen as much easier to simply track costs in terms of across-the-board dollars per kilowatt-hour. After all, life is complicated enough! So, for a long time, there has been a decided lack of attention on the cost avoidance opportunities presented by the very existence of demand charges.

Now, to make life even more complicated for these already beleaguered facility managers, along comes the specter of electric utility deregulation. As we are all aware, facility managers have increasingly been asking questions about this impending deregulation, wondering just what it will mean to their organizations and to themselves. One of the things that it will mean is that there is now a need to go beyond a mere understanding of the cost impact of instantaneous demand, and to fully understand that the many demand components within a facility form a "load profile", and that that load profile is something that can and must be *managed.* The thesis of this paper is that one of the most powerful and meaningful responses to deregulation that is available to the facility manager of tomorrow is to develop the ability to control and to modify the load profile of his/her facility, for both economic reasons as well as with an eye toward the protection of the environment. This paper will first establish the link between deregulation and load shaping, then discuss the major load shaping technologies (with examples and case studies), placing special emphasis on perhaps the most powerful strategy: thermal energy storage (TES). Finally, the paper will establish and discuss the link between load shaping and pollution prevention.

The Link between Deregulation and Load Shaping

The overall load factor (percent utilization of electrical generating capacity) in the U.S. today is approximately 50%, largely due to the poor electrical load profiles of commercial customers, which typically have load factors in the 30–40% range. Compare this to industrial facilities, which are generally in the 60–85% range, and one quickly begins to see why industrial customers have long been the beneficiaries of the most favorable electrical rates. This overall load factor of approximately 50% means that generating facilities consistently experience substantial idle capacity for considerable periods of time (i.e. in the middle of the night). As discussed in the section below which focuses on the link to pollution prevention, this idle capacity is experienced by the power provider as a very significant operating cost component. In the past, before deregulation, the capital costs associated with this idle capacity were simply passed on to the "ratepayers" who were captive to their monopolistic power provider. In the future, under deregulation, the costs associated with this idle capacity will be seen as a huge competitive disadvantage by all power providers, since, for the first time, they will have to compete for customers in an industry which is extremely capital intensive. As idle capacity can be reduced, both capital and operating costs will be cut, and power can be offered at a lower price.

This means that the power providers will be doing everything they can to improve the load profile of their portfolio of customers. They will be actively courting both individual and aggregated customers who can offer flatter, more attractive load profiles. More and more, the utilities will be providing incentives in their standard rate structures and they will be increasingly motivated to negotiate deals directly with their customers. It will be the smart customers who will respond by developing the ability to quantify, manage and alter their load profiles. This will enable them to negotiate the best possible rates with power providers, who are operating in a newly competitive marketplace.

So, the ante has been raised, and end users will increasingly turn to load shaping in order to take advantage of the financial incentives for load shaping within electric rate structures across the country. Many such incentives already exist, and they will certainly become even stronger, more prevalent, and much more customized to the individual end user as deregulation takes hold across the country. For the reasons stated in the introduction above, the incentives offered by the monopolistic power providers of yesterday have been insufficient to induce many facility managers to address their load profiles, so a great deal of potential for load shaping still exists. Moreover, in the new world of deregulation, with unprecedented competition by the utilities themselves for those attractive load profiles, there will certainly be an upsurge in load shaping activities, and the facility managers who delay will soon see themselves missing the boat. In this way, deregulation will drive load shaping at the end-use level.

Load Shaping Strategies

There is a variety of proven load shaping strategies available to facility managers today. Among them are electrical peak demand shaving, electrical demand limiting, fuel switching, non-electric chilling, desiccant dehumidification and Thermal Energy Storage (TES). A brief discussion of each follows:

Electrical Peak Demand Shaving: this refers to any of the various techniques for temporary fuel switching (see below) during certain times of high electricity cost, while continuing to serve a given load at an unreduced level. This is beneficial in any rate scenario which offers variable pricing per kilowatt-hour as a function of the time of day (commonly called "Time of Use" rates) and/or charges based upon peak demand as measured in kilowatts. An example would be to use an on-site generator fueled by diesel, steam or gas during times of higher kilowatt-hour pricing and/or during peak demand periods. Under that scenario, the electric rates themselves provide the incentive. Another type of incentive which has been in common use is that of programs (often with names like "curtailable load') which provide direct payments for the reduction of load at times designated by the utility. These "curtailments" are usually done upon short notice, thereby necessitating an automated shifting of load onto a generator or other automated load transferring response. Under deregulation, the negotiation of this type of incentive should be very commonplace.

Electrical Demand Limiting: generally refers to techniques for the setting of upper limits for instantaneous electric power demand levels, usually through the use of automatic controls such as an EMS system. By their nature, demand limiting techniques differ from demand shaving techniques (see above) in that they result in the temporary reduction or interruption of some energy-consuming function. A simple example would be to have certain non-critical loads shut off whenever a predetermined demand limit is approached. In a multiple-chiller application, one might temporarily shut off one chiller (and its auxiliaries); one might selectively shut off fans or air handlers temporarily (without compromising air change requirements); one might shut down an elevator or any other non-essential device temporarily; etc. The hallmark of this category of load shaping technique is that, one way or another, the end user will be temporarily "doing without" some function. For this reason, care must be taken with regard to any potential ramification (IAQ, etc.). When a number of options is involved, they should be scheduled to go off line and then back on line on a priority basis. Again, the driver for these types of techniques could be the rate structure itself, or this could be a part of a curtailable load agreement as described above. Thought should also be given to the routine reduction of demand where possible during whatever time of day peaks are usually set. For example, in an office building, the peak is usually set around mid-day. Knowing this, a facility manager could, for example, install carbon monoxide sensors to control garage exhausters since they experience their peak load during morning and evening rush hour (and *not* at mid-day).

Fuel Switching: simply refers to the permanent replacement of electricity with some other energy source to perform a particular function. A common example is the replacement of electric domestic water heaters with gas-fired units.

Non-Electric Chilling: a form of fuel switching wherein a gas or steam absorber, or an engine-driven chiller, rather than an electric chiller is used for the chilling of water for air conditioning or refrigeration. A chiller can be driven by a natural gas, gasoline or diesel engine. Many larger plants are of a hybrid design, incorporating both electric and non-electric chillers. While retrofit projects of this type generally have substantial first costs, these technologies have been around for years, and case studies demonstrating excellent return on investment abound. There is a wide variety of good examples available in the bi-monthly newsletter *Cool Times,* a publication of the American Gas Cooling Center (AGCC), which is available on the AGCC website at www.agcc.org.

Desiccant Dehumidification: refers to techniques whereby the latent cooling load (humidity) in a facility is addressed separately from the sensible load, using one of a variety of desiccant materials that is then regenerated by some non-electric energy source. By separating the cooling loads in this manner, the required tonnage for the sensible load is significantly reduced. In many facilities, this technique is used in combination with non-electric cooling. Even where electric chillers are used for the sensible load, the effect upon load shape is very beneficial. The means of desiccant regeneration is often by direct-fired natural gas, but could also be by means of waste heat recovery (as from the exhaust and/or cooling water of an engine-driven pump). The popularity of this technology has grown rapidly in recent years, particularly in facilities which have stringent humidity control requirements. The classical application is in ice rinks, which require a dew point below 30 degrees F and which experience high evaporation rates off of the ice surface. Other types of facilities in which this technology is gaining widespread acceptance in recent years include restaurants and manufacturing facilities that require low humidity. As above, many good case studies can be found in the *Cool Times* newsletter on the AGCC website at www.agcc.org.

Thermal Energy Storage (TES): refers to any of several techniques for the off-peak production of a low temperature medium (usually ice or chilled water) which is then stored for later use in air conditioning systems during on-peak periods (when electricity is more expensive). For reasons stated below, this maturing technology merits special consideration:

Thermal Energy Storage

Thermal Energy Storage (TES) for commercial cooling merits special mention for two reasons. First, the largest contributor to poor load factor at the generating station is commercial air conditioning, which is the primary target market of TES technology. Second, among load shaping strategies, TES has perhaps the greatest potential for load shaping because rather than merely reducing on-peak electricity consumption and demand, TES moves the consumption and demand off-peak. Thus TES provides the double benefit of *reducing* demand at exactly the time when generating costs are highest, while *increasing* demand at exactly the time when generating stations have unused capacity on line. This maximizes the beneficial effect upon generating station load factor while allowing the end user to serve his/her loads unabated (unlike with demand limiting techniques). It is for this second reason that many people are coming to see TES as perhaps the most powerful negotiating tool a facility manager could have in his/her arsenal when sitting across the table from an unregulated prospective power provider.

Moreover, TES is now a proven technology. While many early systems consumed more kWh (as compared to a conventional system) because of the inefficiency of ice-making chillers and/or storage losses, a well designed system today actually consumes LESS kWh by virtue of improved system sizing criteria, better control strategies, the downsizing of fans and pumps made possible by lower chilled water temperatures, and other factors. Even if a particular TES system consumes more kWh (as it will in many retrofit applications), recent studies [such as the September, 1995 "Source Energy and Environmental Impacts of Thermal Energy Storage" prepared by Tabors Caramanis & Associates for the California Energy Commission (CEC)] show that such a system can still result in source energy savings for reasons which are discussed below.

For additional information on the solid link between deregulation and TES, see the article "Thermal Storage and Deregulation" by Brian Silvetti, P.E. and Mark MacCracken, P.E in the April, 1998 edition of the *ASHRAE Journal;* or the article "The Merits of Thermal Storage in An Unregulated Power Marketplace" by Brian Silvetti, P.E. in Volume 18, No. 3 (Winter 1998–99) of the Association of Energy Engineers publication *Strategic Planning for Energy and the Environment.*

The following capsule TES case studies are derived from press releases of the Air-Conditioning and Refrigeration Institute (ARI), dated March 25, 1997 and October 9, 1997. They demonstrate the wide range of applications of the technology:

Whitehall Elementary School (Norristown, Pennsylvania)

The TES system for this 70,000 square foot school uses an 80-ton chiller to make ice at night. When melted during the day, the ice covers the 144 ton peak cooling load. Because the building was designed to supply low temperature 44°F (6.7°C) air, system components such as air handling equipment, ductwork, chilled water piping, fans, and circulating pumps were downsized. This resulted in savings in construction costs of $192,000. Furthermore, electrical energy costs for the first year were significantly lower than a similarly-sized, and less-used school in the same vicinity.

Chrysler Motors New Technology Development Center (Auburn Hills, Michigan)

In operation since 1990, the Chrysler Motors Corporation's new technology development center reaped both capital and operations savings from its use of a 68,000 ton-hour chilled water TES system. The TES capacity allowed the center's chiller plant to be downsized from 17,710 tons, which would have been needed to meet peak cooling loads, to only 11,385 tons. With the TES system, chilled water is stored at night to supplement the chiller during peak cooling conditions the following day. The chiller plant savings more than offset the cost of the TES installation, resulting in an immediate net capital cost savings of $3.6 million. In addition, the TES system shifts over 5,000 kW of peak electrical demand to off-peak periods, contributing to an energy cost savings of over $1 million per year.

San Francisco Marriott Hotel (San Francisco, California)

Use of a TES system in conjunction with a real-time pricing strategy from the local utility is expected to yield $135,000 in annual savings. Only 1,800 ton-hours of ice storage are needed, enough to satisfy the 450 ton cooling load during the peak daily rate time period which, under the real-time pricing schedule, only lasts for two or three hours. Over one-third of the installation cost of the TES system will be covered by a rebate from the utility; the remaining amount is expected to be recouped in less than two years of operation.

Gillette Capital Corporation (Gaithersburg, Maryland)

The addition of 1,050 latent ton-hours of ice storage to this facility in August 1994 saved the building owners both installation costs and subsequent operating expenses. The project cost just over $121,000, with 57% of this expense paid for by utility incentives in the form of a $350 per kilowatt rebate and other bonuses. An existing air-cooled reciprocating chiller was originally used to cool the 62,000 square foot building, resulting in the chiller operating 14 to 15 hours during the peak summer months. By adding a full storage TES system, the cooling load from 8:00 a.m. to 5:30 p.m. is now carried by ice alone, with the chiller normally running only five hours during the night to replenish the ice supply. The on-peak load during the four month peak period is reduced by 198 kW, avoiding the $12.95 per kW demand charge and resulting in over $2500 of operating savings each month. Including both up-front incentives as well as operating savings, the system is on track to realize complete payback soon, for a total simple payback time of 3.5 years.

Miller Electric Company (Appleton, Wisconsin)

In 1990, this industrial manufacturer of welding equipment converted its cooling system from once-through well water units and conventional rooftop direct expansion units to ice thermal storage. The owner was concerned with the high sewer costs associated with the well water units and the pending phase-out of chlorofluorocarbons which were used in the direct expansion units. All of these concerns were eliminated when the system was changed out to the thermal storage system. The 500,000 square feet of conditioned space requires a peak design air-conditioning capacity of 3,000 tons. This load is handled by 1,380 tons of ice harvesting equipment operating on a weekly load shift strategy with ammonia as the refrigerant. The ice making equipment operates only during off-peak times including all of the weekend hours and at night throughout the week. In addition to a $905,000 rebate from the local electric utility company, the owner realizes a 65% reduction ($140,000) in annual air conditioning energy costs.

Rohm and Haas Research Facility (Spring House, Pennsylvania)

This facility consists of 13 buildings all connected to a central district cooling plant. Until 1995, these buildings were served by a central 4,000 ton cooling plant utilizing conventional electric chillers. The owner became concerned with ever-increasing peak demand costs, since almost half of the facility's electrical demand was contributed by the chiller plant. Further, the owner was concerned with the environmental impact of the refrigerants used in these chillers: chlorofluorocarbons R-11 and R-114. A 1,280-ton ice harvesting thermal storage system was constructed in late 1994 and early 1995. The system was operational at the beginning of the summer months of 1995. The thermal storage system, which uses refrigerant hydrochlorofluorocarbon R-22, was designed to shave a minimum of 1,600 kW from the 10 hour daily on-peak period. In actual operation, the owner realizes an average peak demand shaving of 2,300 kW, a 70% reduction in peak cooling demand from the conventional chillers. The consistently low water temperature (34°F, 1°C) available from the ice thermal storage system allows for an increase in heat transfer in the air handlers and the increased capacity compensates for increased loads, saving in replacement costs of the air handlers.

Brazosport College (Lake Jackson, Texas)

In operation since 1991, the Brazosport College's 4,000 ton-hour chilled water TES system provides environmental as well as economic benefits. Installed as part of the college's new CFCfree chiller plant, the TES system allowed the plant to be sized for average, rather than the peak, cooling loads. The TES system shifts 570 kW of peak electrical demand to off-peak periods, saving the college $62,500 in annual energy costs. Furthermore, the installation provides an 8 to 9% reduction in the college's net annual energy consumption per unit of cooling delivered.

Kraft General Foods Headquarters Building (Northfield, Illinois)

Today, all air conditioning loads are being met by melting ice that is built and stored overnight. It is anticipated that additional loads from future expansion will be handled by running some of the chillers during the day as well as at night. The system was designed to pump 36°F (2°C) water to the air handling units which would provide 45°F (7°C) air to the building. Using these lower temperatures allowed for the use of smaller pipes, pumps, air handling units and ductwork, resulting in lower first costs. Electric bills for this building were compared to an almost identical building, just three miles away, which did not use a TES system. During a one-year period, the total energy consumption at the building without TES was 11,695,468-kilowatt hours (kWh), while the building with TES used only 10, 114, 460 kWh, or about 15 % less energy.

The Link between Load Shaping and Pollution Prevention

As the deregulation of the electric power industry unfolds, resulting first in an acceleration of the implementation of load shaping strategies, an increase in source energy efficiency (and a corresponding decrease in air emissions) at the nation's generating stations will inevitably occur. What will happen is that as deregulation drives load shaping at the end-use level (as described above), the improvements in load shape will, in turn, result in improved source efficiency, for the reasons cited below.

The CEC study cited above focuses specifically on the relationship between TES (as a preferred load shaping strategy) and pollution prevention. However, the fundamental reasons for concluding that an improved load factor leads to pollution prevention are equally valid under other load shaping scenarios.

One key factor here lies in an understanding of the relationship between the load on a generating facility and its source fuel efficiency, coupled with an understanding of the manner in which a power provider must operate its generators. First, a large steam turbine cannot be turned on and off like a light bulb. Therefore, a power provider routinely must "commit" generating units to warm up in the middle of the night although they are only needed to meet the on-peak loads. This is known in the industry as "unit commitment", and results in a condition known as "spinning reserves" (unloaded or lightly loaded generators). Then, one must recognize that the efficiency of a lightly loaded generator is much lower than that of a fully loaded one. The CEC study states that the heat rates for a typical power plant are 11,744 BTU/kWh for 30% of full load, and 7,900 BTU/kWh at full load (a difference in source efficiency of 14.1%!!). Any end-use strategy which improves load factor at the power plant will reduce the need for unit commitment, thereby increasing the average load on all of the generators and, hence, increasing the source efficiency of the entire power plant.

As for pollution prevention, the CEC study finds that the reduction in emissions can actually EXCEED the source efficiency gains due to load shaping, in part because there are generally less stringent emission control requirements imposed upon "peaking" plants (which will be used less as load factor improves).

Another key factor, often overlooked, has to do with the line losses, which occur when electricity is transmitted from the power plant to the end user. These losses can be 10% or more, and are proportional to the square of the flow rate of current. Any end-use strategy which reduces on-peak load will reduce line losses accordingly. Moreover, line losses are 5–7% higher when ambient temperatures are highest (i.e. during daytime, on-peak periods). Again, any reduction in on-peak demand will reduce transmission line losses. To the extent that line losses are reduced, the quantity of electricity that must be generated to satisfy a given end-use requirement is reduced.

On the bottom line, the CEC study concludes that a 20% market penetration for TES alone (among all load shaping strategies) in the State of California will reduce carbon dioxide emissions by 260,000 tons per year. Other studies, such as a recent EPRI study of Texas Utilities and another recent study in the U.K., have shown the same link between TES and emissions reductions. These studies demonstrate a strong link between load shaping and pollution prevention.

Conclusion

As with many situations in life wherein we are faced with uncertainties born of change, the impending deregulation of the electric utility industry holds more than its share of mysteries. However, we <u>do</u> know that power providers will be competing for customers as never before, we <u>do</u> know that these power providers will be seeking a competitive edge through reductions in their own generating costs as never before, and we <u>do</u> know that a primary means of reducing those generating costs is by improving the load shape of their customer base. Therefore, it follows that a proactive facility manager will undertake to understand, quantify, control and modify his/her own load shape in order to make his/her account more attractive to the power providers with whom he/she negotiates. Moreover, as an added incentive, we see that the benefits of load shaping extend beyond the economic incentives to the end user, and include environmental benefits to us all.

SECTION 3—
STRATEGIC GAS FORUM

Chapter 43— Purchasing Commodity Power from Third Parties: Are We Having Fun Yet?

William A. Monsen
MRW & Associates, Inc.

Abstract

California and other states have established regulations permitting customers to purchase commodity power from their supplier of choice. This change has brought about both opportunities and risks for customers. Re-bundling of services by Energy Services Providers (ESPs) can provide benefits to customers although it also complicates the evaluation of proposals. New products and services have been developed which can add value to an ESP's bundled service or merely increase customer costs.

An understanding of the ESP's perspective on valuing direct access opportunities is key to evaluating a customer's opportunities to profitably acquire power from an ESP. Loadshape analysis is the first step in assessing opportunities for direct access purchases. The incumbent utility supplier may have an obligation to supply loadshape information. Often these obligations are not clearly explained to customer service personnel in the field, which can cause delays in power buying programs.

Determination of the potential for savings under direct access depends on a particular state's program. "Standard Offer" rates, "Shopping Credits," Transition Service Charges" and the "PX Credit" are different variations on the costs avoided by the incumbent utility if a customer takes direct access service. Unless care is taken, it is possible to increase power costs even with guaranteed discounts off of the commodity cost of power. Changing rules regarding determination of these avoided costs can cause significant uncertainty among suppliers, thereby limiting offers to sell.

Understanding how transition charges are recovered from customers is critical in deciding the approach to take regarding cost control after deregulation. Often times transition charges cannot be avoided except under very limited circumstances. In most cases, energy efficiency measures installed on the customer side of the meter do not trigger exit fees. However, self-generation may or may not allow avoidance of transition charges. On the other hand, even if self-generation does not avoid transition charges, it can often prove cost-effective since, for the present time, self-generation does avoid transmission and distribution (T&D) charges. However, some states are beginning to examine T&D bypass issues.

This paper outlines some of our experiences in attempting to procure power for customers in both the public and private sectors.

California and other states have established regulations permitting customers to purchase commodity power from their supplier of choice. This change has brought about both opportunities and risks for customers. Re-bundling of services by Energy Service Providers (ESPs) can provide benefits to customers, but also complicates the evaluation of proposals. New products and services have been developed which can add value to an ESP's bundled service or merely increase customer's cost.

MRW & Associates, Inc. (MRW) has assisted several companies and public sector entities with procurement of direct access power. In general, we have followed a process that includes:

- development of load data
- identification of potential suppliers
- development of Request for Proposal (RFP) and evaluation of proposals
- detailed discussions and selection of provider
- final negotiations

On more than one occasion, a subset of these steps has been repeated due to material changes in regulations, proposals, and/or receipt of bids outside the established process.

In assisting our clients with energy procurement, MRW has identified a number of issues that frequently arise and that should be addressed or planned for prior to the solicitation in order to avoid a potentially unexpected and undesirable outcome. This paper begins by outlining four such issues, proceeds to discuss three case studies (two private sector and one public sector) which illustrate, to varying degrees, these issues, and concludes with a summary of lessons learned.

Issue #1—
Service Bundling by ESPs

In our experience, customers are usually looking to obtain commodity power through a direct access program for the seemingly simple purpose of achieving a clear and meaningful reduction in their cost of electricity. What we have found, of course, is that this task is not so simple after all.

The first roadblock is the lack of attractive commodity-only offers. Many customers expect to achieve significant savings (e.g., 10% or more off of their otherwise-applicable rates) simply by switching away from monopoly-supplied electric power and choosing a direct access supplier. In fact, it is common for the best offer received for a commodity-only deal to represent a savings of no more than 2–3%, even for customers with the best load shapes.

These scant commodity savings result from the structure of deregulation. In California customers who switch suppliers must continue to pay a "Competition Transition Charge" to help pay for the utilities' stranded costs. Other states have similar mechanisms. Customers also must pay transmission and distribution (T&D) costs which are based on traditional utility cost-of-service ratemaking. Therefore, the commodity component of a customer's rate is often much less than half of the overall cost of power.

ESPs generally compete to supply just the commodity portion of the customer's load and are therefore forced to compete on cost with the utilities' incremental cost of providing commodity energy (which, in California, is now purchased by utilities on the Power Exchange (PX)). Because the wholesale power markets are relatively efficient and the commodity energy market is derived from these wholesale markets, it is very difficult for ESPs to provide energy at a cost substantially lower than that of the utilities.

As a result of the low margins available to ESPs on commodity-only deals, most focus their efforts on value added services. ESPs see commodity supply as a necessary product to "get in the door," but typically try to bundle the commodity offer with a host of other products, such as energy efficiency upgrades or information services such as customized billing or online access to loadshape information, to provide greater savings to the customer, enhance customer value, and increase profit margins.

Thus, in order to realize significant savings, customers must often enter into complex, multi-faceted deals. Given the variety of products being offered and bundled together by ESPs, it is often difficult to determine the true cost (or value) of individual components of these proposals. This makes comparing proposals difficult. In most cases, ESPs are generally willing to work with a customer to make substantial changes to a proposed deal structure in order to win the deal. Thus, careful RFP design, clarity in specification of products being solicited, and good negotiations on the part of the customer are critical.

Issue #2—
Load Data

Despite the relatively small magnitude of commodity-only savings, customers will still want to do everything they can to maximize commodity discounts. One step customers can take to achieve this is to provide ESPs with accurate and detailed load data. Without reasonable load data, ESPs are forced to assume the worst about a customer's load shape in order to protect themselves from the risk of offering a discount greater than they can profitably provide. By providing detailed load data, customers with superior load shapes stand to increase their commodity savings.

Developing these data is often not simple. In some states, utilities are under no obligation to provide load data to customers (or the data that they provide is often in a form that is not easily used). In other states, such as California, utilities are required by the Public Utilities Commission to provide detailed load data to any customer that asks. In practice, getting this data from utilities may require some effort. Utility personnel may be uncooperative or, more likely, unfamiliar with the rules that require them to provide this information. As a result, it is wise to plan ahead and make requests for load data early in the process. In at least one case, MRW has abandoned hope of obtaining useful data from the utility in a timely manner and relied on other methods of estimating load shape. In another, it took MRW over four months to obtain detailed, accurate load data from the local utility. In states where there is no requirement for utilities to provide data in a timely manner and in a format that is useful, customers should expect long delays.

Issue #3—
Obtaining Net Commodity Savings

Opportunities for obtaining true commodity savings depend, in part, on the rate design of the local utility. In some states, customers have frozen rates during a "transition period". During that time, if a customer buys power from a third party, the customer allows the utility to avoid supplying power to the customer. These customers receive a credit from the utility which is intended to approximate the costs that the utility avoids. These avoided costs go by different names, such as "Standard Offer", "Shopping Credit", or "Transition Service Charge". In some states, such as Massachusetts and Pennsylvania, these credits are predefined through regulatory proceedings. A different approach is taken in California, where the "PX Credit" is calculated based on the utility's average cost of serving customers in a particular customer class. ESPs must supply energy at a cost below this credit in order to provide the customer with savings.

It is important to have a thorough understanding of the operation of this credit mechanism in order to interpret offers and ensure savings. In some cases, it is actually possible for customers to end up paying *more* for electricity than they would have if they had remained with the utility, even though their ESP offered them a guaranteed discount. For example, in California a customer might sign a deal with an ESP for a guaranteed discount off the commodity price (e.g., a 5 percent reduction off of the hourly PX price). If the customer has a poor load shape (for example, the customer has more consumption in the peak period than the average customer in its rate class), then it is possible for the discounted PX price paid to the ESP to be higher, on average, than the PX credit received from the utility, since utility PX credits are based on average load shapes for the customer class. Thus, the customer must carefully evaluate the structure of both the discounts being offered by the ESP and any crediting mechanisms that ultimately will effect the net cost of power.

Issue #4—
Competition Transition Charges

As mentioned earlier, Competition Transition Charges (CTC), such as are in place in California, can leave ESPs with little room for savings on electricity supply. CTCs can also add to the confusion surrounding commodity supply offers. Some ESPs have offered guaranteed discounts compared to the current frozen utility tariff for multi-year terms. While such offers may initially appear attractive because of their apparently large savings, such offers might do no more than pay in advance savings the customer would have seen anyway when CTCs are later eliminated. Such a possibility occurs if the term of the transition period is not pre-determined but is instead a function of market prices. To evaluate such a proposal, it is important for the customer to estimate the period over which transition costs will be recovered.

CTCs can also complicate other energy options that a customer may be considering. Prior to industry restructuring in California, customers who installed self-generation but received utility backup service were not responsible for stranded costs. In other words, these customers would avoid commodity costs, stranded costs, and often T&D costs by installing self-generation. Shortly thereafter, however, the rules were amended; customers who installed self-generation but continued to receive utility backup power are now responsible for payment of CTCs equivalent to those they would have paid had they not installed the self-generation.

As it happens, this counter-intuitive change in rules occurred precisely when MRW was working with a customer who was installing self-generation. By taking early action to ensure that the exempted from CTC responsibility for its generation, the customer was able to avoid payment of CTCs pertaining to the self-generation in question. This matter was highly fought out in a highly-contentious regulatory proceeding, requiring significant time and effort by the customer. This highlights the importance of being thoroughly up-to-date on shifting regulatory rules.

The issues described above are illustrated in the case studies below.

Case Studies

Case Study #1—
City of San Diego

As a public entity, the City of San Diego faced a unique set of issues and considerations. Because it is a public agency, the City of San Diego established a more formal proposal process than private entities typically follow. Any last minute re-considerations of new bids by ESPs that had previously been rejected would have to be carefully examined to assure that other bidders were not dealt with unfairly. Also, the City required ESPs to fill out detailed forms indicating that they met the City's requirements of contractors, including being a drug-free workplace and an equal opportunity employer.

In addition, the City faced a political consideration: discontinuing utility service would mean that the local utility would lose its second largest customer. Such a move would require substantial savings in order to be politically acceptable. Signing with an out-of-state ESP would likely add to the controversy.

The City also required certain special services. Emergency backup power was required by U.S. EPA regulation for the City's sewage treatment plant (which were in the process of developing on-site self-generation facilities). Finally, the City had a high preference for predictable pricing to facilitate budget-making.

MRW's overall process in helping the City of San Diego procure power was similar to that we used with other clients. We began by developing load data that could be used by ESPs to provide the best offer possible, as the City had an attractive load-shape. Rather than pre-select certain ESPs or move directly to an RFP, however, we worked with the City to create a Request for Qualifications (RFQ). This step was taken to allow the City to exclude unqualified bidders from the RFP. By pre-screening through the RFQ process, we precluded the potential case of the City being forced to choose a less desirable provider based on lowest cost, or any other single criteria.

The criteria that were most important to the City of San Diego included the following:

- Retail experience
- Back office support
- Billing services
- Power delivery experience (volume, number of customers)
- California presence
- Financial strength
- Price, pricing structure, guaranteed savings, and risk management

Somewhat surprisingly, the initial proposals received were not very attractive. Furthermore, over the period of time the City was going through the process, several ESPs left the business or refocused their efforts in other states.

Because of the lack of attractive offers and the political concerns of discontinuing utility service, the City briefly considered aggregating its load with the Association of San Diego Area Governments (SANDAG) and allowing SANDAG to handle power procurement for the City. However, since the City's load shape was very favorable compared to other members of SANDAG, such a move would have provided little benefit to the City.

Ultimately, a late but attractive proposal was received and accepted by the City. Because of the flexibility built into the process, the City was able to entertain this option. The fact that the proposal was from Sempra, the unregulated subsidiary of San Diego Gas & Electric, likely helped make its acceptance feasible. The City entered into a commodity agreement that provided significant up-front payment and allowed the City to terminate the agreement in the event that the local utility was able to fully recover its stranded costs during the term of the agreement.

Several important lessons emerged from our work with the City:

- Particularly for a public entity, it is important to build flexibility into the selection process

The supplier market is fluid and changes should be anticipated

It is important to define evaluation criteria prior to issuance of an RFP, especially where the selection process will be under outside scrutiny

***Case Study #2—
Tenet HealthCare***

Tenet HealthCare (Tenet) is a national healthcare provider that wanted to initially focus its efforts on opportunities in California. If significant savings could be realized in California, then Tenet would expand its efforts to other areas of the country. Tenet's number one concern was the overall level of savings. As a healthcare provider, Tenet was also very concerned about reliable service and performance by its ESP. This meant that Tenet required significant financial security from its suppliers.

Based on Tenet's criteria, MRW developed a short list of qualified ESPs and facilitated meetings between Tenet and the ESPs. MRW then put out an RFP to the firms that Tenet was comfortable with and helped Tenet evaluate the proposals.

Six pre-qualified firms responded to the RFP. MRW recommended two finalists based on the following criteria:

pricing proposal/guaranteed discounts

reliability of electricity supply source

overall qualifications and financial strength

risk

scope of services offered

approach to providing services

As MRW and Tenet began discussions with the two finalists, we received an unsolicited bid from one of the four pre-qualified RFP respondents that had been rejected based on their initial offer. This new bid appeared substantially more attractive than that of either of the two selected finalists. As a result, Tenet and MRW reconsidered and began negotiating with the latecomer.

As the negotiations "progressed", the ESP made several significant changes to its offer. As might be expected, each new offer was always less attractive than the last. Finally, Tenet and MRW cut off negotiations and returned to the original finalists, whose offers had also changed. Ultimately, one of the two was selected and a contract was signed.

In fairness to the ESPs, some of the changes in terms were due to evolving regulatory rules that impacted the ESPs ability to make certain offers. However, this example illustrates several issues and lessons we have learned:

Back channel offers are to be expected from losing bidders

Offers are likely to change, sometimes drastically, up until the moment of contract signing

It is important to be aware of changing regulations and rules. If the regulatory rules are in flux, it is likely that offers will be highly dynamic as well.

***Case Study #3—
Otis Spunkmeyer***

Otis Spunkmeyer (Spunkmeyer) is a national food processor that was interested in procuring low cost energy for its facilities in several states (California, Pennsylvania, and South Carolina) from a single ESP. Two of Spunkmeyer's characteristics proved to be a challenge: Spunkmeyer's load is relatively small, and its business operates on a 5–6 day work week, which resulted in a load shape that was concentrated in the peak period.

As a result, Spunkmeyer received only a few responses to its RFP. In fact, MRW evaluated only two of the proposals that were received. One of the two bidders submitted a proposal that was limited to Spunkmeyer's California facilities and included options for load shifting and load curtailment in an effort to realize energy savings. Metering costs were not included. This offer also included options for natural gas, power quality, energy information management, energy efficiency, and rate optimization. In evaluating this particular offer, Spunkmeyer had to consider how these services would effect its daily operations (e.g., how load shifting or curtailment would impact production cycles).

The second bidder, focused mainly on energy efficiency. This bidder conducted energy audits at Spunkmeyer's Pennsylvania and California facilities and identified substantial potential savings from energy efficiency, bill auditing, voltage upgrades, O&M improvements and electric and gas supply aggregation. Because it addressed its proposal to more than just the California facilities, and because it provided the more aggressive pricing structure for energy efficiency services, this bidder was ultimately chosen.

The Spunkmeyer case highlights three important points. First, many suppliers were unwilling to even respond to the solicitation because of the size of the potential load to be served. Second, Spunkmeyer's loadshape relative to other customers in its customer class would have resulted in a net increase in commodity costs in California as a result of the PX credit mechanism (i.e., many suppliers were unable to offer a commodity discount). Third, Spunkmeyer may be able to achieve relatively significant savings. However, these savings will come from energy efficiency improvements rather than from commodity power buying.

Lessons Learned

Several lessons are common to many of the procurement efforts MRW has worked on.

The Biggest Savings are not in Commodity

For a small customer such as Otis Spunkmeyer, perhaps it is not surprising that ESPs do not offer great savings on commodity supply energy. But it is also true that the largest customers with the best load shapes are receiving offers with saving much smaller than originally anticipated. This highlights the importance of being willing to look at other options, such as energy efficiency, to achieve bottom-line savings.

The Supplier Market is Fluid

Even today we are still in the early days of industry restructuring and not all the dust has settled. Suppliers may enter or exit the arena while the customer is making decisions, and specific offer terms are likely to shift until final contracts are signed.

Flexibility is Important

It is important to be flexible in terms of the types of services entertained, and it is important to build flexibility into the evaluation process. Because offers are shifting and back channel offers are to be expected, the selection process should ensure that the customer retains the leeway to choose the best option. This is particularly important for public entities.

Regulatory Knowledge is Paramount

Because the method for paying ongoing utility costs or receiving credits from utilities after switching is complicated and varies from state to state, it is crucial to fully understand the mechanics of the system. Otherwise, it is actually possible for some customers to pay more for energy, even while receiving a discount to some index. Moreover, shifting regulatory rules can directly impact energy measures underway at a facility. Early anticipation of these changes can allow a customer to retain favorable treatment.

Conclusion

Although the regulatory environment can be confusing, the commodity savings small, and the constantly changing offers frustrating, the situation is far from hopeless. ESPs are hungry for business, eager to please, and continually on the lookout for new ways to increase efficiency and create savings. By keeping in mind a few guidelines, customers should be able to find many opportunities to reduce overall energy costs in the new, deregulated energy world.

Chapter 44— Side-By-Side End-Use Metering at Bonneville Power Administration

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Abstract

Many electric metering options are available today. Bonneville Power Administration needed to better understand these options to support its customer service programs. This paper describes what we have done to learn more about new metering technologies, including a demonstration of several end-use metering systems on the Bonneville Power Administration headquarters building. Several examples of how we have applied advanced metering are given.

Introduction

Bonneville Power Administration (Bonneville) markets wholesale electric power to public utilities, federal facilities, and industries in the Pacific Northwest. Bonneville also has a mandate to promote energy efficiency. One way to promote such efficiency is to help customers understand metering and introduce them to new metering technology, so that they may manage (monitor and shape) energy use.

For several decades, metering of electricity changed little. Electric utilities metered primarily for billing purposes. For a typical facility, the only electric utility information recorded was a monthly total of energy consumption, and perhaps a single reading of peak demand and another single reading of power factor.

In the 1980's, this picture began to change. Microprocessor and digital computers began a transformation of electric metering that continues to this day:

A wide range of equipment manufacturers began to offer advanced "smart" metering equipment.

Personal computers and sophisticated software became widely available to store and process information.

Data communication networks began to offer fast transfer of large quantities of data.

In the 1990's, these advances continue, but with some new driving forces: (1) deregulation has opened up energy supply acquisition, and (2) many businesses area embracing information technology.

At Bonneville, we came to realize that we needed to understand these new metering technologies better, both for our own needs and for those of our customers. Many of our small utility customers do not have the staff or time to investigate the new technologies becoming available. Many of the Federal facilities with which we work want advice on how to sort through the new metering technologies and how to apply them to lower their energy costs. We believe that customers need more and better information to better purchase and use electricity.

To address this issue, Bonneville researched the new metering technologies and installed several different systems in the Headquarters building in Portland, Oregon. We have also formed partnerships with several metering equipment vendors. These steps allow us to conduct equipment demonstrations and provide Bonneville staff with hands-on experience that can be shared with our customers.

We had several specific objectives for this project:

1. To demonstrate new metering systems in a real-world environment, providing our customers the opportunity to see how these systems operate and the benefits they could gain by using these or similar metering systems to collect and use data about electric use;

2. to build internal staff expertise with various systems available; and

3. to provide the Headquarters building manager and staff with current information about how the building is using energy.

The following sections describe what we have done to date, what we have learned, and how this information might be used.

Metering Demonstration

Preliminary Product Research

Many different companies now offer electrical metering equipment. What they offer, however, seems to change faster than anyone could keep up with. We spent months investigating what is currently available. We went to trade shows and read periodicals to gain an overview of what is being offered, and followed up with invitations to a series of manufacturers to give presentations on their equipment.

Given the many approaches to electric metering, we initially came up with three different product categories:

1. utility-provided information,

2. third-party systems that tap into the utility meter data, and

3. stand-alone metering systems.

Our goal was to install at least one metering system from each of these categories.

BPA Headquarters Metering Installation

We choose to use our own office building as the site for metering hardware installation. Bonneville Headquarters is a 7-story office building of approximately 50,446 square meters (543,000 square feet), with a peak demand in excess of 2 MW. To gain experience with systems requiring different levels of effort for installation and operation, we chose several different types of systems to install in the building.

Installation and setup has now gone on for more than 18 months. We had most of the expertise in-house to install the hardware and software, and we were able to coordinate this installation with other ongoing projects. Table 1 summarizes the metering systems installed to date.

Table 1: Metering systems installed to date

Provider	Description
Pacific Power (serving utility)	1. Mail monthly reports of interval data.
	2. Provide a pulse signal from revenue meter.
	3. Provide access to revenue meter register data.
TeCom	Hardware and software for collecting pulse and analog data.
Energard	Hardware and software for collecting pulse data and temperature, incorporated into predefined reports distributed via internet.
Enerlink	Software only for access to utility register data.
Schlumberger	Utility-type meter with pulse output along with software for accessing register data (used for submetering).

Reading the Utility Meter

Our first objective was to get information from the electric utility meter. We contacted our serving utility and asked to have the existing standard electronic demand meter replaced with a newer meter with an internal modem. The utility installed an ABB Alpha meter, and the local ABB representative provided us with DOS-based software to access the meter register data. At our request, the utility later replaced the Alpha meter with a newer ABB Alpha + meter with much larger internal memory and with pulse outputs. This gave us direct access to the utility interval data, but only a limited graphing and analysis ability (although much more capable software can be purchased from ABB).

Next, we installed the **TeCom** and **Energard** systems. The InterLane Power Manager by TeCom includes an *Interactive Control Unit* (ICU) installed on site. The ICU can accept nine pulse as well as eight 4–20mA analog inputs. These inputs can be used to activate a warning device or can be interfaced with a control system. Data downloads and programming are done via modem. This system has extensive analysis and graphing capabilities, including data analysis, load profiling, data normalization and user-created bill generation.

The Energard Envision system includes a *Remote Processing Unit* (RPU) installed on-site. It monitors pulse data from the building revenue meter, along with outside air temperature. After installation, the user is not required to undertake any setup or download data from the system. Extensive reports are made available to the user on a Web site. These reports include real-time displays as well as various energy tracking reports. Energy use is normalized based on temperature for the energy-use tracking reports.

Installation of both the TeCom and Energard hardware was straightforward. After the Energard RPU is installed and connected to a phone line, Energard staff accomplishes setup via the phone line. The user simply accesses the reports using a standard Internet browser. After the TeCom ICU is installed, the user must set up the ICU to reflect the unique characteristics of the site and to define the quantity (e.g., kWH, kVAR, water, gas) that each connected channel will monitor. The user may then access the ICU via modem and TeCom-supplied software. Data downloads are initiated manually or automatically, as set up in the software.

One critical step in the setup of both these systems is defining the pulse weight (kWh per pulse). Pulse signals (often referred to as "KYZ pulse") are the traditional output signal from a utility watt-hour meter. In the case of a revenue meter, this quantity can be supplied by the serving utility. In the case of pulse signals from a non-revenue meter, this device is programmed (or preset) with a given pulse weight that is then used to set up the recording device. (If the recording device is set up with an incorrect pulse weight, the system will give incorrect values.)

It is also important to understand how a changing load or changing interval affects pulse-data. Pulse weights must be set to an appropriate value for a given load and given recording interval in order to achieve good resolution. For example, assuming a 30-minute interval and a 500-kW load, a *pulse weight* set at 1 kWh per pulse will give a *pulse count per interval* of 250, giving relatively good resolution. However, if the user wants "real-time" data, and views the data at a 1-minute interval, there will be only eight pulses per interval, giving very poor resolution. Likewise, if the load decreases at night to 100 kW and we choose to look at a 5-minute interval, the pulse rate will also be eight pulses per interval, again giving poor resolution.

As we used these systems, we learned some lessons about pulse data. At first, we used an incorrect pulse weight. This was readily corrected because we could compare the values from several systems metering the same load. Also, we misinterpreted rapid fluctuations in a "real-time" display as an abnormal condition, when in fact it was simply a result of using *a pulse interval* that was inappropriately short.

Installing wiring between the various hardware components took some doing. The building itself allows for straightforward wiring to most locations. Additionally, our internal telephone office staff was experienced and capable of installing wiring. We used standard telephone wire for pulse signals with runs over 30.5 meters (100 feet). Even so, we have not yet monitored the gas meter or the water meters because we cannot readily run wire to these meters. Installation of the outside air temperature is not yet satisfactory and will require more work.

Finally, we installed the **Enerlink** system, which consists of a software package only. The software was installed on a PC equipped with a modem and with access to a phone line. The software has several built-in protocols designed to communicate via modem with a variety of standard utility meters and recorders. This software package has the capability to generate a bill; however, the manufacturer must create the rate files for installation into the software package. The package can also apply different rates to the same load profile. Users can also graphically modify their actual load profile to observe the change in their energy bill if they were able to decrease peak demand or shift the peak to a lower rate period, assuming time-of-use rates apply.

Submetering Building Loads

Once the systems were installed, our goal was to submeter the energy consumption of a new 24-hour-a-day operation added on the Headquarters' 5th floor. Two primary feeders were added to supply this operation; both were connected to an Uninterruptible Power Supply (UPS) and an emergency generator. The building manager was interested in finding out how much additional load the operation added and what the extra utility cost was.

We choose to use utility-type electric meters, with their pulse signals supplied to the TeCom system. Installation of a utility-type meter requires interruption of the power supply, so we had to coordinate this installation with a planned power outage. We installed an electronic meter (Schlumberger Fulcrum) on one feed and an electronic meter with an internal modem (Schlumberger Vectron) on the other feed.

Output data showed that the 24-hour operation was relatively constant. By programming our utility's rate schedule into the TeCom system, we found that the new operation is costing about $2,000 per month.

Although the systems we installed are very well suited for energy management, we have not yet aggressively pursued such management in the building. After monitoring the building's energy use patterns, we found that there is no opportunity for demand reduction: to decrease our energy bills, the building base load would have to be lowered (which may or not be feasible, given the building use patterns).

Application

Currently, we have access to the utility meter register data via modem, as well as pulse outputs that feed two other metering systems. The Envision system currently monitors the pulse output from the ABB Alpha + electric revenue meter, as well as the outside air temperature. The TeCom system monitors pulse data from all three meters involved in the project (the ABB revenue meter, and the Schlumberger Vectron and Fulcrum meters that monitor the consumption of the 24-hour operation of the 5th floor). We use Enerlink to access load profile data from the ABB Alpha + revenue meter and the Schlumberger Vectron meter.

Following are several specific results:

1. We have excellent information on the building electric load profile.

   We can readily view daily load profiles of 15-minute interval data. We have found that the minimum building load is about 50% of the peak load. We hope to implement and monitor operational changes to reduce this off-peak consumption.

   We can readily compare one period with another. Especially useful are overlays of one week to another, and single-screen views of an entire month of daily load shapes. Also very useful is a load profile modeler that allows easy graphic modeling of proposed consumption changes.

   Consumption data can be normalized, by user-defined quantities. We are especially interested in making weather-related adjustments to see whether we can provide a better comparison of one time period to another.

   We have over one year's worth of historical data readily available.

2. We can accurately monitor the electric use of our 24-hour operating area and accurately calculate the cost using the serving utility's rate schedule.

3. Our account representatives can effectively demonstrate the various systems at utility customer sites. Using a laptop, account representatives can easily dial into the building and demonstrate real-time energy use and various software features, as well as access Web site energy accounting. Some customers, after seeing a remote demonstration, have visited the installation site to learn more of the details of the installation.

4. We have installed hardware that can accommodate additional submetering as the need arises.

5. We have obtained valuable information to help troubleshoot abnormalities with our UPS system.

Plans for Additional Demonstrations

We plan to continue to install more submetering in the building. One main goal is simply to keep informed of new metering technology.

We plan to meter two chillers in our building to provide continuous monitoring of electric use and chilled-water output. This step will require kW meters, as well as temperature and flow measurements. We plan to monitor the kW input with kW transducers with an analog output that can be connected to the building automation system, as well as to the TeCom ICU. We will use this information to evaluate operating efficiency on a continuing basis.

We are particularly interested in integrating end-use metering into the building management system using evolving communication protocols. Systems are available that use networked power metering using multiple metering points on a single RS-485 network.

Conclusions

1. **Wiring our building has presented difficulties.** We will be watching the development of wireless sensors and data systems with great interest.

2. **Installation and setup of the system has required having a skilled technician on site.** Throughout this project there have been continual hardware and software upgrades, requiring some attention to keeping everything working together. We now advise facility owners to carefully weigh their staff expertise and time available when selecting a system. If you have the expertise, doing more of your own installation and operation will allow a more customized and adaptable solution. If you have clearly defined information needs that are not expected to change much, it may be wise to stay away from doing more of your own installation and operation.

3. **Increasingly, electrical metering is being driven by new computer and communications technology.** Consequently, one should expect a continuous string of hardware and software upgrades; something better will be coming along soon, and you are likely to be caught in both the good and the bad resulting from numerous upgrades.

4. **Even with a willing and capable utility, it may take longer than expected to get a metering information system set up: start now.**

Chapter 45—
Distributed Power Resources Activity at the Pacific Northwest National Laboratory

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This paper presents an overview of current and upcoming work at the Pacific Northwest National Laboratory[a] (PNNL) in the area of distributed power resources. The concept of distributed power resources goes by many different names in the literature today, e.g. "distributed generation", on-site generation, "distributed utility", etc. The narrowest definition of the concept is small-scale power generation (typically less than 1 MW) located close to its point of ultimate use. It contrasts with the traditional large power generation plants that are typically located far from most points of ultimate power consumption. These small-scale generators may or may not be connected to the power grid, and they encompass a wide range of traditional and emerging prime mover concepts. Examples of distributed generation concepts include internal combustion engines, combustion turbines (large and small), fuel cells, photovoltaics and wind turbines.

A broader definition of "distributed power" addresses the systems within which small generators are used and the loads they serve. Examples of additions under this perspective include customer demand-side management, energy storage at the customer site, controls and grid interconnections for these generators, and connected customer loads, etc. Consideration of these additional systems enables full characterization of the benefits of distributed energy concepts on both sides of the customer meter. For the purposes of this paper, "distributed power resources" is defined in the broader context of small-scale power generation concepts as well as controls and customer demand-side management.

The Pacific Northwest National Laboratory has been involved in various aspects of distributed resources since the early 1980s, and is currently pursuing an initiative in distributed power systems directed at developing next-generation distributed power systems that support long-term U.S. energy policy goals of clean, efficient generation at economic prices. PNNL's activities are in the following four focus areas:

distributed power generation

fuels processing for distributed power generation

ancillary customer systems

institution and commercialization support.

Distributed Power Generation and Space Conditioning

Distributed power generation technologies that are or will soon be commercially available typically fall within one of three categories; combustion engines (internal and external), fuel cells, and renewable technologies. Combustion engines comprise the largest population of currently deployed distributed generation (DG) technologies, including diesel generator sets, gasoline generators, gas combustion turbines (large and small), and externally fired engines such as Stirling engines. Because these concepts are mature technologies with substantial investment in commercial product development, PNNL is not active in these DG concepts. Similarly, the renewable DG concepts such as photovoltaics and wind turbines are the primary responsibility of the National Renewable Energy Laboratory in Golden, Colorado; thus, PNNL is not active in developing renewable DG concepts, either. PNNL has been active in the fuel cell area for the past decade.

Four concepts dominate fuel cell research today; phosphoric acid, molten carbonate, proton exchange membrane (PEM) and solid oxide fuel cells (SOFC). The phosphoric acid (PA)

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[a] Operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLD 1830.

and molten carbonate (MC) concepts are being commercialized for installations of 500 kW and larger, making them applicable for large commercial and utility applications. For smaller applications commensurate with the needs of residential, small commercial and vehicular transportation, the PEM and SOFC concepts are the leading contenders. PNNL's fuel cell technology development efforts focus on the SO and PEM fuel cell concepts.

PNNL's SOFC Activity

PNNL has participated in the DOE solid oxide fuel cell program since the early 1980s. The SOFC concept has the typical fuel cell attributes of efficient, clean power production. Advantages of the SOFC concept include:

Higher efficiencies at both full and partial loads than other fuel cell concepts

Solid-state construction, making it amenable to low cost fabrication

Fuel flexibility as a result of greater tolerance for impurities such as CO, CO_2, S and P

Scalability for small applications in both stationary and mobile settings

Fuel flexibility using direct and indirect reforming of logistic, common, and complex liquid and gaseous fuels

The relatively high temperatures utilized in the SOFCs make them suitable for integration with gas turbine bottoming cycles to drive net efficiencies to very high levels.

The primary barriers to commercialization of SOFCs are the current high fabrication costs and long start-up times necessary to accommodate the thermal mechanical limitations inherent to ceramic materials. PNNL's role in the DOE program to date has focussed on materials research to help reduce the cost and enhance the manufacturability of the ceramic SOFCs. Specific materials targets addressed at PNNL include

interconnect materials—stable in both air and fuel

air electrode—maintain porous structure; stable interface with electrolyte

fuel electrode—high sulfur tolerance

low cost fabrication technology—design dependent

seal technology—planar designs to isolate air and fuel

performance modeling—enhance existing component and system models to enable systems optimization and lower fabrication costs.

long-term performance—target at least 40,000 h lifetime.

Future PNNL efforts will integrate the SOFC cell design with ancillary controls and thermal management systems, resulting in functional SOFC systems that seek to meet market cost performance targets of the DOE programs.

PNNL's other activity in prime movers associated with distributed resources is the development of compact heat pumps for distributed space conditioning. PNNL developed fundamental techniques for heat and mass transfer conducted in microscale devices in the early 1990s and has extended that concept to portable heat pump devices. Likely applications include portable heat pumps for remote grid independent structures, mobile refrigeration for vehicles or back-up applications.

The heat pump is based on the lithium bromide/water absorption cycle, yet conducts heat and mass transfer in channels approximately 10 microns in width. Using many such microchannels in parallel, heat pumps can be deployed with radical reductions in size and weight compared to conventional systems. For lithium bromide/water-absorption cycle systems, the heat pump size can be reduced to $1/60^{th}$ of the size needed for a comparable conventional heat pump [see Figure 1].

An important benefit of these heat pump systems is their ability to utilize waste heat from various DG devices such as fuel cells in mobile applications to provide space conditioning. In addition, use of such heat pumps distributed through a designed space reduces peak power requirements, thus reducing the capital requirements for DG installations needed to provide facility power. These system interactions extend the value of DG devices, driving net system efficiencies quite high. PNNL is currently working with government and commercial interests to develop products based upon this revolutionary concept.

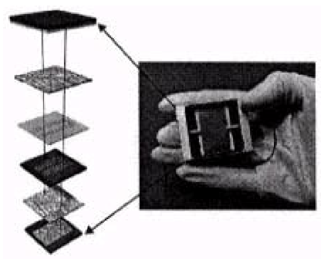

Figure 1
Microscale heat exchanger

Fuels Processing

Distributed power concepts will have significant impact upon the nation's fuel mix if these technologies achieve significant market penetration in the next few decades. Recent growth in natural gas demand driven by gas turbine construction in the U.S. is the first major evidence of this trend. As fuel cells enter the market, sources of hydrogen gas and liquid fuels will be in increasing demand. PNNL is developing several novel fuel processing concepts to serve this growing distributed power market.

The microtechnology concepts discussed earlier have led to the development of a compact chemical process system for converting liquid hydrocarbons to hydrogen to power portable or miniature fuel cells. This fuel processor is unique in that the size and weight are dramatically reduced compared to conventional approaches; thus truly enabling compact and lightweight power generation [see Figure 2].

One application of this microscale fuel processor is in converting liquid hydrocarbons into hydrogen for use in portable PEM fuel cells. For application in military or consumer products, PNNL is developing a 1-kg system that would provide 5 watts of base power and 10 watts of peak power for a week using butane as the fuel. The system would include two modules that run the fuel processor continuously to provide the base load and use a compact lithium power battery for load leveling and to meet peak electric power demands. This same fuel processor module could be replicated to provide greater capacity for distributed fuel cell use in mobile applications, residences or small commercial settings.

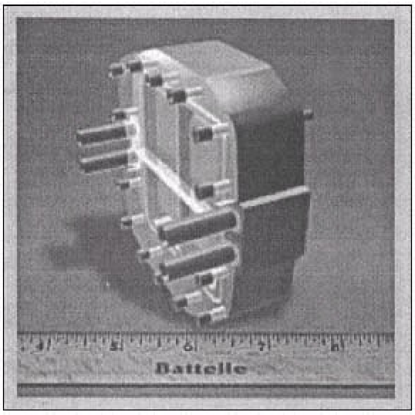

Figure 2
Miscroscale fuel vaporizer for transportation applications

A second fuel processing effort is the development of thin film ceramic membranes designed to partially oxidize natural gas for use in fuel cell systems. This effort developed processing methods that form electronic ceramic gas separation membranes that enhance gas separations. In addition to application in reforming methane for fuel cells, these membranes can also be used to separate O_2 from air for industrial processes. Commercial products incorporating these forming concepts are under development.

Ancillary Customer Systems

In addition to developing distributed generators, space conditioners and fuel reformers, PNNL is active in developing tools that help target high value applications of distributed power concepts.

PNNL conducted research on a tool set designed to conduct short-term (hourly) load forecasting on an electric utility distribution feeder and to link this tool with generation and end-use technology options to identify the benefit of distributed power generation within that feeder. The desired outcome is to enable either a utility or an end-user (Energy Service Companies (ESCO) or major utility customer) to identify how much of the load on the feeder could be served by distributed generation, thus determining the avoided cost of feeder upgrade that could be attributed to the distributed power option. The research is still underway, and Figure 3 depicts the hypothetical suite of capabilities that the tool could include.

A second PNNL activity designed to value the system benefits of distributed power concepts is the role of distributed resources in supporting grid reliability. Distributed generators can provide ancillary grid benefits such as spinning reserve, Volt-Amp Reactive (VAR) support, and back-up in case of grid failures. PNNL has also evaluated the potential benefit of intelligent controls on end-use devices to cycle the devices on and off in ways that help the grid "ride through" temporary problems, but to do it without affecting the apparent service to the customer. For example, PNNL simulated the role of intelligent device controls to support the transmission grid feeding power to southern California from the Colorado River basis [see Figure 4]. When compared to conventional grid protection devices such as FACTS, the distributed intelligent controls required 30% less capacity investment than required using centralized FACTS devices. Results are obviously very case specific, yet they point to the potential for distributed resources to provide both local benefits to the direct user, as well as ancillary benefits to the regional grid in which they operate. Tools to determine the value and optimal dispatch of distributed resources in these examples is the subject of research at PNNL today.

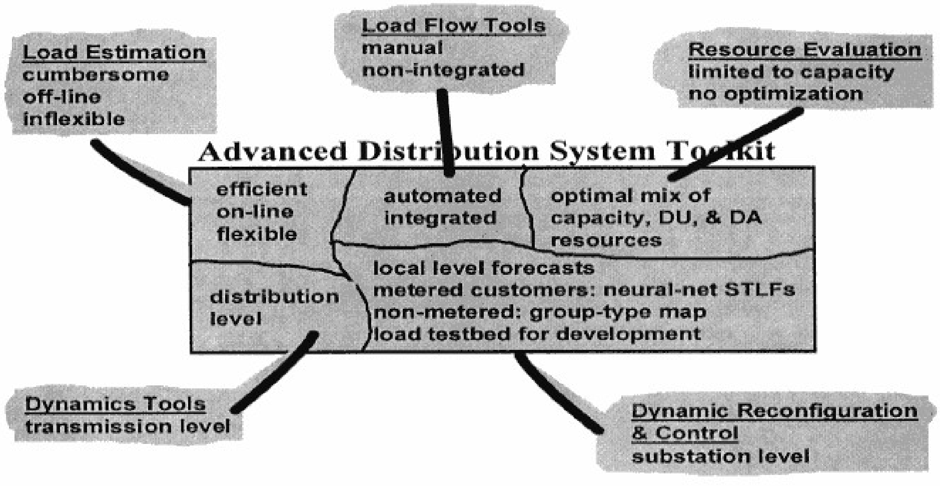

Figure 3
PNNL concept for a tool kit to support DG planning

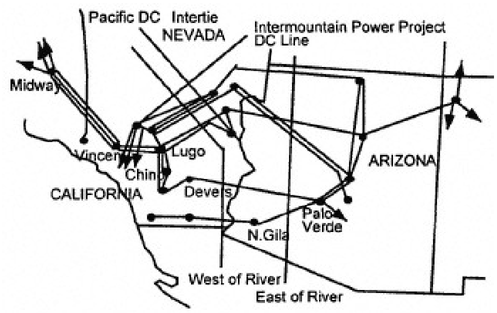

Figure 4
PNNL evaluation of power grid dynamics in the Southwest
using distributed load control versus centralized power electronics

Institutional and Commercialization Support

The fourth area of distributed power resources efforts at PNNL is the evaluation of institutional barriers and market needs to support the rapid commercialization of these exciting new technologies. Many vendors of distributed power technologies face barriers such as codes and standards, technical performance gaps, regulations barring the realization of potential system benefits, and as well as market structure barriers. Together, these barriers delay the ability of vendors to grow their market share. PNNL is working with government and commercial clients to identify barriers, facilitate industry collaboration between vendors and codes organizations to overcome barriers, and to help vendors develop commercial products that address barriers in a timely fashion. Examples of such activities include the following:

BTS Annual Summit—PNNL supports DOE in an outreach effort to the fuel cell industry to facilitate adoption of code revisions that enhance fuel cell commercialization.

FEMP Tech Alerts—PNNL supports the FEMP program in communicating fuel cell technology descriptions and demonstrations results from across the Federal infrastructure. The purpose is to help Federal facility managers better understand the new technologies and their actual performance in Federal demonstrations.

Vendor product planning support—PNNL is providing commercialization support to various distributed power vendors who are in the process of finalizing their product offerings. This support typically includes codes and standards reviews, safety analyses, and/or technical support.

The Next Few Years

Facility managers and energy engineers will face many opportunities for considering distributed power options over the next several years. There is significant market investment in a broad range of DG concepts, and many vendors are positioning for imminent deployment of a new wave of products that will join the current internal combustion engine products that comprise the majority of DG installed base today. The challenge will be identifying cost-effective applications of DG concepts, obtaining systems that are fully ready for the market, and overcoming local barriers to installing the systems.

The most cost-effective options in the near-term will be internal combustion systems, which offer lower installed costs, as well as products that are currently on the market and recognized by local codes. For applications that value renewable concepts, photovoltaics and wind systems will see the most market growth in the next few years. Many firms have commercial offerings in these technologies today, and global production capacity is growing, indicating downward trends in system costs in the next few years.

Microturbines are expected to enter the market over the next 12 months and appear to offer attractive benefits based upon a proven technology. The challenges facing microturbines are in ancillary systems of power electronics and providing natural gas at sufficiently high pressures.

Multiple fuel cell technologies are in various stages of demonstration and commercialization. Costs will remain high for the next few years, but facility managers can expect to see PEM systems commercially available for residential and commercial applications in the next 12 to 24 months. SOFC systems are getting increased attention for both transportation and stationary applications; these systems are not likely to be commercially available for 3 to 5 years. The molten carbonate and phosphoric acid systems are likely to be positioned for larger applications, such as utility level generation (greater than 250 kW installations).

For all technologies other than internal combustion technologies, facility managers can expect challenges with local code officials. These institutional barriers are being addressed by government and code organization officials and are likely to be resolved in the next 12 to 24 months.

Chapter 46— Distributed Generation Benefits and Barriers—The Perspective of a Combined Heat & Power/District Energy Developer

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Abstract

Distributed Generation configured as Combined Heat & Power (CHP) / District Energy systems, if implemented widely, will provide substantial improvements in energy efficiency and dramatic reductions in emissions of pollutants including greenhouse gases (notably Carbon Dioxide, the major contributor to Global Climate Change). These efficiency and emission benefits will not cause economic belt-tightening and, in fact, can be obtained while capturing economic benefits for energy consumers. However, the realization of the full potential of the benefits, and doing so in a timely manner, requires that existing institutional barriers are recognized and effectively eliminated.

Distributed Generation is described from the perspective of a developer / owner / operator of dozens of CHP / District Energy systems. The benefits of Distributed Generation are described, including benefits to energy efficiency, to the environment, and to energy consumers. The author's corporate Mission Statement serves to illustrate some of the key benefits, namely: *"to provide heating, cooling and electricity with half the fossil fuel and half the pollution of conventional generation."* Examples of actual Distributed Generation CHP / District Energy systems are described. An integrated approach, incorporating the provision of heat and cooling, as well as electric power, is generally found to be advantageous. Unique technological advances which have been developed and commercially deployed are described, including such technologies as "trigeneration", hybrid chiller plants, distributed chiller plants, serial chilling combined with low temperature thermal energy storage, distributed back-pressure steam turbine generators, and the use of biomass fuels. System energy use and emission reductions are presented to quantify the benefits.

The customers of the Distributed CHP/District Energy systems cover a broad cross-section of large commercial, institutional and industrial, public and private end-users of thermal energy for heating and/or cooling. Examples of specific customers are presented from among the more than 1,500 served by the author's corporation. Testimonials are presented to illustrate the benefits to system customers and the benefits to the communities in which systems are located.

Barriers to the widespread implementation of Distributed CHP/District Energy systems are identified. The U.S. electric power generation industry has an average energy conversion efficiency in the low 30 percents. There has been virtually no improvement in the industry's average efficiency during the last half of the 20th century, in spite of the many technological advances actually achieved. Among the key barriers to efficiency improvements have been the entrenched system of monopoly utility regulation and the well-intentioned but often self-defeating environmental regulations. Methods to eliminate or overcome those barriers, and to realize the energy, environmental and economic benefits, are proposed.

Introduction

Distributed Generation configured as Combined Heat & Power (CHP)/District Energy systems, if implemented widely, will provide substantial improvements in energy efficiency and dramatic reductions in emissions of pollutants including greenhouse gases (notably Carbon Dioxide, the major contributor to Global Climate Change). These efficiency and emission benefits will not cause economic belt-tightening and, in fact, can be obtained while capturing economic benefits for energy consumers. However, the realization of the full potential of the benefits, and doing so in a timely manner, requires that existing institutional barriers are recognized and effectively eliminated [1].

Distributed Generation can take a variety of forms, utilizing diverse technologies and being deployed in a very wide range of capacities. There is also a broad range of costs associated with the different technologies. And while some technologies are still undergoing extensive technological development, other technologies are relatively mature, exhibiting an extensive past history of successful implementation. In this paper, Distributed Generation is described solely from the perspective of a developer / owner / operator of dozens of CHP / District Energy systems, which in fact represent one of the distinct technologies employed as Distributed Generation.

The benefits of Distributed Generation are varied, and include benefits to energy efficiency, to the environment, and to energy consumers.

Reduced Energy and Emissions

The author's corporate Mission Statement serves to illustrate some of the key benefits of Distributed Generation CHP/District Energy systems, namely:

> *"to provide heating, cooling and electricity*
> *with half the fossil fuel*
> *and half the pollution*
> *of conventional generation."*

CHP provides the potential for these dramatic improvements in energy efficiency and emission reduction by its ability to ***burn fuel once, but use it twice,*** once for electric power generation and again for the production of useful thermal energy.

As an example, in 1998 the author's corporation utilized CHP/District Energy systems in approximately two dozen locations serving over 1,500 customers with over 5,000 megawatts of combined heating, cooling and electric generation, and did so while producing half the emissions of conventional (non-CHP) generation. Specifically, corporate-wide consumption of fossil fuel was approximately 77% of that which would have been consumed by conventional generation [2]. The corporate-wide emissions of criteria pollutants (including nitrogen oxides, sulfur dioxide, carbon monoxide and particulate matter) were 46% of conventional generation emissions [3]. And corporate-wide emissions of greenhouse gas (carbon dioxide) were 55% of conventional generation emissions [3].

Technical Approach and Examples

An integrated approach, incorporating the provision of heating and cooling, as well as electric power, is generally found to be advantageous. Unique technological advances have been developed and commercially deployed where justified. They include such technologies as "trigeneration", hybrid chiller plants, distributed chilling plants, serial chilling combined with low temperature thermal energy storage, distributed back-pressure steam turbine generators, and the use of biomass fuels.

"Trigeneration"

A single piece of equipment, the patented "trigeneration machine" can be utilized for the simultaneous production of electric power, chilled water and steam or hot water. Specifically, in several District Energy plants, we employ a gas turbine drive, a refrigerant compressor, and an induction motor/generator, integrated on a single driveline. The refrigerant compressor, which is used to produce chilled water, can be driven either by the gas turbine, or by the induction motor, or by both working in combination. The gas turbine can drive either the screw compressor, or the induction generator, or both. Additionally, whenever the gas turbine is operating, waste heat is recovered in a heat recovery steam generator (HRSG) either for use as steam or hot water heat, or for use in powering absorption or steam turbine-driven chillers.

Hybrid Chiller Plants

Chiller plants are advantageously configured to incorporate both electric motor-driven chillers and one or more forms of non-electric chillers, such as gas engine-driven, gas turbine-driven or steam turbine-driven chillers, or heat-driven absorption chillers (using either gas, steam, or hot water as their heat source).

Distributed Chilling Plants

Two or more interconnected chiller plants are often employed in large District Energy networks. Interconnection of the plants can be via chilled water piping; however, interconnection can also be via district heating piping, for example when the distributed chillers are steam turbine-driven chillers or heat-driven absorption units.

Serial Chilling

The multiple chillers employed in large District Energy systems are often advantageously configured in a series-parallel arrangement. By staging the chillers in series, it is practical to achieve large temperature differences between the chilled water system's supply and return temperatures. The serial chilling arrangement allows a low chilled water supply temperature to be efficiently produced for delivery to the system customers. The large temperature differential also reduces both the capital and the operating costs associated with the distribution piping network.

Low Temperature Thermal Energy Storage

Thermal Energy Storage (TES) is often utilized effectively to shift the use of electric chillers to low-cost, off-peak periods, and to level the demand for chilled water, thus reducing the installed capacity of the chiller plant. A patented low temperature TES system has also been developed and deployed. It combines the low supply temperature capability of ice storage systems with the simplicity, dependability and economy of chilled water storage systems. This is achieved using an additive that allows the stored supply water to be thermally stratified at temperatures below the conventional minimum of 39 °F, down to temperatures of 30 °F or lower. The reduced supply temperature also minimizes the required storage volume and the size of distribution piping and pumps [4].

Distributed Back-Pressure Steam Turbine-Generators

Steam District Heating networks generally involve steam transmission in the main distribution piping at pressures well above the pressures employed in the end-user facilities. Accordingly, it is common practice to use pressure-reducing valves to lower steam pressure from the relatively high transmission pressure to the lower end-use pressure. The pressure reducing valves represent significant energy loss. However, it is practical to capture most of this otherwise wasted energy through the utilization of distributed back-pressure steam turbine-generators. Rather than the steam flowing through the valve to reduce its pressure, the steam flows through a steam turbine, thus reducing its pressure but also powering a generator to produce electricity at the end-use site. Typical capacities range from 50 kilowatts to several megawatts of electric power [5].

Biomass Fuels

Various types of biomass fuels are employed in CHP plants, where practical. Examples of such fuels include municipal waste, wood residue, rice hulls and paper sludge. Applications using biomass fuels include numerous industrial CHP systems, as well as some urban District Energy/CHP systems, such as those in St. Paul, Minnesota and Charlottetown, Prince Edward Island. Typically, the biomass is utilized as the baseload fuel, with conventional fossil fuel being employed if required for peaking and back-up [6].

Customers

The customers of the Distributed CHP / District Energy systems cover a broad cross-section of large commercial, institutional and industrial, public and private end-users of thermal energy for heating and/or cooling. A short list of specific customers, from among the more than 1,500 served by the author's corporation, serves to demonstrate the wide-ranging applicability of Distributed CHP / District Energy systems, in terms of customer type, size and geographic locale.

Commercial Office and Retail Facilities

Blue Lake Corporate Center (business park, 2 million square feet)—Boca Raton, FL

Cincinnati Gas & Electric Building—Cincinnati

CNL Center—Orlando

John Hancock Building—Boston

MetLife Building—Philadelphia

Williams Headquarters Complex (5 buildings, 2.5 million square feet)—Tulsa, OK

Hotels and Residential Complexes

Hilton—Baltimore, Boston and London (Ontario)

Holiday Inn—Baltimore, Cincinnati, Kansas City, Philadelphia (2 locations) and St. Louis

Hyatt—Baltimore and Chicago

Marriott—Boston (2 locations), Kansas City, Long Island and St. Louis

Sheraton—Boston and Philadelphia

Wyndham—Baltimore, Boston and Philadelphia

Hospitals and Medical Facilities

Boston University Medical Campus—Boston

Massachusetts General (Spaulding) Rehabilitation Hospital (284 beds)—Boston

Queen Elizabeth Hospital (350 beds)—Charlottetown, P.E.I., Canada

Thomas Jefferson University Hospital (over 600 beds)—Philadelphia

Tufts University Medical School—Boston

University of Maryland Hospital (747 beds)—Baltimore

Universities and Colleges

Drexel University (12,000 enrollment)—Philadelphia

Nassau County Community College (26,000 enrollment)—Long Island

Suffolk University (2,900 enrollment)—Boston

University of Maryland (2 campuses: 5,000 and 35,000 enrollment)—Baltimore and College Park

University of Pennsylvania (25,000 enrollment)—Philadelphia

University of Prince Edward Island (2,500 enrollment)—Charlottetown, P.E.I., Canada

Government Facilities and Convention Centers

Bartle Hall Conference Center, Convention Center and Municipal Auditorium—Kansas City

Civic Center Complex (5 buildings, 1 million square feet)—Tulsa, OK

Federal Courthouse and Federal Office Facilities—Cincinnati

McCormick Place Exhibition Center (North America's largest at 5 million square feet)—Chicago

Nassau County Government Facilities—Long Island

State of New Jersey Facilities—Trenton

Sports and Entertainment Facilities

Busch Memorial Stadium (home to Major League Baseball's St. Louis Cardinals)—St. Louis

Camden Yard (home to Major League Baseball's Baltimore Orioles)—Baltimore

Nassau County Coliseum (home to the NHL's New York Islanders)—Long Island

Paul Brown Stadium (future home to the NFL's Cincinnati Bengals)—Cincinnati

PSI Net Stadium (home to the NFL's Baltimore Ravens)—Baltimore

Trans World Dome (home to the NFL's St. Louis Rams)—St. Louis

Industrial Facilities

Baxter Healthcare—Marion, NC

Boeing Company (rocket booster core manufacturing facility, 1.5 million square feet)—Decatur, AL

Coors Brewing Company (world's largest single-site brewery)—Golden, CO

London Free Press (newspaper printing facility)—London, Ontario

Sara Lee/National Textiles (3 locations)—Eden, NC, Forest City, NC and Greenwood, SC

United States Mint—Philadelphia

It is interesting to note that many of these types and sizes of customers are not typically considered to be realistic candidates for on-site cogeneration applications, either due to their small size or due to their lack of substantial and continuous demand for both electricity and thermal energy. However, by combining customers into District Energy networks, CHP can typically be economically justified and implemented.

Testimonials

Testimonials illustrate some of the common benefits realized by District Energy customers and by the communities in which the systems are located.

"As the largest hotel on Long Island, we pretty much guarantee our guests a certain level of service, and we count on a lot of different purveyors to help provide us with this. Nothing will make for a worse stay than a hotel that's uncomfortable, and [our District Energy provider] gives us that comfortable feeling. Not once during the past summer or winter, did we lack for service from [them]. That is what I count on. That's what my guests need."

— ***Ed Rudzinski,*** General Manager, Long Island Marriott Hotel, Long Island, New York, 1994

"We're very happy with the quality of service. . . . My overall impression of [our District Energy provider] is that they are quality people and they really care about what they do. . . . We look forward to continued savings and dependable heating and cooling through our arrangement."

— ***Harry L. Walder,*** Senior Development Manager, Chicago Metropolitan Pier and Exposition Authority, Chicago, Illinois, 1994 and 1997

"We were looking at replacing our centrifugal chillers. This way we were able to avoid the expense of new chillers and ongoing Operation & Maintenance costs. No more refrigerant issues. [Our District Energy provider] also provides us with colder water so we can provide our tenants with better temperature and humidity control."

— ***William Nooney,*** Operations Manager, U.S. General Services Administration, Cincinnati, Ohio, 1997

"We were faced with aging inefficient chillers, which utilized CFC refrigerants and whose reliability was increasingly questionable. We were also facing either a major cost for tube replacement, or the purchase of costly new chillers, or opting for District Cooling service. DC service solved all our problems and avoided any upfront capital costs. It got us out of the business of dealing with the day-to-day risks associated with chillers, cooling towers, water treatment, etc. DC also allows us to downsize our workforce via attrition. And the colder water temperatures enable us to get enhanced capacity and comfort from our HVAC system."

— ***Gary F. Carver,*** Senior Engineer, Orlando Utilities Commission, Orlando, Florida, 1999

"This recent [District Energy] development at Blue Lake is a continuation of the commitment we have made to offer our tenants improvements which represent the latest in cutting edge technology . . . Our goal is to offer standards of service which are unequaled in this industry."

— ***Michael D. Masanoff,*** Director, Blue Lake Corporate Center, Boca Raton, Florida, 1998

"The joint efforts of The City, The County and the GSA helped make this [District Energy / CHP] project happen and reflect their commitment to the continued growth of downtown Kansas City. We believe that this new energy infrastructure makes our downtown more competitive than other options developers may have in the metropolitan area."

— ***George Blackwood,*** Mayor Pro-tem, Kansas City, Missouri, 1998

" . . . the whole community is in this together. We share the cold winters, we share the problems, and we're going to share the solution . . . to install district heating to help stabilize the economic development of our nation. I think it can make that kind of a difference in our future . . . district heating is one of the greatest gifts we can bestow on future generations."

— ***George Latimer,*** Mayor, St. Paul, Minnesota, 1983

"We, at the Department of Energy and the [White House] Administration, are absolutely convinced that it is possible for us to do responsible things for our environment at the same time we do things that are positive for the economy. Projects such as this particular [Grays Ferry Philadelphia] cogeneration project are proof positive that the two can go hand-in-hand."

— ***Elizabeth Moler,*** Deputy Secretary, United States Department of Energy, 1998

"The future across Europe looks bright for combined heat and power. CHP can play a significant role in helping the EU meet its carbon emission reduction targets because it delivers both environmental benefits and energy efficiency gains. The European Commission has proposed a strategy with a view to doubling the share of CHP in the community as a whole by 2010. In the UK, we have already been actively promoting CHP. We now have some 1,300 CHP schemes accounting for 4,000 megawatts of capacity, in a whole range of applications."

— ***John Battle,*** Energy Minister, United Kingdom, 1998

"district energy can provide environmental, energy efficiency, and socio-economic benefits to society, communities, and District Energy customers . . . There is still a need for more action to realize the opportunities provided by district energy and to address current obstacles . . . We challenge these stakeholder groups . . . to identify what action they should take so that those benefits may be realized."

— ***The District Energy Option in Canada,*** Natural Resources Canada Handbook, 1996

Barriers

Barriers to the widespread implementation of Distributed CHP / District Energy systems have been identified. The U.S. electric power generation industry has an average energy conversion efficiency in the low 30 percents. There has been virtually no improvement in the industry's average efficiency during the last half of the 20th century, in spite of the many technological advances actually achieved. Over two-thirds of U.S. generating capacity was built before 1972 (i.e. over 28 years old) and these plants employ outmoded, inefficient polluting technology. Among the key barriers to efficiency improvements have been the entrenched system of monopoly utility regulation and the well-intentioned but often self-defeating environmental regulations. Some of the key barriers to improved efficiency via CHP are briefly introduced below.

Laws and Regulations That Protect Monopolies

Monopoly utilities are protected from competition, and insulated from incentives to innovate and to improve efficiency, in numerous ways.

Lack of Incentives for Efficiency: Regulated monopolies lack the incentives to be efficient. Regulators focus on limiting profits, rather than focusing on reducing costs. Notably, little if any attention is paid to fuel efficiency, even though fuel cost typically represents 45 to 55% of total price [1].

Retail Electric Sale Prohibitions: The retail sale of electricity by potential competitors of the local monopoly utilities has been prohibited. Even as the industry moves slowly toward retail access, additional barriers and delays are being imposed.

Laws Banning Transmission Competition: Even when the time comes that both generation and the retail sale of electric power are open, monopoly control of transmission lines will continue to impede competition.

Interconnection Rules: The rules and regulations regarding the electric power interconnection between independent power plants or on-site cogenerators and the grid are controlled by the local monopoly electric utility. Requirements can be arbitrary and abusive to the potential competitor of the monopoly utility.

Back-up Power Access: Access to back-up power for on-site cogenerators is available only from the local monopoly electric utility. Once again, pricing can be arbitrary and abusive to the potential competitor of the monopoly utility.

Condoned Anti-competitive Practices of Monopolies

In spite of the spirit and the letter of the Sherman and the Clayton Antitrust Acts, by and large, monopoly utilities have been allowed to function outside the antitrust rules. Such condoned practices have included those noted below.

Bundling Heat and Power: e.g. lower electric rates for customers employing all electric facilities.

Buying-out Cogenerators: Utilities are often allowed to consummate secret deals involving payments or lower rates that are unavailable to other customers, in exchange for customers not implementing a new cogeneration system.

Manipulation of Pilot Programs: Various pilot programs incorporating special electric rates and/or special demand-side management (DSM) cash incentives can be selectively started and stopped, penalizing potential competitors and even directly subsidizing unregulated companies affiliated with the local monopoly utility.

Percent-of-Load Rate Ratchets: Punitive rates can be utilized in which a potential cogenerator would pay an exorbitant price for power purchased from the monopoly utility in the event that cogeneration was utilized for a substantial portion, but not all, of the customer's electric load.

Environmental Laws That Ignore Efficiency or Assume That Central Generation is Optimum

Environmental regulations, though well-intentioned, are often self-defeating to the extent that they fail to incent, and often penalize, efficient new technologies.

Input-Based Rules Ignore Efficiency: Typical regulations limit the quantity of pollutant emissions as a function of the power plant exhaust. This ignores the fact that the exhaust is itself a function of the fuel consumed. Thus a doubly inefficient plant, burning double the fuel, is permitted double the emissions of a more efficient plant.

Present Regulatory Approach Extends Use of Inefficient Plants: Ever tightening requirements on new plants create an economic incentive to keep old, inefficient, and heavily polluting plants in service.

Permits Required to Start Construction Delay Efficient Plants: The Clean Air Act of 1972 forbade even starting new power plant construction until after the granting of an air permit. This process is unlike that employed in general building construction and is even unlike that employed when applying power plant engines or gas turbines to other uses such as transportation or industrial drives.

Lack of Pollution Offsets

Although a typical CHP / District Energy system will eliminate the use of dozens or even hundreds of individual in-building boilers, the avoided pollutant emissions from those boilers are not credited to the system development.

Regulations That Prohibit Optimizing Plant Operations

New, efficient, clean power plants, if operated at off-design conditions such as part-load, are forced to shutdown due to increased emissions at those conditions, even though the result is that old, inefficient, polluting power plants must make up the lost capacity, often at an order of magnitude higher pollution [1].

Tax Policies Penalize Efficiency

New and efficient power plant equipment is burdened with an inequitably long tax depreciation life. When used in different applications such as transportation, the same equipment is granted a depreciation period only half or even a third as long [1].

Federal Reimbursement and Reward Structures

Federal subsidies (e.g. those typically provided to low income housing) fail to recognize the economic value of efficiency improvements. A reduction in energy costs, achieved by a more efficient energy system to serve the subsidized facilities, simply results in a similar reduction in the subsidy. Accordingly, the facility operators have no incentive to opt for the more efficient energy approach.

Obsolete State and Local Laws

Existing state and local laws are often based on obsolete technology assumptions, often passed originally to protect public safety or union jobs. One of many examples is the Massachusetts requirement for dedicated local operators for steam turbines, effectively precluding the economic deployment of efficient back-pressure steam turbines in District Energy customer buildings.

Elimination of Barriers

Methods to eliminate or overcome those barriers, and to realize the available energy, environmental and economic benefits of CHP / District Energy, have been proposed:

1. Deregulate all electric generation and sales and modernize regulatory laws impacting energy.

2. Modernize environmental regulation of power plants.

3. Change taxation to encourage efficiency.

4. Include energy efficiency in all federal activity and funding.

5. Take miscellaneous federal actions to promote energy conservation

Further details of these proposals are presented in Thomas Casten's book, "Turning off the Heat" [1]. With the implementation of these recommended actions, it is projected that within a twenty year period:

the efficiency of the nation's electric power generation industry can be doubled,

the resultant emissions of criteria pollutants and greenhouse gas can be halved, and

the nation's consumers will save 30% or more in their electricity costs.

Conclusions and Recommendations

Clearly, Distributed Generation configured as CHP/District Energy systems can fulfill a significant role in reducing energy use, reducing pollutant emissions and reducing the emission of greenhouse gas (carbon dioxide). It is practical to achieve reductions of half or more in all these areas, relative to conventional means of independent generation of electricity and thermal energy.

Just as clearly, CHP / District Energy systems have been demonstrated to provide economic and other benefits to customers and communities.

The widespread deployment of the technology and its benefits are severely hindered by numerous barriers.

Notable among the barriers are those associated with the continuing monopoly regulation of electric power and the well-intentioned but often self-defeating environmental regulations.

It is recommended that these barriers be systematically eliminated. This will allow the marketplace to provide choice and savings to consumers as well as efficiency and emission reductions to the energy industry.

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Chapter 47— Power Solutions for Distributed Generation

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Abstract

The economic benefits of distributed generation offers an opportunity to recover stranded costs from installed standby and emergency power equipment as well as a means to subsidize the enhanced capability of these systems to meet the demands of modern electrical loads. This discussion centers on the available switching and control strategies providing insights to the selection process for the best strategy for a given application. It will discuss load transition strategies while revealing the essential background decision making criteria for the best economic decision.

Introduction

The owner of dispersed generation facilities is not likely to be in the business of electric power generation. Rather, electric power generation will be the coincidental result of controlling the cost of operations. In the past this translated to the installation of optional standby power systems. With utility deregulation upon us, dispersed generation becomes a viable alternative in the energy source mix. Now, cost control will be a result of either business continuity during a loss of the normal power supply or avoidance of the high cost of electric energy during peak demand periods. Whatever purpose is served, both roles have the potential to enhance operating profit. The coincidental use of an optional standby power system for peaking provides a real and measurable return on the incremental equipment, as well as the initial investment in the system. If the peaking strategy is initially included in the optional standby power system at the design phase, its cost could be little or nothing. Thus peaking could provide a real return on invested capital that otherwise could not be achieved. Businesses that have a large disparity in electric energy demand between the day and night time will have an energy cost structure supportive of dual use of the optional standby power system.

Not being a business owner's primary product, any investment in electric energy production is in competition with other investment opportunities more directly related to the core business. With the increasing dependency on electrical energy and the companion increasing costs, managers are realizing that the bottom line is better managed when energy use is better managed. As a consequence, these managers are more likely to make investments in energy production facilities, but only when they make sense.

The project champion of the energy production facility is faced with minimizing total cost to achieve the best return on the investment.

$$ROI = \frac{AS}{IC}(100)$$

where:

ROI—annual percent return on the initial investment

AS—annual savings produced by the energy production facility

IC—Initial cost of the energy production facility

This project champion must strike the optimum balance between initial capitalization and operating costs. Initial capitalization dollars have a fixed cost. Operating dollars have an escalating cost subject to the vagaries of fuel, consumables and manpower cost. The annual saving is the difference between energy cost without the energy production facility and the annual operating cost of the energy production facility. Consequently, the best balance becomes the judicious selection of operating strategy, initial equipment, operating costs and equipment performance. Caution must be exercised, what sounds like a good deal in reducing initial capital expenditures, could easily become an operating capital hog.

Given that a facility could achieve a desirable return by generating some portion of its demand for electric energy, a thorough evaluation must be conducted to maximize the return on this opportunity. Among the considerations are

What operating strategy offers the best return?

How much energy should be produced?

What generating technology should be used

What is the impact on staffing?

It is hoped that the information contained herein will provide some assistance in answering these and other questions.

Operating Strategy

The question of operating strategy is a fundamental decision point. Some of the issues are

Is there a need for multiple forms or only for electric energy.

Should the on-site power production facility provide all or a portion of the energy need?

If the plant is to run in parallel with the serving utility, how much of the electric energy demand should it produce?

Other issues?

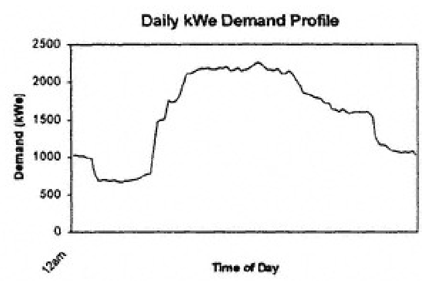

Figure 1
Typical daily electric demand
profile for single shift facility

For the purpose of this discussion, it will be assumed that the electric load profile of the facility follows that of an average single shift facility. Typical of such facilities is the significant difference between the night time and day time energy demand profiles. Figure 1 is a daily electric demand profile for such a facility. This is a plot of actual 15 minute demand data for a specific facility. Note that there is a significant peak in the demand for electricity during the 8am to 6pm period and that it is relatively constant. That peak oscillates around a value of 2170 kWe.

For the purpose of discussion, it is helpful to define some useful terms. One of these is Load Factor. Load factor is a relative measure of the efficiency of use of the installed electric delivery infrastructure.

$$LF = \frac{kWh_{used}}{(kW_{Demand}) \times Hours_{BillingPeriod}}$$

where

LF—Load Factor

KWh_{used} —kWh used in respective billing period

KW_{Demand} —Maximum kW demand in the billing period

Hours—Total number of hours in the billing period

For the case of figure 1, where the maximum demand in the billing period was 2260 kWe, if we assumed that the billing period had 30 days, the denominator of the equation would be 1,627,200 kWh. Actual use for that month was 907864 kWh. The load factor is therefore 0.56. There is a relationship between lower load factors and higher electric costs. The electric rate structure carries a higher charge for kWh used in the on-peak period than in the off-peak period. This is precisely because the cost of kWh in the on peak period is higher. In terms of cost of generating electricity, the most cost effective, lowest cost, kWh come from the base and intermediate generating plants. The peak kWh are produced by the least efficient peaking generators. Peaking generators run only when the demand requires them. Consequently, their capital cost is amortized over fewer operating hours. For these reasons, on-peak energy costs more that off-peak energy. If the rules of deregulation allowed a consumer to purchase energy from a single plant and the consumer signed a contract with a base generating plant, ostensibly, that consumer could pay a fixed cost per kWh for all energy used. This is not a broad based reality because the consumer varies the rate at which electricity is used and thus places a varying stress on the generation and delivery infrastructure. That variation in demand has a cost. The greater the disparity between on- and off-peak demand, (on-peak demand being higher) the higher the average cost per kWh of electric energy will be. It is thus demonstrated, that Load Factor is a relative indicator of expected cost performance of the energy use profile.

Table 1. Estimated cost per kWh generated.

Fuel	Prime Mover Type			
#2 Oil	Reciprocating		Combustion Turbine	
$/Gal	w/o HR	HR	w/o HR	HR
0.55	$ 0.053	$ 0.032	$ 0.067	$ 0.031
0.65	$ 0.060	$ 0.036	$ 0.077	$ 0.034
0.75	$ 0.067	$ 0.039	$ 0.086	$ 0.037

Note: Includes $.015/kWh for maintenance.

Every facility uses energy in multiple forms. In the overwhelming number of cases the two most common forms are thermal and electrical. In some cases, the electrical energy used produces all or portions of the thermal energy need as well. For example, facility cooling can be provided by chillers. The chillers can be centrifugal or absorption. The centrifugal are electric; the absorption can be gas or steam fired. That steam can come from any number of sources, one of which could be the heat recovery system of an electric generation process. Typical throughput efficiencies of generation processes vary with respect to the type of prime mover. As an illustration, a reciprocating diesel engine driven generator, (1200 or 1800 rpm) will be about 34 % efficient in converting the energy content in a unit of fuel to output kwh of electricity. A combustion turbine will be about 25% efficient in the same measure. If heat recovery is added to each of these generation processes and energy recovery is optimized, the reciprocating diesel generation process will rise to about 75% efficiency and the combustion turbine process will rise to about 80% efficiency. For common understanding, through put efficiency is defined here as that percent of the energy content in the unit of fuel converted to usable energy at the output of the process. It is a given that 1 kWhe = 3413 BTU. Thus if the fuel were #2 oil, whose energy content is 144000 BTU per gallon, at 34 % efficiency, the reciprocating diesel engine would produce 14.34 kWh/gal. Whereas the combustion turbine would produce 10.55 kWh/gal. Adding heat recovery to the processes, the efficiencies would change to 31.64 kWh/gal and 33.75 kWh/gal, respectively. It can now be understood why, the issue of heat recovery is a significant decision in the operating strategy.

With respect to cost, if #2 oil cost $.55/gal., then the fuel cost of generating with the reciprocating diesel process would be $.038/kWh and that for the turbine would be $.052/kWh. When the operating cost of the generation process accounts for maintenance of the prime movers, an additional $.015/kWh is added. Without heat recovery, estimated total cost of generation for each scenario would be $.053/kWh and $.067/kWh, respectively. Table 1 presents various projected energy costs for differing cost of fuel. As can be expected, the best cost performance, minimum cost for displacement kWh by on site generation, will be with the combustion turbine with heat recovery. Throughout the evaluation process, the impact of design decisions on the final capital and operating cost must kept in mind. If operating cost per kWh were the only consideration, the operating strategy decision would be simple.

While the immediate reaction to heat recovery in a standby power plant may invoke a skeptical response, it is plausible. In a specific application, it was determined that a peaking plant could provide 500 kW demand reduction and 400 kW of standby power. A 1200 rpm reciprocating engine was selected. It was equipped with hot water heat recovery to provide either heating for a portion of the plant in the winter, (direct water to water heat exchange) or 100 t AC cooling in the summer (hot water driven absorption chiller). The plant ran from 8 am to 8 PM each working day of the facility. It provided 430 kWh/hr of electricity and displaced 140 kWh demand with absorption chilling. The net reduction in electric demand was 540 kW. It proved to be economically justified, the plant paid for itself in less than 3 years. The norm will not likely use heat recovery equipment in a peaking plant. However, it should not be rejected out of hand without judicious investigation. The point is made simply to encourage the designer to explore all opportunities for cost reduction.

Nothing is simple though. When considering the choices, cost of prime mover and suitability for all services enters into the decision process. If it is assumed that the prime purpose of the on site power plant is to provide standby power to critical loads and the secondary purpose is to provide peaking power, evaluation of the plant performance must be based primarily upon its performance as a standby power plant. In this case, if the critical load requires restoration of power quickly, less than 10–15 seconds after loss of normal power, the reciprocating engine is the only choice. Combustion turbines will take from one to several minutes to start and assume load. If restoration of power to the critical load can wait those few moments, then the combustion turbine can be the prime mover. Combustion turbines are available in a limited number of ratings. Their output power rating is adversely affected by higher inlet ambient air temperatures. If peaking is to respond to a summertime operation, it will most likely be when the ambient temperatures are elevated. Care must therefore be exercised in rating the plant.

If the fundamental strategy of the on site power plant is standby and peaking, it is unlikely that the plant can be cost effectively sized to carry the entire load of the facility. It will therefore be sized to carry the standby load when its primary purpose is to provide power continuity protection to the critical loads. In some cases:

Sizing the plant for the critical load may provide less than optimal peak demand reduction

Peaking operation may provide cost justification for increasing the size of the standby power plant

Providing multiple generators can be justified

Mixing prime movers may be desirable

Where there is a continuous need for low quality heat during the demand for peaking, it may be possible to cost justify a fuel cell or microturbine as the peaking source. These power sources can be operated in parallel with other generation sources to provide extended standby power. By themselves however, they would not provide the same level of performance that the typical standby diesel generator set would.

As a side issue, to this point, this discussion has focused on the optional standby power system. There is nothing barring the use of emergency and legally required standby power systems for peak demand reduction. However, there are NEC (National Electrical Code) and qualification (UL) issues that impact the equipment used in these applications that differ slightly from those required of optional standby power system equipment.

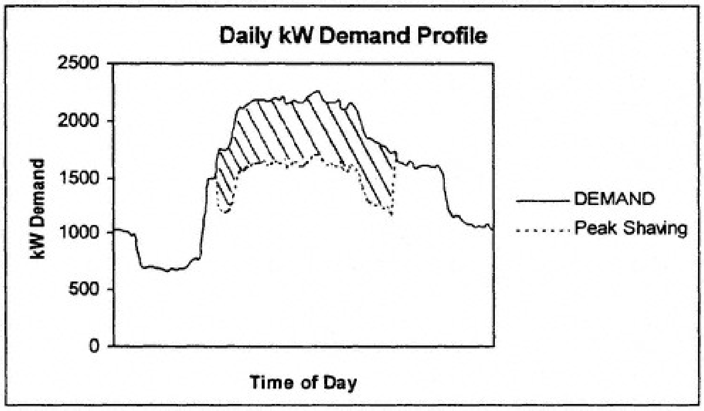

Figure 2
Daily kW demand profile with 550 kWe of on-site peaking power generation

Given the discussion to this juncture, if peak demand reduction were applied to the energy demand profile shown in figure 1, a suitable rating for the plant might be 2260 kWe –1710 kWe = 550 kWe. Experience has show that as a rule of thumb, one can estimate the critical load segment of the electrical load profile for commercial and light industrial facilities at about 25% of the operating demand. This percentage will vary as the function of the facility varies. Accepting it as a starting point, to provide both the optional standby and peaking function would suggest an on site generation capacity of 0.25 X 2260 = 565kWe. In peaking applications where the prime mover is to be a diesel engine, it is suggested that the selection be based on the continuous rating of the engine generator set and not its standby rating. In this scenario, one would pick an engine generator set with a continuous rating of 550 kWe. Such a set would have a standby rating probably well in excess of 600 kWe. Thus, it would be able to support additional critical load.

What would be the result of operating the peaking plant at 550 kWe? As can be seen in figure 2, during the peak period the on-site power system would provide 550 kWe and the utility derived service would supply the remainder. Assuming a reciprocating diesel engine and that heat recovery is not employed in this peaking plant, the cost of operating the plant can by calculated based on table 1 data. Given a fuel cost of $0.75/gal, and adding the cost of maintenance, the hourly cost of operation would be 0.067$/kWh X 550 Kwh/h = $36.85/h. For an average month of 22.5 working days and operating 10 hours/day, monthly cost would be $8291.25. The purchased cost of this electric energy in the on-peak period under normal circumstances could be $.08–.09/kWh. (Under abnormal circumstances, for example during that time when a megawatthour of electricity sold for $7,000.00, the cost of a kWh would have been $7.00.) It would not take too many of these occurrences to accelerate the return on this investment. However, for the scenario as developed, the monthly savings could be $2846.25. Keeping this evaluation idealized and simple, the annual savings could total $34,155.00. If the desired payback period were arbitrarily chosen as two years, then the budget for the peaking power plant is limited to $68,310.00. Coincidentally, the budget for the standby power plant can now be zero because, standby power is automatically available when the peaking power plant is installed.

The Interface

The operating mode at the point of interface between the utility derived and on site power sources is one of the most significant cost determinants in the operating strategy of the on site power plant. There are two basic modes to choose between:

1. isolated operation of the plants

2. parallel operation of the plants

There are pros and cons to both. Regardless of the selected operating mode, both provide a suitable return on the invested capital while providing critical load backup. In the isolated mode, peaking loads are disconnected from the utility derived source and connected to the peaking plant. In the parallel mode, both power sources are connected to the load simultaneously. In this latter mode, there is a need for additional control and protective circuits. The function of these additional circuits is to provide adequate safety to personnel and equipment on both sides of the point of common connection. (The point of common connection is that point in the electric power system where the utility derived service and the customer owned distribution system come together.) The objective of these additional circuits is to determine when the operation of the two power sources in parallel is acceptable so as to permit it and when that operation is not acceptable so as to prevent or end it.

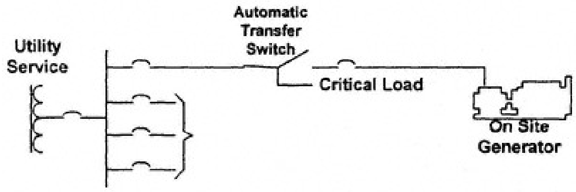

Figure 3
Simple peaking power system using the critical load as the peaking load

The operating strategy providing the minimum cost would be the isolated operation of the power sources. In this scenario, a selected load would be switched from the utility derived source to the peaking power source. The switching device would be a transfer switch. This is essentially a double throw device having two positions: Closed on the Utility Source or Closed on the Peaking Source. The device is relatively simple and straight forward and has been around and in this specific service for decades. It is typically used in emergency and standby power systems to transfer critical loads between two power sources as a function of source acceptability. Implicit in this statement, is the need for intelligent sensing control circuitry to determine which source to connect the load to. The Automatic Transfer Switch has a minimum set of control functions and features mandated by the Art. 700 of the NEC and UL 1008. Among these are

voltage sensing of the preferred source

voltage and frequency sensing of the alternate source

means to initiate transfer to the alternate source for testing

timing functions for

- ridethrough of transient voltage sags and outages, preferred source
- post operative power plant cool down
- stabilization of power source on availability
  - preferred source
  - alternate source

This set of control functions will serve peaking as readily as standby and emergency power applications.

Figure 3 illustrates perhaps the most cost effective and simplest scenario for peaking and critical load protection. An automatic transfer switch that is in compliance with the NEC will be qualified and approved to UL 1008, Minimum Standard for Safety for Automatic Transfer Switches. This can be assured because the NEC requires that any device used in the electrical system of a building must be qualified and listed, by an agency regularly engaged in the investigation of such equipment, for its intended use to the satisfaction of the authority having jurisdiction. Of significance, the NEC requires that electrical equipment be evaluated and approved for their intended use. The automatic transfer switch is the only switching device specifically tested and qualified for switching between unsynchronized power sources.

In the circuit of figure 3, the critical load is used as the peaking load as well. The control circuitry of the ATSE (Automatic Transfer Switching Equipment) used for emergency or legally required standby systems, must have a means of initiating load transfer for test purposes. This same or similar control circuit can be interfaced with a controller that would monitor the facility kWe demand and initiate a load transfer to the on site generator when that demand exceeds a preset value. From our example, that value would be 1710 kWe. When that demand fell to a value below 1710 kWe minus the kWe demand of the critical load, the monitoring control could permit retransfer of the load to the utility supply. The cost of such a controller would be less than $2,000. Thus, for the addition of $2,000 to the cost of the standby power system, it can now provide a return on its investment by reducing the on-peak operating costs of electrical energy. Some intelligence could be cost effectively added to the decision process in the form of a programmable logic controller.

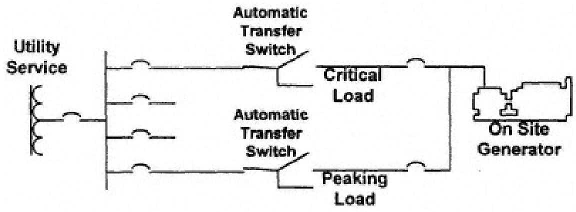

Figure 4
Simple peaking power system using noncritical load as the peaking load

Where the critical load is judged to be unsuitable for use as the peaking load, additional ATSE can be installed to provide a peaking load transfer capability. This will more likely be the case for the typical load transfer peaking strategy. Figure 4 shows such an installation. In this case, the load can be any load that is operational and constant in demand during the peaking period. In the light industrial or commercial facility this could be a bulk lighting load. These loads are typically turned on at the beginning of the day and turned off by the cleaning crews at the end of the day. It therefore provides a known and constant kW load for peak demand reduction. As an alternative, this load can be one of the offending loads that contributes to the high and varying peak demand during the on-peak period. Such a load could be the HVAC system. A potential advantage of using this load is that it minimizes the kWh produced because its load varies but provides the peak reduction because of its known rating. When the production of kWh is minimized, the operating cost of the plant is minimized.

There are those that would shy away from transferring an HVAC load between sources for various reasons. Transferring running motors between unsynchronized sources has been a concern whose origin dates back to the pre 70's. Given the development and integration of microprocessors into ATSE and industrial control strategies in the past two decades, this no longer need be a concern." . . . The burden of restoring automated critical loads to service after a power loss is no more difficult than starting them. The burden of transferring these loads between adequate sources, restoration to normal power after an outage or transferring to the alternate source for load demand abatement or system testing can easily be orchestrated with the proper control and switching strategies. Where it is undesirable to shut loads down for switch over, short duration open transition transfer times, 2 to 3 cycles coupled with inphase transfer control strategy is suitable for application to motor loads. . . ."[1]

On the subject of switching, the contact structure of the switching device should be evaluated for the intended service. It should be expected that electrical equipment will perform its intended duty when that equipment is evaluated and listed to its applicable safety standard. One should not hesitate to use a device for its designed purpose. There should, however be a hesitancy to use a device originally designed for some other purpose. The switch should be qualified for its intended use, as is required by the NEC, (NFPA 70) and other electrical building codes. Qualifying standards for ATSE require these switches to complete 50 cycles of load transfer at 600% of their rating before the temperature rise test. Following this and using the same sample, the switch undergoes the endurance switching regimen. This regimen requires the sample to complete half of the switching cycles at 200% rated current and the remaining half at 100%. For the overload and endurance switching regimens, the sample must be controlled by its intended control strategy. The total number of switching cycles varies with the continuous rating of the switch. The larger the switch the fewer the number of operations. Table 2 presents a partial comparison.

Table 2. Switching performance requirements for ATSE as per ANSI/UL 1008

Regimen/Rating	**400**	**800**
Overload @600%	50	50
Endurance		
@200%	2000	1000
@100%	2000	1000
@0%		1000

While the intent of qualifying standards is to assure a minimum performance criteria, for application in electric demand abatement, this performance criteria provides an expectation of service free longevity. Thus, it addresses controlling operating costs. For the 400 A switch, assuming 250 working days per year, the expectation is 8 years before major contact service is required.

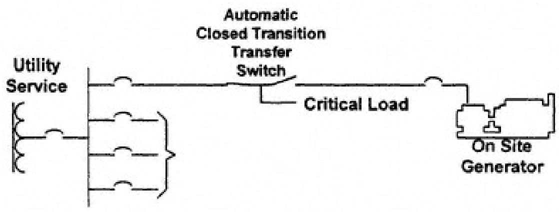

Figure 5
Peaking power load transfer using closed transition transfer strategy

Closed Transition Transfer

The issue of confidence in the control strategy of any power system that parallels with a utility derived power source is a universal concern. The electric utility supplier, in any such application, must provide safety to its maintenance staff as well as continuity and reliability in electric service to its customers. For these reasons, serving utility companies are quite demanding of the synchronizing and paralleling control strategies that they will allow at the point of common coupling.

On the other side of this issue is the increasing demand automation of customer facilities places on continuity of electric service. Increased automation in building environmental and production process control, coupled with reductions in operations staffing, impose less intrusive load transfer strategies on critical electrical loads. Having suffered an interruption in the process upon loss of the utility power source, it is often costly to suffer a second disruption upon restoration to the utility service. Additionally, periodic testing of the complete emergency power system is the only means to instill confidence in its operation. Consequently, upon restoration of the critical load to the normal power source and for test transfer in either direction, closed transition transfer has become the preferred transfer control strategy.

Figure 6 is a simplified logic flow chart of the closed transition transfer control strategy. Because the closed transition transfer strategy must be capable of both open and closed transition, both logic paths are illustrated in fig. 6. The left hand path is for closed transition transfer, the other is for open transition. Because the strategy is required to determine when either strategy is to be implemented, it must be capable of both. As an overview, closed transition transfer is initiated by restoration of the preferred source of power to acceptable values for the time set in the respective delay functions or by initiation of either the unit mounted test switch or remote initiating contact. Open transition transfer is automatically initiated when the source to which the load is connected becomes unacceptable and the other source is determined to be acceptable.

Looking at fig. 6 and following the left logic path, assume that a closed transition transfer is called for and initiated. The strategy continuously checks the two sources of power to determine their acceptability. As long as they remain acceptable, the strategy will make the differential determination of voltage, frequency and phase angle. Only when the sources are acceptable, the voltage difference is less than 5%, the frequency difference is less than 0.2 Hz and the relative phase angle difference between the two sources is less than 5° (electrical) should the strategy initiate the transfer operation. When transferring the load to the normal (preferred) source, the strategy will close the CN contacts and initiate a timing function to permit an overlap time of no more than l00ms. At the end of this time, the strategy will, initiate opening of the CE contacts. (CN is the operator and main contacts for the preferred source and CE is the operator and main contacts for the alternate source.) Parallel operation is limited to 100 ms or less in this scenario because this operation requires no interactive controls between the power sources and separation of the sources in less than 100 ms will not impact any protective relaying in either of the two power sources.

If the CE contacts fail to open within the time as set in t>T, the strategy will reopen the CN contacts and lock out the controls from further attempts at closed transition transfer. When the strategy is successfully completed, the regimen is ended until the next load transfer operation is initiated. As can be seen in the open transition transfer logic stream, the mains of one contact are opened before the mains of the other are closed. This strategy is the typical open transition transfer strategy implemented with a dual operator switching subassembly. Since the closed transition transfer switch

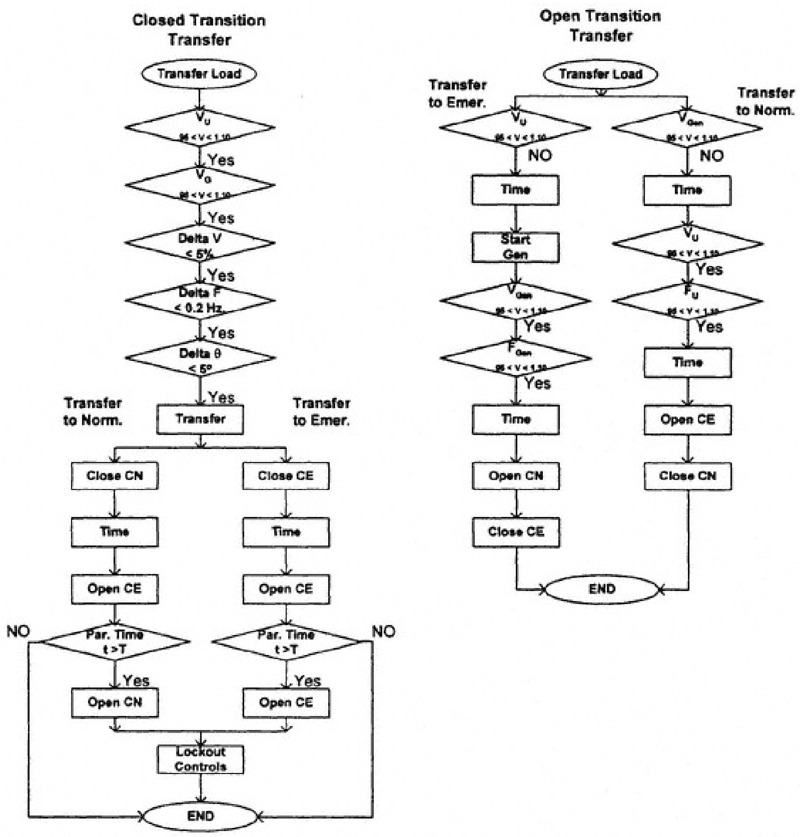

Figure 6
Simplified flow chart for closed transition transfer control strategy

is qualified to ANSI/UL 1008, it is required to meet the same overload and endurance switching regimens.

The control strategy, when embedded in the ATSE, assures the power system operators that paralleling will only occur when both sources are adequate and within a very narrow window of synchronism. The stability and repetitive accuracies of the control strategies are better than actually required. The control module is also evaluated in the qualification process of the same standards. The control strategies must meet specified repetitive accuracies and stability over a temperature range of –5° C to 40° C. The control strategies include voltage and frequency sensing, time delays and various other control functions. Modern control strategies are typically a microprocessor based design. The repetitive accuracy is typically ± 1% of nominal at ambient temperature and the stability is typically ± 0.5% of setting across the temperature range. In addition to acceptability of the two power sources, the control strategy measures the difference between the sources in voltage, frequency and phase angle. A typical operation sequence for closed transition transfer is to first determine acceptability of both power sources. Only when both sources are determined to be acceptable and have remained acceptable for a preset time, will the strategy determine if the differentials are met. Only when synchronism is determined, (for purposes of discussion, synchronism is defined as the voltage difference between the two sources is less than 5% and the frequency difference is less than 0.2 Hz and the phase angle crosses 5° (electrical) and is going toward zero), will the strategy initiate a closed transition transfer. Upon initiation of transfer, the open contacts are closed. After closure, the initially closed mains are opened. Timing is arranged to limit parallel operation of the sources to less than 100 ms. The control strategy should include automatic recovery should a malfunction occur during the closed transition transfer operation. The recovery would act to separate the power sources if prolonged parallel operation occurs.

The closed transition strategy without interactive controls between the two power sources will work well where the load being transferred is equal to 25%–30% of the engine generator set rating. Loading transients for step loading to about 30% of the set rating does not typically cause bothersome transients. Where the switched load represents a higher percentage of the engine generator set rating, consideration for controlled load transition transfer, commonly referred to as soft loading, should be given. In the soft load scenario, controls are added to bring the engine generator into synchronism with the utility derived service and hold it there. When synchronism, as previously defined, is achieved, the CE contacts are closed, Upon closure, an engine loading control increases fuel flow to the engine at a predefined rate. As the fuel flow to the engine increases it assumes increasing load. Simultaneously with load control, control of generator excitation is initiated so that whatever kWe the engine generator is producing, it is produced at a fixed power factor. Since it takes a very short time for the engine generator set to respond to loading control actions, in soft loading, parallel operation can be limited to 30 to 60 seconds.

Optimum flexibility in load and source dispatch occurs with long term parallel operation of the two sources. Under this operating strategy, engine generator loading can be adjusted to match the real time best economic operating scenario. It should be obvious that this is also the most costly operating strategy from the equipment point of view. However, if the intertie is an add on to the standby power system, the incremental cost may be readily justified by the savings to be gained. There is the impression that the protective relaying at the point of common coupling is expensive and extensive. Given the size disparity of the on-site power source in comparison the utility derived source at the point of common coupling, the protective relaying scheme can be quite simple yet be adequate in redundancy to meet the demands of personnel and equipment safety. Microprocessor based protective packages can cost effectively provide the necessary scope of protective functions.

Given the expansive capabilities of microprocessor based controls, communications between microprocessor based strategies is relatively inexpensive and most desirable. The ability to communicate between these various equipments, engine, generator, transfer switch, load control, etc. conjures the image of a controllable virtual power plant that can be made responsive to changing power demands in the electric distribution system. One could even imagine agrigating several unrelated standby power systems into a virtual power plant that could offer local geographical demand relief for over burdened distribution systems. For any given megapolitan area, there must be 100's of Mwe in standby power plants available. More immediately, communications capabilities addresses the staffing issue. It has been acknowledged that the primary product of the facility is not electrical energy. Therefore, it is unlikely that there will be competent staff in house to do more than just monitor some points that are readily accessible. As most facilities contract for outside services to maintain and service special equipment and processes, it would be natural to contract for service and maintenance of the power plant and its associated equipment. The engine generator dealer who furnishes the set can eagerly and readily provide appropriate service for it. Similarly, the provider of the electric control and switching system is a ready source of maintenance and service. Incorporating communications into the control scenario, enhances this maintenance capability.

Summary

The opportunity to reduce the operating cost of electrical energy as a result of utility deregulation can be further enhanced through the use of standby power systems. Electric energy pricing incentives can be exploited by maximizing load factor. Parallel operation of on-site sources with utility derived sources is not the only way to taker advantage of these opportunities. Load factor can be improved through judicious use of standby power plants and cost effective transfer strategies. Communications can provide the link that gives the final cohesiveness to the operating strategies. Finally, whatever scenario is implemented, the equipment is required to be qualified for its intended use. Using codes and standards as guides in equipment selection not only leads to legal and adequate designs but also assures long reliable performance of the systems.

Biography

James M. Daley PE; Senior Member of IEEE; BSEE '72, MSEM '86, New Jersey Institute of Technology; Professional Engineer registered in New Jersey; Senior Member and Certified Cogeneration Professional of the Association of Energy Engineers; Member, Tau Beta Pi—National Engineering Honor Society.

Mr. Daley has been with Automatic Switch Co. since November 1965. In his tenure, he has served in several product oriented engineering and marketing capacities dealing with Power Control Systems, the most recent being Director of Engineering, Switchgear. Currently he holds the staff position of Division Engineer, Switch Division. In his tenure, he has made numerous contributions to the development and advancement of power switchgear and controls for engine generator power systems. He has pioneered high current switchgear designs and holds a patent on control elements. Mr. Daley has written and presented several tutorials on generation, distribution and control of on site electric power as well as other topics. He has published several papers and articles for IEEE, EGSA and industry periodicals. These include Transaction papers in both the IEEE and SAE. He is the 1999 Prize Paper Award recipient from the Power Systems Engineering Committee of the Industry Applications Society of the IEEE.

Daley, JM, IEEE Transactions on Industry Applications, Page 1410, Vol. 34, No. 6, Nov/Dec 1998, IEEE, Piscataway, NJ 08855-1331

Chapter 48— Case Studies of Small Cogeneration

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Abstract

Cogeneration systems at twenty facilities were studied for economic costs and benefits. Cogeneration units of 60 to 600 kilowatts (electrical, kWe) capacity were located in urban and suburban areas of northern California. Combined nameplate thermal and electrical efficiency of up to 83 percent for small cogeneration was found in comparison to 33 percent on average for utility electrical generating plant.[1] Simple paybacks of three to five years were typical. The economic benefits are also quantified with internal rate of return and life cycle cost. More attention to market signals could result in improved performance, reduced operating costs, and improved economic efficiency. Regulatory requirements assure that cogeneration qualifying for economic benefits will also yield net environmental benefits.[2] The authors present guidelines for investigation of feasibility at readers' facilities and recommendations for operating staff.

Outline

Introduction
Principles of Small Cogeneration
Findings and Discussion
Conclusions

Introduction

This paper offers case studies of small cogeneration systems at a range of facility types and sizes. For energy managers considering new investment, the paper presents both simple payback and life cycle cost models. For chief engineers and facility managers of new and existing cogeneration units it offers a more quantitative approach to the question of how many hours and which hours a cogeneration unit should operate. For readers interested in environmental and energy policy it offers observations on the beneficial effect of utility declining block rates on distributed power production.

Principles of Small Cogeneration

Cogeneraton is defined as the sequential production of electrical or mechanical energy and thermal energy from a single fuel. Smaller automotive-derived engines and high electric rates are leading more energy managers to investigate cogeneration.

Minimum Size of Host Facility

Facilities operated on a 24-hour schedule usually present the best opportunity for cogeneration because they tend to have complementary thermal and electrical load profiles. The recent guideline that thermal demand should be on the order or 2,000 pounds of steam per hour[3] to justify cogeneration no longer applies. This steam flow corresponds to a cogeneration plant electrical output of approximately 400 kWe. Since small cogeneration units do not make steam, a guideline used by the authors is that a monthly usage of 4,000 therms (4×10^8 Btu) of boiler natural gas and 40 MWh are necessary although not sufficient conditions for successful cogeneration. These correspond to an electrical output of 40 to 60 kWe, an order of magnitude smaller than the traditional value. Contributing to the use of this smaller scale is the declining block rate structure in both electric and gas services of major investor owned utilities. "Declining block rate" means that large users pay a lower unit cost for a commodity than small users. It is ironic that more than twenty years after the oil price increases declining block rate structures are still in place, but that now they are encouraging decentralized power production. These rates allow small users to participate in a field previously limited to large commercial or institutional facilities. The application of automotive-derived engines operated on natural gas has brought a less expensive option to industrial engines in the 60 kW class. Time-of-day electrical rates offer additional options to medium and large commercial users.

A topping cycle in cogeneration is one that first generates electricity and then draws on the waste heat to satisfy thermal demand. Innovative design and controls that enable a topping unit to follow thermal demand capture both benefits and allow a smaller unit to be economical. This case study examines thermal and electrical demands that have been deemed sufficient to justify cogeneration. This perspective could enable facility managers to investigate cogeneration for their facilities with a good idea of whether it will attract management support. The subjects of this case study range from one 600 kWe unit down to one or more units of 60 kWe nominal capacity.

Figure 1 illustrates site thermal and electrical demand before each installation and the cogeneration unit sizes later installed. While these site characteristics are not the only indicators of suitability for cogeneration, they are based on data that are easily available. This figure enables the reader to see what other energy managers have done with sites of similar demand. The more meaningful loads are minimum thermal and electrical demands. These minima will determine the potential load factor, how many hours the cogeneration unit can be employed in each rate interval, and economic potential.

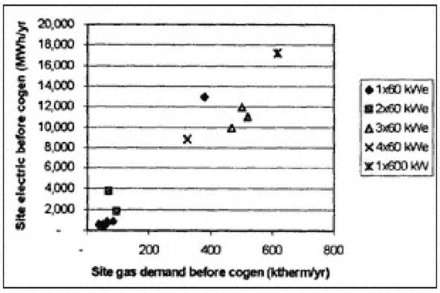

Figure 1
Site Thermal and Electric Demand Prior to Cogeneration

The overlapping symbols near the origin of Figure 1 stand for six of the single-unit installations. These six used annually 38,000 to 84,000 therms of natural gas and 450 to 890 MWh of electricity prior to cogeneration. These six and all but one of the multi-unit cogeneration systems in Figure 1 were selected as representative of the hundred or so cogeneration units designed by co-author R. Spitzka.

Electricity generated and used on-site will displace utility power at the full rate schedule. I.e., the utility electric meter will show fewer kW and kWh. Electricity generated on-site that is in excess of site demand can be sold back to the utility, typically at a much lower rate. In northern California, power can be sold to contiguous sites, called "over-the-fence" sale, but the exercise is complicated. Therefore it is important that the electricity from the cogeneration unit be considered in light of the minimum site demand.

Each nominal 60-kW unit used 7.76 therms (776,000 Btu) per hour of natural gas fuel and produced 59 kWe net after parasitic loads. Of the fuel input 4.4 therms (440,000 Btu) per hour can be recovered as useful thermal energy. To the extent that the boiler not used has an efficiency lower than 100 percent, as they all must, the reduction in natural gas usage will be proportionately better than the 4.4 therms per hour. Cogeneration fuel is supplied at a lower price per unit than fuel for process heat. All of these factors improve the potential for cogeneration.

TABLE 1.
COGENERATION STUDY FINANCIAL INPUTS

Ident.	Facility	kW	First Year	Capital Cost $	Capital Cost $/kW
TE1	High School	60	1986	107,000	1,783
TE3	High School	60	1987	115,000	1,917
TE7	Hospital	60	1988	105,000	1,750
TE8	Swim Ctr.	60	1988	105,000	1,750
TE9	Multi-res.	60	1988	105,000	1,750
TE10	Swim Ctr.	60	1989	140,000	2,333
TE11	Assist. Lvg.	60	1989	115,000	1,917
TE12	Hospital	180	1990	390,000	2,167
TE13	High School	60	1991	151,000	2,517
TE14	Hospital	180	1991	392,000	2,178
TE15	Hospital	180	1994	394,000	2,189
TE16	College	120	1994	250,000	2,083
CA18	Hospital	600	1991	665,000	1,108
TE19	Hospital	120	1995	256,000	2,133

The projects shown in Figure 1 and those listed in Table 1 differ in a few cases because historical and operating data were sometimes incomplete.

To determine how the units performed over time, the actual run hours were tabulated. The familiar simple payback (SPB) is the capital cost divided by the first year savings or the annual savings. Usually these two savings figures are considered to be equivalent, but this was frequently not the case. In the interest of completeness there are two simple paybacks for each project in Table 2, one for the first year and one for the average of all years. The reader is encouraged to think about which payback is more meaningful:

Does a full year of successful operation amount to proof of concept? . . . and justify relying on the first-year simple payback? (or)

Does the proof depend on how well the unit performs over the payback period? . . . and require the use of a longer period?

This choice would not come up if the two paybacks were the same value. And normally the choice does not come up because an engineer is satisfied to have one value or the other. This path leads to the question of why there should be any difference. Individual sites may have changes in personnel or loads, but the message more frequently from operating staff was that a rigorous maintenance program is always a good thing.

The adjusted internal rate of return (AIRR) and the life cycle cost are both calculated using the Department of Energy (DOE) program BLCC (Building Life Cycle Cost).[4] This program is revised annually with DOE estimates of future energy costs. Therefore these analyses describe the period from 1999 forward. Different managers may prefer one or the other of these indices so all three are presented in Table 2. The AIRR and life cycle cost (LCC) values are what a project built in 1999 would achieve with the actual performance of the cogeneration units in the study. These analyses thus describe future projects operated at past performance levels and must be interpreted carefully. The DOE inflation rate of 3.1 percent and discount rate of 5.7 percent were used. The AIRR is not return on investment. It is the discount rate at which the costs and benefits would balance to zero. Therefore if AIRR is greater than the discount rate, the investment is a good one. Turner discusses more advantages and disadvantages of AIRR.[5]

TABLE 2.
COGENERATION STUDY FINANCIAL OUTPUTS

Ident.	Load Fact Avg.	SPB 1st yr	SPB Avg yr	AIRR 20 yr	LCC 20 yr benefit
TE1	0.539	3	5	0.114	200,548
TE3	0.623	4	4	0.125	288,366
TE7	0.925	4	4	0.125	262,933
TE8	0.622	5	-	0.126	264,448
TE9	0.736	3	3	0.147	431,565
TE10	0.583	4	6	0.107	212,722
TE11	0.534	3	5	0.110	188,791
TE12	0.836	4	4	0.120	858,495
TE13	0.770	4	5	0.117	304,199
TE14	0.939	4	3	0.134	1,206,488
TE15	0.723	4	5	0.106	580,490
TE16	0.612	5	4	0.121	557,650
CA18	0.585	7	7	0.084	528,718
TE19	0.944	4	-	0.131	727,249

For completeness, some physical characteristics of the cogeneration equipment are presented in Table 3. There are many manufacturers of the 600-kW class cogeneration unit.[6] Of the 60-kW class, over a dozen smaller manufacturers have entered this market, mostly with automotive-derived engines. In the authors' opinion there are only two remaining firms in production and committed to this technology. The introduction of small turbines and fuel cells into cogeneration promises competition in the future.

TABLE 3.
CHARACTERISTICS OF COGENERATION UNITS

Element	60 kW class	600 kW class
Engine	4-stroke V-8	4-stroke V-12
Cycle	Otto	Otto
Type	Auto-derived	Industrial
Disp.	460 cid (7.5 liter)	3,158 cid (52 liter)
Fuel	Natural gas	Natural gas
Size (lwh)	7' x 4' x 4'	14' x 6' x 6'
Weight (lb)	3,000	24,000
New structure?	No	Yes
Cost ($/kW)	2,200	1,300
kWe (net)	59	510
Fuel flow	7.76 therm/hr	57 therm/hr
Heat recovery	4.40 therm/hr	27 therm/hr
Combined eff.	0.827	0.779
Engine replacemt.	30,000 hr	not app.
Engine rebuild	not app.	25,000 hr
Generator	Induction	Synchronous

Findings and Discussion

When given a choice of several electric accounts and meters, select the best one for the cogeneration unit. The reflex is to connect the cogeneration output to the largest load, since that maximizes the chance that all of the electricity can be used on site. Utility rate structures, however, charge the lowest electrical rates on the largest accounts, typically those over a Megawatt of maximum demand. If there is a smaller account, say 100 to 300 kW peak demand, and that account is large enough to absorb the 59 (or 118) kWe of generation at its minimum, then it should make a better profit. Select the electric account that will bring the highest avoided cost.

Determine minimum loads and size the unit accordingly. Small facilities generally do not record or sub-meter utilities, so it may be necessary to install temporary recorders to monitor minimum electrical demand. If possible, read the existing meters or obtain 15-minute interval recorder information from the utility. Do not oversize the cogen system. This error has historically been the biggest mistake in those facilities with problems. It is better to start conservatively and add additional units as justified. Note that the highest load factor of the units in this study is also the most undersized (Figure 1 facility at 400 ktherm and 13 GWh).

Instrumentation should be specified prior to installation. The 60-kWe Tecogen design has a digital display of system status mounted on the unit. The 60-kWe Coast Intelligen is capable of remote monitoring and may be installed with no local or on-site display. Operators prefer the former.

Have a current copy of your rate schedule and read it. There is a standby charge levied by the utility when a cogeneration unit is operating because the utility has to be prepared to provide that capacity. If the cogeneration unit goes down and the demand charge for that month is incurred, then the utility will refund the standby charge. This refund may or may not be automatic.

Do not use the average, blended, estimated, or inexact electricity cost; consider each time-of-day and seasonal energy price combination as a separate decision on whether to run the unit. Using an average is much easier, but the results are illustrated in Table 4 for a single 60 kWe unit on various rate schedules. For example, an hour on peak in the summer (electricity cost high, gas low) may bring a net benefit of $7.54 while the same hour off peak in the winter (electricity cost low, gas high) may bring only $0.53. The average hourly value, although correct in a mathematical sense, is of limited value in the operating sense. The dollar amounts in Table 4 appear modest but sites may have up to ten cogeneration units and there are 8,760 hours in a year.

TABLE 4.
CONSEQUENCE OF USING "AVERAGE" VS.
ACTUAL TIME-OF-DAY PRICES

Rate Schedule		Benefit $/hour 100% load factor	Benefit $/hour Missing Peak hr
Small Commercial	(10-499 kWe maximum)		
"Average" value		$ 2.29	$ 2.01
Actual summer		3.14	2.59
Actual winter		1.44	1.44
Medium Commercial	(500–999 kWe maximum)		
"Average" value		1.64	1.49
Actual summer on peak		7.54	5.93
Actual summer part peak		2.38	2.38
Actual winter part peak		1.38	1.38
Actual summer off peak		0.87	0.87
Actual winter off peak		0.53	0.53
Large Commercial	(1,000 kWe and up)		
"Average" value		1.62	1.47
Actual summer on peak		7.50	5.89
Actual summer part peak		2.35	2.35
Actual winter part peak		1.35	1.35
Actual summer off peak		0.84	0.84
Actual winter off peak		0.51	0.51

The use of the term "average" with quotation marks is intended to remind the reader that Table 4 seeks to illustrate why one should not use the average value for day-to-day decisions. The average value does however correctly express the integrated annual potential under each tariff and the "advantage" of the small commercial user. The results in Table 4 are specific to one set of assumptions and cannot be applied to another engine, location, or time. The calculation is a simple one. Moreover, under some unfavorable combinations of circumstances, the return can "go negative" meaning it would be cheaper to shut down the unit than to operate it.

The owner should not count on receiving the electrical demand charge reduction with a single cogeneration unit on-site. That is, if a single unit is off-line for the month's peak hour, that month's demand charge is ratcheted up. The third column of Table 4 illustrates. If two units are installed, then one unit's worth of demand reduction is likely. This disadvantage can be greater where a single large unit is installed.

A New Accounting Tool

Another way of looking at this situation is illustrated in Figures 2a and 2b. Figure 2a shows the annual operating hours as a pie chart with slices for the time-of-day intervals. Assuming the unit is operated as baseload capacity, the slices are proportional to load factor.

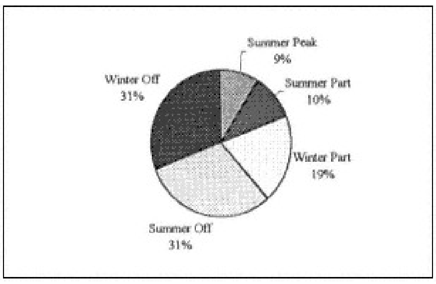

Figure 2a
Proportion of Annual Hours in
Time-of-Day Intervals (PG&E)

Figure 2b shows the economic benefit of operating those same hours under a time-of-day rate schedule.[7] These slices are proportional to the time-of-day effect of rate schedules and represent profit. Adding the values of the slices yields a new index analogous to load factor. We call this new index the profit maximizing or "max" factor.

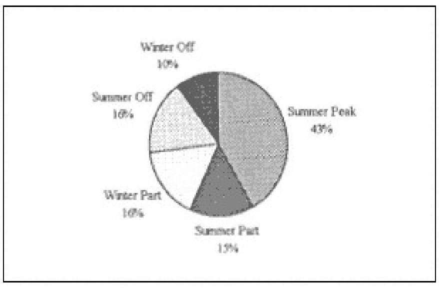

Figure 2b
Proportion of Annual Profit In Time-of-Day Intervals (Specific Project)

One percent of annual load factor (87.6 hours) can be worth as much as 4.7 percent (decimal 0.047) or as little as 0.33 percent (decimal 0.0033) of the annual net profit. The inputs to Figure 2b are weighted for the electrical, gas, thermal, maintenance, and other costs and benefits. These steps are necessary to find out when a cogeneration unit is making a profit. The difference between Figures 2a and 2b demonstrates that an average energy price would seldom lead to a true accounting.

An Example of the "Max" Factor Applied

From inspection of Figures 2a and 2b, one can see that a profit maximizing factor of 90 percent of potential profit can be achieved with a load factor of only 69 percent by choosing to omit winter off-peak operation. Alternatively, a max factor of 74 percent could be achieved with a load factor of only 38 percent by foregoing off-peak operation altogether. This need for added precision will become greater with deregulation and a different energy price every hour of the day.

It may be desirable to run the cogeneration unit at times of low heating demand. Normally the unit follows thermal demand and if it falls too low to cool the engine, then the engine will shut down. Since minimum heating demand coincides with peak electrical rates (the six-month summer), consider auxiliary cooling or a modular absorption chiller if an analysis shows it to be justified.

The reader should note that all of these considerations respond to intentional market signals that will enhance overall economic efficiency and meet environmental goals. They do not take advantage of a regulated utility nor do they cause a net environmental harm.

General Remarks

Do not accept the opinion that small cogeneration is not serious engineering. Energy analysts see small and distributed generation and cogeneration as the inevitable future. One project in design employs absorption chillers and demonstrates cost-effective tri-generation.

Energy policy was advanced in the 1980s with the concept of "hard energy" vs. "soft energy"—i.e., large centralized power vs. small distributed—a debate begun by Amory Lovins (see endnote 8 for early references). Two critics of Lovins cataloged 78 specific social, economic, and environmental benefits claimed by Lovins for a soft energy path.[8] While the engines described in this study are not the realized "soft path", they are a step in that direction. In fact they further at least 76 of the 78 claimed benefits. Of particular note is number 74, "(m)ore joy, fun, and excitement in (the) energy system". This phrase well describes operators we found who mentioned satisfaction at getting a particular piece of equipment to work, sometimes a difficult piece. It is hard to quantify this social benefit, but it is worth something.

Conclusions

Small systems of one or more 60 kW units are suitable for unattended operation. They have generally yielded good results as shown in Table 2. Sites with full-time operating staff, however, will have better results over the long term. Systems of the 600 kW class are not designed for unattended operation.

Provide professional maintenance whether in-house or on contract. This applies to cogeneration units of any size. For the 60 kW class, the prime contractor will usually offer maintenance as a line item option. The 600 kW class is large enough to justify an independent maintenance contract.

Know which financial model your management uses for decision making, whether simple payback, rate of return, or life cycle cost. Present projects for funding in the preferred format in order to "speak their language". For existing and future cogeneration, know the value of operating in each time-of-day electric period and inform the operating staff. Consider the additional step of profit maximization using the "max factor". This task could be automated in typical energy management systems.

References and Notes[9]

1. An average utility heat rate of 10,239 Btu/kWh is recognized in California (California Energy Commission, Title 24, Section 102, July 1, 1999). [3,413/10,239 = 0.333]

2. Federal Energy Regulatory Commission (18CFR292); in California, Public Utilities Code Section 218.5 and 372(a).

3. California Energy Commission, Cogeneration Handbook, 1982, p.2–1.

4. BLCC is a public domain code (freeware) available as of July 1999 at: http://www.eren.doe.gov/femp/techassist/softwaretools/softwaretools.html#blcc.

5. Turner, W.C. (Ed.), *Energy Management Handbook,* Wiley, 1982, pp. 92–95.

6. EUN Product Guides, "Packaged Cogeneration", *Energy User News,* **23,** 11, November 1998, p. 34.

7. In this case, a medium commercial rate schedule in northern California, maximum demand of 500 to 999 kWe. There are only five time-of-day periods because winter part-peak rates apply to winter on-peak hours.

8. Morrison, D.E., and D.G. Lodgwick, "The Social Impacts of Soft and Hard Energy Systems: The Lovins' Claims as a Social Science Challenge", *Ann. Rev. Energy,* 1981, 6:357–78.

9. Manuscript dated July 20, 1999 for presentation at 22nd AEE World Energy Engineering Conference, Atlanta, Georgia, October 22, 1999. Authors' addresses for correspondence: David Dietrich, Dietrich Engineering, P.O. Box 300, Petaluma, CA 94953; Robert E. Spitzka, Water and Energy Management, Inc., 79 Hillmont Place, Danville, CA 94526; David Jones, Catholic Healthcare West—Shared Business Services, 3033 N. Third Ave., Phoenix, AZ 85012. The authors wish to recognize the creative contribution of M. Gregory of San Francisco who first used the term "max factor" in place of the more awkward "profit maximization factor".

SECTION 4— GEOEXCHANGE

Chapter 49— GeoExchange: The HVAC Technology of Choice

Conn Abnee, Executive Director
Geothermal Heat Pump Consortium

Abstract

This paper will discuss the history, current activities and future direction of the Geothermal Heat Pump Consortium and the use of GeoExchange heating and cooling technology in the national marketplace today.

Making a Difference

Since its creation in 1994, the Geothermal Heat Pump Consortium (GHPC) has worked to promote the use of GeoExchange technology (geothermal heating and cooling) throughout the United States.

It has been a challenge, requiring numerous adaptations to a changing economic and political landscape, but I am happy to report that we are making striking progress. In fact, over the period from 1994 through 1997, sales have grown more than 32%. This, in spite of utility deregulation and the predominance of cheap energy.

The benefits of GeoExchange are cumulative. Each and every system installed in a residence, a commercial building, a school, a government facility, a library, or even an ice arena reduces our country's energy consumption and harmful carbon emissions. We are seeing more and more successful installations every year, but we must increase public awareness of the technology's benefits and availability.

Moreover, we must also remain committed to raising system efficiency, extending system life, and reducing system installation costs at every opportunity. Only by continuously improving the technology and diligently increasing its benefits over competitive technologies can we hope to meet our goals for GeoExchange installation growth.

Certainly, we still face barriers to growth, but we have identified and analyzed them, and have formulated a number of creative strategies to overcome them.

Without strong partnerships with all of those interested in the same goals and cause, we will not realize the full potential that GeoExchange technology has to offer.

Perfecting Technology

Initially, implementing GeoExchange technology required a technical approach on three fronts: 1.) build an infrastructure capable of installing first-rate GeoExchange systems, 2.) help the industry develop ways to reduce the first-cost premium associated with GeoExchange systems, and 3.) build confidence in the technology on the part of the consumer and business buyers of heating and cooling systems. Today, much has been accomplished.

The Consortium's six regional training centers have trained thousands of technicians, installers, architects and engineers, improving the quality of the work force across the nation. Their positive impact on each region's economic development goes far beyond the simple one-time training mission; they have educated many individuals who have gone on to establish GeoExchange-related businesses that have become significant employers in their regions.

Consortium support has also helped to develop technology, processes, and materials to overcome regulatory barriers across the country. Moreover, the Consortium's technical support has led directly to more precisely defined system engineering parameters and dramatically enhanced design tools. Simultaneously; other projects have helped ameliorate environmental concerns.

A New Direction

Today, technical approaches are not enough. The market is multitextured. We must be more creative in the financing of system installations, more ardent in our promotion of public awareness, and more vocal in our requests for support from those who benefit from industry growth and success.

We must look to partnerships beyond those that have been common in the past. It is our role to bring creative organization and strategic self-promotion to the industry. And we intend to do that in fresh, new ways as we move toward the pivotal year of 2005, and the culmination of our program to make the market self-sustaining.

We have accomplished much through our past demonstration projects.

Current total installations stand at about 400,000 units, and 1998 industry estimates put GeoExchange installation growth at more than 20%. This is certainly a notable achievement for the industry. But we must still sell and install another 1,600,000 units by 2005 to meet the industry's goals. Such growth cannot be achieved without extraordinary effort, especially in the current business and economic climate.

Technical development has come a long way, and other industry participants are stepping up to support it. Clearly, dramatic growth in unit installations will require an equally dramatic increase in the awareness of GeoExchange technology and its benefits by the general public and key target market segments. Thus, the Consortium has embarked on a public awareness campaign of unprecedented scope, on behalf of the entire industry.

This campaign targets national newspapers, consumer magazines, the business press, network, cable and syndicated TV and radio broadcast outlets, as well as carefully selected trade press in seven market segments.

In the first six months alone, this program put information about GeoExchange in front of 14,760,000 readers of daily and weekly newspapers, consumer magazines, and the trade press. In addition, syndicated radio carried the GeoExchange message to another 6,430,000 people around the country.

Crucial Partnerships

None of our successes would have been possible without the initial backing of the Edison Electric Institute (EEI), the support of the nation's electric utilities, and the close coordination of the US Department of Energy (DOE) and the Environmental Protection Agency (EPA). Moreover, the Consortium has enjoyed continuing support from the National Rural Electric Cooperative Association (NRECA) and the Electric Power Research Institute (EPRI). The contributions of all of these agencies have been crucial to the Consortium's success to date, as has the support of the equipment manufacturers, developers, installers, architects, engineers, and other trade allies.

But now is not a time for business as usual. We have been challenged as never before, and we must respond as never before.

As part of our new approach to building industry support and expanding industry involvement, the GHPC has embarked on a bold new initiative with the Department of Energy. In 1998, we entered into a cooperative agreement, which allows GHPC to operate more efficiently, while remaining responsive to the needs of the industry and of the DOE.

In essence, a number of performance goals have been established and set down in a cooperative agreement signed by both GHPC and by the DOE. Funding has been tied directly to the accomplishment of those goals, with funds transferred only when certain performance milestones have been met.

We are held accountable for our activities, and the success of those activities helps to proliferate our efforts. The DOE is also expecting us to continue to increase participation by members and beneficiaries of the industry. In fact, our overriding goal is for GeoExchange to become a self-sustaining technology, the foundation of an industry ultimately carried forward by its own momentum, and funded exclusively by the proceeds generated by the sale and installation of residential and commercial GeoExchange systems.

Again, this is an attainable goal, if all who potentially benefit from a self-sustaining industry work together to bring it about.

Formidable Challenges

In an era of utility deregulation, this will not be an easy task. Demand-side management programs are disappearing because of regulatory changes, which diminishes corporate support within many utility operations.

Yet research shows that utility participation is key to buyer acceptance of the benefits of GeoExchange technology. Consequently, the Consortium is working to develop programs that will help bring real benefits to its utility members and supporters in a deregulated business climate. We are expending more effort to develop and commercialize loop-leasing arrangements that will help electric utilities retain customers in a competitive environment. Creative financing options and a utility's ability to increase its participation in the revenue stream generated by both installations and financing are also being explored.

We are perfecting promotional programs aimed at helping electric utilities use GeoExchange promotions to recruit customers, and to build their image among consumers as environmentally responsive members of the community.

Even as we are working to make GeoExchange programs responsive to the needs of our utility partners, we are putting in place programs to streamline the dissemination of information to the manufacturers and trade allies whose support is crucial to the industry's growth.

Novel Approaches

To broaden the reach and effectiveness of the many industry programs carried out to date, we have initiated an aggressive business development effort. We have developed an ambitious schedule to repackage and distribute throughout the industry the documents containing the technical knowledge, research data, and marketing insights accumulated through each of our partnership programs and demonstration projects. This material can save our members and active industry participants substantial time and financial resources by eliminating their need to repeat the vast amount of work already done by others.

To increase the likelihood of GeoExchange being specified as the heating and cooling system of choice, we instituted what has become a very popular design assistance program. Through it, the Consortium offers GeoExchange design experts to architects and engineers who wish to begin using GeoExchange in their own projects. Through the end of 1998, the Consortium had authorized design assistance for 79 projects totaling 50,142 tons of heating/cooling capacity. Of the projects that have selected a heating/cooling system to date, 76% have committed to using GeoExchange.

As part of our overall strategy, we are also taking the necessary steps to make public service advertising a formidable weapon in our communications arsenal. To do that, we are establishing a nonprofit, educational corporation to solicit grant funds from charitable trusts and foundations for the specific purpose of educating the public about the energy savings and environmental benefits of GeoExchange. In 1998 alone, our Strategic Outreach program identified more than 50,000 tons of GeoExchange projects, and we've tripled the program for 1999.

Targeted Growth

In another move to build general market knowledge and to develop practical approaches to selling GeoExchange systems in a variety of market segments, we have begun a series of regional initiatives and are developing an aggressive communications program of our own for the national school market.

The regional markets will be developed in partnership with electric utilities and trade allies. These regional marketing efforts will help us to hone our marketing strategies, and provide invaluable feedback for others in the industry interested in embarking on programs to build profits through GeoExchange.

Our own school marketing program will include national trade advertising, publicity, and the development of a school market response package comprised of a new promotional brochure specifically geared to the school market, our "Smart Choice for Schools" cost projection software on CDROM, and a video describing successful school applications of GeoExchange.

The public relations effort also targets key decision-makers in the education market. Customized media kits have already been sent to all editors and reporters who write about educational issues for appropriate trade publications, national and regional publications, syndicated columnists, and radio personalities involved in education issues. Aggressive follow-up is underway, and articles have already been placed in such key school publications as School Planning and Management and American School and University.

With the DOE's focus on its Energy Smart Schools program, and the success GeoExchange has enjoyed already in the school market, we expect significant growth as a result of this new initiative.

Final Perspective

Our goal is to help our members and partners to enjoy profitable growth, even as we work to expand public awareness of GeoExchange, and to fuel the continued double-digit growth of the overall market. We are stepping into a new competitive landscape, and we truly believe the horizon is endless, the growth potential unlimited.

Chapter 50— IGSHPA—The Geoexchange Network

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Abstract

GeoExchange is one of the fastest growing technologies today. A network of resources is available to those interested in learning more about the lower maintenance and operating costs associated with GeoExchange systems. This paper features ways for HVAC professionals to get industry materials, training, and design support. GeoExchange system design, rather than being new or experimental, follows an organized approach that integrates the performance of the ground heat exchanger with energy-efficient heat pumps and the building's thermal requirements. This review covers design and research methods to reduce heat exchanger initial costs, current design and analysis software, soil thermal conductivity testing, case studies, and other available support materials.

Introduction

Just as every journey begins with one step, so every geothermal heat pump installation begins with one person's desire to make it happen. But where does that person obtain the skills, the talent, and the materials necessary to ensure the job is done right?

Anyone who has ever been a part of a professional organization like the Association of Energy Engineers knows the value of being connected to like-minded individuals with complementary skill sets. For solving problems and creating an environment conducive to learning, there is no substitute for the kind of network provided by membership in a professional organization.

The professions that use GeoExchange are no exception. Architects, engineers, designers, installers, and others all need to be connected to a network of other industry professionals willing to share their experience and expertise—a group of people committed to excellence in the GeoExchange industry.

That is where the International Ground Source Heat Pump Association comes in. With our network of industry professionals, training programs, and research activities, IGSHPA is the ideal first stop for anyone interested in GeoExchange technology.

What IGSHPA Does

IGSHPA is an organization that exists solely to advance the GeoExchange industry and the current state of geothermal technology. Through its membership, training, and research activities, IGSHPA has developed a large network of professionals in the field. That network is available to help others in the industry when they need it.

Networking

IGSHPA maintains listings of manufacturers, installers, designers, and other industry professionals who can share their knowledge with those less experienced in the field. IGSHPA members become part of this group and stay connected through IGSHPA's newsletter, *The Source,* and annual conferences that feature forums, seminars, and demonstrations conducted by industry leaders.

Another way our members stay connected to the industry is through access to new GeoExchange research focused on improving various aspects of the geothermal system, as well as testing new materials and methods. Researchers at Oklahoma State University are constantly working to improve the state of the art in geothermal heat pump technology. Current projects include:

A portable in-situ thermal conductivity testing unit that will offer accurate results in less time than previously required, allowing for better design decisions.

Design alternatives using supplemental shallow ground heat exchangers.

A new test bed for evaluating the effectiveness of different types of grout in a controlled situation.

Possible solutions to dangerous bridge icing via the geothermal "Smart Bridge" project.

The individual installer, architect, or engineer can benefit greatly from the latest information on topics such as "Which grout should I use?" and "How can I reduce the system's installation cost?" Oklahoma State University geothermal researchers work in concert with IGSHPA's staff, and they are able to answer whatever design and installation questions you may have.

Installers benefit from IGSHPA's training and certification programs as well as the added exposure and marketability associated with membership in a professional organization.

IGSHPA training and materials can help architects and engineers better understand the benefits of GeoExchange and how to apply this technology to their current and future building designs.

Materials and Publications

IGSHPA produces a variety of software tools, manuals, and other publications that are designed to help GHP designers and installers do their jobs better.

CLGS is a ground heat exchanger design program for residential applications. It calculates the proper sizing of the ground heat exchanger, along with associated costs and other design criteria.

IGSHPA's commercial design software package is called GLHEPRO. With an emphasis on the total building heating and cooling load under various conditions, GLHEPRO accepts input from several popular building energy analysis programs and can simulate ground loop heat exchanger design performance.

In addition to instructional manuals, IGSHPA produces marketing materials for use in educating the public and promoting the GeoExchange heat pump industry.

IGSHPA also educates the public through its presence on the World Wide Web (http://www.igshpa.okstate.edu). The IGSHPA web site contains nearly 1500 pages of information on topic such as geothermal basics, case studies, training, and listings of domestic and international geothermal businesses.

IGSHPA continually builds upon its network by forging partnerships with other geothermal and HVAC organizations. The Electric Power Research Institute (EPRI) often works with IGSHPA to improve the state of the art in GeoExchange technology.

Researchers at Oklahoma State University are heavily involved with the American Society of Heating, Refrigerating, and Air-conditioning Engineers (ASHRAE), providing committee leadership, writing papers, making presentations, and participating in joint research projects.

Geothermal research funded in part by EPRI and the National Rural Electric Cooperative Association (NRECA) has led to the creation of several standards-setting industry publications, including IGSHPA's *Soil and Rock Classification Manual,* the *Closed-Loop/Ground Source Heat Pump Installation Guide,* the *Slinky Installation Guide,* and others. IGSHPA makes these manuals available to its members at discounted rates.

Additionally, the US Department of Energy (USDOE) has provided funding for development of application-specific materials for residential, commercial, and industrial projects. These materials focus on operating costs, typical successful applications, system operations, the benefits of GHPs, design considerations, and how the systems operate.

Training

IGSHPA offers training programs for Architects and Engineers, Installers, and Trainers. Currently, all training is conducted on the campus of Oklahoma State University or at one of several IGSHPA-certified regional training centers.

The Architects and Engineers seminar lasts three to five days and covers topics such as system design, economics and personnel, installation methods, grouting, and refrigeration. Students leave with a clear understanding of geothermal technology and how to apply it to their future building designs.

The Installers course provides the student with the tools necessary to become an IGSHPA-certified installer. Topics for this course provide the GeoExchange installer with the knowledge needed to properly select materials, design and lay out the system, join and install pipes, and prepare the system for use. Students who take this course and pass the exam become IGSHPA-certified installers.

In IGSHPA's Train-the-Trainer Program, participants are trained in the use of IGSHPA training materials and demonstration equipment. After successfully completing the program, participants receive IGSHPA training accreditation.

The upcoming Certified Geothermal Designer (CGD) training program will eventually be conducted entirely online. This program is aimed at experienced HVAC professionals who wish to increase their professional standing and credibility in the GeoExchange arena. The comprehensive curriculum will give Certified Geothermal Designers the knowledge and tools necessary to succeed in today's GeoExchange marketplace, from organizing a project to design, installation, and maintenance. The certification will be renewable, so those holding the title of Certified Geothermal Designer will be assured that their training and knowledge remains state-of-the-art.

IGSHPA staff are now making plans to adapt all current training courses for correspondence and online use, creating viable options for those who desire certification but are unable to travel to Stillwater for an IGSHPA training workshop.

Conferences

IGSHPA hosts two professional conferences each year, each one focusing on a different aspect of the GeoExchange industry.

Each May the IGSHPA Technical Conference and Expo is held on the campus of Oklahoma State University in Stillwater, Oklahoma. Activities and presentations at the Technical Conference feature the latest in geothermal research and technology. Participants are invited to get their hands dirty with new GeoExchange developments, case studies, and live demonstrations. The traditional outdoor field day is a hands-on experience unlike anything else the industry has to offer. The Expo features a wide variety of geothermal products and materials, along with the opportunity for participants to speak one-on-one with experts in the field.

Then, each fall IGSHPA hosts the GeoExchange Industry Conference & Expo. The location for this conference varies each year in an effort to reach a different region of the country. The Industry Conference focuses on issues affecting the industry itself: marketing, education, customer awareness, quality, etc. Participants are given new tools that help them increase their customers' acceptance of GeoExchange technology and, in the process, grow their own businesses.

Additionally, IGSHPA members participate with the International Energy Agency Heat Pump Centre in presenting the latest research and applications work in the United States. The USDOE has supported the dissemination of research results at presentations for ASHRAE, ASME, and utility seminars, as well as meetings of the Geothermal Heat Pump Consortium.

Design Procedure

Before concerns over energy consumption and the environment became widespread, HVAC designs were built around raw Btu output. Then came the energy crunch, thermo-pane windows, and better insulation. Many different products now exist for the sole purpose of increasing a building's energy efficiency.

Now, more than ever, industry professionals are beginning to recognize the importance of incorporating such items with energy-efficient GeoExchange heat pumps into an integrated whole. The result is an integrated design philosophy centered not around the HVAC system itself, but around how the entire building envelope affects comfort and efficiency.

With its connections to other organizations like the Electric Power Research Institute (EPRI), the National Rural Electric Cooperative Association (NRECA), the USDOE, other research universities, heat pump manufacturers, and building load modelers, IGSHPA has been a pioneer in this new integrated design philosophy.

Controlling Costs

Research at Oklahoma State University is characterized by a continual effort to reduce GHP installation costs by finding more efficient and cost-effective materials and methods.

One of the most important factors in designing an efficient ground heat exchanger is the thermal conductivity of the surrounding soil. In-situ thermal conductivity testing yields the most accurate value possible for this critical design factor, but current methods for obtaining this information are generally too expensive and time-consuming to make thermal conductivity testing a common practice. Consequently, most designers tend to over-design, resulting in higher installation costs through excess materials and labor.

Researchers at Oklahoma State University are working to alleviate this problem by developing advanced thermal conductivity algorithms that drastically reduce the time needed to obtain accurate results from real-world data, as well as a new type of thermal conductivity testing apparatus that will be self-contained, rugged, and portable.

Oklahoma State University researchers' pioneering investigation into multiple-pipe heat exchangers led to the development of the Slinky® ground heat exchanger, a significant development in reducing first costs for many residential applications. The resulting *Slinky® Installation Guide* established the standard for installing this type of heat exchanger.

Summary and Conclusions

The GeoExchange heat pump industry is no longer just for daredevils and thrill-seekers. A solid network of dedicated professionals stands ready to aid and support newcomers. There has never been a better time to become an active part of this exciting industry. Get in the loop with IGSHPA.

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Chapter 51— Geothermal Systems for the Fast Food Market: First Month Operation Report by EPRI on the Wendy's Restaurant, Kingston New York

Howard W. Newton

The Electric Power Research Institute and Central Hudson Gas & Electric Corporation are sponsors of an all-electric restaurant demonstration project to investigate the performance of a number of high efficiency electro-technologies. The restaurant partner is Mid Hudson Wendico, Inc., a franchisee of Wendy's International.

The Wendy's restaurant is located in Kingston, New York, in the Hudson Valley region.

Final design and construction were completed in the first and second quarter of 1996. A sophisticated data acquisition system was installed during the final stages of construction to record energy used by all major energy end uses in the building. The restaurant opened on May 15, 1996.

This report summarizes metered data collected during June 1996 and compares it to computer models of the originally planed gas-electric design and the as-built all electric design. The major differences between planed and as-built construction include a larger HVAC system, the addition of a cookline appliance, extension of exhaust hood to accommodate the additional appliance, and changes in lighting systems.

The following demonstration electro-technologies are implemented in the as-built restaurant design:

Heat pumps for space heating and cooling in the kitchen and dining room zones connected to a vertical, closed-loop geothermal system

An all-electric cookline, including two griddles, three deep fat fryers, a pressure fryer, a range/oven unit, and a steam jacked kettle

High efficiency lighting in the dinning room

Heat pump water heater

The resturant used 41,719 kilowatt hours during the calendar month of june. The 15-minute peak demand duriing the calendar month was 119 kw, occuring at 6:45 PM on June 14th. Table 1 shows the breakdown by end use. The items included in each end use are the following:

Sanitation includes only water heating since there is no dishwasher. The heat pump water heater (HPWH) is the only source of service hot water for the restaurant. Hot water for beverages is heated in dedicated appliances for coffee and tea brewing. These appliances are included in the Miscellaneous category.

HVAC includes the Trane Geothermal HVAC rooftop units for the kitchen and dinning room heat pumps and the geothermal closed-loop circulation pump.

Cookline includes all the hooded cooking appliances and two exhaust fans.

Refrigeration includes the walk-in cooler/freezer unit that is accessible from the kitchen and the bun freezer that is outside the rear entry at the kitchen.

Miscellaneous contains all unhooded cooking or food process equipment as well as incidental loads such as cash registers, office computer, the telephone system, and others.

Table 1
Energy Consumption and Percentage Distribution by End Use

End Use	Consumption, kWh	Distribution
Heat Pump Water Heater	1,706	4%
Geothermal HVAC	10,478	25%
Cookline	11,783	28%
Lighting	5,201	12%
Refrigeration	4,124	10%
Miscellaneous	8,427	20%
Total	41,719	100%

Table 2 shows the coincident demand breakdown for each end-use for the peak 15-minute period during the month. This is equivalent of billing demand.

Table 2
Metered 15-Minute Peek Demand and Percentage Distribution by End Use

End Use	Demand, kW	Distribution
Heat Pump Water Heater	1	1%
Geothermal HVAC	41	35%
Cookline	45	38%
Lighting	5	4%
Refrigeration	9	7%
Miscellaneous	18	15%
Total	119	100%

Model and Measured Data Comparison

Prior to selection of the electro-technologies, a customized DOE-2.1e computer model was prepared to predict the relative energy performance of the demonstration restaurant compared to the standard restaurant that would have been built. Four version of the model were developed: a baseline model with standard gas-electric equipment normally specified by Wendy's, an adjusted gas-electric baseline with an all-electric cookline and high-efficiency lighting, an all-electric cookline with other recommended high-efficiency options and a final model that represents the actual store as built. Each technology was evaluated independently with separate substitutions. Details regarding the results of the models are reported in a separate report. Table 3 summarizes the appliances and equipment assumed in the models.

Table 3
Appliances and Equipment Assumed in the DOE-2 Models

End Use Category	Gas-Electric Baseline	All-Electric with High-Efficiency Options
Heating, Ventilating & Air Conditioning (HVAC)	Two Conventional 12-ton Units with Drect Expansion Cooling and Gas-Fired Furnace	Two 15-ton Geothermal Heat Pumps with Closed-Loop Vertical Ground Heat Exchanger
Cookline (Hooded Appliances)	Gas Deep Fat Fryers (3) Gas pressure Fryer (1) Gas Range Hot Top/Oven (1) Electric Grills (2)	Gas Deep Fat Fryers (3) Gas pressure Fryer (1) Gas Range Hot Top/Oven (1) Electric Grills (2) Electric Steam Kettle
Sanitation (Water Heating)	Conventional Electric Water Heater	Heat Pump Water Heater
Lighting	Standard Lighting Package	High-Efficiency Lighting Package

The final selection of actual appliances and equipment was made during the early stages of construction. A number of differences exist between the initial model assumptions and the restaurant as actually built. The installed geothermal heat pumps were 15-ton units with backup resistance heating instead of the 12.5 ton units as modeled. The 15-ton heat pumps were installed to cover the required heating load in this northern climate. The cookline as installed included a steam-jacketed kettle for preparing chili. The steam kettle required an additional 2.5 feet of hood be added to the planned back-shelf style hood. An additional 300 cfm was added to the exhaust hood requirements, raising the total exhaust from 2,000 cfm to 2,300 cfm The high-efficiency lighting package was used in the dinning room only, instead of both the dining room and the kitchen. Each of these changes causes an increase in energy use compared to the predictions from the initial model. The as-built DOE-2 model input parameters were adjusted according to the final design for better comparability of the predicted results to the actual energy consumption.

Energy Consumption

Table 4 summarizes the predicted energy consumption of the as-built DOE-2 model and the actual energy consumption by end-use.

Table 4
Summary of Monthly Actual and Predicted Energy Consumption

	Restaurant as Constructed	Gas-Electric Baseline Model		All-Electric Final Model
End Use	Actual Electric Consumption, kWh	Predicted Electric Consumption, kWh	Predicted Gas Consumption Therms	Predicted electric Consumption, kWh
Water Heating	1,706	2,680		1,641
HVAC	10,478	11,655		10,974
Cookline + Miscellaneous	20,210	9,997		14,604
Lighting	5,201	6,246		5,336
Refrigeration	4,124	4,533		4,533
Total	41,719	35,111		37,088

The predicted energy consumption is about 11% lower than actual. In a given month, variances up to 15 % between the actual and predicted energy consumption may be due to differences in the weather, water usage, operations hours, and the number of customers. However, the dominant cause for the difference between model calculations and actual electric peak demand during June of 1996 is the significantly higher number of customers during the month. Customer volume was estimated to be about three times greater than typical. June was the first full month the restaurant was open and it is the only Wendy's restaurant within about a 30-mile radius.

The average daily temperature in June at the restaurant was about 1.5 degree Fahrenheit warmer than the mean for the past 20 years. The daily maximum temperature set during June was about 11°F higher than normal. Temperatures higher than typical would increase the cooling loads for the HVAC systems and the walk-in cooler and freezers. The reference temperatures are based on National Climatic Data Center Data for the Albany region which is about 50 miles north of Kingston. Typical Meteorological Year data for Albany was also used in the computer models. Figure 4 shows high, low and average daily temperatures at Wendy's in Kingston.

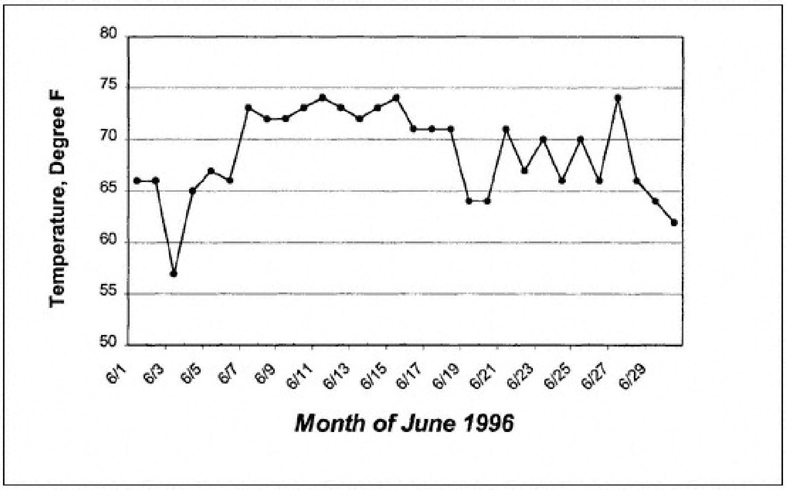

Figure 4
Actual Ambient Temperatures for June 1996 at Wendy's in Kingston, New York

Electric Demand

Table 5 summarizes actual and predicted demand by end use for the month of June. The 15-minute peak demand during the calendar month was 119 kW, occurring at 6:45 PM on June 14th . The one-hour peak demand for the month was 110 kW, occurring the same hour (6 to 7 PM) on June 14th. The predicted one-hour peak demand was 74 kW. The predicted demand for the all-electric model is about 33% lower than the actual store demand. The predicted demand for a gas-electric store that represents the standard restaurant design was 34% lower than actual demand. The end use break down shows that Cookline, Miscellaneous, and HVAC were significant contributors to the difference.

The high actual cookline demand and miscellaneous plug load demand is caused by exceptionally high customer volume during June. The cookline load shape for the models peak at 1 PM on weekends for the all electric store model and at 2 PM during the week for the gas-electric model. The actual demand peak occurs on a Friday at 6:45 PM. The difference between actual and predicted demand is due to the differences in the number of customers and when they visit the restaurant. Another factor is that the model profiles are based on one-hour averages. The measured demand is based on a 15-minute interval. Based on previous investigations, 15-minute demands for all cooklines may be 10 to 100% higher than hourly averages.

The increased customer volume also impacts the HVAC and refrigeration demand. The demand for these two end uses is additionally increased due to warmer weather than normal. Based on temperature profiles in Figure 3, it would appear that the combined effect of *very* high customer volume and slightly warmer weather exceede the available heat sink capacity of the geothermal ground loop.

Table 5
Actual Demand and Predicted Demand by End Use for June 1996.

	Restaurant as Constructed		**Gas-Electric Baseline Model**	**All Electric Final Model**
End Use	**Actual 15-Min Demand, kW**	**Actual 1-Hour Demand, kW**	**Predicted 1-Hour Demand, kW**	**Predicted 1-Hour Demand, kW**
Water Heating	0.7	2.4	10.0	5.8
HVAC	41.3	37.7	33.8	27.0
Cookline	44.9	38.0	1.5	17.6
Lighting	5.0	5.2	5.9	4.3
Refrigeration	8.8	8.9	6.5	6.5
Miscellaneous	18.4	18.1	15.1	12.3
Total	119.1	110.3	72.8	73.6
Peak Time of Day	6:45 PM	6–7 PM	2:00 PM	1:00 PM

A limitation of currently available versions of DOE-2 software is that calculates demand on an hourly basis. The variation in metered demand readings when comparing 15-minute intervals and one-hour intervals can be significant, particularly in restaurants. The EPRI-sponsored PowerDOE™ Windows-based software, which uses an improved version of DOE-2, will permit calculation steps less than one hour. Demand prediction in particular is expected to improve using PowerDOE™ if less than one-hour time steps are used in simulation.

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Chapter 52— Geoexchange Design Applications for Schools

William E.D. Geoghegan, Jr., P.E.

Introduction

Choptank Elementary School Cambridge, Maryland

This is a new 45,900 SF educational facility which includes classrooms, kitchen, cafeteria/multi-purpose, gymnasium, and administration area. WEDGCO provided complete mechanical, electrical and plumbing design and construction administration services. This school used an earth coupled ground source heat pump design for the HVAC system. The earth is used as a heat sink to provide heat during winter and a source for heat rejection when AC is required. The earth will provide up to 65% of the heating energy and 33% of the cooling energy. There are no boilers, chillers or cooling towers. The HVAC system will allow automatic heating or cooling in each room year-round. The building has a DDC automatic heating temperature control and building management system. The Electric System includes power, lighting, fire safety and communication systems. The Plumbing System incorporates a ground source heat pump domestic hot water preheat system with a gas fired back-up water heater for peak kitchen loads.

Choptank Elementary School was the first Public School in Maryland to be Heated and Cooled by a Geothermal System.

Life Cycle Cost: Simple Payback of 2 years when Compared to Traditional HVAC Systems

Gross Floor Area—45,900 Square Feet

Cooling Requirements:

- Calculated Block Cooling Load = 137 Tons
- Installed Equipment Capacity = 148 Tons

Earth Coupled Heat Exchangers

- 100 Boreholes, 275 Feet Deep
- One Inch Polyethylene Vertical Pipe Loop in Each Hole
- Boreholes are 15 Feet on Center
- There are 10 Horizontal Headers, Each Connecting 10 Vertical Loops to the Building HVAC System. The Headers are 2 inch Polyethylene Pipe.
- Capacity = 157 Tons (Sized for 6 Future Classrooms)

Choptank Elementary School

- 35,900 btu/sq. Ft./year

Cost

Total Construction	=	$ 4,667,370
Mechanical Cost	=	$ 1,183,151
Electrical Cost	=	$ 453,317
Earth Heat Exchanger	=	$ 189,000

Average Public School

- 60,000 btu/sq. ft./year

State of Maryland Goal

- 45,000 btu/sq. ft./year

Due to the success of Choptank Elementary School, the State of Maryland has issued a mandate requiring architects and engineers to include GeoExchange systems in all life cycle cost analysis for new and renovated school projects.

Background

Bob Rader, Supervisor of Facilities Planning for the Dorchester County Board of Education, has had an interest in GeoExchange technology since the early 1990's, when, as maintenance supervisor for Dorchester County schools, he became concerned about the environmental damage caused by certain air-conditioning refrigerants. He first learned about GeoExchange technology, which leaks considerably less than traditional HVAC systems, at a seminar sponsored by Delmarva Power. At the time, no one in Dorchester county had considered building a GeoExchange system—not the architect or even sales representatives for manufacturers that sell heating and cooling equipment.

During the final design state, a life cycle cost-analysis of using a GeoExchange System at the Choptank school. The results showed that the county could achieve an eye-popping internal rate of return of between 40 and 90 percent depending upon which alternative system was used in the comparison.

There is no other place on earth where you can achieve that kind of return on your investment. Armed with the cost analysis, Rader asked Assistant Superintendent of Schools Karen Lankford and Dorchester County Superintendent of Schools Spicer Bell for permission to propose a GeoExchange system to the five-member school board. Together, they met with the representatives of the board about the merits of the technology. In January 1995, the board approved and directed WEDGCO Engineering to design the GeoExchange system. Rader also toured Salem Community College and reported on the successful instructor-led student team installed a GeoExchange system.

"By the time we got to the point of designing an HVAC system, Superintendent Bell and Board members were aware of the advantages of Geothermal technology. That made their decision a lot easier," Rader says. The school board has a legal responsibility to ensure that everything it does meets health and safety need of students as cost effectively as possible, he notes.

Construction began in September, 1996 and by July 1997, the GeoExchange system was turned on. It kept the school comfortably cool (below 74 degrees F.) throughout a hot July and August, even though all of the school's doors were left open by construction works [1].

Overview

What Is Geothermal?

The earth is a giant energy collector that absorbs and stores heat from the sun. At depths greater than 20 feet, the ground temperature remains within five degrees Fahrenheit of the average annual air temperature. This ground temperature is stable throughout the year, so in most climates, the ground temperature is warmer than the air in the winter and cooler than the air in the summer.

Geothermal/Ground Source Heat Pump Systems don't actually create heat. Instead, they move heat that already exists. At Choptank Elementary, a water and antifreeze solution is circulated through a closed Ground Loop system consisting of HDPE pipes buried beneath the ground. These one inch diameter pipes are buried in 100 vertical bore holes, 275 feet deep.

During winter, the system extracts heat from the ground and moves it into the school.

During the summer, the system extracts heat from the school and moves it into the ground.

At Choptank Elementary School thirty-eight water-to-air heat pumps, mounted above ceilings throughout the school, are used to transfer heat between air in the school and the Ground Loop. There are three larger Rooftop Heat Pump Units, which provide heating and cooling to the gymnasium, cafeteria and media center. Three Rooftop Heat Recovery units supply fresh air to the school. Water-to-Water heat pumps transfer heat from the Ground Loop to domestic water in a 500 gallon storage tank raising the temperature to 120 degrees Fahrenheit.

Heating Cycle

A water-to-air heat pump consists of a water-to-refrigerant heat exchanger, a bi-directional expansion device, a reversing valve—for switching between heating and cooling mode, a compressor, an air coil, and a fan. During winter, heat is transferred from the Ground Loop solution to air in the school. The cycle begins at the water-to-refrigerant heat exchanger, essentially a tube within a tube, where heat is transferred from the ground loop to a cooler refrigerant. Next, vaporized refrigerant flows through the compressor, where its pressure and temperature are increased. Hot gaseous refrigerant leaves the compressor and flows to the air coil where air is blown over the warm coils, transferring heat from the refrigerant to the air in the school. The refrigerant, having now given up its heat, is condensed into a liquid. The liquid refrigerant flows through the expansion device, where it is vaporized and its temperature lowered. The vaporized refrigerant now returns to the water-to-refrigerant heat exchanger, where the cycle starts over.

Cooling Cycle

For air conditioning in the summer months, the refrigerant cycle is reversed, transferring heat from the air in the school to the ground loop solution.

Choptank Site Specific

Site Conditions

The Eastern Shore of Maryland is located between the Chesapeake Bay and the Atlantic Ocean. Cambridge is on the Choptank river. The water level is very high and when it rains this slide shows what can happen. The soil is a mixture of clay, silt and sand with traces of shale.

Inside the Building

The polyethylene header pipes are connected to copper. The copper pipes are connected to schedule 40 steel mains with victaulic fittings.

The contractor chose to use type L copper for the smaller piping and schedule 40 steel for the larger piping. Schedule 40 PVC is also acceptable. The avoidance of welding makes it easier to flush the piping system.

The geothermal heat exchanger piping and the building piping are flushed separately before they are joined together. We insisted that the water run perfectly clear in both systems.

Two five ton water-to-water (WTW) heat pumps are used to preheat hot water. Water from the WTW heat pumps is circulated thru a heat exchanger in a storage tank. The tank is maintained at 120°F. A gas fired domestic hot water heater is supplied with hot water from the storage tank and is used to provide 140°F hot water to the kitchen. The heater only operates when the dishwasher is used. The heat pump water supply and return mains exit the mechanical equipment room and are circuited through the building.

A horizontal water-to-air (WTA) heat pump is located above the ceiling of each classroom. Each room in the building is zoned by a separate heat pump. Piping connections to the are insulated right up to the heat pump. When the system was initially started up, before the building was completely closed up, any pipe or fitting without insulation sweated profusely.

To minimize the removal of ceiling tiles for service, the return duct connection of each heat pump was ducted to a filter back ceiling grille. Two inch filters are used and the face grille swings down. All of the grilles and filters throughout the building are the same size.

Rooftop WTA heat pumps were used to condition the Media Center, Cafeteria and the Gymnasium.

Heat reclaim ventilation air units supply air to each WTA heat pump in the building. This unit uses plate heat exchangers to simplify maintenance. We should have installed a cooling coil connected to a WTW heat pump. We have done this on every project since Choptank. The cooling coil working in conjunction with the heat exchangers guarantees humidity control in the building during the cooling season.

Each room has a temperature sensor (thermostat). The teachers are allowed a 4°F adjustment range by the ATC system. There is a button located on the lower right hand side of this thermostat. By pushing this button when the building is in the unoccupied mode it allows the teacher to put his or her room in the occupied mode for two hours. This remainder of the system stays in the unoccupied mode.

Circulating Pumps

There are two circulating pumps. One pump is a standby for the other.

Variable Speed Drive

The variable speed drive is for the circulating pumps. Its features include an automatic by-pass if the drive fails and automatic change over from one pump to another.

Electric motor actuated valves were installed on each heat pump and interlocked with the compressor. When the compressor is not operating the valve closes. This allows pressure differential controllers in the piping system to control the variable speed drive.

The building has a Johnson direct digital building management and control system. The top panel of the control system has eight time clocks. This zones the building into eight control zones: Cafeteria, Gym, Administration and Classrooms. This allows people who are not computer friendly to put those zones into the occupied cycle when the computer has put the building in the unoccupied mode.

The Supply Headers

Each supply circuit has a drain connection, ball valve, balancing valve and pressure gauge. Each return circuit has a drain, a ball valve and a pressure gauge.

The piping and fittings inside the building are just like any other hydronic system.

Water Heating Cycle

During both summer and winter, domestic water is heated to 120 degrees Fahrenheit, by a water-to-water heat pump, for use in water faucets throughout the building. A water-to-water heat pump consists of an expansion device, an evaporator, a compressor, and a condenser. Liquid refrigerant flows through the expansion device where it is vaporized and its temperature lowered. The vaporized refrigerant then flows through the evaporator, where it absorbs heat from the Ground Loop. The vaporized refrigerant flows to the compressor, where its pressure and temperature are increased. Hot gaseous refrigerant leaves the compressor and flows to the condenser, where heat is transferred from the refrigerant to a separate closed water loop. The cooled refrigerant condenses to a liquid and flows to the expansion device, where the cycle starts all over again. An electric pump circulates water in the separate closed water loop, through the domestic hot water storage tank transferring heat to the domestic water. A supplemental 250 gallon gasfired hot water heater is used for kitchen and other purposes.

This is the site of the geothermal heat exchanger. In the past the site had been a pig farm. One can imagine the odor during the drilling and looping process.

Heat Transfer Characteristics

Thermal Conductivity

k = 1.12 BTU/°F - HR - FT.

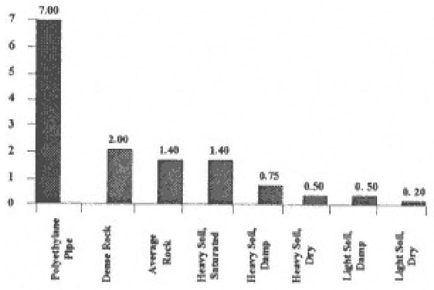

Figure 1
Heat Transfer Characteristics

Materials/Joining Methods

Polyethylene tubing only (HDPE)

Heat Fusion is the only way to join tubing

- Butt Fusion
- Saddle Fusion
- Socket Fusion
- Electro Fusion

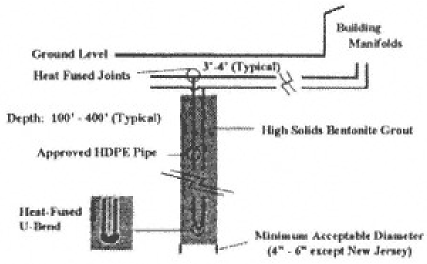

Figure 2
Cross Section of Vertical Heat Exchanger

Heat Pump Configurations

Horizontal

Vertical

Rooftop

Console

Unit Ventilator

Vertical Stack

Industry Ratings and Standards

Three Air Conditioning and refrigeration Institute (ARI) standards exist today for rating GeoExchange systems.

ARI-320: Water-Source Heat Pumps (narrow—range equipment not generally appropriate for ground connections in may locations; designed for boiler/chiller applications)

ARI-325: Ground Water (open-loop) equipment.

ARI-330: Ground Source (closed-loop) equipment

Look for ARI proof-of-performance certification

Designing a Closed Loop Geothermal Field

Design Process Inputs:

- Loads (tons, kW) and Energy (Btu/yr)
- Thermal Conductivity (ground, pipe, grout)
- Allowable loop temperature limits

Trade-Offs:

- Loop length vs. max/min loop temperatures
- Number of boreholes vs. borehole depth
- Loop Length vs. spacing of boreholes

[1] Geothermal Heat Pump Consortium, Inc. (GHPC); International Ground Source Heat Pump Assoc. (IGSHPA). *Choptank Elementary School, Cambridge, Maryland—February 1998,* Case Study #CS-074.

Chapter 53— Federal Application of Geo-Exchange Technology

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Abstract

The purpose of this paper is to introduce the Department of Energy Federal Energy Management Programs's geothermal heat pump (GHP or Geo-Exchange) technology-specific program. The goal of the GHP technology-specific program is to harness the purchasing power of the federal government to transition GHP systems from their current status as "proven but under-utilized" to "a mainstream energy cost saving measure" within the next four years.

This paper reviews the family of GHP systems, explains why they save energy and money, cites evidence that they also have lower maintenance costs, and reviews feasibility considerations for the family of GHP systems. This information builds a strong case for broader consideration of GHPs in federal facilities and provides a starting point for determining which GHP system may be most advantageous for a given site.

Next, the paper provides a brief overview of the GHP technology-specific program, its relationship to other existing GHP programs, and how it plans to work with allied programs to achieve its goal. The paper concludes by identifying the GHP technical resources that federal agencies and others would likely expect to be available four years hence if GHPs are to be considered mainstream by then. The GHP technology-specific program will endeavor to work with allied programs to jointly meet those expectations.

Introduction

Geothermal heat pumps (GHPs or Geo-Exchange Systems) are proving to be an energy-efficient, cost-effective choice for heating and cooling federal facilities. For a wide range of conditions, GHPs heat and cool more efficiently than conventional HVAC systems, and they offer other benefits as well: they cost less to maintain, have a longer life expectancy, operate quietly, and cause less CO_2 emissions than conventional heating and cooling systems.

There is growing evidence that GHPs have an important role to play in helping federal agencies meet their energy savings mandates. For example, at the U.S. Army base in Fort Polk, Louisiana, 4003 GHPs were installed in 1995–96. This project has demonstrated the technology can yield substantial energy and cost savings for federal facilities. The Fort Polk project reduced electricity consumption in base housing by 33% while eliminating natural gas consumption altogether. (For details, see www.eren.doe.gov/femp/financing/tecspec.html. Click on "Geothermal Heat Pumps," or see Hughes, et. al., 1998 [1]).

The purpose of this paper is to introduce the Department of Energy Federal Energy Management Programs's (FEMP's) GHP technology-specific program. The goal of FEMP's GHP technology-specific program is to harness the purchasing power of the federal government to transition GHP systems from "proven but under-utilized" to "a mainstream energy cost saving measure (ECM)" within the next four years.

This paper reviews the family of GHP systems, explains why they save energy and money, cites evidence that they also have lower maintenance costs, and reviews feasibility considerations for the family of GHP systems. This information builds a strong case for broader consideration of GHPs in federal facilities and provides a starting point for determining which GHP system may be most advantageous for a given site.

Next, the paper provides a brief overview of the GHP technology-specific program, its relationship to other existing GHP programs, and how it plans to work with allied programs to achieve its goal. The paper concludes by identifying the GHP technical resources that federal agencies and others would likely expect to be available four years hence if GHPs are to be considered mainstream by then. The GHP technology-specific program will endeavor to work with allied programs to jointly meet those expectations.

The Family of Geo-Exchange Systems

Several GHP system types are available for application in federal facilities (Figure 1). The common denominator is that the system moves heat between a building and one or more geothermal source/sinks—such as the ground, groundwater, surface water, wastewater streams, or potable water supplies (where allowed)—via water source heat pumps to provide services such as space heating and cooling, water heating, and refrigeration. This broad choice of GHP systems enables system providers and federal sites to pick the options that make their GHP projects most economical.

Hybrid systems using several of these source/sinks, or outdoor air in combination with one or more of these source/sinks, are commonly considered where they make the overall GHP system more economical Hybrid approaches are especially effective where cooling needs are significantly larger than space and water heating needs.

A GHP system may serve one or many water source heat pumps, depending on the application. For example, military family housing might be served with systems having one heat pump per living unit, each with its own vertical ground heat exchanger. Larger facilities might have many heat pumps on a common loop with a central variable-speed pumping station and one large geothermal source/sink.

Why Geo-Exchange Systems Save Energy and Money

GHPs save energy and money because the equipment operates more efficiently than in conventional systems. GHPs use the ground, rather than ambient air, as a heat source and sink, using its stable temperature to improve energy efficiency. Ground temperatures are cooler than the air in the summer and warmer during the coldest months, so GHPs benefit from cooler condensation temperatures for cooling and warmer evaporating temperatures for heating. Therefore a given compressor will generally operate much more efficiently in a GHP systems water source heat pump than in an air source unit. In addition, air need be moved only on one side of the GHP, and less power is needed to move the water (or anti-freeze) on the other side than would be needed to move air. The geothermal source/sink is far more stable than outdoor air and has much less severe high and low temperature extremes. Unlike air source units, GHP systems do not need defrost cycles nor backup electric resistance heat at low outdoor air temperatures in most cases.

Common loop GHP systems recover heat as part of their design. In cooler weather, the heat pumps serving the building perimeter extract heat from the common loop to provide space heating, while units serving core areas are cooling space and rejecting heat to the common loop. When the common loop is in balance, no net heat exchange with the ground is required; under many operating conditions, the offset between heating and cooling units reduces the thermal load on the geothermal source/sink. Recovered heat also can be used to heat water, using either desuperheaters on the heat pumps or dedicated water-to-water units.

GHP systems save money because they use less energy and improve energy consumption patterns. The 4003 GHPs in family housing at Fort Polk reduced the summer electric peak demand of that city of 12,000 people by 43% and increased the annual electric load factor from 0.52 to 0.62 (Hughes, et. al, 1998 [1]). Federal sites may be able to purchase electricity at lower costs when their load characteristics improve so dramatically.

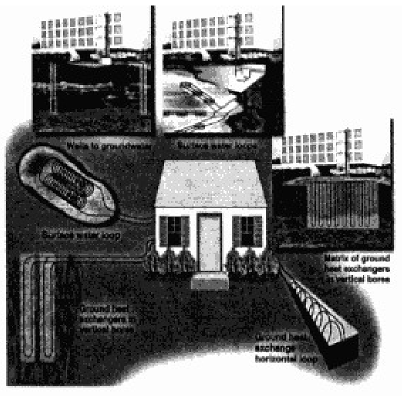

Figure 1
Examples of Several Ghp System Types

Maintenance Benefits of Geo-Exchange Systems

Lower maintenance costs are another advantage GHPs have over conventional systems. A DOE sponsored analysis of 1996–98 maintenance work records for the Lincoln, Nebraska, school district shows that annual corrective maintenance (repair) costs for four GHP-equipped schools averaged 2.1 cents/ft^2, compared with 2.9 to 6.1 cents/$ft^2$for conventional systems in 16 other schools (Martin, et. al, 1998 [2]). Another analysis sponsored by the Geothermal Heat Pump Consortium found average total (preventive and corrective) maintenance costs for 25 GHP-equipped buildings to be about 11 cents/ft^2 – 16 to 30 cents/ft^2 less than for conventional systems (Cane, et. al, 1998 [3]). Both studies are published by ASHRAE.

Feasibility of Geo-Exchange Systems at Federal Sites

For the government to receive the best value from GHP technology, the GHP system provider and designated federal site personnel need to determine which GHP system or combination of systems is most economical for each site. The order of preference is not universally applicable. Considering GHP systems in the following order, however, helps evaluators take advantage of unique site characteristics that enable especially economical applications of GHPs.

Groundwater Already Being Pumped

Is groundwater currently being pumped to the surface? Some federal sites pump groundwater to the surface, treat it, and re-inject it as a part of groundwater remediation projects in areas near buildings. Tapping into already existing heat source/sinks may be economical. A heat exchanger (typically the plate-and-frame type) can be used to transfer heat between the groundwater and a common loop serving water source heat pumps in nearby buildings. After remediation is completed, pumping on the groundwater side of the heat exchanger can be re-optimized for the HVAC application and continued using the same supply and reinjection wells.

Stationary Surface Water

Are large volumes of stationary surface water on the site, owned by the government and with government use restrictions, near buildings with significant heating and cooling loads? It may be economical to use surface water impoundments such as reservoirs, runoff retention basins, reflecting pools, ponds, and lakes for heat exchange. A common loop serving water source heat pumps in nearby buildings can be submerged directly into the body of water. If the water is used for recreational or other purposes that might interfere with this approach, an on-shore pump house with a heat exchanger and protected intake from and discharge to the body of water could be considered.

Moving Surface Water

Are large volumes of reliable moving surface water (e.g., large rivers with reliable flow and modest current), owned by the government and with government use restrictions, on the site near buildings with substantial space? An on-shore pump house with a heat exchanger and protected intake from and discharge to the moving body of water could be considered. Issues such as historical high and low water conditions, debris flow, and commercial and recreational traffic would require serious attention.

Potable Water

Potable supply water systems are often overlooked as a geothermal source/sink. If the cognizant state and local regulatory bodies allow such use, a public water utility distribution system can be used as a geothermal source/sink. This requires a two-pipe recirculating water distribution system. The two-pipe system enables water passing through GHP heat exchangers to be returned to the system rather than wasted down the sewer. Since nearly all public water utility distribution systems are one-pipe, where water exiting outlets enters the sewer after use or is applied to lawns, not much effort has been made to gain regulatory approvals. However many large federal sites have their own potable water supply and distribution systems. In these cases the regulatory issue is moot, and so are health and safety concerns when two-pipe systems are properly designed. Federal sites having their own water systems are urged to consider two-pipe recirculating potable water distribution for any system expansions to accommodate use of GHPs in new building construction. Sites with water distribution systems needing major repairs or renovation should also consider this option and GHPs in their existing buildings.

Wastewater Streams

Does the site have large-volume, reliable flowing wastewater streams near buildings with significant square footage? A common loop serving water source heat pumps in nearby buildings could be conditioned by a heat exchanger in contact with the wastewater. Heat exchanger maintenance must be considered, as well as the stability of the missions of the facilities that are the source of the wastewater.

Groundwater

Are large quantities of groundwater available at a reasonable depth, as well as an acceptable and economical means of disposal, near buildings with significant heating, cooling, and water heating loads? The groundwater can be used with a heat exchanger to condition a common loop serving water source heat pumps in nearby buildings. Poor water quality might require the use of expensive heat exchanger materials, and additional maintenance and aquifer re-injection in some formations might be expensive.

Standing Column Well

Standing column well GHP systems are similar to standard groundwater GHPs, but because water is recirculated between the well and the building, only one well may be required (larger projects may have several wells in parallel). Standing column wells are feasible in areas with near-surface bedrock. Deep bores are drilled, creating a long standing column of water from the static water level down to the bottom of the bore. Water is recirculated from one end of the column to the other. During peak heat rejection or extraction periods, the system can bleed part of the water rather than reinjecting it all, causing water inflow to the column from the surrounding formation. This cools the column during heat rejection, heats it during heat extraction, and reduces the required bore length.

Ground Heat Exchangers (Or Ground Loops)

Does the site have sufficient land area near buildings with significant square footage to accommodate ground heat exchangers? If so, heat exchange with the ground, using vertical or horizontal loops, may be economical. Horizontal loops require considerably more land area but may be less expensive to install, depending on the types of soil and rock formations encountered in drilling. Ground heat exchangers are an option almost anywhere. They are listed last not because they are less economical, but merely to ensure that other geothermal options that may be even more economical are considered where they exist.

Femp's Geo-Exchange Technology-Specific Program

The Department of Energy's Federal Energy Management Program (FEMP) has developed a Technology-Specific Program Strategic Plan/Roadmap to Success (FEMP 1999). The program is designed to take selected proven but not yet widely known and utilized energy efficiency and renewable energy (EERE) technologies for buildings, and boost them into wider use in the federal sector and beyond.

Each technology-specific program is custom designed to the circumstances of the designated technology. Generally the goal of each technology-specific program is to harness federal purchasing power to help make the designated EERE technology mainstream in a reasonable period of time. Mainstream means that federal energy project activity, no matter how the projects are financed (e.g., appropriations, Utility Energy Services Contracts (UESCs), Energy Savings Performance Contracts (ESPCs), Super ESPCs), sustains the technology at its federal market potential after the brief technology-specific program is over.

As part of its overall program, FEMP has established a technology-specific program for the family of GHP systems. The goal of FEMP's GHP technology-specific program is to transition GHP systems from "proven but under-utilized" to "a mainstream ECM" within the next four years.

The GHP technology-specific program has been customized to the circumstances of GHPs in the market place. At the time the program was developed, the GHP industry was already benefitting from efforts by the Geothermal Heat Pump Consortium (GHPC 1999), the International Ground Source Heat Pump Association (IGSHPA 1999), the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE 1999), DOE's Oak Ridge National Laboratory (ORNL 1999), and others. The efforts of these organizations were largely funded by the Department of Energy, Office of Power Technology—Geothermal Division. Such foundation activities helped create an interest in GHP technology by many federal agency sites. However they also expressed frustration.

The sources of federal agency frustration were all related to GHP delivery infrastructure rather than with the technology itself. Mentioned were the lack of credible documentation of GHP benefits; no guides for surveying or auditing facilities and performing analyses to quickly determine whether GHPs were feasible; poor or no representations of GHP systems in the building energy analysis programs used by agencies; no guides for GHP system construction or maintenance cost estimating; multiple ground heat exchanger design tools that gave conflicting recommendations and that required design inputs that were not readily available; lack of engineers willing to consider GHPs in their designs; and lack of quality (or any) GHP installation, commissioning, and service contractors in their area. In short, federal sites were interested in GHP technology, were expecting to have all of the delivery infrastructure for GHPs that they had for mainstream energy cost saving measures (ECMs), and became frustrated when they learned that this level of GHP delivery infrastructure was not yet in place. Even more frustrating, in some cases where all of the technical barriers were overcome for particular GHP projects, the agencies then lacked sufficient capital appropriations for implementation.

FEMP's GHP technology-specific program is designed to leverage off of the foundation activities sponsored by DOE-OPT, and to develop over time the materials necessary to overcome information gaps so that agency efforts would more often lead to projects than frustration. A basic premise of the program is that a significant number of large federal "best practice" GHP projects are required to prove techniques and provide cost and other data to be generalized into the tools and guides that mainstream ECMs are expected to have. For example, only real GHP projects could produce the necessary data for development of a cost estimating guide.

The program design had to address a "chicken-or-the-egg" problem of how to motivate a sufficient number of agency sites to implement GHP projects in a reasonable amount of time. Since the "business as usual" processes of some agencies were observed to break down when applied to GHPs (e.g., GHP system components not in the guide used by the in-house cost estimators, GHPs not represented in the software used by the in-house energy estimators, consequently "garbage in garbage out" by the in-house life cycle cost team, a site's task order design services contract being held by an engineer that always recommends another system [that he/she has designed before], etc.), it was recognized that the DOE-OPT program and its participants, the GHPC and IGSHPA and ORNL and others, would have a critical role to play in outreach to help motivate projects, and in providing general GHP technology education and technical assistance.

With so many federal sites having no access to GHP delivery infrastructure at all, it was decided to include a national GHP Super ESPC procurement as a component of the FEMP GHP technology-specific program. The GHP Super ESPC competitive procurement resulted in awards in February 1999 of national indefinite delivery indefinite quantity ESPC contracts to five ESCOs who demonstrated specialized expertise in the application of GHP systems through past performance and proposals for a specific project. This step ensured that every federal site nationwide would have access to at least five quality sources for the family of GHP systems and up to $500 million in private financing for project development and implementation. Since every delivery order project implemented under the GHP Super ESPCs must include GHPs, these ESCOs are also highly motivated to market agency sites and go the extra mile to find economic applications of the family of GHP systems. Contact information for the ESCOs and the DOE Contracting Officer's Representative is available at www.eren.doe.gov/femp/financing/ghp.html.

Electric utilities are also expected to continue to be strong proponents of the family of GHP systems, and many are expected to offer federal agencies private financing and expertise to implement GHP projects through UESCs. At FEMP's July 1999 Federal Utility Partnership Working Group meeting, a draft industry-wide commitment letter from Edison Electric Institute entitled "Utility Industry Commitment to Federal Energy Efficiency and Renewable Energy Goals" was circulated. The letter pledges $2 billion of private financing for EERE projects of all sorts, and specifically mentions geothermal heat pumps as a focus area.

With DOE-FEMP, DOE-OPT, GHPC, IGSHPA, ORNL, five specialized ESCO teams, and a growing number of utilities all involved, there is cautious optimism that timely implementation of a sufficient number of federal GHP projects will occur. This would enable the GHP technology-specific program to utilize the project experience to address the technical issues, prove techniques, and provide cost and other data to be generalized into the needed GHP tools, guides, and training.

Conclusion

Over the next four years the FEMP GHP technology-specific program plans to work with allied programs in order to put in place all of the "technical machinery" necessary for the entire family of GHP systems to be routinely considered for every federal new building construction project or existing building renovation project. The geothermal source/sinks in the family of GHP systems include groundwater already being pumped, stationary surface water, moving surface water, wastewater streams, potable water streams (where allowed), groundwater, standing column wells, ground heat exchangers, and hybrids of these or with outdoor air.

The program managers currently anticipate that federal agencies and others would expect the following GHP technical resources to be available four years hence if GHPs are to be considered mainstream by then. The items are separated into the major stages of the project development process.

1) SURVEY/AUDIT STAGE

a. **GHP Survey Guide** expandable for each GHP family member.

b. **GHP Survey Training** based on the GHP Survey Guide.

2) FEASIBILITY/DECISIONMAKING STAGE

a. **GHP Constuction Cost Estimating Guide** expandable for each GHP family member.

b. **GHP Maintenance Cost Estimating Guide** expandable for each GHP family member.

c. **Proven GHP Representations in Building Energy Analysis Methods** expandable for each GHP family member. Proven GHP representations in at least one, and hopefully all, commonly used mainstream building energy analysis methods.

d. **GHP Feasibility Study Guide** expandable for each GHP family member.

f. **GHP Feasibility Study Training** based on GHP Feasibility Study Guide.

3) DESIGN STAGE

a. **Proven In-Situ Tests for Soil/Rock Formation and Vertical Bore Backfill Thermal Property Determination** ASHRAE Research Project 1118RP (in progress).

b. **Proven Vertical Borehole Ground Heat Exchanger Design Tools** Several technical papers documenting the comparison of available design methods to models calibrated to data are published in ASHRAE Transactions.

c. **Proven Borehole Completion Methods** ASHRAE Research Project 1016RP (in progress)

d. **Proven Standing Column Well Design Tools** ASHRAE Research Project 1119RP (in progress)

e) **Proven Surface Water Loop Design Tools**

f) **GHP Design Training** ASHRAE Short Course (ongoing), ASHRAE Professional Development Seminar (starting in late 1999)

4) IMPLEMENTATION STAGE

a. **GHP Guide Specifications** expandable for each GHP family member.

b. **GHP Guide or Series of Guides Covering GHP System Commissioning, GHP Preventative Maintenance, and GHP System Troubleshooting** expandable for each GHP family member.

The program managers also currently anticipate that to maximize acceptance, the various guides and training courses should be developed, published and offered to the public in accordance with the policies and procedures of the most recognized professional societies or associations in that mainstream field of endeavor. For example designers of HVAC systems for large projects generally turn to ASHRAE for their technical information needs, therefore the design items should be developed, published, and offered through ASHRAE. It is believed that the Association of Energy Engineers (AEE), the National Ground Water Association (NGWA), and other groups may be the most appropriate mainstream organizations for some of the other items on the list.

The FEMP GHP technology-specific program will endeavor to work with allied programs such as those at DOE-OPT, GHPC, IGSHPA, ASHRAE, AEE, and NGWA to jointly meet the expectations of federal agencies and others, by making available the GHP technical resources listed above over the next four years. The cooperation of the ESCOs, utilities, and agency sites with GHP projects is also critical to the success of the program.

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5. Geothermal Heat Pump Consortium (GHPC), see www.geoexchange.org.

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SECTION 5—
ENVIRONMENTAL TECHNOLOGY

Chapter 54—
The Need for Technical Standards to Simplify CDM Project Baselines

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Abstract

Investments in greenhouse-gas (GHG) emission-reduction projects in developing or transition countries require a *carbon-offset* mechanism, under which investors from industrialized countries can claim credit toward their own reduction commitments. The Kyoto Protocol to the UN Framework Convention on Climate Change (UNFCCC) provides for the establishment of the Clean Development Mechanism (CDM), which enables such project-based carbon-offset transactions. Under the CDM, emitters can potentially receive reduction credit through investments in emission-reduction projects in developing or transition countries without binding emission reduction obligations.

Because carbon offsets represent emission *reductions* or *increases* in carbon storage, they are quantified as differences that can only be measured relative to a *baseline.* The definition of the baseline is inherently counter-factual (it will be replaced by the proposed project) and therefore somewhat uncertain. Nevertheless, the establishment of the baseline is the key step in determining the extent to which a carbon offset project satisfies the requirement of *additionality* under the CDM or other carbon-offset trading regime.

At a minimum, the certification of carbon offsets will require some degree of standardization in baseline definition and carbon-accounting procedures, with a goal of creating a standard offset product. To date, progress toward standardizing such procedures has been slow, despite much discussion and debate. The reasons for this lack of progress seem to stem from the many linkages that have been made between these (mostly) technical issues and other, policy-related issues such as additionality, making the CDM regime unnecessarily controversial.

If the baseline issue can be reduced to technical issues, questions about additionality of offset projects could then be reduced to technical problems of proper design, necessary accuracy and acceptable cost. It appears that the technical problems can be bounded and the uncertainties reduced by applying, whenever possible, specific technical performance standards to the baseline case for common offset project types, such as energy efficiency, renewable energy and forestry projects. Some simple examples are offered in this paper.

Background on the UNFCCC

The UNFCCC was signed in Brazil in June 1992. The key element of the UNFCCC is Article 4.2, which commits the Annex I (industrialized) countries to adopt policies to mitigate global climate change by reducing GHG emissions and enhancing sinks, and to communicate their policies and measures with respect to the aim of returning emissions to 1990 levels. Article 4.2 also allows for the joint implementation (JI) of measures to reduce the emissions of GHGs. The concept of JI refers to the implementation of such measures in one country with partial or full financial and/or technical support from another country, potentially fulfilling some of the supporting country's emission-reduction commitment under the UNFCCC.

The first meeting of the Conference of the Parties to the FCCC (COP1) was held in Berlin in March–April, 1995.

During the meeting, the Parties (i.e., the participating countries) agreed to a pilot phase for JI to be reviewed by the end of the decade. The purpose of the pilot phase, known as "activities implemented jointly" (AIJ), was to gain experience with the concept, to better define methodological issues, and to identify institutions to manage JI. During the pilot phase, Annex I Parties cannot credit reductions achieved through AIJ against national commitments.

At the third Conference of the Parties (COP3) in Kyoto, Japan in December 1997, the concept of JI was endorsed, and the Kyoto Protocol provides for credit against emission reduction commitments in the time frame of 2008–2012. In addition, JI involving non-Annex I (developing) countries was endorsed and given yet another new label, the "clean development mechanism" (CDM). More specific decisions about the application of these regimes were left to future COP meetings.

At the fourth Conference of the Parties (COP4) in Buenos Aires in November 1998, few new decisions were taken regarding JI and the CDM. Perhaps the most interesting development was that Argentina and Kazakhstan announced that they would be the first developing countries to join Annex I and accept emission reduction limits, in exchange for the ability to participate in the JI activities that are open to Annex I countries only.

The Kyoto Protocol and Its Flexibility Mechanisms

The Kyoto Protocol recognizes the different economic resources and responsibilities of Annex I countries by adopting specific targets and timetables for emission reductions by those nations. For the first time, the Kyoto Protocol includes quantified emission limitation and reduction obligations (QELROs), i.e., emission caps for the Annex I countries. Under Article 3, the overall commitment is to reduce emissions by a combined 5 percent below 1990 levels in the time interval 2008–2012. This is a substantial step toward fulfilling the UNFCCC's goal of atmospheric GHG stabilization, as many Annex I countries already exceed their 1990 emissions. Some countries would need to reduce emissions by as much as 40 percent below their projected emission levels during the first commitment period.

In addition to direct actions to be taken by the Parties, and the corresponding Annex I QELROs, the Kyoto Protocol provides for three mechanisms that could potentially fund emission reduction measures in participating countries. These three "flexibility mechanisms" all represent variations on the theme of joint implementation of emission reductions between two or more countries, as introduced in Article 4.2 of the UNFCCC. Each provides for exchanges of a different type, between different sets of countries and using a different type of unit, or currency, to denote the emissions or emission reductions exchanged:

Article 6 provides for the transfer of "emission reduction units resulting from projects" that reduce net GHG emissions in Annex I countries. This project-based regime would essentially entail JI within Annex I. It is unclear whether the carbon offsets resulting from these activities would have to be backed by emission trading under Article 17 or whether such offsets would stand alone.

Article 12 provides for the exchange of "certified emission reductions" in non-Annex I countries under the newly-defined Clean Development Mechanism. This carbon offset mechanism is specifically defined to support sustainable development while helping Annex I countries comply with their existing and future QELROs.

Article 17 provides for emission trading between the countries that have assumed QELROs under Annex B, i.e., the Annex I countries. This trading appears to entail sharing of QELROs between Annex I countries, without clarification regarding the relationship between this mechanism and the project-based exchanges provided for in Article 6.

Table 1 summarizes the options for crediting project-based carbon offsets under the Kyoto Protocol, depending on the type of project, its timing and the host-country location.

For Annex I JI, Article 6 of the Kyoto Protocol makes no provision for early crediting, or banking of credits from reductions made before the 2008–2112 commitment period. This exclusion limits the risk of trading "hot air;" i.e., it limits the amount of credit that Annex I countries can take for reduced EIT emissions during the period until 2008. On the other hand, Articles 3 and 6 seem to allow credit for net increases in forest carbon storage since 1990 and trading of resulting credits.

For projects in non-Annex I countries, a key feature of the CDM is the ability to bank emission-reduction benefits from projects between the years 2000 and 2008. These reductions can then be credited toward QELROs for the 2008–2012 commitment period or later periods. It is not yet fully clear if land-use and forestry measures can be credited under the CDM; or if so, whether protection of carbon sinks is included.

TABLE 2. OPTIONS FOR CREDITING CARBON OFFSETS UNDER THE KYOTO PROTOCOL

	Annex I host countries (under Article 6)	Non-Annex I host countries (under Article 12)
Energy projects	1990–2007: May not be credited during commitment period	1990–1999: May not be credited during commitment period 2000–2007: Certified emission reductions can be banked for CDM credit against QELROs
	2008–2012: Emission reduction units can be credited and/or banked for use in future periods	2008–2012: CDM crediting and banking for future periods
Forestry projects	1990–2007: Relatively uncertain, but Articles 3 and 6 seem to allow credit against QELROs for net increases in forest carbon storage since 1990 and trading of resulting emission reduction units—Credit status of forest protection and agriculture measures unclear	1990–1999: May not be credited during commitment period 2000–2007: Under CDM, certified emission reductions from actions taken after 1990 can be banked for credit against QELROs
	2008–2012: Emission reduction units can be credited and/or banked for use in future periods	2008–2012: CDM crediting, although credit status of forest protection measures is unclear

Annex I Reduction Obligations

From 2008 to 2012, the QELROs defined in Article 3 and quantified in Annex B of the Kyoto Protocol are to take effect for the Annex I countries. These commitments may enable international trading of emission "allowances" under Article 17 and carbon offsets under Articles 6 and 12. Within Annex I, trading in allowances may also serve a similar function in meeting domestic reduction requirements as trading in offsets.

The specific QELRO figures are given in Annex B, in terms of the percentage of 1990 emissions to be reached by the 2008–2010 commitment period. These values range from a reduction of 8 percent for many European countries, including the European Community as a whole, to 7 percent for the US, 6 percent for Japan, no reduction or increase for the Russian Federation and Ukraine, and an increase for Australia, Iceland and Norway.

In general, meeting these reduction commitments will require serious policy measures and technological change in the Annex I countries. However, some countries will have little difficulty meeting their commitments and are expected to have surplus emission allowances to trade under Article 17 of the Kyoto Protocol. These countries are mostly the economies in transition (EIT), i.e., Eastern Europe and the former Soviet Union.

Determining CDM Project Additionality

The essential prerequisite for a carbon offset under project-based JI and the CDM is additionality. The criterion of additionality requires that a carbon-offset project represents emission reductions that would not have occurred otherwise. This is the "but for" criterion: total GHG emissions would be higher, *but for the effect of the carbon offset project.* A clearly additional project is one that represents actions that would have little chance of being taken without the use of JI or other flexibility mechanism.

Definitions in the UNFCCC and Kyoto Protocol

In the FCCC itself, the concept of additionality is not directly tied to joint implementation, which is only mentioned in Article 4.2 in connection to the Annex I countries' general commitment to undertake mitigation measures. However, additionality is mentioned specifically in Article 4.3, with regard to "financial resources needed by developing country Parties to meet the agreed full incremental costs of implementing measures" under Articles 4.1 and 12. These articles deal mostly with providing emission inventories and other information, and with activities of the Convention's "financial mechanism." Article 11 defined this mechanism, which became the Global Enviromnent Facility (GEF), to provide financial resources and technology transfer on a grant or concessional basis.

Thus, the FCCC itself says little about the additionality of carbon-offset projects under its JI provisions, which evolved into the CDM under the Kyoto Protocol. The main concern was that the cost of simply participating in the FCCC, which strictly requires only inventories, plans and other information, should not be borne by non-Annex I countries. The FCCC, however, does specifically call for technology transfer to assist developing countries in participating in the Convention.

The Kyoto Protocol reaffirms the commitments of the Parties to the UN FCCC. All Parties agree to continue updating their emission inventories, formulating climate change mitigation and adaptation options, and communicating their past actions and future intentions. Without assuming any new commitments, the developing countries share in this effort, the cost of which is to be borne by the Annex I countries. There is a general commitment to increased research and development, education and training, and technology transfer, again to be supported by "new and additional financial resources" from the Annex I countries.

Under Article 12, which defines the CDM, section 12.5 specifically states that participation is voluntary, that emission reductions must be certified by designates of the COP as being real, measurable, long-term and "additional to any that would occur in the absence of the certified project activity." Thus, the key issue in the CDM is ensuring that the credits represent real reductions from the emission levels that would otherwise occur. The reason that an independent body, such as that called for by Article 12.5 of the FCCC, is needed to certify emission reductions is that an offset transaction is not "zero-sum." Both the buyer and the seller could benefit from exaggerating the emission reductions that are credited. Because the creation of CDM certified emission reductions in a non-Annex I country does not reduce the total emission allowances, the reductions must be real to ensure that total emissions decrease rather than increase as a result of the CDM project.

Other Parties' Definitions

The Kyoto Protocol requires that CDM projects produce emission reductions that can be certified as real and additional. It does not address the financing of CDM projects, the source of such finance, or the intentions and alternatives to such finance. The criterion of additionality refers to emission reductions only, and it requires that the reductions satisfy the "but for" condition, that they would not occur in the absence of the CDM project.

Despite this rather clear definition, there remains a great deal of controversy about the nature of the additionality criterion for JI and the CDM. This controversy probably stems from the language in Article 4.3 of the FCCC, which calls for the Annex I countries to finance the incremental costs of the developing countries participation in the Convention.

This provision appears to be the justification for the criterion of *financial additionality,* which has been applied to JI project proposals by, among others, the U.S. Initiative on Joint Implementation (USIJI). Financial additionality refers to the financial flows of an offset project, posing the question of whether the expenditures involved would have been made without the offset project. This question addresses the 1) sources of funding for the project, 2) the alternative uses of that funding, and 3) the motivation for choosing the carbon offset project.

The financial additionality criterion requires that financing of JI/CDM activities should be additional to present GEF and bilateral official development assistance (ODA) funding in developing countries. This requirement has led project developers to construct formal boundaries between parts of projects that may receive ODA funding and other parts that do not, and to seek letters from host-country agencies certifying that no ODA funds are supporting a given part of the project.

The development of the CDM requires the participation of Annex I emission sources as offset buyers. These industrial firms and energy utilities are clearly distinct from any sources of ODA, making this additionality criterion rather easy to satisfy. In contrast, however, during the "activities implemented jointly" (AIJ) pilot phase initiated at the first COP in 1995, some projects identified as AIJ were supported by Annex I governments or multilateral institutions, rather than carbon emitters. Thus, these projects were not carbon offsets as such, and it is unclear if they were additional to ODA from the donor countries.

The "but for" condition is also applied to the investment choices made by the project's technical or financial developers. The idea is that, if a firm or other institution would use its limited human and financial resources to develop, for example, clean energy projects, regardless of which specific projects are implemented, then an individual project developed by such an entity is not fully additional. This would create a sort of corporate additionality, under which firms that specialize in clean energy or other climate-friendly projects would be excluded from offering CDM carbon offsets.

This interpretation of additionality, in addition to creating counter-productive incentives, is highly suspect. Certain firms and individuals are indeed dedicated to developing clean energy projects, but the degree of success and growth that they will realize with these and other climate-friendly technologies is by no means fixed or assured. Rather, their market share depends on greater mainstream recognition of local and global enviromnental benefits. Given the rather low penetration of these technologies in global markets today, most such efforts in the foreseeable future should clearly be considered additional.

Regarding the motivation for choosing an offset project, the issue that is sometimes raised with regard to financial additionality is the treatment of projects that are to any extent profitable for the investors. The argument is simply that if a project is profitable to its sponsors, they could be expected to implement the project without the need for carbon offsets. In such a case, the project would fail the "but for" condition for additionality.

This condition requires examination of the economics of project finance. For example, a CDM offset project with a modest cost per ton of emission reduction, on a net-present-value basis, would generally produce revenues that, over the life of the project, could exceed the corresponding investment, on an *un-discounted* basis. However, a project that earns a very low rate of return would not be considered commercially financable under any normal conditions, and thus additional funding would be needed to make it viable.

The analysis becomes more difficult, however, when a project's rate of return is high enough that it might be financable *under certain conditions.* Such conditions generally involve relatively low risks, which could make a project attractive to investors at relatively modest rates of return. This might be the case for a conventional fossil-fuel power station with relatively low risk and corresponding modest rate of return.

However, there are many sources of risk for the types of projects, technologies and locations likely to be involved in carbon offset investments, particularly small energy efficiency and renewable energy projects. These risks tend to drive the required rates of return for commercial finance higher than those required for conventional energy project investments.

In other words, additional funding may be necessary to raise a risky (in conventional financial terms) CDM offset project to a high enough rate of return to make it viable, while other more familiar (and safer) projects may be viable at lower rates of return (see Table 2). This relationship is entirely plausible to those familiar with the risk-return relationships applied to many types of commercial financing decisions. However, to those unfamiliar with such analysis, it would appear that one could be demanding incremental financing and offset credit for a project that is "already profitable."

TABLE 2. THE HIERARCHY OF THE ECONOMIC VIABILITY OF CARBON OFFSETS PROJECTS

Projects with negative rates of return	Clearly not viable without concessional financing resources or carbon offsets available Offset cost per mtC would be expensive
Projects with rates of return below normal market threshold	Probably not viable without concessional financing resources or carbon offsets available Offset cost per mtC would be moderate
Projects with rates of return above normal market threshold, but below risk premium for project type, technology, country	Marginal with private finance only, viable with concessional finance or carbon offsets available Offset cost per mtC would be inexpensive
Projects with rates of return above normal market threshold, including applicable risk premium	Viable with private finance only; concessional finance unnecessary; carbon offsets precluded by lack of additionality

Relation to Project Baselines

The question of whether emission reductions are additional to what would have been achieved without the offset project, i.e., the "but for" test, depends on the counterfactual conditions without the project, i.e., the baseline. The baseline emissions are the GHG emissions that are expected to result in the absence of the proposed project. To the extent that the credibility of an offset depends on additionality, it requires a quantifiable and verifiable baseline of GHG emissions and/or carbon storage.

Because carbon offsets represent emission *reductions* or *increases* in carbon storage, they are quantified as differences that can only be measured relative to such a baseline. The definition of the baseline is inherently counter-factual (it will be replaced by the proposed project) and therefore uncertain. The level of uncertainty and credibility of the baseline depends on the type of offset project and the existing energy plan or land-use practice.

Thus, the establishment of the baseline is the key step in determining the extent to which a carbon offset project is additional under the CDM or other open-market regime. As discussed above, emission reductions must be additional to be valid under such a regime. Additionality is required because carbon offsets are (by definition) implemented in host countries without binding emission limits, and they do not lead to corresponding reductions in national emission limits.

In addition, the expected timing of emission reductions or carbon storage benefits can depend on the dynamics of the baseline or reference case. To the extent that the baseline case involves a pattern of emissions over time, the earlier those emissions occur and can be reduced by a carbon-offset project, the sooner the project can claim offset credit. This timing can strongly influence the economic performance and risk exposure of a project.

Baselines for CDM Projects

The certification of emission reductions from CDM projects requires the assessment of a project's performance compared to the baseline emissions that are expected in the absence of the project. This can be complex because the baseline is counter-factual, but it is necessary in estimating the impact of both forest and energy projects. At a minimum, it appears that the certification of CDM credits will require some degree of standardization in baseline definition and carbon-accounting procedures, with a goal of creating a standard offset product. To date, progress toward standardizing such procedures has been slow, despite much discussion and debate. The reasons for this lack of progress are not entirely clear, but seem to stem from the many linkages that have been made between these (mostly) technical issues and other, policy-related, issues.

The analysis of baselines has been complicated by linkages with other criteria that make the issue unnecessarily controversial. These criteria include the types of projects to be selected, the possibility of emission leakage and especially the issue of additionality. As shown above, the concept of additionality has been confused and exaggerated by the imposition of additionality criteria, such as those related to financial issues, that exceed the requirements of the FCCC. However, the essential requirement for CDM projects is the "but for" concept, and this is the primary criterion to determine project baselines under the CDM.

Because a CDM project does not affect the emission reduction commitments of the participating countries, it must create a new and additional emission credit or offset. Therefore, the baseline case for creating a CDM credit must be a project-level baseline. If the project reduces net GHG emissions compared to this baseline, the result can be expected to be a reduction in global GHG emissions. Thus, a specific project that reduces emissions in an Annex I country releases an equivalent amount of allowed emissions under that country's QELRO, unless those emission allowances are sold to another country, in which case the buying country's allowed emissions are increased.

This type of project-level baseline is different from the national-level or regional baselines that apply to emissions trading between Annex I countries. Under the Kyoto Protocol, these countries are subject to quantified emission limitation and reduction commitments (QELROs), i.e., national emission caps.

Criteria for Baselines

In order to reduce the controversial policy issues regarding additionality and baselines to clearly-bounded technical issues, specific criteria for establishing project baselines are needed. Ideally, baseline criteria should be universal, but the potential range of CDM projects is too diverse. The criteria for baselines may vary geographically across different countries and regions, as well as technologically across different sectors and types of projects.

To the extent that criteria can apply to most locations or to most technologies in a sector, they can be more useful. Conversely, the need to define baseline criteria for individual projects, rather than large classes of projects, would add to transaction costs and potentially undermine the credibility of the resulting credits or offsets. Below we examine some possible policy, economic and technical criteria for baselines.

The basic requirement for additionality under the CDM is that reductions are "additional to any that would occur in the absence of the certified project activity." Since non-Annex I countries have not yet taken on any reduction commitments, one can assume that no special efforts to reduce emissions would be made in the absence of the CDM. However, the prospect of gaining CDM credit for any and all measures that reduce emissions could create an incentive for policies that unnecessarily encourage emissions, so that even obvious or trivial measures might be claimed for CDM credit.

Thus, from the policy perspective, the absence of project activity is generally considered to be "business as usual," i.e. neither special measures to reduce emissions nor any measures to increase emissions. Specifically, with regard to energy policy, this means development of energy resources to minimize costs, without new environmental requirements. Although it is widely recognized that energy services can be provided at minimum cost by including end-use efficiency measures with supply resources in integrated resource planning (IRP), such measures are still not in the mainstream of energy development.

The present structure of energy economies in developing countries does not encourage investments in energy end-use efficiency measures, either via policy incentives or via the risk profile of energy project development and investment. This situation is only being accentuated by the restructuring and privatization of the energy sector that is underway in many developing countries.

Thus, "business as usual" can be summarized as least-cost energy-supply development, without special regard for environmental protection. On the other hand, energy price subsidies are still common in developing countries, although subsidies are being reduced. As such, "business as usual" can reasonably be assumed to gradually eliminate energy subsidies, but not to introduce incentives for end-use efficiency measures or renewable sources.

With regard to land-use policy, "business as usual" is harder to define, but similar principles apply. Many developing countries have removed direct or indirect subsidies for clearing forest land. However, these countries generally do not have sufficient resources to implement sustainable forest development programs. Again, "business as usual" can be summarized as an absence of special forest protection measures, but with the elimination of subsidies for land clearing.

The policy criterion of "business as usual" helps to define the baseline activities "that would occur in the absence of the certified project activity." Based on this policy criterion, a consistent economic criterion is that the baseline represents least-cost development under "business as usual" financial conditions. This criterion closely parallels the concept of financial additionality discussed earlier. However, the baseline economic criterion relates directly to financial decision-making practices in the host country, and the energy technologies and land-use choices that are favored as a result of this "business as usual" financial thinking.

In other words, rather than use the vague concept of financial additionality based on what appears to be "profitable" globally, the economic criterion for a project baseline should reflect the local market conditions for project risk and return. For example, new energy technologies that are considered too risky to apply in the host country market, despite attractive potential returns, are not part of the baseline in that country or region. Similarly, sustainable land-use practices that are not bankable in existing rural markets would not be in the baseline, despite potential long-term returns.

More specifically, the baseline energy supply system can generally be described by traditional least-cost planning methods, as opposed to integrated resource planning methods, in which energy efficiency, renewable sources and co-generation are given more equal treatment. The traditional approach reflects rational (albeit limited) economic thinking, and in general this accurately represents the baseline activities "that would occur in the absence of the certified project activity."

The economic criterion may be adequate to establish the baseline for major components of the power sector, such as the least-cost (traditional) electricity generation resources. However, for smaller-scale resources such as energy end-use technologies, the analytic task of determining the least-cost options across a wide range of technologies would quickly become too complex. In addition, taking this approach at a micro-level would likely invite widespread "gaming" to inflate the baseline and exaggerate savings.

Instead, at the detailed level of individual projects and technologies, a simpler and more robust approach may be to consider uniform technical criteria or standards to define the baseline performance of familiar classes of energy technology. Such an approach could perhaps be applied to some types of land-use projects as well. If this approach can be implemented, it would reduce the complexity of case-by-case baseline analyses for offset projects, by reducing the selection of the baseline technology to a uniform standard.

One of the main difficulties in baseline analysis is the diverse nature of potential offset projects, and this complicates the task of defining technical standards of performance that could be used widely. However, at least for a range of common and familiar energy supply and end-use technologies, it appears feasible to generalize a level of performance that is compatible with the "business as usual" definition of a project baseline.

Beyond the simple baseline criteria, the goals of defining technical criteria are to balance precision and generality against simplicity and cost, to facilitate measurement and verification, and to minimize "free riders" without discouraging low-cost emission reduction measures. The latter issue might be the key consideration in selecting specific baseline levels of technical performance.

If the baseline performance is too high in terms of emissions (or low in terms of, for example, energy efficiency), then there is a strong risk of *free riders,* i.e., offset sellers who would have implemented the reduction measure even without the incentive of JI/CDM. By definition, such measures would not be truly additional.

On the other hand, if the baseline performance is too low in terms of emissions (or high in efficiency), then crediting only high-performance technologies could discourage the implementation of less ambitious, lower-cost reduction measures that should be of highest priority in terms of economic efficiency. If the baseline performance level is chosen properly, the few free riders should be more than compensated by offset sellers that are pushed to reach the baseline level on their own, in order to qualify for offsets based on still higher performance.

Examples of Common Project Baselines

There appears to be reasonable potential for establishing technical baseline criteria for several classes of common offset projects. Depending on the type of project, there are different potential problems to address with regard to the baseline. One important issue is the type of project and the relative difficulty in observing the baseline. As shown in

Table 3, we have classified both energy and land-use projects according to whether they involve production (of energy or timber, for example), operation (of a power plant or a forest, for example) or conservation (again, of energy or forests). The general observation is that production products are simpler because the baseline is more clearly observable; operation projects have only partly observa baselines; and conservation projects are the most difficu because the baseline can be entirely counter-factual. The are variations within each project type; for examp energy-efficiency retrofit projects are simpler because observable "before" case provides the baseline.

TABLE 3. ADVANTAGES AND DISADVANTAGES OF DIFFERENT CARBON OFFSET PROJECT TYPES

	General type of project		
Sector	Production—clearly observable baseline	Operation—partly observable baseline	Conservation—un-observable baseline
Energy-sector offset projects—irreversible emission reductions	Renewable energy sources, e.g., wind power generation	Fuel switching, e.g., coal to natural gas or biomass	End-use energy efficiency in e.g. industry, buildings
Land-use offset projects—reversible gains in carbon storage	Forest plantations on degraded land	Forest management that increases carbon stock	Forest protection in national park or forest reserve

It is impossible to anticipate all the technical measures that might be employed to reduce GHG emissions. However, many proposed offset projects will involve technologies that can be readily defined and evaluated by experts in the relevant technical fields. Table 4 provides a preliminary set of power-sector technologies, together with some suggestions for the form of a technical standard that could be applied to each technology. It is beyond the scope this paper to suggest specific values for each standard, this should be an achievable goal for selected groups experts appointed, for example, by the IPC

TABLE 4. POWER-SECTOR EMISSION REDUCTION TECHNOLOGIES AND POSSIBLE BASELINE STANDARDS

Sub-sector	Reduction Strategy	Example Reduction Technology	Units of Possible Technical Standards
Power supply	Supply-side fuel switching	coal to natural gas	mtC/MWh generated
	Power plant efficiency	raise steam pressure	GJ/MWh or % efficiency
	Distribution loss reduction	power factor correction	losses as % of generation
	Renewable generation	wind power	mtC/MWh in power replaced
Industrial use	End-use fuel switching	fuel oil to natural gas	mtC/MWh used
	Process efficiency improvement	Alcoa process	MWh/ton produced
	Manufacturing efficiency	motor control upgrades	product-specific MWh/unit
	Biomass energy use	wood, sugar residues	mtC/MWh in power replaced
Commercial use	End-use fuel switching	fuel oil to natural gas	mtC/MWh used
	Lighting efficiency	efficient lamps, ballasts, luminaires, controls	average lumen/W, W/sq. m for different light levels
	Heating and cooling efficiency	heat pumps	MWh/sq. m — °C-day
	Equipment efficiency	auto-shutoff computer displays	MWh/year normalized by size, equipment capacity
Residential use	End-use fuel switching	electric to natural gas	mtC/MWh used
	Lighting efficiency	efficient lamps	average lumen/W, W/sq. m for different light levels
	Heating and cooling efficiency	building shell upgrades	MWh/sq. m — °C-day
	Appliance efficiency	efficient refrigerator	MWh/year normalized by size, equipment capacity
	Solar heating	solar water heater	mtC/MWh in power replaced
Agricultural use	End-use fuel switching	diesel to electric	mtC/MWh used
	Irrigation efficiency	efficient pumps, pipes	MWh/cubic meter
	Solar/wind pumping	photovoltaic pumps	mtC/MWh in power replaced
	Biomass energy use	crop residues	mtC/MWh in power replaced

The technical analysis needed to select the proper level for this type of standard could build on existing work and should not involve prohibitive costs. This means that individual carbon-offset project baselines need not require a complex multiparty agreement on all aspects of "business as usual" performance in the host country, or even for each individual project. Instead, technical standards for broad classes of reduction measures can be defined, discussed and agreed on, with periodic review and updating to account for changes in technology, economics, or policy.

Prospects for Reducing Policy Issues to Technical Issues

Confidence in the reliability and additionality of carbon offsets could be increased if the baseline issue were reduced to technical questions. As shown above, it is possible to define specific technical criteria for a broad range of common offset projects. This process will require a significant amount of technical analysis, and the results will have to be reviewed and approved at the policy level. Some issues will be more difficult and controversial than others.

In this regard, we can identify three levels of difficulty in generalizing technical criteria for project baselines, which can be handled in different ways at the international level:

Technical standards that can be defined and accepted for application in most countries: this is the simplest case, in which technical analysis can identify widely applicable performance standards for common baseline technologies, subject to periodic review and updating via the same process.

Standards that can be applied for certain regions, but must be adjusted for use elsewhere: in this case, technical analysis can yield default performance standards for certain types of baselines, but the variation between countries and regions is sufficient that regional adjustments are needed to make the standards fair and realistic.

Specific baseline cases that are unique to certain countries and must be treated individually: there are likely to be a few cases where important potential emission sources, and corresponding reduction measures and offset prospects, are unique to the conditions in a certain country or region, and where it is sufficiently difficult to treat the baseline in general terms, requiring specific international review and agreement.

The latter category of unique baseline conditions probably applies in only a few cases. Presumably, the importance of these few cases would justify specific attention at the international level, and a small number of such cases would not create an excessive institutional burden. For example, it might be necessary to examine China's coal development as a special case, or the methane emissions in countries with very large livestock populations. There are a number of potential baseline issues specific to Brazil, including the treatment of the existing ethanol fuel industry and the role of deforestation in the Amazon region. If these special cases can be resolved fairly and efficiently, it would facilitate the application of general technical standards in the large majority of other, simpler cases.

In summary, it seems that the problem of determining additionality at the project level can be bounded and the uncertainties reduced. This would entail applying explicit technical performance standards to the baseline case for many common offset project types, such as energy efficiency, renewable energy and forestry projects. As a result, questions about additionality of a class of projects could be reduced to technical questions of proper design, necessary accuracy and acceptable cost. With the problem reasonably bounded, qualified organizations can be engaged to reduce the remaining uncertainties.

Chapter 55— Municipal Opportunities in Greenhouse Gas Management

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Increased concentrations of carbon dioxide and other greenhouse gases in our atmosphere boost the likelihood of global warming and world wide climate change. Municipal governments have significant opportunities to reduce greenhouse gas emissions. This paper examines the primary methods available to local governments to control greenhouse gases from their own operations, and from operations within the community.

Introduction—Global Warming & Climate Change

Consideration of the opportunities for local governments to mitigate greenhouse gases first requires consideration of the reasons for mitigation of greenhouse gases. Carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, perfluorocarbons . . . these are the primary gases referred to as greenhouse gases. The greenhouse gas theory hypothesizes that some solar radiation, reflected from the earth's surface is re-emitted back to earth from greenhouse gases trapped in the earth's atmosphere. As concentrations of greenhouse gases emitted from earth increase, the intensity of this greenhouse effect increases as well. Should this greenhouse effect intensify, global warming and climate change is predicted to result.

While there are questions about the exact extent of anthropogenic contributions to climate change, there is strong evidence that an increase in man-made greenhouse gases is having an effect on our global climate. According to the EPA, atmospheric concentrations of carbon dioxide have increased nearly 30%, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by about 15% since the beginning of the industrial revolution. Greenhouse gas emissions in the U.S. continue to grow at an average annual rate of 1.5 percent over this decade. And global temperatures are rising. Observations collected over the last century suggest that the average land surface temperature has risen 0.45–0.6°C (0.8–1.0°F) in the last century. With 1998 the warmest year on record, the 10 warmest years in this century have occurred in the last 15 years. (http://www.epa.gov/globalwarming/climate/index.html).

The potential effects of global warming and climate change are numerous and far-reaching. As polar ice and alpine glaciers melt, sea level is expected to rise, affecting coastal lands. Rising global temperatures are likely to change regional climates affecting wildlife habitat, agriculture, and even water supplies. Regional precipitation may increase or decrease. The frequency and intensity of storms is likely to change. Many ecosystems or elements of ecosystems may not be able to adapt at the speed at which climate change evolves.

To minimize the problems potentially manifest by global warming and climate change municipalities can initiate measures to diminish anthropogenic greenhouse gas emissions. The human-caused increase of atmospheric greenhouse gases stem primarily from fossil fuel combustion, and the destruction of carbon sinks such as forested lands. In U.S. emissions totaled 1,814 million metric tons of carbon equivalent (MMTCE). Carbon dioxide emissions from fossil fuel combustion for energy accounted for the lion's share of that total. Fossil fuel combustion was responsible for 1,466 out of 1,487 MMTCE of carbon dioxide emitted nationwide in 1997. Methane sources are slightly more varied, but the largest source was landfills—

contributing 66.7 of 179 MMTCE nationwide in 1997. Natural gas systems and enteric fermentation associated with domestic livestock each accounted for an additional 34 MMTCE of methane. Nitrous oxide (N_2O) contributed about 109 MMTCE of our annual total, primarily coming from agricultural soils management. HFC's, PFC's and SF6 resulted in release of some 37 MMTCE's annually from varied sources including replacement of ozone depleting substances. (http://www.epa.gov/gobalwarming/inventory/1999-inv/execsum.pdf). Changes in land use can either increase or decrease greenhouse gases. Increases in greenhouse gases occur when carbon-sequestering forest land is replaced with agricultural land or urban development. Decreases happen with net additions to forest biomass or carbon content of soils.

Cities and counties can lessen greenhouse gas emissions and protect greenhouse gas sinks through proactive regulation, efficient management of municipal properties, and innovative outreach programs. Additionally the measures available to control greenhouse gases have significant collateral benefits in reducing costs and enhancing local quality of life. Municipalities have already begun to respond to the challenge. For example, more than 170 local governments worldwide are participating in the International Council for Local Environmental Initiatives (ICLEI) Cities for Climate Protection (CCP) campaign. These participants, including over 50 cities and counties in the U.S. are making inventories of community-wide greenhouse gas emissions, and designing action plans to reduce their impact on global warming. Measures that municipalities can implement to minimize their community impacts on greenhouse gas emissions are described in the following sections.

Municipal Regulation and Control

Far reaching municipal policy and regulations can affect greenhouse gas emissions within the local government's jurisdiction. Examples of such municipal control include land use planning, transportation planning, and building codes.

Land Use Planning

Geographic separation of land uses increases automobile traffic as people are required to drive further to get between work, home, recreation, services and shopping. Increased vehicle miles traveled (VMT), traffic congestion, and vehicle trips exacerbate greenhouse gas emissions. In *The Next American Metropolis,* Peter Calthorpe recommends parameters for reducing traffic generation through transit-oriented design (Calthorpe, 1993: 43,64). Key to this is a land use plan that promotes mixed-use districts where residents could work or shop. In fact, by some estimates, new development that improves accessibility by mixing land uses and clustering development generates about half as much VMT as does urban sprawl (Ewing, 1997:11). Combining an overall city land use plan that lessens the distances residents must travel to work, shop, or play, and integrates transit with urban design criteria that promote pedestrian access is a powerful way that municipalities can reduce VMT and trip generation; thereby reducing greenhouse gas emissions.

Transportation

In addition to land use planning to promote a pedestrian-friendly environment, local governments can provide additional incentives to reduce fossil fuel combustion from transportation. After all, cars and light trucks emit nearly 25% of all U.S. carbon dioxide (CO_2) emissions (http://www.iclei.org/co2/air/air.htm). Municipalities may be concerned that they don't have the budget to support alternative transportation. However, a careful analysis of municipal budgets can reveal considerable expenditures supporting conventional car and truck transportation. Such costs include road construction and maintenance, snow removal, signage and signals, parking space, traffic and parking law enforcement, and accident clean-up. Reducing a portion of these expenditures could allow local governments to enhance alternatives such as mass transit, bike and pedestrian access, and alternative fuels vehicles.

Municipalities can promote mass transit with budget planning for infrastructure, urban planning that provides adequate population densities for transit, and land use planning that provides acceptable right of ways and supports transit use. Bicycle and pedestrian access is enhanced, as described above, when urban planning promotes mixed-use development and pedestrian friendly design. And requiring bike racks in addition to parking spaces facilitates bicycle use. In addition, municipalities can provide incentives for alternative fuels refueling stations.

Additionally, local governments can have significant impact on greenhouse gas emissions through control of transportation infrastructure. Allowing alternatives to parking space requirements for new commercial development, such as allowing reduced parking space requirements where transit access is available, promotes alternative transportation at the same time that asphalt surface area is decreased. Minimizing concrete or asphalt surfacing is likely to reduce localized temperatures and concurrent cooling load requirements.

Building Codes

DOE calculates that updating energy codes and improving implementation could decrease energy use in new buildings by 35 percent from 1990 levels by the year 2000. National and international builders' organizations have prepared several model energy codes for residential and commercial buildings.

The 1995 *Model Energy Code* (MEC) contains energy-related requirements for both residential and commercial construction. Several states have adopted the MEC by direct reference, or have made State-specific modifications of the MEC provisions. A major focus of the MEC provisions is on building envelope thermal insulation requirements for ceilings, walls, floors, and foundations, and thermal conductance ("U-factor") limits for windows and doors. It also has requirements for HVAC controls (including thermostats and humidity controls), duct and pipe insulation, shower heads, swimming pools, and maintenance documentation for energy-related equipment. The MEC is currently incorporated by reference in each of the three regional model building codes. Those three building codes are: the Building Officials and Code Administrators International, Inc. (BOCA) *National Building Code* (in Chapter 13), Southern Building Code Congress International, Inc. (SBCCI) *Standard Building Code* (in an appendix), and International Conference of Building Officials (ICBO) *Uniform Building Code* (in an appendix). In 1998, the MEC was re-published as the *International Energy Conservation Code* (IECC) under the auspices of the International Code Council (ICC).

An energy code such as the MEC achieves the force of law when it is adopted directly by a State or local government having authority over new construction. More than half the states have adopted and implemented energy codes that meet or exceed current model energy code standards. Hawaii's Energy Division estimates that Hawaii's energy code will save about $1.1 million per year in consumer electricity costs. It will reduce fuel use by the equivalent of 21,000 barrels of oil per year—enough oil to cut greenhouse gas emissions by approximately 2,800 metric tons of carbon equivalent annually. (http://www.epa.gov/globalwarming/greenhouse/greenhouse9/energvcode.html). Local codes can also diminish greenhouse gas emissions by promoting the use of renewable energy systems. For example, Boulder, Colorado, adopted a solar-access ordinance designed to protect solar resource availability in existing buildings and in new construction.

Municipal Property

In addition to the influence a municipality exerts through externally exercised policy and regulation, local governments influence greenhouse gas emissions through direct management of government property.

TABLE 1.

Demand Side Management Recommendations for New Pittsburgh Convention Center

Exceed ASHRAE/ES 90.1 Standards by at least 20% for lighting, bldg. Envelope, foundation insulation, equipment efficiencies, etc.	Use of occupancy detection sensors in all office, suites, restrooms, utility, and other closed spaces; integrate into the building management system.
Implement Building Commissioning practices. Verification and documentation to ensure facility meets operational needs and design criteria resulting in a fully functional, fine-tuned system.	Employ use of network-metered breakers in all distribution panels and integrate into the building management systems; use to implement automatic load-shedding strategies.
Implement Group-relamping to allow lower installed lamp wattages and/or less fixture density.	Install power factor correction capacitors in all medium voltage switchgear.
Hire a qualified Energy Manager responsible for monitoring, maintaining and optimizing energy goals and efficiency levels specified by design and facility Owner.	Utilize daylighting control algorithms in lighting controllers. Integrate sensors and lighting into building lighting systems.
Use LED exit signs	Use of high power factor ballasts in all fluorescent and HID fixtures.

Building Energy Efficiency

Local government can have a significant effect on greenhouse gas emissions by implementing energy conservation measures in city and county owned buildings. Such measures not only lessen municipal contributions to global warming, but enhance the city coffers as well. For example, CH2M HILL identified demand side management recommendations for the new Pittsburgh Convention Center, which are estimated to present annual utility cost savings to the city of $350,000. Table 1 presents these demand side management recommendations.

A similar program in Kern County resulted in verified savings of $260,000 a year in lighting, heating, ventilating, and air conditioning (HVAC) energy costs from its sweeping energy efficiency upgrade of five buildings and the central plant. Completed in March 1993, this award-winning project has reduced energy use by about 20% and will pay for itself in 4.1 years (http://www.energv.ca.gov/efficiency/partnership/kernprofile.html).

Grounds

Reducing paved areas can positively affect greenhouse gas emissions. Asphalt and concrete absorb solar radiation, producing heat and an increased need for air conditioning. Alternatives using permeable geotextiles or other permeable coverings can provide the structural stability needed for vehicle access or parking, while reducing solar absorption. In fact, such permeable ground surfaces conveniently accommodate carbon sequestering ground cover plants as well. Using permeable ground surfaces, interplanted with ground cover could enhance stormwater drainage and reduce atmospheric heating associated with paved surfaces.

Landscaping can be used for greenhouse gas mitigation in a number of ways. Increased tree and shrub plantings provide increased carbon sequestration opportunities. Strategic tree planting can be used to shelter buildings thereby reducing fuel consumption needed to cool buildings.

Utilities

Municipal utilities not only offer the traditional method of reducing greenhouse gas emissions through energy efficiency, but the more innovative option of recovering waste methane from certain operations. Opportunities exist for electric utilities, municipal landfills, and water and wastewater treatment plants.

Electric utilities can effect greenhouse gas use in a number of ways. Fuel switching to less carbon intensive fuels or renewable energy, and promotion of demand side management programs are primary methods. Upgrading generation equipment to more energy efficient equipment, such as converting a simple cycle gas turbine to combined cycle, is another effective method of minimizing potential impact on global warming. The Sacramento Municipal Utility District (SMUD)'s PV Pioneer provides an example of an innovative method to reduce fossil fuel dependency. The PV Pioneer program makes partners out of customers who pay an extra "green price" each month to host PV systems on top of their homes that generate power for the community as a whole. The PV Pioneer program was launched in 1993 and now includes over 400 residential rooftop solar units and 20 commercial and church rooftop systems. These systems feed over 1.5 MW of clean electricity directly into SMUD's grid (http://www.smud.org/home/pvpioneer).

Landfills are the primary source of methane emissions in this country. The first step to reducing this emissions source is to decrease the volume of waste traveling to landfills. Municipal recycling programs, and procurement policies as described below go a long way to reducing this problem. New Jersey estimates that its recycling programs avoided 8.7 million tons of greenhouse gas emissions from 1990 through 1995. Municipal composting programs for yard waste to diminish organic material in landfills are also effective.

EPA estimates that up to 750 landfills could economically recover their methane for energy, yet only about 130 projects are in place (http://es.epa.gov/partners/land/landmeth.html). Only 14% of the methane from landfills in 1997 was captured and combusted, often for energy in the forms of electricity, heat or steam. Direct use of landfill gas, such as for industrial boilers, is probably the most cost-effective application of this gas, since it avoids electric generation equipment capital costs. The 1993 North Carolina Governor's Energy Achievement Award went to Raleigh, North Carolina where a landfill gas-fueled boiler generates 24,000 pounds per hour of steam. The gas is collected from the city-owned Wilder's Grove Landfill. Natural Power, Inc. and Raleigh Landfill Gas Corporation invested $1.6 million in the project and enjoy annual gross revenue from steam sales ranges from $450,000 to $500,000, of which the city of Raleigh receives annual royalties of $65,000 to $75,000 (http://www.eren.doe.gov/cities counties/landfil.html).

A March 1996 U.S. federal regulation required the nation's largest landfills to capture and combust non-methane volatile organic compounds (NMVOCs). By some estimates this new regulation will have the effect of reducing landfill methane emissions by 50%.

Wastewater treatment plants are another municipal utility emitting greenhouse gases. Since the focus of waste-water treatment is the stabilization of biodegradable organic matter (i.e. its conversion to CO_2 and CH_4), wastewater treatment plant design and operation offer important opportunities in the management of these greenhouse gases. Greenhouse gas emissions mitigation can be divided into three general categories: (1) liquid process modifications, (2) solids processing modifications, and (3) energy conservation.

Liquid process modifications could involve the replacement of a methane producing anaerobic treatment system with a CO_2 producing aerobic process. Since CH_4 has global warming potential 21 times greater than CO_2, the aerobic processes result in decreased impacts. Replacement of anaerobic systems, such as on-site system septic tanks or anaerobic/facultative lagoon systems with a fully aerobic process (activated sludge, trickling filters, and rotating biological contactors, etc.) will result in reduced methane emissions. Another liquid process modification entails reduction of the mass of biodegradable organic matter stabilized in the liquid process train. For example, installation of a primary clarifier allows some of the biodegradable organic matter to be removed by simple sedimentation rather than stabilization. This will result in increased sludge production but less greenhouse gas emissions. Of course, to provide a complete analysis, the fate of carbon in the solids processing train must be considered. Alkalinity consumption results in CO_2 emissions as a result of the conversion of inorganic carbon to carbon dioxide. A third liquid process modification, alkalinity consumption results in CO_2 emissions as a result of the conversion of inorganic carbon to carbon dioxide. Denitrification results in the production of alkalinity that fixes CO_2 in the form of bicarbonate alkalinity.

Other methods for greenhouse gas mitigation include solids processing modifications, such as the land application of biosolids, particularly to forest lands, and energy conservation measures. Reduction in electricity consumption particularly, potentially decreases fossil fuel combustion at electricity generation facilities. Energy efficiency measures apply to both water and wastewater treatment plants.

Vehicles and Vehicle Use

Municipalities not only affect the transportation patterns of their community; they can directly control greenhouse gas emissions by modifying the use or character of their own vehicle fleets. Modifications can range from reductions in VMT, increased fuel efficiency, and use of alternative-fueled vehicles. ICLEI's Alternative Fuels, Fuel Efficiency and Fleet Reduction web page (http://www.iclei.org/co2/air/air.htm#chart), gives numerous examples of local government programs to lessen municipal vehicle emissions.

The simplest way to diminish emissions related to vehicle use is to reduce vehicle miles traveled. Municipalities can promote telecommuting, carpooling or van pooling, net meetings and teleconferencing. ICLEI describes San Francisco's Videoconferencing/Trip Reduction Project, which allows public defenders and probation officers to conduct interviews with incarcerated clients without traveling. The program will eliminate an estimated 15,000 vehicle trips and 600,000 vehicle miles in its first year of operation, avoiding over 500,000 lbs. CO_2 emissions annually. Where individual trips are necessary, local governments should encourage use of the smallest, most fuel-efficient vehicle possible. For example, building inspectors rarely require full-sized pickup trucks, and yet their use for this purpose is widespread. Local governments can focus on stocking their fleet with fuel-efficient vehicles. ICLEI notes that Denver, CO established specific miles-per-gallon fuel efficiency standards in its bid specifications; now more than 90% of its vehicle fleet are compacts or sub-compacts.

Alternatives to conventional vehicles include use of bicycles and alternative-fueled vehicles. Use of bicycles for community policing and parking enforcement has increased in cities throughout the country. In Denver, police on horses are a common sight in the downtown-shopping district. Miami has even begun outfitting some of its officers with in-line skates (*LA Times* 4/23/98). Since 1992, visitors to Chattanooga's downtown and local workers have enjoyed clean, quiet, convenient, and free electric-bus service, courtesy of the Chattanooga Area Regional Transportation Authority (CARTA). CARTA's growing fleet of locally manufactured electric transit buses will eventually serve riders throughout Chattanooga and neighboring Hamilton County. Besides electric vehicles, natural gas-fueled vehicles offer 5–20 percent reductions in greenhouse gas emissions compared to conventional fuels (http://www.iclei.org/co2/air/air.htm#chart).

Energy efficiency through direct management of transportation infrastructure is also effective. Replacing conventional traffic lights with LED's saves energy, thereby reducing greenhouse gas emissions. In fact since LED's last much longer than conventional lights, maintenance and capital costs are reduced as well over the life cycle of the light. The City and County of Denver recently replaced 17,036 traffic signals with LED's. Projected annual energy savings are 7.8 million kWh and $229,000. Additional savings from decreased material and labor costs could add $127, 693 annually. (ICLEI, 1998)

Procurement

A local governments' procurement policy can play a powerful role on the demand-side of the market in promoting environmentally sound products and services. Upgrading internal procurement policies to favor energy efficient and environmentally friendly products can reduce greenhouse gas emissions and help to develop a market for such products. Example policies include prioritizing recycled content materials, non-toxic products, and green energy supplies, as well as requiring vendors provide recycling services and recyclable products (such as recyclable toner cartridges). San Jose, Sunnyvale, and Oakland are just a few examples of municipalities with procurement policies favoring recyclable and recycled-content products. Energy savings can be substantial—4,200 kWh per ton of recycled paper, and 6,300 pounds of CO_2 per 300 tons of recycled waste paper (http://solstice.crest.org/efficiencv/ghgcasestudies/industrial/sanjose.html).

Santa Monica, California, provides another example of a progressive procurement policy. On February 23, 1999, the Santa Monica City Council voted unanimously to enter into negotiations with Commonwealth Energy of Orange County to purchase five megawatts of renewable power for its municipal needs for one year. The city's goal is to serve all of its municipal power needs through clean, renewable energy. Santa Monica will pay a 5 percent premium, or roughly $140,000 more per year, for using "green energy."

Municipal Outreach

Municipalities can build upon their relationships in their community, and understanding of their jurisdiction's business environment and needs to promote voluntary measures for greenhouse gas management. Voluntary programs can address emissions from industrial, commercial, or residential sources.

Programs with Local Industry

Local governments have a unique opportunity to work with community industry to identify energy efficiency and pollution prevention measures. Local government may be better positioned than other government entities because they have a more concise understanding of local industrial conditions, challenges, and potentials. Climate Wise State and Local Government Allies work with EPA's national Climate Wise program to provide companies technical assistance in their efforts to diminish greenhouse gas emissions. The national Climate Wise program is described below under "Resources."

Four ICLEI CCP campaign jurisdictions have received awards through the CCP Local Government/Industrial Partnership with EPA Climate Wise support. Seattle, Berkeley, Miami-Dade County and Portland will focus on developing and implementing industrial company Action Plans to lessen greenhouse gas emissions. Improvements range from waste heat recovery to installation of efficient motors and other equipment.

Programs with Commercial and Residential Community Members

Nationwide municipalities are involved with energy efficiency programs for commercial and residential community members. Programs include education and subsidies to promote weatherization, compact fluorescent and other energy efficient lighting, high efficiency appliances, and energy conservation practices. The Burlington Electric Department implemented such a program when they introduced a leasing plan for compact fluorescent lamps, and promoted a program to convert electric resistance heating to other fuels in order to reduce winter peak load. Six other demand side management (DSM) programs offered customers a comprehensive package of DSM options. Cumulative energy savings from 1991 through 1993 totaled 33,944 megawatt-hours (preventing 2,444 metric tons of carbon dioxide emissions). In some cases, municipalities offer free or lower price energy audits for homes or businesses. Other times, local government may be directly involved in project development. An example from Florida is the Metro-Dade County's Jordan Commons project.

This project is a partnership with Habitat for Humanity developing a $17 million, 200-home, model community for low-income families that were left vulnerable to homelessness by Hurricane Andrew. This project strives to achieve the highest standards of energy efficiency and environmental sustainability.

Resource Programs

EPA State and Local Climate Change Program

The State and Local Climate Change Program's *Climate Change Outreach Toolkit for State and Local Officials,* soon available on CD-ROM, includes a brochure and a sample exhibit that you can order to distribute at meetings, and three camera-ready background pieces for sending to the media. More than 100 fact sheets in the kit cover topics from the science of global warming to strategies for reducing greenhouse gas emissions. The kit also includes a side show for presentations on climate change suitable for delivery to community groups. The kit contains a list of additional resources on climate change including a list of videos and Internet links. http://www.epa.gov/globalwarming/actions/state/index.html

U.S. Department of Energy's Building Standards and Guidelines Program

DOE's Building Standards and Guidelines Program provides assistance, training, and information for residential and commercial energy codes. Telephone: 800-270-CODE. http://www.energycodes.org

Climate Wise

A stated focus of the U.S. EPA's Climate Wise program is to help industry " turn energy efficiency and environmental performance into a corporate asset." Climate Wise industrial partners submit a Climate Wise Action Plan that identifies specific cost-effective energy efficiency and pollution prevention measures; and then report their results annually. In return, partners receive free EPA technical guidance, in some cases free energy and environmental assessments, and free tools for quantifying results. http://www.epa. gov/climatewise/

Energy Star® Buildings and Green Lights® Partnership

Green Lights was the EPA's flagship program, the first voluntary effort to work with businesses to slash energy bills and pollution by installing energy-efficient lighting. More than 2,400 participants—called Partners—have committed to lighting upgrades. The Energy Star Buildings Program was initiated in 1995 as an expansion of Green Lights. This five-stage approach takes advantage of the interaction between various building systems: Modifications are made in phases, trimming energy use along the way and assuring appropriate load matching when heating, ventilating, and air-conditioning (HVAC) machinery is upgraded during later phases. Three hundred Partners are presently involved. According to the EPA, participating organizations have prevented 35.8 billion pounds of carbon dioxide (CO_2) from being released into the atmosphere as a result of their energy-efficiency upgrades. http://www.epa.gov/buildings/

ICLEI Cities for Climate Protection Campaign (CCP)

ICLEI's CCP offers grants, technical assistance, training, publications, and marketing tools to support the implementation of programs and policies that improve energy efficiency and result in greenhouse gas emissions reductions in all sectors. Program participants initially pass a resolution stating a commitment to reduce greenhouse gases. Participants then conduct an emissions inventory and establish an emissions reduction target, and develop then implement an emissions reduction action plan. In addition, ICLEI offers a new *Local Action Plan Development Grant Program,* created through funding from the EPA State and Local Climate Change Program.

U.S. EPA Landfill Methane Outreach Program

Through this program EPA is working with municipal solid waste landfill owners and operators to promote the use of landfill gas as an energy resource. EPA provides technical resources to program partners. http://es.epa.gov/partners/land/landmeth.html

Collateral Benefits

Pursuing the goal of decreased greenhouse gas emissions has substantial local benefit to match the potential global benefit of reduced global warming potential. Collateral benefits, also referred to as co-benefits such as decreased environmental impacts, lessened energy and life cycle costs, and improved quality of life are likely outcomes of an aggressive greenhouse gas management program.

Diminished Environmental Impacts

The environmental co-benefits of mitigating greenhouse gases are widespread. Reducing combustion of fossil fuels reduces emissions of criteria air pollutants, such as oxides of nitrogen, which form ground-level ozone. Constructively controlling landfill gas emissions can lessen local smog and control unpleasant odors. Promoting alternative transportation lessens the need for road construction. Roads replace wildlife habitat and natural stormwater drainage. Asphalt surface runoff containing vehicle fluids affects water quality and vehicle emissions degrade our air quality. All of these consequences are potentially diminished.

Decreased Energy and Life Cycle Costs

Saving energy often means saving money. Payback periods of three to six years are common for capital investments in energy efficient products. And some energy conserving fixtures and appliances actually last longer than conventional products, resulting in lower maintenance and capital costs over the product lifetime. Recycling and source reduction programs typically mean lower material costs and disposal fees. Land use planning to create more compact, pedestrian and transit friendly communities has the fortunate co-benefit of maximizing municipal investments in existing infrastructure such as roads and utility lines.

Improved Quality of Life

Whether improving our energy independence or decreasing inefficient urban sprawl, diminishing greenhouse gas emissions is likely to improve our quality of life. Promoting compact, transit and pedestrian-friendly cities and towns instead of urban sprawl tends to preserve the vibrancy of downtowns, while conserving valuable open space and farmland. Sprawl also has the deleterious effect of dangerously increasing emergency vehicle response time. Promoting alternative modes of transportation means less traffic congestion and additional time for more productive pursuits.

Conclusion

While the threat of climate change is global, the challenge is local. Nations, states, local governments, and private entities are faced with the challenge to reduce greenhouse gas emissions and mitigate the threat of global warming. Municipalities have a considerable arsenal of measures available to them to participate in this challenge. Whether progressive policies and regulations, efficient management of municipal properties, or proactive community outreach programs, municipalities have considerable direct and indirect control of greenhouse gases in their jurisdictions. This paper outlines many of the opportunities municipalities have to manage greenhouse gases. Readers are encouraged to contact the resources identified herein for additional approaches.

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Chapter 56— Microbial Abatement of a Moldy Hotel

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Abstract

A hotel constructed with an exterior insulation finish system (EIFS) had problems with water penetration of the building shell. This resulted in substantial mold growth in greater than 100 rooms in the ten-story hotel. Microbial abatement was completed in about three months. Standard microbial abatement procedures were used. These included containment with critical barriers, airlocks, curtained doorways, the use of negative pressure, HEPA filtration, and worker protection. The hotel configuration and demands of this project created interesting abatement design problems. The problems included a bathroom in every guestroom, abatement on multiple floors at a time, concurrent abatement and re-construction, and freezing temperatures. This presentation shows how these problems were dealt with to successfully complete the project.

Introduction

A 10-story hotel in a small mid-western city in the U.S. was constructed using the barrier exterior insulation finish system (EIFS). The hotel was constructed in the late 1970's. Since that time, many buildings, commercial and residential, have been constructed using this system. In the 1990's large-scale moisture problems have been discovered on buildings across the country as a result of the inability of intruding water to escape the wall cavity. Figure 1 is a typical barrier EIFS wall section. This hotel wall was not built with the cavity insulation or vapor retarder as shown in this figure.

In 1997 the hotel management hired a contractor to replace the caulk sealant between the large EIFS panels on the hotel. The winter of 1997 was the winter of an el niño weather pattern resulting in an unusually wet winter in the mid-west. In the spring of 1998, large areas of mold were appearing on the interior guestroom walls. Wind-driven rain may have penetrated the EIFS through faults in the caulked joints and pinholes in exterior finish and basecoat layers of the panels caused by erosion.

Over a period of several months, more and more guestrooms were found to have moldy wallboard behind vinyl wall covering. Eventually, over 100 rooms in the hotel were affected. Hotel management had an industrial hygiene consultant investigate the problem. Environmental sampling identified several different fungal species growing on the wallboard, including *Penicillium sp., Aspergillus sp.,* and *Stachybotrys sp.* Air levels indicated that some of the spores from these molds were airborne. These are all molds that can cause health problems like allergy, asthma, and potentially more severe lung disease to exposed people. These problems eventually led to closing the hotel for exterior repair and mold abatement in the fall of 1998.

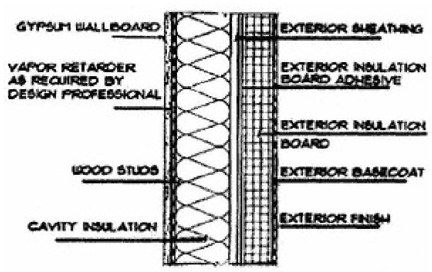

Figure 1
Typical Barrier Eifs Wall Section

Microbial Abatement

An abatement contractor was hired and microbial abatement specifications were written. The abatement began on the 10th and 7th floors of the hotel in December 1998. It was completed in February 1999.

Microbial decontamination projects involve the disturbance of hazardous materials. Disturbance of microbial amplification sites can literally release millions of spores into the air. It is important to choose the abatement contractor carefully. They should know the basics of building containment systems, establishing negative pressure enclosures, have good health and safety plans, and a trained and reliable workforce. Appropriate training is required for respiratory protection, clean-up procedures, and potential health hazards associated with the microorganisms to be removed. Many asbestos abatement contractors have made the transition to microbial abatement because the work is similar and their workers have much of the required training.

Proper remedial project design is critical to prevent potential human and environmental impacts from the release of microorganisms. The first step in any microbial abatement project is the elimination of the source of water/moisture. The microbial abatement specifications contain components for worker safety, decontamination protocols, and environmental protection.

Worker Safety

1. Comply with appropriate OSHA Standards, e.g. hazard communication and respiratory protection.

2. Use appropriate respiratory protection, which normally includes full-face mask with HEPA cartridges. Use full-body protection, e.g. TYVEK® coveralls with hood and foot protection.

Decontamination Protocols

1. Collect appropriate environmental samples to identify the microorganisms present and to define the scope of work.

2. Remove contaminated porous materials and debris.

3. Dispose of all contaminated materials (waste may be regulated depending upon the substrate and local regulations).

4. HEPA vacuum all vertical and horizontal surfaces.

5. Wipe all non-porous surfaces with a cloth dampened with water:bleach solution (10:1).

6. Ventilate the area with clean air with at least 96 air changes (i.e. 4 air changes per hour for 24 hours).

7. Visually inspect the area and, if clean, conduct appropriate clearance sampling (air spore counts, surface spore counts, etc.).

Environmental Protection

1. Determine the need for regulated areas, negative pressure containment systems, and occupant relocations.

2. Shut down ventilation systems serving the work area and install critical barriers. Seal all return air openings from the area.

3. Construct an appropriate work area containment system. This system could be a simple regulated area with critical barriers or a fully contained area with double layers of polyethylene sheeting on walls, floors, decontamination units, and negative air filtration devices for depressurization.

4. Employ a continuous pressure differential monitor between the inside and outside of the contained area. The monitor should have a printout of the pressure differential and an alarm to warn of a loss of pressure differential. The target AP should be –0.02 inches of water gauge.

5. Control access to the regulated area.

6. Double-bag or wrap all waste material and dispose through the decontamination unit.

7. HEPA vacuum all material removed from the regulated area.

8. Collect environmental samples for quality control.

Hotel Project

The hotel was closed for repair and microbial abatement in October 1998. Many rooms had up to 100 square feet of wall covered with mold. The worse areas were in rooms at the ends of the building, but many rooms along both sides had significant damage. Figure 2 is a typical floor plan for the guestroom tower. Room furnishings not obviously affected by the mold were removed by workers wearing protective gear (coveralls and respirators) and placed in trailers. At the end of the abatement work, the decision was made to replace all mattresses and upholstered sofas, chairs, and loveseats. Room curtains were dry cleaned and then stored.

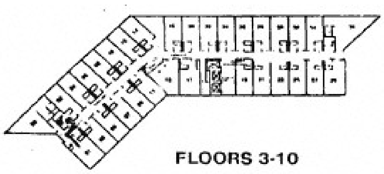

Figure 2
Typical Hotel Floor Plan

The regulated area was an entire floor of the hotel. The entrance to the area was through an airlock constructed in the elevator lobby. This airlock was framed with 2x4 lumber and the walls were two layers of 6-mil polyethylene. There was a three-flap curtained doorway at each end of the airlock. This also served as the decontamination area. Inside the regulated area, all doorways that did not lead to a guestroom and the ceiling were cleaned and covered with a critical barrier, two layers of 6-mil polyethylene sheeting taped at all edges and seams. All supply and exhaust air grilles in the hallway and guestroom baths were sealed with duct tape. Guestroom heater/air-conditioning units were removed and the openings were insulated and sealed with plastic and duct tape. Air filtration devices (AFDs) were connected to the outside through these room openings. About fifteen AFDs were distributed across the floor to achieve the desired negative air pressure inside the containment. A manometer at the entrance to the airlock monitored negative air pressure inside the regulated area.

The decontamination procedure began with removing room carpet, then stripping vinyl wall covering, followed by removing contaminated material. Workers wore powered air-purifying respirators (PAPRs) with full-face pieces, hooded coveralls, and gloves. Frequent cleaning with HEPA vacuums kept debris accumulation minimized.

The areas were cleaned following decontamination. All surfaces were thoroughly HEPA vacuumed. A brush was used to help dislodge debris in cracks and crevices. Nonporous surfaces were wiped with a cloth dampened with water and bleach (10:1) after vacuuming. After a 24-hr ventilation period, the areas were cleaned again.

The last stage of the project was clearance sampling. In this project air samples were collected using Air-O-Cell® particle samplers. Ten-minute samples were collected at a flow rate of 15 liters per minute. Samples were collected in ten guestrooms per floor, the elevator lobby outside of the contained area for each floor, and an outdoor location. Two samples were collected at each location. The samples were analyzed using light microscopic techniques. Spore counts indoors were compared to outdoor air.

Problems Encountered During Abatement and Solutions

The first problem to be solved was how to get clean replacement air to the abatement areas. The solution was to construct a tunnel from the hotel lobby doors to the elevators. Two elevators were enclosed inside the tunnel. Outdoor air could then travel up the elevator shaft to the floors under negative pressure. All elevator doors were sealed with critical barriers except for the elevator doors to the abatement areas.

Within each room there were sources of microorganisms that would not be removed as part of this abatement. These sources needed to be addressed so that they would not interfere with the clearance of the area after decontamination. One source was moldy wallboard in the bathrooms and the other was moldy wallboard that was the inner layer of the EIFS. Since the offending moisture source would not be addressed in the bathrooms (condensed water from showers, overflowing toilets and sinks, etc.), only deteriorated wallboard was removed and replaced. Other wall areas of mold were cleaned by HEPA vacuuming and then sealed with white pigmented shellac. The high alcohol content (~60%) helped to denature the microorganisms.

The moldy inner EIFS layer was handled similarly, but none of it was removed. The entire exposed surface was cleaned by brush and HEPA vacuum, then coated with an anti-microbial paint. As long as no moisture was introduced after coating, any surface contamination under the sealant should be controlled.

There were a few problems that had to do with abatement on two floors at a time. The outdoor air tunnel and two elevators solved one problem. Because of time constraints, reconstruction and demolition were also occurring simultaneously. Because the floors under decontamination and cleaning were negatively pressurized, any type of debris from adjacent floors was an interferent during cleaning and clearance sampling. A minimum one-floor buffer zone was absolutely necessary. However, both construction debris and demolition debris nullified cleaning and clearance sampling at least once during the project. Every time the manager had to pay for 25 to 50 additional clearance samples he was reminded that he could not get ahead of the abatement.

The problem more uncontrollable problem was the cold weather. Unit ventilators had been removed from the 6th through 10th floors at the outset of the abatement project. The abatement areas were under negative pressure so all leakage was into the building. When the temperatures dipped below freezing outside there were thousands of feet of water pipe to be concerned about inside. To make matters worse, the hot water recirculating pump broke down. The abatement began on the 7th and 10th floors so that heat could be introduced to the center and top of the guestroom tower as soon as possible. When these floors were cleared, new heating/air-conditioning units were installed. The lower floors still had heat because the second through fifth floors did not have any mechanical systems removed yet.

Another problem with conducting abatement in cold weather involved clearance sampling. The clearance criteria were to compare indoor air samples to outdoor air samples. The indoor samples should be lower in total numbers of spores than the outdoor samples. The dominant fungal species in the indoor air should be similar to those in the outdoor air. The marker species (*Stachybotrys* in this case) should not be present. The problem in cold weather is that with freezing temperatures and snow, which there was plenty of, outdoor fungal concentrations get very low. There was no good way to solve this problem. Reliance on someone experienced in the interpretation of sampling results and a good cleaning crew minimized these effects.

Conclusion

This project was relatively complex and involved several competing priorities. At times work was proceeding on EIFS repair, mold abatement, and building construction simultaneously. The mold abatement part of the project was something new for most of those involved. Problems such as those discussed here are ordinary in all projects. Experienced workers and cooperation were key elements in the success. In the end the hotel was back in business on schedule.

Chapter 57— Strategies for IAQ Mitigation and Closure

Charles F. Wiles

Abstract

Perhaps the most important factor in performing indoor air quality mitigation is providing proof that the actions taken accomplished all that was intended.

All cases of mitigation and remediation should be proven with numbers. Number values can be applied to all indoor air quality problems, regardless of the problem's origin. This paper will primarily address mold contaminants and the transport mechanisms that influence them.

Strategies for conducting meaningful microbial investigations should be completed before beginning to develop the data necessary to prove the cause of the indoor air quality problems in a building. All too often microbial air sampling is conducted without taking into consideration what regimen will specifically provide the necessary information to prove cause.

Closure to a microbial indoor air quality problem will come only when one can prove the problem has been remediated.

Introduction

Mold (fungi) growths within buildings usually require two things: moisture and nutrients.

Different molds require different moisture conditions. Usually molds require either humidity above 60% ~ 70% for extended periods or a prolonged wetting of building materials. As an example, *Stachybotrys chartarum* needs about 90% humidity to start and then more than 15% constant humidity in the building material to thrive thereafter.

Different molds prefer different nutrients. Our example of *Stachybotrys chartarum* likes cellulose products, such as cellulose ceiling tile, the paper on gypsum board, the stiff cardboard backing of a picture tacked on a wall, etc.

In addition to the two requirements, some molds prefer a lack of ventilation. If our example mold, *Stachybotrys chartarum,* has little ventilation, it simply means that it has less competition from other molds. In fact, our example mold would be much happier if *Aspergillus* or *Penicillium* (molds that it doesn't compete with well) never invaded its domain.

Most are alarmed when they find mold within their indoor environment and set about to get rid of it. What most don't understand is that molds have a mechanism for defending themselves from competing molds. Their defense is the toxic secondary metabolite they store within their cell walls. Since these toxic substances are within the cell walls, molds are considered toxic whether they are viable (alive) or non-viable (dormant or dead). Our example mold, *Stachybotrys chartarum,* is considered one of the more toxic molds by many.

So what are the health effects of mold exposure? A fair statement would be that most molds are allergenic. Another fair statement would be that most molds have the ability to lower the human immune system. It is not fair to state that any specific amount of mold within the indoor environment is a health hazard. Three things must be considered when determining the risk assessment of mold indoors. The first is the amount of mold or 'dose' to which one is exposed. The second is the mold type or 'taxa' to which one is exposed. Third, and most important, is the general health condition of the one who is exposed.

Microbial Sampling

So what do you do when mold is found or suspected within the indoor environment of the building you manage?

The first suggestion would be to make inquiries as to who has the equipment and the experience to determine the extent of the problem. These inquiries are best directed toward your peers, perhaps those with whom you have networked in professional associations. The firm should have someone on staff with a certification that demonstrates specialized knowledge in the field of indoor air quality, such as Certified Indoor Air Quality Technician, Certified Indoor Air Quality Professional, or Certified Industrial Hygienists. Even those with such specialized certifications should be asked about their expertise in microbial investigations. Any firm presenting itself as capable of determining the extent of the problem should be aware of recent changes to national standards and guidelines, such as those made by ACGIH.

Once you have decided who is going to conduct the microbial investigation, you will probably want to discuss the methodology they plan to use in their strategies to measure the amount of mold contaminants.

Air sampling is recommended in all cases because the amount of airborne mold exposure needs to be documented. Because no single methodology provides all the answers to mold questions, no single methodology of air sampling is recommended. In most cases, it would be recommended to do both impactor and spore trap sampling during the same period.

An impactor sampler (i.e., Aerotech A-6 and Andersen N-6) impacts air into a selected growth media that is then grown under controlled conditions (cultured). By taking samples for a given time at a given volume rate, the number of growth colonies within each impaction can be related to mold per cubic meter of air. The growth colonies are usually reported as colony-forming units since more than one mold spore (conidia) or mold branch (mycelial fragment) may be impacted (planted) into the same place on the media growth plate. The impactor sampling would provide data indicating the type and number of molds within the air that were viable.

The spore trap sampling would indicate the general type and number of molds within the air that were both viable and non-viable. Again, by taking samples for a given time at a given volume rate, the number of mold spores (conidia) can be related to mold per cubic meter of air. It is important to note the activity in the area during the sampling protocol because it will probably be useful when interpreting the data collected and its meaning as it applies to the building and its occupants.

Swab, bulk, and tape sampling may be useful in determining what kinds of molds are visible. Swab sampling is like taking a long sterile Q-tip, dipping it into a sterile buffered solution, and then 'swabbing' a surface. Bulk sampling is simply obtaining a piece of material to be analyzed by the laboratory. Bulk samples usually are pieces of fabric, carpet, filter media, etc. The laboratory usually needs only about 25 square centimeters of material to perform their analysis. Tape samples are easy to do. Simply place the sticky side of clear tape over the moldy surface and then place the tape on a glass slide to be analyzed. The problem with all three of these sampling methods is that they do not necessarily correlate directly to airborne exposures. This data can be compared to the air sampling data to help confirm that the areas of amplification or manifestation have been found.

The WallChek™ methodology is a fairly new sampling methodology pioneered by Metro Environmental Company and Aerotech Laboratories during the past two years. It involves non-destructive sampling of wall cavities to ascertain whether there is growth within the walls. Not only can it ascertain the significance of the growth, it can identify the type (taxa) of growth. In some cases, we have been able to establish whether or not occupants have been exposed to the contamination within a perimeter wall cavity by the absence or presence of pollens.

Last, but not least, all sampling must be done at a time and in a methodology that can be repeated so that mitigation and/or remediation can be challenged.

Data Interpretation

Data interpretation is perhaps the most difficult part of determining the extent of microbial contamination within a building.

Don't look to the laboratory to be of much assistance since they didn't do the sampling and weren't privy to all the site details involved with the sampling regimen. There are many examples of site details that affect the interpretation of data.

Were people moving about?

What types of activities were being conducted?

Is there carpeting, draperies, wallpaper, etc.?

Were doors opening or closing?

What are the normal indoor humidity and temperature levels?

Was the HVAC system on?

How much outside air was being effectively introduced into the area?

Was the area sampled within the effective air distribution?

Was the area sampled positive or negative to the adjacent building areas?

All these questions become important when mitigation or remediation becomes necessary.

Mitigation and/or Remediation

Mitigation is synonymous with alleviation, lessening, improvement, and easing. Mold infestations may be such that logistically mitigation is the only action that can be taken.

Remediation is defined the act or process of correcting a fault or deficiency.

Remediation of a building's mold problem would include:

Identifying the mold contaminated areas.

Identifying the underlying cause of the mold.

Correcting the moisture cause.

Erecting a properly depressurized containment (similar to asbestos containments).

Removing the contaminated building materials.

Conducting a visual inspection and air-sampling regimen.

Replacing as many of the building materials as possible while the project area is still under containment.

One note of caution . . . removal of the moisture cause prematurely on our example mold, *Stachybotrys chartarum,* (a type of slime mold) can allow it to dry and become airborne. All logistics of the mitigation or remediation project should be planned in detail, and the removal of the water source should be accomplished just before the mitigation or remediation project begins.

Closure

Mitigation of mold contamination can include treatment of the mold with biocides; however, given the fact that molds may remain toxic even though they are nonviable, treatment doesn't provide closure to the problem.

Final closure can only be achieved with full remediation. Full remediation means the cause of the problem has been corrected and that all mold-contaminated building materials have been removed and replaced with new building materials.

Conclusion

Gut feelings, guesswork, and assumptions may assist an indoor air quality investigator in formulating a hypothesis or theory for the cause of the indoor air quality problems within a building. However, after the hypothesis has been established, all these guiding forces no longer have a place in the investigation, the mitigation, or the remediation of the indoor air quality problems.

Sampling must be conducted to prove the mold contamination is gone. Sampling must be conducted to prove adjacent areas were not contaminated during the remediation process. This same sampling can become the new bioaerosol baseline for the building. While sampling provides the numbers necessary for remediation clearance, there is no substitute for a detailed visual inspection of the building.

Mitigation may alleviate a mold problem, but full closure comes only after successful remediation.

Chapter 58— U.S. Environmental Protection Agency's Strategy for Cutting Greenhouse Gases: A Program of Environmentally Preferred Purchasing

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Abstract

The U.S. Environmental Protection Agency (EPA) has the opportunity to become the leader among federal agencies in providing cleaner, less expensive government services. EPA's adoption of energy efficiency strategies and improved environmental technologies also demonstrates how industry can voluntarily improve environmental performance in a cost-effective manner. The public, other federal agencies, and Members of Congress should look to EPA as an example. This paper presents EPA's response to President Clinton's request to cut greenhouse gases through Energy Savings Performance Contracts (ESPCs). Specifically, the President required the following:

— 30 percent reduced energy consumption below 1985 levels by 2005;

— Plans for ESPCs and Energy Star labels for facilities;

— Proposals for expanding the Government use of these tools; and

— A strategy for using ESPCs for renewable energy production systems.

EPA'S Energy Situation

EPA currently pays for energy consumption at 16 of its facilities. All of these facilities are laboratories, used for environmental research, testing, and experimenting. Laboratories have an inherently high energy consumption rate, due to energy intensive equipment, strict temperature and humidity levels, and a one-pass air ventilation requirement. Therefore significant energy reduction is a challenge that must take into account occupant comfort, safety, health, and environmental issues. EPA could have exempted its laboratory space when reporting its energy consumption to the U.S. Department of Energy (DOE), but, instead, chose to rise to the challenge. The Agency feels that because energy conservation reduces greenhouse gas emissions, it is an important method of pollution prevention. The Agency has spent the past two years developing an approach to achieving the required energy reduction in its laboratory facilities.

Energy Consumption History

In 1985, EPA was responsible for the energy bills of 12 facilities. The Agency's annual energy consumption was 399,992 Btu per square foot (4.5 GJ/m^2).

In 1992 EPA joined the Green Lights program and completed energy-efficient lighting upgrades in its facilities by 1995, ahead of the scheduled agreement. In 1995, EPA's Facilities Management and Services Division (FMSD) performed an energy analysis of Agency facilities and determined that approximately 70 percent of the energy consumption is used for heating, ventilation, and air-conditioning (HVAC). In response to this situation, the Agency developed a strategy to pursue comprehensive energy systems upgrades, which will allow EPA to balance energy-consuming system components. The strategy will focus on 'right-sizing' of the central plant—meeting building requirements without unnecessary over-sizing of equipment.

Energy Star Buildings MOU

In 1997, EPA signed the Energy Star Buildings Memorandum of Understanding (MOU) and became a federal buildings partner. FMSD is working with the Energy Star Buildings Program to develop benchmark and performance criteria for laboratory buildings. FMSD will use these criteria to upgrade its laboratory space to Energy Star standards. In addition, all new office space will meet Energy Star criteria. EPA plans to obtain energy consumption information from the U.S. General Services Administration (GSA) for office space the Agency leases from GSA. EPA will evaluate these office spaces to determine whether they qualify for the Energy Star label.

Ten Percent Energy Reduction by 1995

By 1995, several EPA facilities had reduced energy consumption at least 20 percent, allowing the Agency to meet the first energy reduction milestone of a 10 percent reduction from the 1985 baseline. The major reasons for this decrease were lighting upgrades and operational improvements. Since 1985, EPA has added four new facilities: Houston, Texas and Newport, Oregon (1991); Montgomery, Alabama (1993); and Richmond, California (1994). Overall, Agency energy consumption in FY95 was 11 percent below the 1985 baseline.

Present Scenario:
20 Percent Reduction by 2000

EPA's current energy conservation strategy includes a combination of large-scale individual projects, energy awareness initiatives, and planned ESPC projects for the long term. As a result, Agency energy use is not expected to drop substantially in the next year or two. However, when ESPC projects are implemented, the Agency should meet the 20 percent reduction goal and, by FY2005, exceed the 30 percent goal.

FY95 to FY97 Projects

Since 1995, EPA has implemented several projects that will help it achieve the 20 percent reduction goal. EPA has targeted measures such as heat recovery, daylighting, as well as control strategies such as night setback and chiller optimization. The following examples highlight some of the measures:

— EPA's National Vehicle Fuel Emissions Laboratory (NVFEL) in Ann Arbor, Michigan installed a photovoltaic energized active daylighting system to provide natural lighting in a hi-bay area. The project uses light from existing roof-mounted skylight devices to replace fluorescent lighting when adequate daylight is present. Motorized reflectors, powered by photovoltaic cells, track the sun's path and direct sunlight into the diffusers.

— EPA's Environmental Research Center at Research Triangle Park (RTP), North Carolina installed energy-efficient lights, chillers, air compressors, and vacuum pumps.

— EPA's facility in Duluth, Minnesota incorporated Green Lights, and designed energy-efficient windows. In 1995, EPA began pumping water from Lake Superior to supplement mechanical cooling in the facility.

— EPA's Cincinnati, Ohio laboratory incorporated a night setback strategy to reduce air flow to the building during unoccupied hours by 50 percent. This system utilized the energy management system already in place.

— In 1996, EPA's Gulf Breeze Laboratory in Pensacola, Florida installed a heat pipe dehumidification system to reduce cooling and dehumidification energy.

FY98 Projects

Throughout the past fiscal year, EPA has worked toward the 20 percent reduction goal by supporting ongoing projects, incorporating new innovative technologies, and planning for future energy upgrades at all of its facilities. Summaries of current activities for each facility are provided below:

Ann Arbor, Michigan. An ESPC to conduct a complete energy upgrade at NVFEL has been awarded. The new design will guarantee a reduction in energy consumption of at least 66 percent. The planned upgrade will establish NVFEL as a showcase facility by reducing source emissions, energy consumption, and energy costs. It also will incorporate renewable technologies, while improving the laboratory's mission. Installing a real-time demand meter helped the facility reduce and maintain its electrical demand peak. FY97 also saw NVFEL break ground on its new energy-efficient office building. This building was designed using an integrated team approach to ensure that energy efficiency, pollution prevention, and passive solar features were key components of the design process.

Duluth, Minnesota. EPA has installed an energy and environmental management system to minimize energy waste through improved equipment controls. In addition, EPA will replace two large boilers with 10 small boilers to improve part-load efficiency of the heating system. EPA is determining the energy baseline of the Duluth facility, which is a candidate for a comprehensive upgrade through an ESPC. Geothermal heat pumps, wind turbines, photovoltaics, and other advanced measures will be investigated.

Gulf Breeze, Florida. EPA recently installed timers on approximately 20 electric water heaters, which are expected to save a significant amount of energy. In FY98, EPA awarded a contract to install Nodal Direct Digital Controls (NDDC). This project will improve building controls to minimize energy waste and monitor building security, fire protection, and indoor environmental quality. Also in FY98, EPA installed a photovoltaic system to generate on-site electricity using solar incidence.

Edison, New Jersey. A combination desiccant wheel/heat transfer wheel system has been installed as a pilot program at the Edison laboratory. The system recovers energy from fume hood exhausts to control humidity and conditioning in the analytical chemistry laboratory modules. EPA also installed a solar hot water heating system to supplement three existing water heaters.

Houston, Texas. The facility conducted air system modifications and upgraded the existing DDC system. EPA is incorporating the use of a night set-back system to control exhaust fans, laboratory fume hoods, and supply air. In addition, EPA is evaluating technology and operational options to reduce the large amounts of cooling and reheat that are required to reach temperature set-points.

Cincinnati, Ohio. In FY98, several energy savings opportunities will be pursued and implemented. Energy-efficient projects will include: a closed-loop glycol cooling tower; high-pressure absorption chiller; energy-efficient electric chillers, energy-efficient elevator motors; boiler controls, a revolving door to help maintain temperature and building pressure; HVAC system with improved windows and insulation; Green Lights; and an energy-efficient boiler.

Montgomery, Alabama. EPA developed a protocol for incorporating an NDDC technology system to its Montgomery laboratory. This is done to control and monitor laboratory pressures, fume hood exhausts, pH wash-down fluids, scrubber efficiencies, and indoor environmental conditions. EPA is currently evaluating the program of requirements.

Planned ESPC Projects

Based on the success of the Ann Arbor ESPC project, several other facilities have been targeted for upgrades funded through ESPCs. The Ada, Oklahoma, laboratory will be one of the first facilities upgraded through DOE's Super ESPC Program. Through this program, energy service companies in each of four regions (northeast, southeast, midwest, and west) won the right to bid for super ESPC upgrades in federal facilities. The facilities listed below are targeted for super ESPC upgrades:

Ada, Oklahoma. The laboratory will soon undergo a comprehensive energy-efficiency upgrade of the entire facility, including installation of a ground-source heat pump system and an integrated DDC system for energy, fire, and security management.

Gulf Breeze, Florida. This facility is in the planning stage for an upgrade through the Southeast Super ESPC. EPA is negotiating an interagency agreement with DOE to provide a no-cost energy audit to create the energy baseline model.

Narragansett, Rhode Island. The Agency is designing an HVAC system upgrade that will use high-efficiency chillers, geothermal heat pumps, and latent energy recovery technologies. The design will be based on heating and cooling potential of circulated bay water used for salt water aquatic testing in the laboratory. This project will be pursued through DOE's Northeast Super ESPC and the tender will be required to include renewable energy options.

Manchester, Washington and Newport, Oregon. These facilities are in the planning stage to be upgraded with an ESPC project through the Western Super ESPC.

Richmond, California. This facility is also in the planning stage to be upgraded with an ESPC project through the Western Super ESPC. EPA is working with DOE, the National Renewable Energy Laboratory (NREL), Lawrence Berkeley Laboratories (LBL), and the building owner to make this the first federal ESPC for a leased facility.

Laboratories for the 21st Century

EPA has developed an annual forum for the public and private sectors to exchange ideas on reducing energy consumption in laboratories. EPA and DOE, partners in this program, are committed to providing sound alternatives for energy-intensive laboratories and to obtaining up-to-date information and support for conservation programs.

The first conference was held at the American Institute of Architects headquarters in Washington, DC in September 1997. The conference was well attended with representatives from a wide variety of agencies, including the National Institutes of Health, the Center for Disease Control, Sandia National Laboratory, and Princeton Plasma Research Laboratory. The conference was organized into two sessions, a formal training component and an informal open discussion. Speakers from EPA, DOE, LBL, NREL, and academia provided training. They discussed utility deregulation, passive solar design, and their related effects on laboratories. Attendees presented their agencies' current issues and projects in an informal exchange with their federal peers.

The second conference was held at the University of Southern California in May 1998. The third conference will be held on September 8 to 10, 1999, in Cambridge, Massachusetts.

Thirty Percent Energy Reduction by 2005

EPA's strategy for reducing energy consumption by 30 percent from the 1985 baseline includes a heavy dependence on ESPC projects, combined with a few internally-funded large-scale projects. If every EPA ESPC project results in a 30 to 50 percent energy reduction per facility, and funded projects result in a 10 to 30 percent energy reduction per facility, agency energy consumption will be 270,000 Btu/ft^2 (3.0 GJ/m^2). This would be a 33 percent reduction from the 1985 baseline.

As described in the previous section, EPA plans to utilize ESPCs to upgrade seven of the facilities it owns. EPA also plans to utilize ESPCs to upgrade its leased facilities in Richmond, California; Houston, Texas; and Athens, Georgia. Future construction agreements in Edison, New Jersey, and Las Vegas, Nevada, will include criteria from the Leadership in Energy and Environmental Design (LEED) rating system, developed by the U.S. Green Building Council. EPA will be incorporating several renewable technologies into existing laboratories, including biomass boilers, solid oxide fuel cells, photovoltaics, and solar hot water heaters. In another initiative, EPA plans to purchase green power for several facilities. The following sections describe how EPA plans to use these tools to achieve and exceed the 30 percent reduction goal.

ESPC Projects

EPA expects to achieve a 50 percent reduction from current energy consumption levels for each facility undergoing a comprehensive upgrade funded through an ESPC. The DOE Super ESPC awards and unsolicited ESPCs are two tools developed recently to expedite the process. EPA's Ada, Oklahoma, laboratory will be one of the first facilities upgraded under the Midwest Super ESPC, and the Narragansett, Rhode Island, lab will be one of the first Northeast Super ESPC projects. EPA has been notified of an unsolicited offer to perform an ESPC for the Manchester, Washington, lab under the Western Super ESPC, and plans to include the Richmond, Virginia; Houston, Texas; and Athens, Georgia, facilities in regional Super ESPCs.

Funded Projects

EPA plans to use FMSD funds to upgrade facilities that are not being considered for ESPCs. These include EPA's Cincinnati, Ohio, and Research Triangle Park, North Carolina, laboratories.

LEED Rating System

EPA plans to incorporate the LEED rating system in new construction documents being developed for new facilities in Edison, New Jersey, and Las Vegas, Nevada. The rating system assigns a score for construction proposals that meet specific energy-efficiency and sustainable design criteria.

Renewable Energy

EPA recognizes that the use of renewable energy is the most environmentally beneficial method of reducing energy consumption. EPA is including a requirement in all ESPCs that renewable technologies be installed as part of an overall upgrade. In addition, EPA is pursuing several independent renewable technology projects.

Ft. Meade, Maryland. EPA, with DOE and DOD, assembled a public-private partnership hoping to demonstrate the world's first megawatt class solid oxide fuel cell (SOFC) power station at EPA's new Environmental Science Center in Fort Meade, Maryland. The power station is an innovative, compact technology that functions along the same principles as a battery, yet can be fueled by a variety of resources, among them renewable biogas and solar hydrogen. The technology will provide extremely efficient and clean power to the facility at over twice the efficiency of existing conventional power-generating combustion technologies using a combined cycle power generating system.

Athens, Georgia. A biomass feasibility study for Athens is well underway. A strong partnership between EPA, DOE, Tennessee Valley Authority, U.S. Department of Agriculture, University of Georgia, and Georgia State Forestry will be the foundation for making this a successful project. Preliminary results of the feasibility study indicated that biofuel potentially could be obtained from the large quantities of cardboard, paper, waste wood, and municipal wood currently disposed of in local landfills each month. The next phase of this project will determine the size, type, cost, and potential funding options for the plant equipment best suited for the Athens laboratory. In a separate renewable energy project, solar hot water was installed at the day care center.

Gulf Breeze, Florida. EPA and NREL have jointly funded and awarded a photovoltaic dock lighting project for the Gulf Breeze laboratory.

Edison, New Jersey. EPA and NREL have jointly funded and awarded a solar hot water heating system for the Edison laboratory.

Manchester, Washington. EPA and NREL have jointly funded and awarded a photovoltaic demonstration project for the Manchester laboratory. The project will serve as a training exercise for regional, state, and local personnel to learn about the technology's components and installation.

Golden, Colorado. EPA and NREL are assessing various solar technologies for a newly constructed, leased facility in Golden, Colorado. EPA is considering using a new ESPC program for solar technologies.

Green Power Purchasing

In response to the deregulation of electric utilities, it will be difficult for renewable energy production generators to compete with cheaper, but more polluting fuels such as coal and natural gas. The federal government can help accelerate the growth of renewable energy sources by requiring the purchase of green power for a percentage of their overall energy consumption. EPA has already purchased 100 percent green power for its Richmond, California, laboratory. In addition, EPA will require green power purchasing for 100 percent of the energy consumed by the Athens, Georgia, laboratory and 10 percent of the energy consumption of the Narragansett, Rhode Island, laboratory.

Two renewable projects in the planning stages could assist the Agency's overall fossil fuel energy reduction. A planned installation of a solid oxide fuel cell at the Fort Meade laboratory could reduce utility electricity consumption at that facility by 60 percent, and a planned biomass boiler in the Athens facility could reduce utility energy consumption in that facility by 20 percent. If both of these projects are implemented, the overall Agency energy consumption rate would be 278,000 Btu/ft^2 (3.1 GJ/m^2), well within the 30 percent energy reduction goal.

Conclusion

EPA plans to meet and exceed the 30 percent energy reduction goal by utilizing ESPCs to upgrade the majority of its owned facilities. EPA also plans to utilize renewable technologies, cutting-edge energy-efficient technologies, and green power purchasing to further the goals of pollution prevention through energy conservation.

Chapter 59—
Laboratories for the 21st Century

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Please note: The preliminary information presented below was presented for discussion purposes only at a conference on this subject held in Cambridge, Massachusetts, September 8 to 10, 1999. Conference participants helped EPA determine the direction, implementation, and future of the Laboratories for the 21st Century Initiative.

Abstract

The U.S. Environmental Protection Agency (EPA) is interested in establishing a voluntary energy- and water-efficiency initiative for laboratory facilities called Laboratories for the 21st Century, or Labs21. Participants in the initiative would join EPA in establishing and meeting common goals and objectives.

It is possible to make significant improvements in the environmental and cost performance of the nation's public and private sector laboratories. EPA has recent experience improving its own facilities' energy- and water-efficiency and wants to share this information. EPA invited all interested parties to attend an initial planning meeting on September 8, 1999 to discuss the following:

Improving energy- and water-efficiency in U.S. public and private laboratories.

Lowering laboratory utility and operating costs.

Reducing unnecessary emissions associated with the generation of electricity by improving energy efficiency and, possibly, by generating electricity from clean and renewable onsite energy sources. [1]

Reduce annual water consumption by 80 percent, from 31 million to 6 million gallons.

Anticipating industry changes affecting U.S. laboratories, including the effects of electric deregulation.

Demonstrating that efficiency improvements can improve the quality of the work environment, including health and safety issues.

Applying a "whole buildings" energy and water systems strategy in the design, construction, and operation of U.S. laboratories.

Establishing performance metrics and sharing bench marking data.

Background

EPA recently began modifications at its Ann Arbor, Michigan, laboratory that will accomplish the following:

Reduce annual electricity demand by 68 percent, from 2.5 MW to 0.8 MW.

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[1] Generating electricity onsite can enable a facility to obtain its electric power more efficiently by eliminating transmission losses. In addition, a facility can use waste heat to produce more electric power or to offset thermal generation in the facility. Generating electricity from renewable sources can further increase the conversion efficiency and environmental preferability of onsite power generation.

Produce energy and water savings that will reduce the laboratory's annual utility bill by 74 percent, from $1.1 million to $286,000.

Recoup the cost of the equipment upgrades in 8 years.

In addition, the resulting decreases in energy and water demand will reduce the emissions associated with electricity generation, decrease the laboratory's demand on limited natural resources, and dramatically improve the building's environmental performance.

The Agency is currently implementing similar modifications to many of its other laboratories and is expecting similar results. Based on its success with its own facilities, EPA is proposing a national, voluntary initiative to encourage similar improvements throughout U.S. laboratories.

Why Focus on Laboratories?

There are four primary reasons to examine laboratory energy- and water-efficiency:

Laboratories consume significant quantities of energy and water, so utility costs per square foot are higher than commercial buildings (a target of many efficiency efforts).

Laboratories are often owner-occupied, which could facilitate the use of life-cycle cost strategies in energy- and water-efficient infrastructure investments.

Laboratory construction is growing.

Laboratories are high-tech buildings run by skilled facility technicians and engineers.

Laboratories Consume Significant Quantities of Energy and Water

Laboratories consume significantly greater energy per square foot than many other buildings. Assuming there are Laboratories are an increasingly important engine of economic growth. As a result, the construction of new laboratory facilities has risen steadily during the past few years. In 1996, new construction was up 4 percent from the 40,000 U.S. laboratories, each with an average of 40,000 square feet, and each consuming 350,000 British thermal units per gross square foot per year (Btu/GSF/year), the annual energy consumption of U.S. laboratories is 560 ***trillion*** (5.6×10^{14}) Btu. [2] If only one-quarter of these laboratories could achieve energy-efficiency improvements of 60 percent (an efficiency gain achieved by EPA laboratories), then the United States could reduce its annual energy consumption by 84 ***trillion*** Btu (8.4×10^{13}). This is the same as reducing carbon dioxide emissions by 19 *million* tons annually, removing 1.25 *million* automobiles from our highways, or planting 56 *million* trees to off-set the carbon emissions associated with this energy consumption.

Laboratories Are Often Owner-Occupied

Laboratories are often owner-occupied. As a result, any cost savings associated with laboratory operations will have an immediate, positive benefit on company profits. In tenant-occupied buildings, however, owners pass energy- and water-consumption inefficiencies to the tenants. As a result, owners of tenant-occupied buildings are less likely to implement significant energy- and water-efficiency upgrades than owner-occupied facilities.

Similarly, EPA's proposed "whole buildings" approach is more appealing to owner-operated facilities. While laboratory owners and managers frequently seek opportunities to reduce utility costs, they typically only examine individual building components (e.g., lights; office equipment; or heating, ventilation, and air-conditioning equipment). Examining a building as an integrated unit creates significantly greater opportunities for improving energy- and water-efficiency. EPA's experience suggests that a "whole buildings" approach works and can lead to significant economic and environmental benefits.

Laboratory Construction is Increasing

previous year. In 1997, it was up 1/2 percent from the 1995 baseline. In 1998, construction was up 15 percent and EPA

[2] EPA laboratories consume an average of 350,000 Btu/GSF/year. EPA assumes this figure reflects the industry average.

expects it to be up another 20 percent in 1999 from the 1995 baseline. [3]

Unfortunately, many of these new facilities do not incorporate the latest energy- and water-efficiency and pollution prevention technologies in their design or operation. Thus, there is a significant opportunity to improve the economic and environmental benefits of new laboratory buildings.

Laboratories are High-Tech Buildings Run by Skilled Facility Technicians and Engineers

Laboratories, by their very nature, are high-tech buildings designed, built, and operated to facilitate cutting-edge testing and research. Due to the need to carefully control the air flow and environment within a laboratory, operation and maintenance personnel are some of the most highly trained facility managers in the country. As a result, their expertise can advance the understanding of the complex energy consumption dynamics that exist within all buildings.

Such an understanding would promote two important objectives:

Identify immediate and future cost saving opportunities for laboratory facilities.

Demonstrate to others the importance of an integrated energy management strategy and the effectiveness of advanced energy- and water-efficient technologies.

The work conducted in U.S. laboratories is charting the future course of the nation and of the world. EPA hopes the Labs21 Initiative will make laboratory buildings as innovative as the research conducted within them.

Proposal

EPA anticipates the voluntary Labs21 Initiative eventually can expand beyond its initial emphasis on energy- and water-efficiency to incorporate other pollution prevention opportunities that exist within laboratory facilities. The Agency recognizes, however, that the Initiative must begin with a strong focus to be successful. As a result, the Agency is proposing the following first-year objectives, which will be refined at the Labs21 meeting in September:

Establish procedures laboratory owners and operators can use to evaluate the energy- and water-efficiency of their laboratories.

Define the participation requirements for a Labs21 laboratory.

Provide opportunities to exchange information on laboratory energy- and water-efficiency (e.g., conferences, newsletters, or Web sites).

Identify, promote, and replicate demonstration projects to facilitate market acceptance of advanced energy- and water-efficient technologies.

Establish award criteria for recognizing Labs21 participants.

As currently envisioned, the Labs21 Initiative will become a voluntary EPA program with two levels of participation as described below.

Members—Members will agree to conduct an energy- and water-efficiency survey of their facilities consistent with the methodology developed by EPA and other participants at the September meeting. The methodology will emphasize a "whole buildings" approach in which members examine the laboratory as an integrated unit. It will examine the building's overall energy- and water-efficiency rather than examining the efficiencies of individual building components.

Based on the results of the energy- and water-efficiency survey, members will agree to review the potential cost savings of any proposed energy- and water-efficiency alternatives.

Champions—EPA will recognize publicly those companies that implement the changes highlighted by the energy- and water-efficiency survey. The Agency will particularly recognize those companies that adopt renewable energy sources or achieve superior performance.

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[3] The growth rate in laboratory construction was provided by a major supplier of laboratory instruments.

Role of the Labs21 Champions

EPA and its federal partners will recognize Labs21 Champions publicly for their participation when the initiative is unveiled at the Labs21 Conference being planned for 2000.

The role of the Labs21 Champions will be to:

Provide national leadership.

Review and refine the initiative's goals to meet their energy- and water-efficiency needs.

Implement projects consistent with the agreed Labs21 program strategy.

Promote the initiative.

Participate in or review demonstration projects.

Federal Role

The Federal government partners will:

Provide leadership.

Develop a detailed "straw" proposal for Labs21 Members and Champions to review.

Implement the Labs21 Initiative in federal laboratories.

Promote the initiative.

Assist with the energy- and water-efficiency surveys.

Provide information and technical assistance.

Conduct demonstration projects.

Recognize participating companies wherever possible.

Provide opportunities to exchange information, including conferences, newsletters, or Web sites.

Compute the environmental improvements resulting from individual company participation in the initiative.

Chapter 60— After Green Globe Certification, What's Next?

Zakaria E. Nyangoro, CEM, CDSM, P.E, SMIEEE

Abstract

Green Globe Certification, a program of environmental certification for the travel and tourism industry was developed by the World Travel and Tourism Council (WTTC) in 1997. This certification program forms part of the WTTC's Green Globe initiative begun in 1994 in direct response to the 1992 Rio Earth Summit held in Brazil. This summit developed a set of principles known as Agenda 21 that provides a blueprint for many companies to meet their environmental, social and cultural responsibilities. Green Globe incorporates aspects of Agenda 21 and also provides a stepping stone for many companies to achieve the ISO 14001 Environmental Management Standard.

In the Caribbean, a special certification program has been developed by Green Globe, SGS (a certification company) and CAST (Caribbean Action for Sustainable Tourism)[1] for the rooming establishments in the region. Several hotels have attained or are in the process of being certified. This paper looks at the experience of Sandals Negril Beach Resort and Spa, a hotel property along the seven-mile beach in Negril, Jamaica.

The process towards certification will be examined in detail and a step by step program for similar properties to maintain this certification and move towards ISO 14001 certification is also proposed.

Background to Green Globe

Green Globe is environmental management and awareness program for the Travel and Tourism Industry. The program is worldwide in its scope and encompasses a wide range of organizations in the industry that are committed to improvements in environmental practice. The primary objective of the program is to increase industry responsiveness and public awareness of the industry's commitment to environmentally compatible development. In so doing Green Globe provides a low cost, practical means for all travel and tourism companies to:"

Commit to undertaking improvements in environmental practice, based on international guidelines

Receive expert help in environment management techniques, based on international best practice

Demonstrate their commitment through a publicly recognized Green Globe Logo and be eligible for special achievement awards."

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[1] CAST is a subsidiary organization of the Caribbean Hotel Association whose focus is on providing members with training materials.

The Green Globe certificate was developed in 1997 with the aim of providing "independent verification of environmental improvements within the Agenda 21 framework made through an Environmental Management System."[2]

The certification program was developed in partnership with SGS, a testing, inspection and verification organization. As of May 1999, seven hotels had received certification.

The Certification Process

The certification process assesses the environment management system of organizations in the following areas. These are:

Waste reduction, re-use and recycling

Energy efficiency, conservation and management

Management of fresh water resources

Waste water management

Environmentally sensitive purchasing policy

Social and cultural development

The assessment however is not limited to these six areas but include other aspects of environmental management such as storage and use of hazardous substances, transport, land use planning and management, sustainable design, air quality protection, noise control and partnership for sustainable development.

To ensure consistency and continuous improvements in environmental management performance in these areas Green Globe recommends that a focused Environmental Management System be implemented.

Certification involves five major steps: Registration, statement of intent, environmental health checks, main assessment certification.

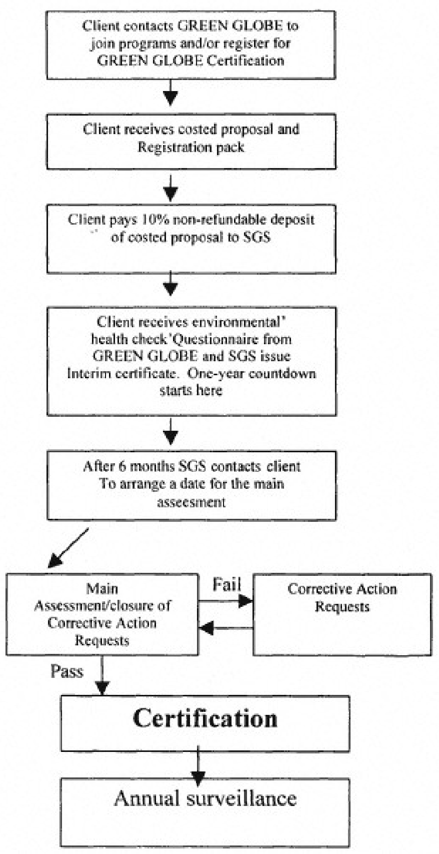

Figure 1
The GREEN GLOBE Certification Process
Source: Green Globe Annual Review 1997–98, p.25

[2] Green Globe Annual Review, 1997/8. P. 23

An organization wishing to achieve certification would first of all need to submit a registration form. Once the proposal has been accepted Green Globe issues the organization a statement of intent. Following this, an environmental health check is undertaken with the assistance of Green globe. The critical aspect of the certification is the main assessment, which is a "detailed evaluation of current environmental practices to ensure that the requirements of the Green Globe standard have been met."" This certification is not a one off result but is upheld through regular surveillance visits.

The Jamaican Green Globe Initiative

Reflecting the need to protect the environment and the need for the sustainable development of the tourism sector, Jamaica undertook a program aimed at sensitizing the main players in the industry of the importance of being environmentally aware. The program, which started in 1997, involved the Jamaica Hotel and Tourist Association (JHTA). Negril, a resort town renowned for its attention to the environment was the focus of the 18 month project- "Greening of Negril for the Year 2000."[3]

The project involved 20 small hotels (under 100 room) where energy and environmental audits were conducted and recommendations made for improvements. These properties were assessed primarily on the basis of landscaping, operations, water, waste and energy management.

It is estimated that this effort will yield estimated annual savings of 1.9 million gallons in water, which translates to $250,000.00 and 1.8 million kilowatt-hours of electricity equivalent to 207,500.00

Another important result of the project was the certification of four hotels, which were the first in the world to achieve Green Globe Certification.[4]

Case Study

The target of the case study is Sandals Negril Beach Resort and Spa located along the seven miles beach in Negril in the western part of Jamaica. The property is operated by Sandals Resorts International (SRI) and comprises 223 rooms and is operated under an all-inclusive concept.

An important step in achieving certification was the recognition that good environmental practices save time, money, energy and other resources. Further, the company lacked the expertise in-house to adequately undertake the assessment process. Hagler Bailly Inc. was given the task of doing an audit of the properties and to assist in the formulation of an environmental management system which would be the operating standard for the company. Hagler Bailly examined in detail all aspects of the operations of the hotel and produced a manual that now forms the basis of the property's environmental management program.

Hagler Bailly examined the current environmental performance of Sandals Negril focusing on water management. Energy management, waste water disposal and solid waste generation.

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[3] The project was funded by the US Agency for International Development under the Environmental Audits for Sustainable Tourism.

[4] These included Sandals Negril Beach Resort and Spa, Negril Cabins Resort, Sea Splash Resort and Mocking Bird Hill Hotel.

Water Management

In the case of water, Sandals Negril water use index, which averaged 229 IG/GN[5], was determined to be poor. A good water efficient hotel has a water use index of less than 147 IG/GN. Recommendations made by the study included the use of water saving showerheads, installation of flow aerators on faucets, and the retrofitting of conventional toilets with water conservation devices such as diverters and dams. The potential savings from improved water conservation practices were estimated at some 40% of total water costs. (See table 1)

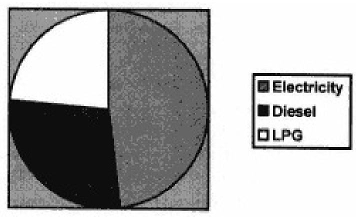
Table 1:

Potential Savings:

Utility	**%**
Water	20
Energy	20
Diesel	40
LPG	10
Electricity	20

Energy Management

Energy consumption which includes diesel, LPG, and electricity averaged 51.8 kWh/GN over the 1997/1998 financial year with electricity accounting for approximately 50% of energy consumption. In terms of costs, electricity also dominated accounting for close to 75% of total energy costs. (See figure 2)



	Use	Costs
**Electricity	48%	73%
Diesel	28%	16%
LPG	24%	11%

Figure 2

Recommendations for the conservation of energy include reducing hot water temperature in the kitchen, ensuring that the hot water supply in all areas of the property does not exceed 120F, the use of energy efficient lamps and the use of window and door sensors to control the operation of air condition units. The estimated savings from the adoption of energy conservation measures was a reduction in energy costs by an estimated of 20%. (See Table 1)

An environmental management assessment was also conducted on a departmental level of the current environmental management practices. This was benchmarked against SRI's Standard Environment Practices as well as the Standard of Green Globe. Each department on property was detailed to determine their current operating practices and to develop department specific recommendations for improvement.

Some of the recommendations were simple with relatively easy and low cost implementation. For Example water saving shower heads, energy saving lights and retrofitting of toilets to

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[5] IG-Imperial gallon, GN-Guest night. The water index is IG/GN.

operate at 1.5 gpf. Longer term recommendations which needed some financial support were put to the management for budget consideration like "Rain Water Harvesting" Program. The study took three months.

Inspection

The inspection phase of the certification program was conducted by the appointed agent for Green Globe which in this case was SGS international. The Environmental Management Practices of the Company was examined then an inspection was done to determine whether what goes on in practice concurs with the written documents. The inspection was not limited to the staff and management of the property but also included interviews with guests, members of the community and NGO's.

In comparing the utility consumption reports before and after the implementation of the E-practices, it was realized that there were savings in several areas.

Green Globe Certification

Based on the recommendations made by SGS International, the Board of Governors of Green Globe approved the certification of Sandals Negril Beach Resort and Spa. Certification reflected an acknowledgement that Sandals Negril Resort and Spa had met all the criteria needed for environmental certification and shown that they were committed to continued preservation and conservation for the environment's sake.

Achievements

After critical analysis and with proper environmental approached and systematic continuous monitoring Sandals Negril has been able to achieve the following:

i. Reduction of waste by 30% has helped reduce garbage disposal budget by 25%.

ii. Water consumption has been reduced from an average of 225 gal/guest night to 190 gals/guest night.

iii. Electricity consumption is down from 24 kWh/guest night to 20 kWh/guest night.

iv. A Quarterly newsletter is now being produced internally for the E-Teams entitled "US THREE- You, Me and the Environment."

v. Departmental E-Teams are monitoring and evaluating various operations for improvements.

vi. Quarterly award for "best environmental ideas from team member has been developed.

vii. Staff motivation and contribution to the green awareness has gone up by 60%.

viii. Guest satisfaction and appreciation of what the property is doing is up. According to the guest questionnaire it has been seen that most (approx. 70%) support the effort to preserve and conserve and are willing to cooperate also.

ix. Participation of staff and managers on community and Earth Day activities has gone up by 50%.

What's Next?

Certification requires that the company shows that it will continue to monitor, improve, research and adhere to environmental practices as they change and develop. Green Globe has developed a systematic re-certification program so that the organization can keep standards high and ensure that there is active systems monitoring process.

An ongoing environmental management program, which is systematically implemented, is necessary to maintain certification. This will ensure that yearly re-certification required by Green Globe will be relatively easily achieved so that the hotel will remain environmentally friendly and globally recognized as such.

Among the recommended steps that hotels can take to maintain certification include:

1. The development of an annual environmental report detailing the Company's goals and achievements. An example of this is the CERES Report 1998[6] where details with respect to environmental policies, organization and management; workplace, health and safety, community participation, supplier relationship and energy use and consumption can be provided.

The advantage of such reporting is that it allows environmental practices to be easily monitored and evaluated by both internal and external entities.

2. Training and education in environmental practices and new developments needs to be undertaken in a consistent manner.

3. Sensitizing management and staff, guests and the community must take priority. A written statement if not communicated effectively to stakeholders would not result in any improvements in environmentally responsible behaviour. Competitions between departments and properties can result in new ideas and a greater understanding of the benefits derived from conserving resources.

4. Emphasis should be placed on self-auditing by using team members from different departments. This should be done at least once a month.

5. Adequate record keeping is critical.

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[6] http://www.ceres.org. See also the global Reporting Initiative.

Chapter 61—
Measuring and Offsetting Greenhouse Gas Emissions

Jennifer R. DuBose
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Abstract

With the increasing certainty that climate change is happening and that anthropogenic greenhouse gas emissions are at the root of this problem, many proactive companies are voluntarily quantifying and reducing their contributions. Interface, Inc. — a global manufacturer and marketer of commercial interiors (floorcoverings, fabrics and raised flooring)—has been working with the Climate Neutral Network to develop a climate neutral floorcovering. This paper discusses the method Interface is using to measure its greenhouse gas emissions and the process it is undertaking to offset those emissions, making a product that is climate neutral.

Introduction

The debate about climate change is over. The scientific community has spoken, and the vast majority believe that increasing concentrations of carbon dioxide and other greenhouse gases, as a result of human activity, have already begun to disturb the global climate. In 1995 the Intergovernmental Panel on Climate Change (IPCC) concluded that the observed increase in global average temperature over the last century "is unlikely to be entirely natural in origin" and that "the balance of evidence suggests that there is a discernible human influence on global climate." [1] Two years later the Union of Concerned Scientists initiated a Call for Action in conjunction with the international meeting in Kyoto stating that global warming is a serious threat, and that steps to address it must be taken. Over 1,500 of the world's senior scientists agreed with this statement and signed their Call for Action. [2]

While the majority of greenhouse gas comes from natural sources, it is emissions from human activity that are pushing concentrations of these gases to dangerous levels. These gases have the effect of trapping heat in the atmosphere by absorbing infrared radiation as it is reflected back to space. This is an essential life-supporting process without which Earth's average temperature would be approximately negative 18 degrees Celsius. By increasing the amount of heat trapping gases beyond their natural concentrations, humankind is disturbing the existing climate.

While predictions of particular impacts are inconclusive, there is a strong possibility that this climate change will result in severe weather that will negatively impact the quality of life for mankind overall and will damage delicate ecosystems. Scientists involved with the IPCC have modeled the conditions of increased greenhouse gas concentrations and have concluded that the global mean surface temperature may rise 1 to 3.5 degrees Celsius between 1990 and 2100. While the estimated change in temperature may seem small, the potential effects are massive in terms of flooding coastal planes, effecting precipitation patterns, increasing the severity of storms and hurricanes, broadening the regions potentially effected by tropical diseases, shifting growing areas for forests and other vegetation and potentially shifting the flow of large ocean streams that warm northern continents such as Europe and North America.

Interface is greatly concerned about activities which destroy the vitality and restorative quality of natural systems. Although we are a very small contributor to the buildup of greenhouse gases it is essential that we begin to take responsibility for our contribution. While the United States has signed the Kyoto Protocol, it will not be binding until the Treaty is ratified by Congress. In the regrettable absence of multilateral governmental action we have nonetheless committed to voluntary action to reduce our impact.

As signatories of the CERES principles we are committed to public accountability and will monitor and report our greenhouse gas emissions yearly. Interface has already made an internal commitment to reduce our per unit product greenhouse gas emissions. The majority of our emissions are a result of our energy consumption in manufacturing. Recognizing that, we have declared all nonrenewable energy consumption as waste, thereby encouraging our manufacturing facilities to procure green energy sources while also reducing total demand through energy efficiency. Several of our facilities are purchasing green energy from their utilities and at other sites we are directly capturing solar energy through photovoltaics.

Part of our efforts include participation in an international group convened by World Resources Institute & World Business Council for Sustainable Development to develop an Internationally Accepted Measurement & Reporting Standard for Corporate Greenhouse Gases. In accordance with the recommendations from the World Resources Institute's "Safe Climate, Sound Business Initiative", we commit to the following actions:

Measure, track, and openly report greenhouse gas emissions from our operations;

Seize near-term opportunities to reduce and sequester greenhouse gas emissions from facilities, products, and supply chains worldwide;

Develop new cost-effective technologies, products, and business ventures for minimizing emissions and achieving sequestration in the 21st century;

Include global climate considerations in new investment decisions in both developing and developed nations;

Educate employees, customers, suppliers, and other key stakeholders to raise their awareness of climate change issues, their own contribution, and potential response options; and

Participate in the debate on climate change at both the national and international levels and contribute constructively to policy formulation and implementation. [3]

As a part of this commitment we have been working with a multi-stakeholder group with representatives from government, environmental nonprofits and industry to develop the concept of "climate neutral." As a result of our work with the Climate Neutral Network we are embarking on an exciting program to take our products climate neutral by offsetting the greenhouse gases associated with them. This concept will be explained further after a description of our measurement technique.

Measurement

The metric used to inventory Interface's impact on climate change is global warming potential (GWP). This metric combines two factors (time and the heat trapping ability of the gas), converting all impacts into the equivalent of carbon dioxide over a 100 year period The major greenhouse gases with which we are concerned are carbon dioxide, methane and nitrous oxide with respective GWPs of one, 21 and 310.

The first step required to begin measuring emissions is definition of the system boundaries, in other words deciding what is part of the measurement and what isn't. We chose to look at two different systems: 1) the total operations of a manufacturing facility and; 2) the entire life cycle of a particular product. Each system will be explained separately.

Within those system boundaries we have captured both direct and indirect emissions. Direct emissions are greenhouse gas releases that happen on site, for instance as a result of burning natural gas in a boiler. Indirect emissions come from activities which occur off-site but are still deemed the responsibility of the facility, this includes the generation of electricity on our behalf at the utility. The quantity of energy used by energy type and category of use is multiplied by established emission factors to produce the quantities of climate gasses produced. The factors we chose are those used by the Intergovernmental Panel on Climate Change. The IPCCs factors are typically used to calculate emissions for entire countries so the units had to be scaled down for our use from terajoules per ton carbon to pounds carbon dioxide per million Btu.

To arrive at the footprint of a "Climate Neutral Facility", the boundaries of a single manufacturing facility were defined as our delivery door where we receive materials from our suppliers and extends to the moment our product is delivered to the customer. The following data is collected from utility bills, invoices, suppliers and some estimates:

Electricity (Broken down by the source (coal, natural gas, renewable, etc.))

Natural Gas

Propane

Transportation (Products to customer, company owned trucks, leased cars, air travel, and employee commuting)

Measuring the greenhouse gas emissions for one specific product involves gathering slightly different data. We started with the manufacturing energy for the product and then looked up and down stream from there. The emissions that we are measuring from the full life cycle of a product are:

Upstream impacts (Process energy for manufacture of the primary materials, and transportation from supplier to our factory)

Manufacturing process (Process energy and transportation from manufacturing location to the customer)

Installation (Adhesives and scrap disposal)

Use and Maintenance (Vacuuming)

Disposal (if not recycled back into the same product)

Exact usage data was gathered where possible. In some cases estimates or approximations had to be made, particularly in the area of transportation. For instance, employee commuting miles can be estimated based on data from a random sample of employees to get the average number of miles per day and then using the national average fuel economy to calculate gallons of gas consumed. The resulting kilowatt hours of electricity, cubic feet of gas and gallons of fuel are then multiplied by emission factors to determine the carbon dioxide equivalent.

Climate Neutral

Climate neutral is the term used to describe a product, facility or operation that has no net greenhouse gas emissions associated with it. This is not to say that there are no emissions generated during the manufacture of the product or the operation of the facility, but rather that the resulting emissions were measured and negated, or offset, through emission reductions elsewhere so that the end result is no additional greenhouse gases. The climate neutral concept has been worked on extensively by the ad hoc Climate Neutral Network which has brought together representatives from a number of different organizations (public, private and nonprofit).

There are a variety of off-site projects that can be used to offset emissions. It is possible to use internal projects as offsets for a climate neutral product, so long as those projects are not double counted, i.e. the project reduces the amount of emissions to be offset and then is also counted against the remaining emissions. Because Interface is already committed to internal emission reductions we felt that we would reduce more emissions globally if we purchased off-site reductions instead of counting in house projects. These include energy efficiency projects to reduce the combustion of fossil fuels, switching to cleaner burning fuels, installation of renewable energy systems, and the capture of methane from coalbeds or landfills. It is also possible to sequester carbon dioxide by planting trees or protecting forested areas from destruction.

The Climate Neutral Network has developed guidelines for selecting credible offset projects. After selecting a project or portfolio of projects a company can submit their emissions calculations, along with the offset information to the Review Panel of the Climate Neutral Network to receive third party verification of their efforts.

The current criteria for individual offsets are:

Transparency: With the exception of proprietary information, implementors should make a broad range of information about each project publicly available.

Additionality: The project must reduce greenhouse gas emissions beyond what would logically occur in a baseline scenario.

Measurement, monitoring and verification: Projects should include a process for tracking activities to ensure that the planned offset/reduction objectives are being achieved.

Leakage: The project should not simply shift greenhouse gas emissions to another site.

Criteria for the overall portfolio are:

Permanence: Projects should result in a permanent (defined here as 50–75 years) reduction of carbon emissions from the baseline scenario. Intentional postponement or leakage of an emission, or temporary sequestration, is not a viable offset.

Collateral Impacts: Projects will likely have impacts other than emissions offsets. These may include environmental, social, or economic effects that are important to various audiences. Projects should seek to promote positive impacts and avoid obvious, significant negative impacts.

Innovative: Preference should be given to projects that could lead to societal change in carbon emissions or could contribute powerful lessons/innovations which could be transferred to others.

Technically Sound: Projects should incorporate appropriate design and implementation qualities that reflect current standards in science.

Domestic: A substantial majority of the offsets should come from domestic projects creating solutions in close proximity to the problem.

Fossil Fuel Reduction: At least sixty percent of the carbon dioxide needs to be offset through projects which reduce the consumption of fossil fuels. This attacks the major cause of climate change and helps to set us on the right path.

In addition to these offset criteria it is necessary that companies pursuing climate neutral certification demonstrate that they have made a serious effort to reduce their own greenhouse gas emissions. This avoids the concern many opponents of emissions trading have that companies would be buying "rights to pollute" and looking at this as a way to buy their way out of the problem. While offsets are a part of Interface's overall climate change strategy, the first and most important part of our strategy is reducing internal energy use through energy efficiency, redesign of products and processes and switching to cleaner fuels and renewable energy sources. Offsets are only part of our strategy to cover the unavoidable emissions as the company works toward the goal of zero emissions.

Our Commitment—Solenium

Interface has committed to measuring and offsetting the greenhouse gas emissions from its newest product, Solenium, which is an entirely new type of floorcovering. This makes Interface the first company to offer a climate neutral durable good. Because Solenium was designed to be 35 percent more efficient in terms of raw materials, it is 100 percent recyclable and part of its manufacturing energy is from solar panels on the mill, it was a natural fit to make it climate neutral.

We measured emissions from the full life cycle of the product, according to the metrics outlined above. The only difference was the treatment of the end of its first life-cycle. Because Solenium is 100 percent recyclable and will not be disposed of in a landfill, no greenhouse gas emissions were added for disposal. The carbon dioxide burden associated with recycling Solenium is assumed to be equivalent to that expended in the production and delivery of virgin raw materials, which will be added to the manufacturing emissions for the second generation Solenium.

The greenhouse gas emissions will be offset through one of more of the following projects: energy efficient design or retrofits for public schools or low income housing, fuel switching and/or projects that reduce the urban heat island effect. We are currently working with a variety of offset brokers to find the appropriate project. The offsets will be purchased at the end of the first year of sales for Solenium. More details on the exact offset project will be available within the next few months.

A detailed report including the greenhouse gas emissions calculations for Solenium and extensive information on the carbon offset project will be submitted to the Climate Neutral Network's Review Panel for approval. The Review Panel has already reviewed a preliminary proposal and has provided us with feedback that will make the eventual certification relatively quick. Their scrutiny and final approval of our project will validate the rigor of our measurements and the quality of the offsets, ensuring that Solenium is in reality "climate neutral."

Conclusion

We cannot wait for the government to take action. This is important and we have the power to act alone. We hope other companies join us. We hope consumers support our decision and use the power of their dollars to make that support known. Alone our actions will be insignificant, but if we can inspire others to join us, perhaps we can avert this systemic disturbance to our planet.

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Bio

Jennifer DuBose is the EcoSense Program Manager at Interface Research Corporation. Her role is to work with all divisions of Interface, Inc. to support the corporate mission of becoming the first name in industrial ecology. Her knowledge of sustainability was gained through a research faculty position at the Georgia Institute of Technology in the Center for Sustainable Techonology and while earning her MS in Environmental Policy at the same Institute.

SECTION 6—
PLANT & FACILITIES MANAGEMENT/OSHA COMPLIANCE

Chapter 62— An Effective Architecture for Industrial Process Management

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Pacific Northwest National Laboratory[(a)]

One of the biggest battles our military forces face may well be found in the bases they use to train their personnel. The energy savings bar has been raised. Military leaders are now faced with a mandate to reduce their base energy consumption not by 20%, but by 35% relative to a 1985 baseline by the year 2010[(b)], and to do so with reduced Operations and Maintenance (O&M) budgets. Many managers are turning to the Energy Savings Performance Contracts (ESPCs) with the hope of achieving their goal and staying within this rigidly bounded budget. Some of these contracts have ended in bitter disappointment. As contractors, hungry for a return on their investment, seek to maximize profits, they do not always have the best interests of the base in mind. The result has sometimes been a rapid decline in the condition of the facility infrastructure, resulting in a similar decline in the ability of the base to meet its mission.

The US Marine Corps has turned to the Department of Energy's National Laboratory system in an effort to maintain base readiness while meeting its energy reduction responsibilities. By applying technology transfer initiatives from the national labs, applied methods for O&M have been paying large dividends in cost reduction while allowing the Marines to maintain control of their own base infrastructure.

This paper provides insights into how the USMC has found:

A new view of managing its facility assets

A holistic model of process information requirements

A life-cycle asset management perspective

A well documented case history of economic success

A new architecture for condition-based O&M cost reduction

The net result of understanding and carefully implementing the condition based approach to operating and maintaining facility O&M processes has been shown to dramatically impact the bottom line.

Evolution of the Condition-Based Approach

Degradation happens. Savvy maintenance managers have long since learned to subscribe to a rigid preventive maintenance (PM) philosophy because it has been made obvious to them that by not following these precepts, they open themselves up to being blindsided by some very unpleasant surprises. Like how not replacing the oil pump bearing seals every 5 years as recommended showed up as 30 gallons of lubricating oil on the plant floor that almost made it to the storm sewer. So, experience makes us firm believers in following even the unpopular tear-it-down-and-measure-the-tolerances routines of the preventive maintenance (PM) regimen.

But, what are the alternatives to this PM approach? Where are the leaders in O&M research headed and what can we expect from these new ways of doing facility business?

There have been, in fact, four distinct evolutionary steps that we have taken in reaching our current state of

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(a)Operated for the Department of Energy by Battelle Memorial Institute under contract DE-AC06-76RL0 1830.

(b)Executive Order 13123—Greening the Government Through Efficient Energy Management. Federal Register Part IV, 8 June 1999.

proactive condition-based O&M. Each successive step has had a positive effect on the efficiency, reliability, and safety of plant processes.

Corrective Maintenance (CM) is the old "if it ain't broke, don't fix it" story. The perennial run-to-failure mode. It is simplicity itself, requires little forethought, and (at least up to the point of machinery failure) requires the least resources from the O&M crew and their support staff. Many "war stories" are told in which equipment is destroyed by rapidly acting degradation mechanisms, erosion or cavitation in a pump for example, that shorten the life expectancy of a component by an order of magnitude or more. In very simple, and non-critical, components (a light bulb for instance) run to failure may be a cost effective mode for maintaining the equipment. In critical applications, however, (like the safety systems of a nuclear power plant) this risky approach is not tolerable. As long as the consequence of equipment failure is not high, this approach can make some sense.

The CM method of plant maintenance is still, surprisingly, the predominant method of commercial plant operation in the U.S. despite the resulting high product loss, capital equipment loss, total manpower expenditure, and accident severity that result.

Preventive Maintenance (PM) is the art of periodically checking the performance and material condition of a piece of equipment to determine if the operating conditions and resulting degradation rate are within the expected limits. If they are not, a search for the reason for the more rapid degradation must be found so problems can be corrected, or at least mitigated, before the machine fails.

PM testing, inspections, servicing, or parts replacement actions are done on a service life (e.g., hours of operation) or purely on a time-in-service basis. Although accurate failure statistics can allow the testing interval to be optimized, the PM method is expensive, and catastrophic failures can still occur. The PM method is also very labor intensive and risky. Much unneeded maintenance is performed, and incidental damage to equipment is widely reported as a result of poor maintenance practices. A PM system can, however, be a cost-effective strategy when the life span of the equipment is well understood and consistent. An air filter in constant use tends to need replacing with a fairly constant frequency. Studies in the utility industry report reactive-to-preventive life cycle cost savings in the 12 to 18% range.

Predictive Maintenance (PDM) advocates measurements aimed at the early detection of degradation mechanisms, thereby allowing the degradation to be understood and eliminated or controlled, prior to significant physical deterioration of the equipment.

There are many nonintrusive measurement methods that allow us to detect and correct the potential for degradation considerably earlier in the life cycle. Technologies such as vibration analysis, oil analysis, thermography and ultrasonic analysis pushes our problem recognition capability to the leading edge of the degradation envelope.

The application of this technology results in

- marked increase in equipment life
- earlier mitigation or corrective actions taken
- decreased process downtime
- decreases in maintenance parts and labor
- better product quality
- decreased environmental impact
- energy savings.

The sum of these advantages can add another 8 to 12% to the O&M savings over a good PM program. Also, the root cause for the degradation can sometimes be identified, and consequently, mitigation can be better targeted and repetitive failures become much less likely to occur.

On the negative side, the costly up-front investment in detection and diagnostic equipment, and the high level of staff training, makes this approach a more difficult pitch to an ever wary, cost conscious management. The savings provided by this technology are now largely in terms of avoided cost (a hard concept for management to grasp) and therefore it becomes more difficult to demonstrate and to ensure program funding.

Condition-Based Operations and Maintenance (CBM) is the immediate detection and diagnosis of off-normal equipment operation and the identification of the root cause stressor(s) responsible for this condition. This final evolutionary step, illustrated in Figure 1, is the real key to optimizing high value, critical, O&M process.

Two things should be noted from the outset:

1) operations has now been engaged and integrated into the maintenance equation by becoming responsible for recognizing and correcting the existence of an abnormal condition, and

2) finding the root cause stressors (parameters outside the design envelope) responsible for the off-design condition is now the prime directive.

In addition to extending the life and performance of critical components, we can be almost certain of absolute reliability—operation without the necessity for failures.

Figure 1
Condition-Based Proactive Maintenance Approach

The use of computers and low cost sensors allows us to:

1) continuously automate stressor recognition (what went out of spec),

2) run degradation mechanistic diagnostics (what's going wrong), and,

3) identify a root cause solution (what needs to be done to correct the situation).

The result is that a computerized real-time picture of the problem and a clear understanding of the solution can be computer generated and presented simultaneously to the operations, maintenance, engineering, and administrations staff. Asset management can now proceed using informed decisions based on known conditions, defined degradation rates and, in most cases, accurate estimates of equipment remaining life (prognostics). Predicting and planning now become the bywords of the maintenance group rather than the 2 am brush fire and panic routine. Over the life of the equipment, the savings provided by this proactive paradigm are estimated to be 5 to 10 % above even the predictive approach, including all the initial investment costs. In a balanced approach using reactive, preventive, predictive, and condition-based, maintenance we now find it possible to generate a total production life-cycle cost savings on the order of 25 to 40%. Part of our work at the Laboratory was to demonstrate that these savings are real, rather than simply a wishful projection.

The Proof of Principal Project

In 1990, the United States Marine Corps (USMC) provided the Pacific Northwest National Laboratory (PNNL) with a perfect opportunity to demonstrate the effectiveness of this emerging CBM technology. The Marine Corps produces thermal energy (heating and cooling) for its base facilities using central energy plants. These plants, like so many Department of Defense (DOD) base installations, are being run with minimum staffing and minimal data available to provide cost-effective O&M decisions. This situation results in the creation of significant improvement opportunities for plant O&M cost reduction.

The central heating plant (CHP) at the Twentynine Palms, California base was selected as the site for the first implementation of the Decision Support for Operations and Maintenance, or DSOM system. The plant, shown in Figure 2 is a gas-fired 120 MBtu/hr pressurized hot water plant that provides thermal energy (heat) for 20,000 Marines at the Air-Ground Combat Center.

The Decision Support for Operations and Maintenance (DSOM) project was designed to provide a proof of the CBM savings potential by having clear before and after measurements of the actual O&M costs. The project itself was built around the proactive condition-based approach and integrates:

1) an understanding of degradation mechanisms from the Nuclear Plant Aging Research Program (conducted by the U.S. Nuclear Regulatory Commission),

2) current computer technology,

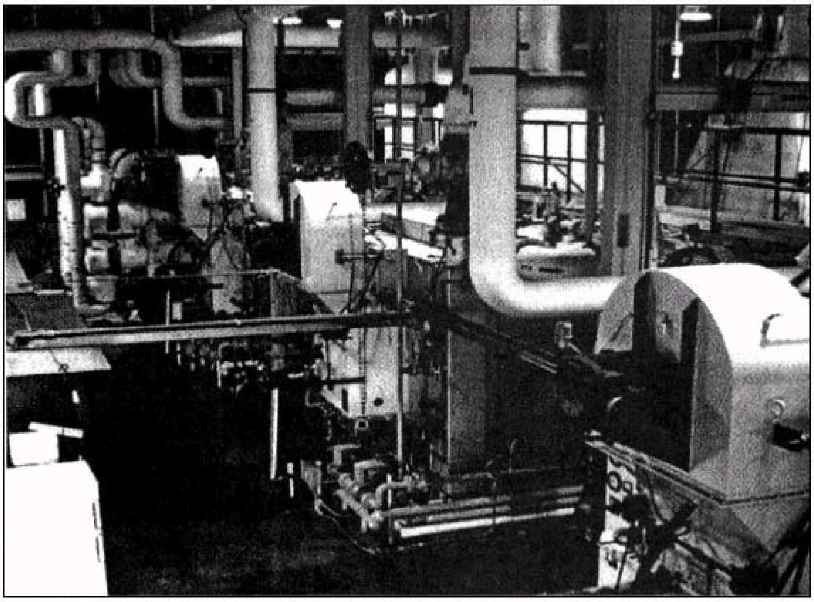

Figure 2
Twentynine Palms Central Heat Plant

3) an integral root cause analysis methodology, and

4) the many years of hands-on O&M experience of the Twentynine Palms O&M staff, as well as the Laboratory's Predictive Operations and Maintenance Technology group.

The end product is a set of on-line computerized, operations-oriented tools that are based on accurate plant design information and provide the plant operations staff with guidance on cost and safety conscious decisions. The principal operations decision support information tools are shown in Figure 3.

At Twenty-nine Palms, the DSOM condition-based O&M tool set provides the operations crew with point and click information access to the processes at the plant, system, and component levels. Both the safety and the efficiency of the components and the process are monitored, and root cause solutions are automatically generated and brought to the operator's attention to regain cost-effective operation. Design basis operation is achieved and maintained by continued vigilance of all O&M infrastructure elements that are required to effectively optimize the process (Operations, Maintenance, Engineering, Training, and Administrative Support, termed OMETA).

Measuring the Economic Incentive

The criteria for success is dominated by the bottom line. To be able to draw an accurate record of change, a detailed baseline characterization was performed. This included not only the common metrics, such as plant overall operating efficiency and maintenance machinery repair records, but also the other OMETA functions that must be integrated to provide the infrastructure required for continued operation.

The effect of the 1994 installation of DSOM was an immediate enhancement of the plant's safety, reliability and available capacity. The project increased plant thermal efficiency by 17%, reducing the plant's greenhouse emissions by over 3,000 tons per year, and reduced its gas bill by over a quarter of a million dollars each year. A concurrent increase in plant available capacity eliminated the need for a fourth generator unit, saving an immediate $1M. The more difficult challenge was to show that these rather spectacular savings are actually not as large a reward as the savings on capital life-cycle economics. To demonstrate this, a life-cycle cost projection was performed based on data gathered thus far from the Twentynine Palms project.

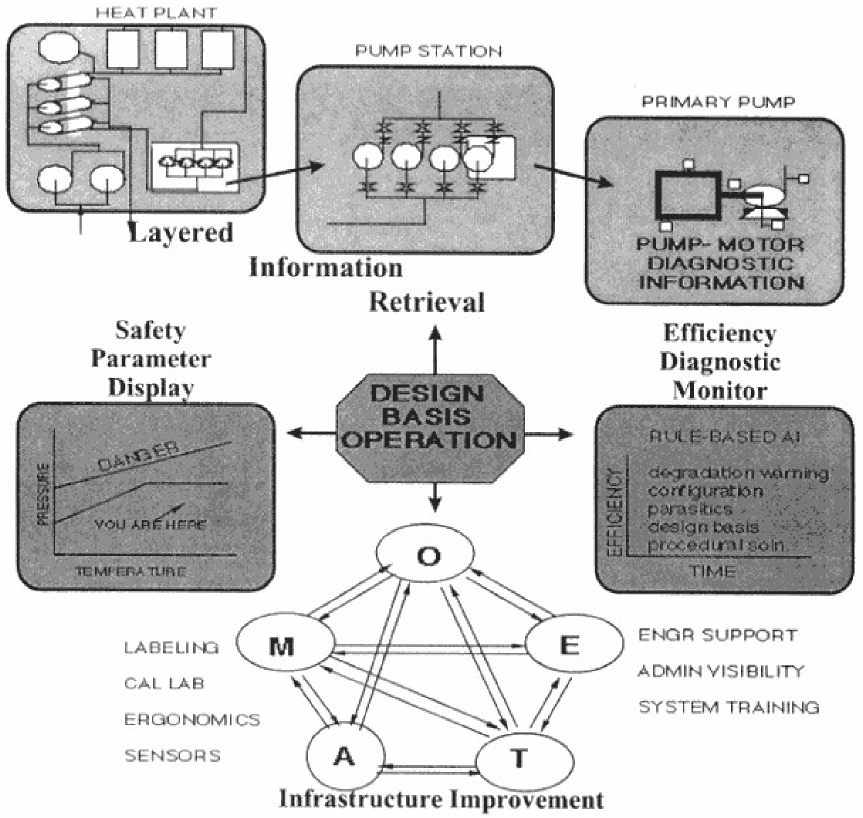

Figure 3
Dsom 29 Palms Production Tools

When we look at the "life cycle" of the process as "providing sufficient thermal energy to support the base needs for the next 60 years," we must include everything necessary to implement and support plant O&M for the duration (capital equipment, personnel, repairs, and fuel). Based on the documented reactive life cycle costs at Twentynine Palms, the data yields the projected figures shown in Table 1.

Thus we see in clear quantitative terms that the largest single gain from the CBM approach is in avoided capital expenditures. This systematic application of a condition-based improvement process at Twentynine Palms is currently saving the base approximately $480 K per year on its life-cycle heat plant O&M bill and paid back the original research investment in 4 years.

TABLE 1

Operations and Maintenance Category	**Projected Life Cycle Savings**
Fuel Savings (operational efficiency)	15 M
Maintenance Savings (condition-based)	16 M
Capital Equipment Savings (life extension)	20 M

DSOM II at Parris Island

With the success of the Twentynine Palms experiment in condition-based O&M, the USMC incorporating this technology as an integral plank in its Energy Conservation Campaign Plan. Currently, the USMC is applying an advanced version of the Twentynine Palms technology to the thermal and electrical generation systems at its Parris Island South Carolina cogeneration plant.

Software Designed to Fit the Infrastructure

The Twentynine Palms software was designed to provide the operations staff with on-line information to allow them precise control of the combustion, heat transport and hydraulic processes in their plant. Parris Island offered the opportunity to advance this concept by providing preformatted information to not only operations, but to all the facilities staff who are involved in supporting the operation of the plant. In order to fully understand the approach taken in structuring the software design, it is first necessary to define the support infrastructure required.

Plant Functional Decomposition

Careful scrutiny in the commercial nuclear industry shows that any process operation can be broken down into five major functions that must work and communicate together to achieve the process goals. For the case at hand, the process is the generation and transport of electrical and thermal energy at a central heating plant. The major functions that must be accomplished are:

Operations (manipulate the process machinery)

Maintenance (provide upkeep and repair of system components)

Engineering (monitor and improve process O&M performance)

Training (teach people the information they need for equipment)

Administration (provide overall control of goals and resources needed).

We can visualize these five areas as a pentagram structure where each of these five functions are essential to any industrial process.

To illustrate how information must flow between each of the functions for the process to proceed effectively, consider the following example. If, for instance, only the engineering support function were to be inactive, ineffective, or isolated from the other functions for some reason, the following can happen (and in fact has):

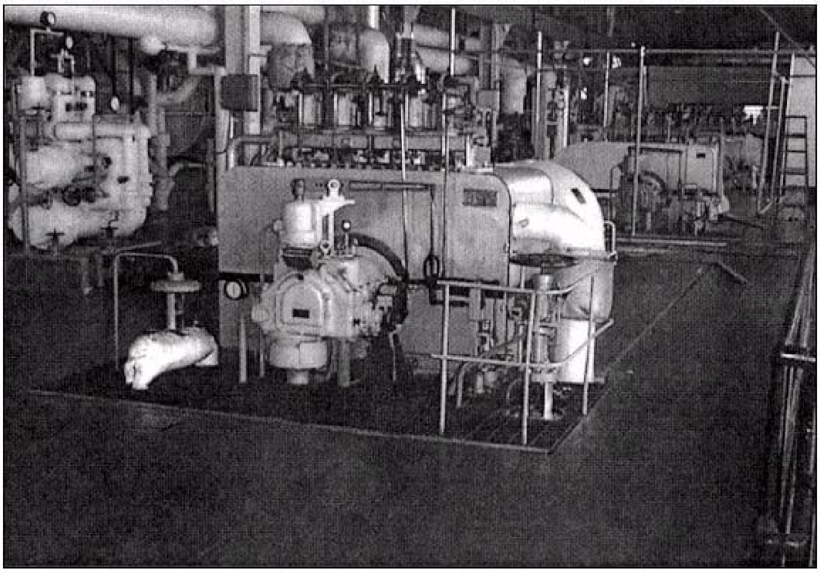

Figure 4
Parris Island Cogeneration Facility

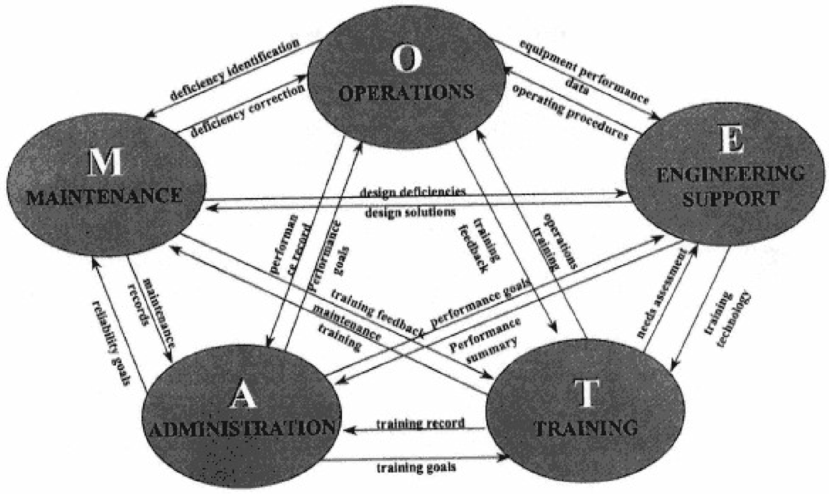

Figure 5
Operations and Maintenance Functional Interactions

equipment problems identified by the operators would be repaired, but would go unresolved, so chronic plant problems would continue unchecked

machinery material deficiencies noted by the maintenance technicians would go uninvestigated and the machinery would continue to break repeatedly from the same cause

the plant administration would not know plant performance level or what resources were necessary to maximize plant life-cycle efficiency and so would loose control of plant costs

as new technology was added to the plant, training needs would not be recognized, procedures would not be changed and, without operator training, the benefits of installing that technology would soon be lost.

Similar scenarios could be generated should any of the other functional entities be missing or not operating effectively. Each of the five functions must, therefore, be effectively performed by some responsible organization/individual to allow the process to continue in a safe and efficient manner.

Subfunctional Areas

As anyone who must work in the O&M arena can tell you, the pentagram graphic provides an over-simplified, single plane view of a very dynamic 3-dimensional hierarchical network. A much more confusing, but realistic, depiction is provided in Figure 6.

Here we can see that each of the five major functions can be broken down into specific functional areas of responsibility. Each of these areas must be accomplished in order to make the system perform well at the major function level. Continuing with the engineering function as an example, we find that five different responsibility areas fall into the circle of the plant engineer. These areas include:

Plant Modifications—produce solutions to problems or upgrades for higher efficiency for the plant process

Performance Monitoring—provide the basis for understanding, reporting, and improving plant efficiency and reliability

Support Organization—ensure effective implementation and control of plant engineering support needs

Document Control—ensure documents provide accurate, as-built information sufficient to support plant O&M requirements

Procedures—ensure procedures provide appropriate direction for plant efficiency.

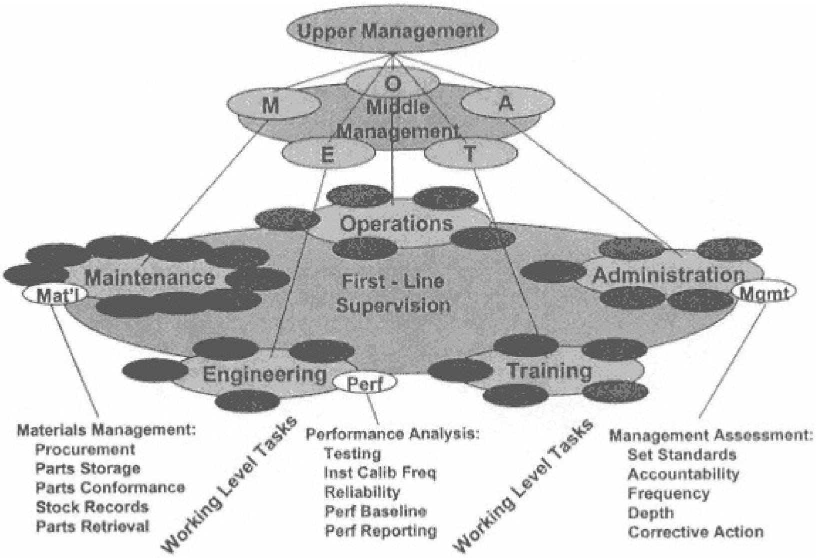

Figure 6
Functional Hierarchy

Although it is not mandatory that these functional areas be performed specifically by the plant engineer, it is essential, even in small process organizations, that responsibility for each area of performance is assigned and effectively accomplished by cognizant personnel. Again, as in the previous discussion, should any of these areas be even partially dysfunctional, that impairment is transferred to some degree to the efficiency, reliability, and safety of the entire plant.

Task Level Structure

Finally, the level of the individual tasks can be examined. The task level provides a working description of the requirements for each individual in accomplishing basic functions related to the success of the process goals. Again, a description of this level is best accomplished through example.

In the engineering function, we found that one of the area responsibilities was Performance Monitoring: provide the basis for understanding, reporting, and improving plant efficiency and reliability. At the working task level this is further resolved as:

Instrument calibration frequency determination

Component, system and process testing

Process performance baseline analysis

Performance analysis (relative to the baseline)

Machinery reliability analysis

Process performance reporting.

These are the basic elements that the engineer must be capable of achieving to accurately determine the adequacy of the performance of the process. In large plants, several "Results Engineers," as they are sometimes called, devote their entire energies to providing these basic building blocks. In smaller processes, these tasks and, other area functions fall into the province of the plant engineer. The level of detail of these tasks is usually less explicit in smaller plants, but the task elements themselves must still be performed. The result of the deletion of any of these elements is reflected in or reduces control of both the economics and safety of the process.

It is at the task level that the information flow, or lack of it, really makes itself apparent. Pick one of the tasks from the engineer's list. Let's say machinery reliability analysis. It is obvious that without the information of the operators regarding availability on demand (pump would not start, valve would not close), a detailed listing of maintenance data on failures (mean time to failure, resources necessary to repair), and the resource availability information of the administrative support group, the completion of this task is virtually impossible. The same is true for all of the other 220 identified task level entries in the infrastructure listing. The importance of accurate, timely information cannot be under-estimated in the effective operation of a process plant.

Design of the Software to Implement Information Exchange

The PNNL DSOM project staff fully appreciate the importance of the forgoing argument. Twentynine Palms was focused on the immediate needs of the operators. Parris Island afforded us an opportunity to extend the infrastructure information net to the full extent of the OMETA team. In fact, the integration concept extends beyond the thermal and electric generation on the site, including the demand side management and waste treatment facilities. The basic idea is shown in Figure 8.

Data generated in the central energy plant (CEP), building energy management and control system (EMCS), and alarm information from the site waste treatment plant are all routed to a central data base in the DSOM computer. That data base can then be queried by the population of users, and, depending on the identified function of the user, the data is displayed in a from customized to the users' need. The CEP operator gets the information he needs regarding the operational status, the maintenance technician finds status and failure information, the engineer can access design and performance data, and the administrator has the plant efficiency translated into readily understandable asset management terms (see Figure 9). This structured interface not only provides each of the plant functions with data it can relate to and understand, but will allow other functional disciplines to "see" the plant through the perspective of their coworkers. A unique cross-training benefit.

And what of the training function? This function has been physically decoupled by requiring that it be performed in a different, non-networked computer. The potential for collisions between a training scenario and real plant operations was not left to chance.

The integration of the functional OMETA areas is expected to pay great dividends in the form of reduced cost, better communication, and an improved understanding of the team effort that is required to meet or exceed today's commercial operating standard. The administrative task of process assessment will now be possible as never before due to the open exchange of information. The admin decisions that are necessary to provide the O&M team with the resources to achieve the commercial efficiency goals will become clear due to the visibility of cause and effect provided by the program.

Conclusions

A new approach to integrating the information needs of the total infrastructure necessary to support the operations and maintenance of a major process plant is being tried at the Parris Island USMC base in North Carolina. This approach provides a level of customized information access that was previously not possible by parsing a common data base into information specific multi-user inter-

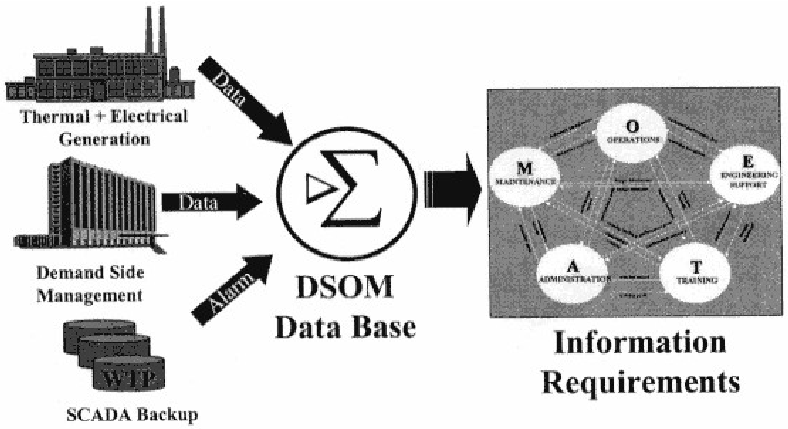

Figure 8
Parris Island Facilities Integration Model

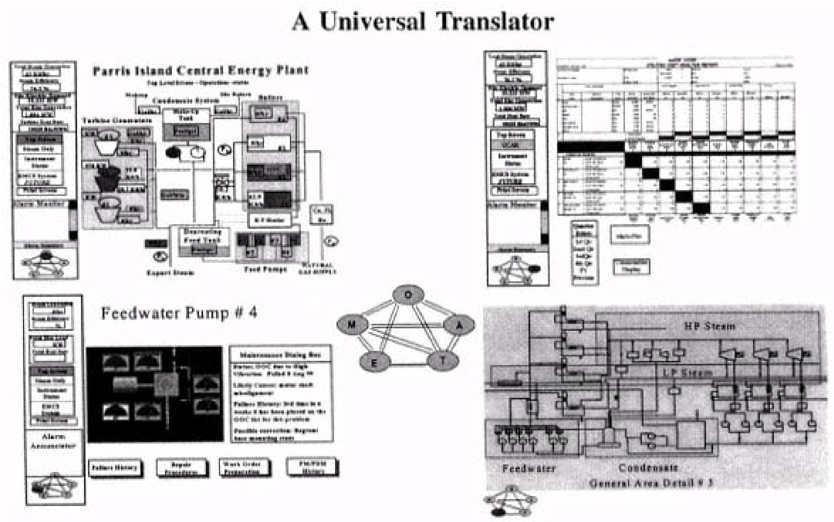

Figure 9
Dsom Ii Functionally Tailored Multi-User Interface

faces. By including all the functional requirements of the total infrastructure, large paybacks in efficiency, work flow, and aware decision making are expected to be gained by this process.

Besides contributing substantially to meeting the goals of the 1999 Executive Order, this technology is reducing environmental pollution, and enhancing the reliability of the thermal energy systems as well. It is estimated that, if applied USMC-wide, proactive condition-based O&M would save the U.S. taxpayer approximately $12.2 M per year on USMC base energy alone. The results from Twentynine Palms have clearly demonstrated that fuel savings is only the first chapter in the condition-based plant asset management handbook. The second chapter on process integration is about to be written in Parris—Parris Island that is.

Chapter 63— Scheduling of Condition-Based Predictive Maintenance in ANSDK Using Computer Based on-Line Monitoring Network

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Abstract

Investment in monitoring systems can be used towards the reduction of the maintenance cost of modern plants. Sensors and instrumentation, which record variables describing performance, vibrations, and other process parameters, have granted new opportunities in the design of trend-monitoring systems. These systems can be used toward scheduling of maintenance without impacting planned production schedules. Further, by monitoring these variables to provide information about the changing life expectancy, maintenance engineers can base service on actual field conditions, rather than relying solely on standard machine life estimates. Moreover, these systems can increase the overall efficiency by reducing energy consumption.

Energy conservation for any industry is critical because of the high cost of electricity and the rapid technological concern for energy efficiency in our society. Significant amounts of energy and money can be saved by proper maintenance in a mechanical drive system. There is a strong linkage between the mechanical vibration, temperature of the machine parts, mechanical efficiency, and energy consumption of a machinery. Through our international joint project, "Scheduling of Condition-based Preventive Maintenance in ANSDK Using Computer-based On-line Monitoring Network", between USA and Egypt, we extend our vibration analysis application in the end user plant. ANSDK is the largest modern steel plant in Egypt. This paper describes our experiences in implementing applications of predictive CMMS in ANSDK and their results.

Background Information

This project has been funded by USAID and the Foreign Relations Coordination Unit (FRCU) of Supreme Council of Universities of Egypt, as the University Linkages Projects. The purpose of this grant is to establish linkage between US university (Southern University), Egypt university (Alexandria University), and end user ANSDK.

There has been good academic, scientific, and industrial relationship between Alexandria University and the end user ANSDK. It grew with time to include consultation services in the fields of vibration analysis and diagnostics, aimed at engineering and maintenance over the last ten years. Alexandria National Iron and Steel Company (ANSDK) at El-Dikhesla is located 15-km from Alexandria. ANSDK consist of 2 Midrex process plants with normal capacity of 1,600,000 Metric Tons per year; 4 electric arc furnace melting plant with capacity of 1,555,200 Metric Tons per year of molten steel. There are 2 separate plants for rolling of steel billets, one produces steel bars and the other produces wire rod. End user (ANSDK) represented by a team of four engineers from maintenance departments participates in this effort by furnishing the required support in software installation, data collection and processing, test running, monitoring and control. A computer network center has been established at ANSDK to provide the required service to different departments.

Introduction:
Maintenance Strategies

To retain the competitive edge, it has become increasingly important to reduce operational costs in order to improve profitability. Maintenance strategies have been fully re-evaluated over recent years and improved in a number of ways. Monitoring and analysis of machine vibration have been found by many[1,2,3] to be in excellent means of predicting incipient failure in sufficient time to allow repairs to be made at the most suitable time. Condition-based maintenance implies that the condition can be monitored from the surface of running machinery and maintenance performed only when needed [4,5,6]. The procedure is made simple by computerizing the process of vibration analysis and fault diagnosis [7,8,9,10], but this needs time and training of personnel.

The perennial question still remains—how can measurements be performed economically and yet still be effective for making decisions concerning maintenance? The answer will be in Tele-monitoring. A center staffed by condition monitoring specialists aided by the most up-to-date condition analysis and maintenance scheduling software, can receive the signal from any remote machine and send back the correct answer concerning the type of the problem and its remedial action together with the appropriate maintenance schedule in a matter of minutes depending on the communication channel used.

Problem Definition & Background

Productivity and product quality represent the main aid to economy reform in most developing countries. Modern high technology has created a challenge for those countries regarding the use of highly sophisticated machines for high levels of productivity, and product quality. These machines will need both, large investment and high level of attention. Keeping these machinery producing—at high level—a product of high quality, as long as possible, is a major challenge of modem industry. Maintenance is the name of the game. The crudest method for operating machines, is to run them until they fail, and then try to repair them in order to make them fit for further service. This is called Corrective (Damage Based) Maintenance. This method of operation can be very expensive in terms of lost output and machine destruction, and in addition, can involve hazards to personnel.

It is well recognized that, particularly in the case of large and expensive plant, it is more economical and operationally satisfactory to carry out regular (Time Based) maintenance. This involves the maintenance of the machine or its various components at regular intervals to reduce the likelihood of failure during the time when the machine is required to be available in use. The problem in planning this type of maintenance, lies in the choice of an appropriate maintenance interval for the machine, because the actual running time before maintenance is really needed, is not constant, but varies from one occasion to another, due to differences in the operation of the machine, and in behavior of its components. Figure 1 shows how the running time to failure of a typical machine, would be likely to vary if no maintenance were carried out. The vertical highlighted line in this diagram represents the safe time interval between preventive maintenance work, which could catch all the failures before they occurred. If this safe overhaul interval is chosen, however, there will be many occasions when the machinery will be overhauled long before it is really necessary, such as those cases at the right hand side of the curve, where it could have run on, for much longer without failing. This situation wastes production time, and by increasing the frequency of maintenance operations, the incidence of human errors on reassemble of the machine, increases.

A more satisfactory compromise, in terms of maintenance strategies, is to carry out preventive maintenance at what may be irregular intervals, but to determine these intervals by monitoring the actual condition of the machine. For such Condition-Based Maintenance to be possible, it is essential to have knowledge of the machine condition and its rate of change with time.

Function of Condition-Based Maintenance

The main function of condition monitoring is to provide knowledge of the machine condition and its rate of change with time. The utmost advantage of condition monitoring is to know, well ahead of time, when the machine condition will deteriorate to an unacceptable level, in order to prepare for remedial actions. This can be made using Trend Monitoring, which involves continuous (online), or regular (off-line) measurements of machine condition, using one of the parameters listed in Figure 2, and the interpretation of data collected during machine operation, to indicate variation in the condition of the machine or its components in the interests of safe and economical operation. The study of the trend in these measurements with time will indicate when deterioration is exceeding a critical rate. This principle is indicated in the Figure 3 which shows the way in which such trend monitoring can give a lead time before deterioration reaches level at which the machine would have to be shutdown. This lead-time is one of the main advantages of using trend monitoring rather than simple alarms or automatic Shutdown devices. Advances in machinery monitoring technology have made it possible to monitor and diagnose failures of groups of machines continuously and remotely.

The last twenty years have seen an explosion in machinery monitoring techniques, new sensors and new data logging and analysis systems, mean, that almost any physical attribute of a machine, can be instrumented and monitored (e.g. Temp., Pressure, Oil analysis, Vibration, etc.), but data is not information. What the maintenance management wants to know, is what needs repair, and when can it be done without interference with production schedule. In summary, how to transform collected data from running machinery into realistic maintenance schedules. Hence, the problem in using this technology lies in two main criteria:

1. Its economic feasibility; and,

2. The need for comprehensive maintenance planning and scheduling programs that use the information about machinery health and the remedial actions necessary, and translate this into definite prescribed activities scheduled so as not to interfere with production plans.

Regarding, the economic feasibility of this technology, to Egyptian industry, in general, and to continuous industries, in particular, many published work [11], was made by the author, that proved it is more than economically feasible.

Energy Conservation by Condition Monitoring

There is a strong relationship between energy consumption in a component and the level of vibration it is undergoing[12]. Steel plants dominate energy use in industry. Energy conservation for industry is critical because of the high cost of the electricity and the rapid technological concern for energy efficiency in our society. Significant amounts of energy and money can be saved by proper maintenance in a mechanical drive system. There is a strong linkage between the mechanical vibration, temperature of the machine parts, mechanical efficiency, and energy consumption of machinery. Machinery monitoring and dynamic maintenance schedules can also help to reduce the energy consumption of a mechanical drive system.

Scheduling of Condition Based Maintenance

Planning and scheduling of Condition-Based Preventive Maintenance is the current research activity of the project group that needs large-scale industrial application, such as the one proposed here. The main streams of this project, will be:

1. To consider fault indicators (Vibration, Temp., Pressure, Oil analysis, . . . etc.) in combinations and to relate them to historical data about the characteristics of known faults. Since the combinations of indicators and the current and historical data, are almost all specific to a particular machine, the data must be organized for flexibility as well as ease of access. Using microcomputer technology, it is possible to apply latest techniques in database design to achieve these objectives.

2. To integrate better points in both the Time-Based and Condition-Based maintenance strategies into a combined strategy and to build on the base of this combined strategy, a realistic maintenance scheduling software that can be used in ANSDK in particular and in the Egyptian industry in general.

3. Based on the above two streams, Maintenance Management Center will be established in ANSDK, that utilizes data on the different machine conditions; both from on-line and off-line networks, for issuing the necessary dynamic maintenance schedules.

4. A complete analysis of the correlation between energy consumption and vibration level of the different machines is to be made in order to make use of energy conservation plans in ANSDK by reducing vibration levels in working machines in one hand and by eliminating machine downtimes on the other hand.

The center will first serve ANSDK complex, including the new Flat Product Rolling factory. Its service can then be extended to other surrounding industries. This center is expected to be the first of its type in the Middle East Area, regarding the high technology used and appropriate services it will introduce to the industry in this area.

Outline of Research Approach:
Rationale for Condition-Based Preventive Maintenance Plans

A Flow production line, typical for continuous production, is the case at "ANSDK". This line can be highly abstracted into a number of series and parallel stations, possibly with standby units at some of the critical points, (Fig. 4). When each unit or element of the flow line is treated individually, and the vibration level of some of the selected measurement points indicates state of the machine, some interesting results can be obtained. A series of readings of the vibration level, taken at proper intervals can be correlated, analyzed and the trend pattern of vibration is found and expressed explicitly as function of time. When proper limits for acceptable behavior of the unit are set in terms Iof alarm and shut down levels—useful and reliable information can be laid down for planing purpose, viz. the time at which the service or maintenance is due and the period after which the machine will be at the lowest performance level, (Fig. 5). The period (t) is that available for making an economic decision on the proper time for maintenance.

In case of a flow line, a problem of shutting down the whole line when a single machine needs maintenance or service is inevitable. However, at that time, maintenance of a number of machines can be carried out simultaneously, and hence, total idle time and corresponding lost production can be reduced. Therefore, it is more economical to plan for maintenance, repair or service of a number of machines at a single stop of the whole line. Bearing in mind that a planned stop of a machine to do some service or repair is a techno-economic aspect, maintenance scheduling will be treated in a different manner.

The actual condition of the machine is indicated and further diagnosed by the proper use of vibration analysis. The decision on when to stop before breakdown of the system (wear-out failure) is a compromise between taking a corrective action once the alarm level is reached at a given cost, or extending the use of the system, under the risk of a catastrophic failure, to a certain period till shutdown. Therefore, the solution depends- among other factors- upon the capital cost of the part to be replaced, cost of catastrophic failure, interval between alarm and shutdown points and accuracy of the pattern or model describing the vibration behavior of the part in question.

Therefore, if Condition-based Maintenance is properly applied and implemented, scheduling maintenance activities will be a balance between under-maintenance with a high probability of catastrophic failure, and the high cost of the safe over-maintenance. Thus a model designed and properly implemented will further lead to a higher reliability, maintainability, availability and extended useful life of the machine being monitored.

An assessment of the above for a single unit, (Fig. 5) is given as:-

CsP: capital cost of a spare part.

I: economic efficiency of capital (Return On Investment, ROI).

Csd: cost of catastrophic shutdown (lost production, hazards, propagated damage . . . etc), given as a function of time elapsed after alarm, as $g(t_i\text{-}t_a)$.

Cm: cost of maintenance activities and parts fixed or replaced

p(t_i): probability density function, p.d.f., of the failure at anytime (t_i) between alarm and shutdown level.

tp: shut-down time, as imposed by production requirements.

In this case, potential gain of using a diagnostic system (gain due to a Condition-based timely shut down) is obtained from:

[*Gain due to extended use—Expected cost of a catastrophic shutdown*].

The problem is reduced to:

$$\underset{t_i}{MAX}\left[Csp * I * g(t_i - t_a) - Csd * \int_{t_a}^{t_i - t_a} g(t_i - t_a) * p(t_i) \cdot dt_i \right]$$

Subject to:

$t_a \le t_i \le t_s$, and $t_p \le t_i$, and t_i □ 0

When a flow line is investigated, the vibration behavior of the units composing the line is critically analyzed. Figure 6 is a typical pattern for the vibration behavior of a flow line. Treating units individually, the line will be stopped at t_1, t_2, such that when stopping the line at t_1, it is possible to include service of machines (2) and/or (3) . . . etc. Alternately, the activities can be scheduled at 2 stops for advantage . . . and so forth. Bearing in mind that the time span for scheduling maintenance (planning horizon) is a continuous variable; there are an infinite number of possible solutions, with a unique optimum. It is evident that some units will be serviced at earlier than the time of complete failure. The Minimum cost schedule depends upon the cost of stoppages (outages), idle time cost, lost production, delays, not meeting demand and the capital cost of the part to be replaced.

The case of a system with (n) units can be figured-out as follows; using the same terminology as before:

$$\underset{t_i}{Max} \sum_{j=1}^{n} \left[Csp_{ij} * I * g_i(t_i - t_a) - Csd * \int_{t_{aj}}^{t_i - t_{aj}} g_j(t_i - t_{aj}) * p_j(t_i) \cdot dt_i \right]$$

along with

$\min(t_{aj}) \le t_i \le \min(t_{sj})$, and $t_p \le t_i$, and t_i □ 0

The proposed study will cover:

1- Building-up a mathematical model for the vibration-time behavior.

2- Optimal scheduling of maintenance for a single unit being monitored.

3- Optimal scheduling of maintenance activities for a multi-unit system.

4- Development of an algorithm to yield a suitable shutdown work schedule with the corresponding milestone chart (s).

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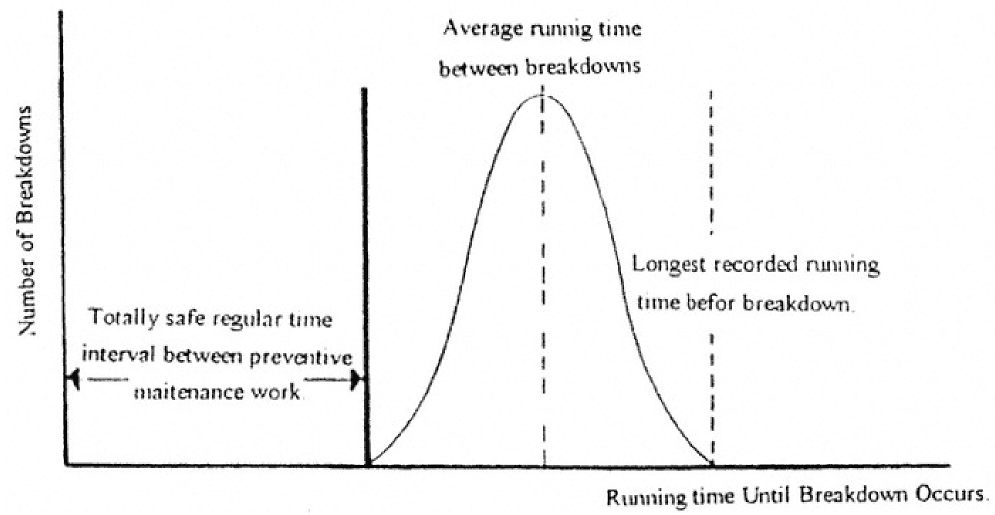

Figure 1
The Pattern of Machinery Failure Without Any Preventive Maintenance

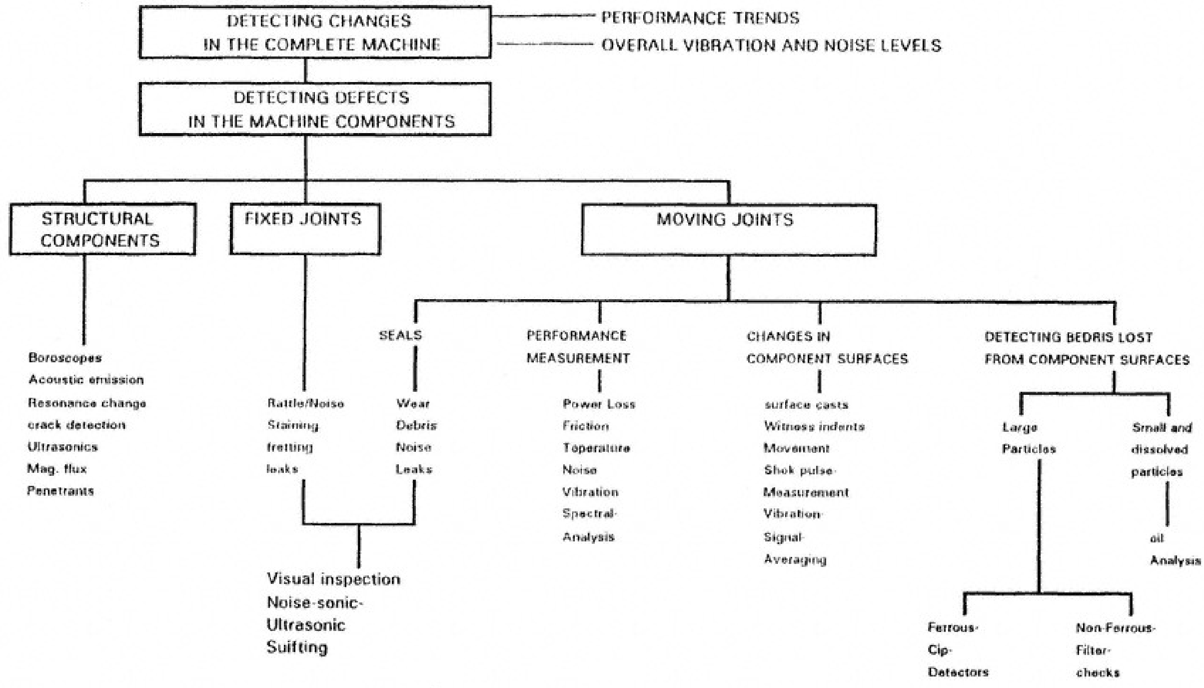

Figure 2
The Indications of Machine Or Component Deterioration

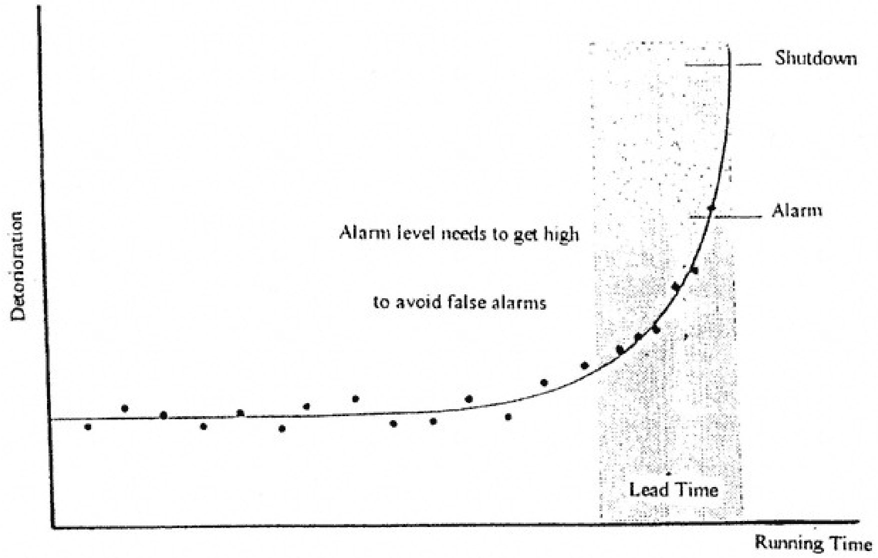

Figure 3
The Regular Monitoring of Deterioration To Give Advanced Warning of Failure

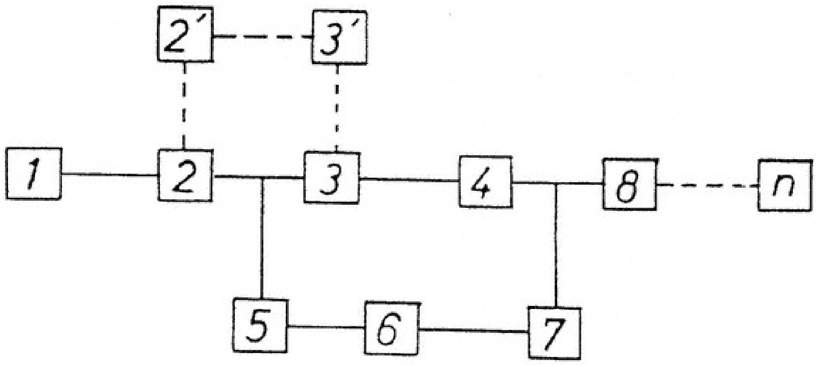

Figure 4
A Typical Flow Line With Parallel and Series Stations

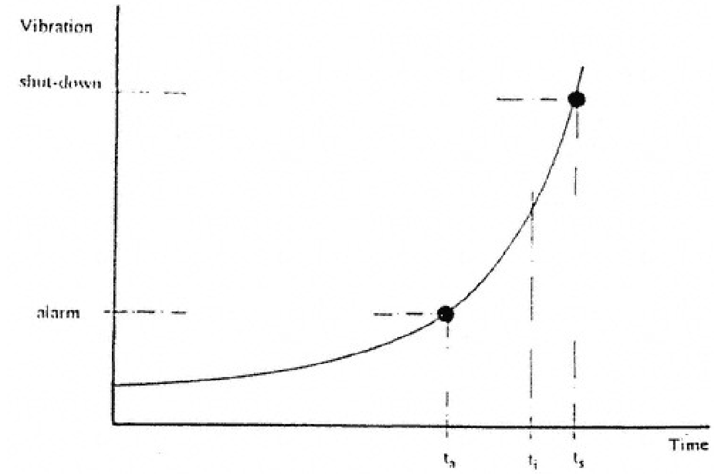

Figure 5
Time for Planned Shutdown for a Single Machine

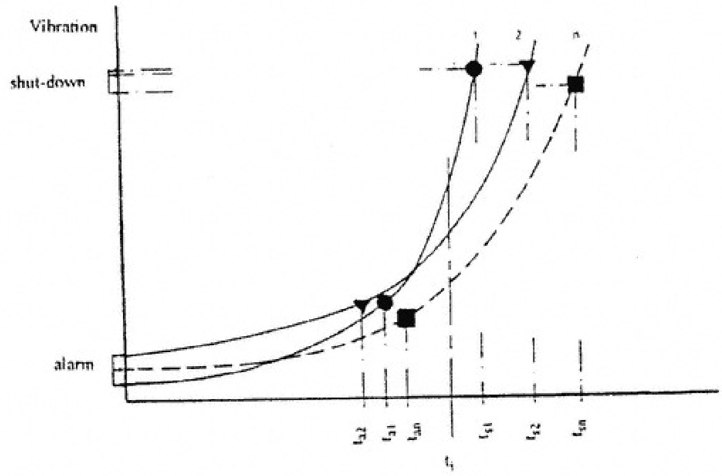

Figure 6
Time for Planned Shutdown for a Flow Line

Chapter 64— Component Diagnosis and Life Span Estimation for Optimal Replacement

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Abstract

The functions of monitoring, failure diagnosis and estimation of remaining operable lifetime of process components must be performed in an integral manner, such that the overall system productivity is maximized. Plant components include sensors (measurement devices) and field devices such as controllers, valves, pumps, motors and other equipment. Some recent advances in monitoring and diagnosis of plant components, and approaches for their life-span prediction are presented in this paper. Examples of applications to operating process systems are discussed.

Introduction

The modern strategy of plant operation and maintenance requires the integration of plant monitoring, impending equipment fault detection and isolation, and life prediction or prognosis. The latter enables the plant personnel in making decisions about maintenance activities and equipment replacement, if necessary. In a global sense, the monitoring and trending of degradation signatures must be performed for sensors as well as for field equipment. The task of fault isolation becomes complicated when failures of multiple devices have to be resolved. This paper presents some of the recent techniques being developed for equipment diagnosis and prognosis, and their implementation. The advanced techniques include digital signal processing, wavelet analysis, group method of data handling, data-driven models, and applied artificial intelligence tools. When needed these tools are integrated with statistical analysis of equipment failure data [1].

Definition of Terms Used in this Study

Equipment Monitoring refers to the tracking of degradation-sensitive parameters that are extracted from measurements made on the equipment. In this task we look for changes in the signatures of interest. **Diagnosis** is performed to determine the cause of changes exhibited in the monitoring phase, and to isolate the devices that indicate incipient failures. **Life Prediction** or **Prognosis** is concerned with the estimation of remaining operable lifetime of equipment [2]. These include process sensors, field devices and other equipment. Generally, life prediction has a higher degree of complexity compared to the other two tasks, since it requires the knowledge of alarm and failure levels, and often the behavior of an individual component would deviate from the population average. These and other complexities of component diagnosis and life-span estimation are discussed in this paper. The ultimate goal is to integrate operation and maintenance such that equipment upgrade, maintenance and replacement may be accomplished with minimum interference with the plant operation.

Equipment Monitoring and Diagnosis

From the definitions presented above monitoring and diagnosis increase in complexity in that order. Equipment monitoring plays a key role in *predictive or condition-based maintenance.* Condition-based maintenance requires the monitoring of equipment performance signatures that are reflective of degradation and incipient failure of both rotating machinery and stationary equipment (such as fossil boilers, nuclear steam generators, heat exchangers, piping and pressure vessels). Some of the techniques used for equipment monitoring and diagnosis are presented in this section.

Process and Equipment Monitoring

The first step in condition-based maintenance is the systematic monitoring of possible degradation of plant equipment. This is performed by certain key measurements. Some of these are measurements are process variables such as pressure, temperature, fluid flow rate, liquid level, chemical concentration, metal thickness, fiber or sheet tension, velocity, actuator settings, control functions, and many others. Changes in process variables are either caused by changes in the process operating point, degradation of sensors, and/or degradation in the process system itself. Other measurements are directly related to the equipment performance. These include vibration, motor current, voltage, flux and other electrical measurements, lubrication oil properties, temperature or thermal profile using infrared sensors, ultrasonic and eddy current testing to monitor cracks, deposits, pitting, and others.

The process measurements may be generally classified as low frequency signals (0–100 kHz), whereas equipment condition monitoring measurements extend to several kHz, and even in the range of MHz. An example of data acquisition in the MHz region is the detection of arcing in DC motors [3]. In many cases application specific integrated circuits (ASICs) are used for machinery condition monitoring. The raw sensory measurements are often compressed to signatures that bear direct relationship to the degradation being monitored. Both time-domain and frequency-domain signatures are computed and trended. When the data length is short or when transient behavior (such as start-up and coast-down of machinery) has to be monitored, special signal processing techniques, such as wavelet analysis and short-time Fourier transform [4] are employed. In many cases, one or more parameters or variables are determined as a function of other related variables. The difference between the measured and estimated values is then monitored to establish equipment performance. Figure 1 shows a block diagram of a general monitoring, diagnosis and prognosis system. This system is designed so that the various modules may be implemented selectively, with the cross-reference among them taking place via the system executive. This approach is useful in optimizing the functional aspects of the system, and to provide effective allocation of maintenance tasks.

Fault Detection and Diagnosis of Plant Components

The second step in achieving a total maintenance strategy is to integrate monitoring and fault detection/diagnosis of plant components such as sensors, actuators, control devices, machinery and other equipment. Several techniques have been reported by industry and academia for monitoring isolated sensors and system components [5-7]. Model-based local sensor and fault diagnosis approaches were developed for specific applications. Such approaches assume that a system fault being monitored is relegated to a specific plant component and occurs in an isolated manner. This assumption is not often valid and may lead to an incorrect diagnosis and improper maintenance actions.

Recently, a new approach for fault detection and diagnosis has been developed, that integrates optimal data-driven models for process and control function estimation, a knowledge base of the relationship among the variables, and a decision-making module. The approach used for process estimation is called the Group Method of Data Handling (GMDH) [8] that generalizes the multi-dimensional mapping among sensors and device specific inputs and outputs. Artificial neural networks and physics models may also be used to achieve this goal. The purpose here is to use algebraic data-driven models that do not require explicit first-principle relationships, and avoid extensive computation involved in training a multi-layer artificial neural network. The model generalization is accomplished by using a rational functional approximation, rather than a polynomial-type approximation.

Figure 2 shows the architecture of this fault detection and isolation (FDI) system [13]. Combining equipment monitoring with an FDI system, and then utilizing this information in a condition-based maintenance program may enhance the overall reliability of a process plant.

Examples of Applications to Plant Monitoring and Diagnosis

The monitoring and diagnosis techniques have been applied to sensors and other field devices. Some examples of applications of these techniques to sensor validation and component diagnosis are presented in this section.

Signal Validation and Instrument Calibration

The validation of sensor signals is performed either by comparison with redundant sensors or by comparing the sensor output with an estimate. Artificial neural networks, data-driven models and the Kalman filtering technique are often used to generate a residual error signal which is then trended as a function of time [9]. An important application of signal validation is in instrument calibration verification. Many process and power plants have thousands of measurement points. The periodic calibration of all the instrument channels is very expensive and may not be necessary. Techniques have been developed [10] to monitor sensor outputs and compare them against their expected values. This deviation is then monitored to isolate any possible decalibration of one or more instrument channels.

Figure 3 shows an example of redundant measurements indicating the level of water in a nuclear reactor pressurizer. The signal validation indicates a high degree of consistency among the three measurements, except in the 0–100 minute initial interval. The deviation shown by sensor #2 is an error as shown by an estimate of the pressurizer level [11] using data-driven models. A generalized consistency checking, that trends the error between the sensor measurement and its expected value, may be used for monitoring the calibration status of instrument channels without performing intrusive tests.

Diagnosis of Incipient Failures

A new approach [8], that combines rational function approximation and group method of data handling, has been developed for component fault detection and isolation. This method is capable of diagnosing multiple equipment faults in large process control systems. The list of devices that are tracked includes instrument channels, controllers, actuators, rotating machinery (such as pumps, compressors, fans, turbines, etc.) and other equipment. The failure diagnosis is performed in two steps: the first module monitors system variables and control functions and checks to determine if the changes in them are due to changes in the system set points or due to a device fault. The second module is used to isolate the device when a fault has been detected, and uses a rule-based decision making method. The technology has been extensively tested with application to an experimental water loop, which consists of sensors and field devices. Figure 2 shows the steps involved in its implementation.

An important observation is that in systems with feedback, even when a sensor that monitors the process set point is degrading, the control action forces the error to go to zero and the sensor measurement follows the set point. In this case the sensor degradation cannot be identified using a routine monitoring technique. If this fault goes undetected, heavy burden will be imposed on the control system in trying to minimize an artificial set-point error. This and other complex degradation cases are diagnosed using the current technique.

Development of Equipment Life Prediction Techniques

Review of Life Assessment Models

The estimation of the remaining service life of a component requires a variety of data and information. These include damage mechanisms, loading conditions, material properties of the component structure, and environmental conditions. The development of models of life assessment fall into three broad categories:

1. Those involving theoretical modeling, the acquisition of loading condition history, and the use of standard material data.

2. Those associated with in-service inspection and testing that need direct access to the component for measurement and monitoring.

3. Those based on probabilistic and statistical inferences using failure rate models that are usually developed for a population of similar devices.

Approach (1) requires the knowledge of operational condition and the physics of degradation. This knowledge allows the life assessment process to be more deterministic than those based only on in-service measurements, and is also useful in the design phase. The application of Arrhenius equation for the degradation of motor insulation is one such example. This approach may not give a good prediction during the actual operation of a component since it depends on standard material data that could be different from operational measurements. The second approach (2) uses stochastic techniques and analysis to past data to establish a trend model which can then be used to forecast future trends and to estimate residual life. The third approach (3) utilizes lifetime or failure time distribution models for a class of identical machinery operating under similar conditions. The failure model and its parameters are determined from measurements of signatures that are indicative of equipment degradation. This technique provides the general characterization of component lifetime; however, it may not provide a reliable life prediction of a specific component. This is due to the fact that there may be several variables associated with a specific component, which is not true for another device from the class. The probabilistic approach is useful for establishing alarm and failure levels based on the desired mathematical reliability of the component [1].

General Regression Models for Life Prediction

One approach for trending machine-specific measurements for life prediction is to establish data-driven models that express the current lifetime as a function of the current and past values of a signal or signature. The linear regression is one such predictive model and has the form

$$L(t) = \sum A_i X(t-i) \qquad (1)$$

where L(t) is the current lifetime and {X(t-i), i = 0, 1, 2, . . ., m} is a sequence of measurements. The parameters {A_i, i = 0, 1, 2, . . ., m} are estimated using a least-squares algorithm and component specific data. The model in Equation (1) may be generalized to include nonlinear terms and multiple signatures [12]. The definitions of time-to-alarm and time-to-failure are shown in Figure 4. The regression modeling technique has been applied to several situations, both rotating machinery and heat exchangers [1,12,14].

Application to Steam Generator Performance Trending

The degradation of performance of steam generators and heat exchangers is caused by material build-up, thinning, and due to tube plugging. These result in a reduction in the overall heat transfer coefficient and a reduction in the heat transfer area. Their performance degradation is defined in terms of the drift in the steam pressure as a function of time. It is desired to forecast the future trend in the steam pressure in a U-tube steam generator (UTSG) caused by tube fouling [12].

The change in the steam pressure is related to the change in the overall heat transfer coefficient (and possibly other factors) and is modeled as a quadratic function of time and past values of the pressure itself. This hybrid model is given by

$$P(t) = A_o + A_1 t + A_2 t^2 + B_1 P(t\text{-}1) + B_2 P(t\text{-}2) \quad (2)$$

The model parameters were estimated using historic data from a UTSG with nine data points over a period of eight years. The final model has the form

$$P(t) = 0.645 - 5.0 t + 0.55 t^2 - 0.685 P(t\text{-}1) + 1.338 P(t\text{-}2) \quad (3)$$

Figure 5 shows the comparison between the actual steam pressure and the values predicted by Equation (3). This model can be used to forecast future values of the steam pressure assuming a similar trend to continue. If the decrease in the steam pressure is caused by tube plugging, then the steam generator performance can be monitored as a function of reduction in heat transfer area caused by tube plugging. This information can then be used to make decisions about future tube plugging or to replace a steam generator or a heat exchanger. This is important in light of the fact that replacement of large steam generators is a costly undertaking. A cost analysis, that compares the cost of loss of performance and its ill effects and the cost of equipment replacement, must be made.

Concluding Remarks

Practically implementable equipment diagnosis and life-span estimation methods are presented and illustrated with applications to industrial problems. We believe that the best approach for optimizing the productivity of a manufacturing system is to integrate operation and maintenance by utilizing equipment monitoring, diagnosis and prognosis technologies. One key to the success is the availability of appropriate equipment performance data. The continuous establishment of this database requires the commitment by the corporate management and must be included in initial planning.

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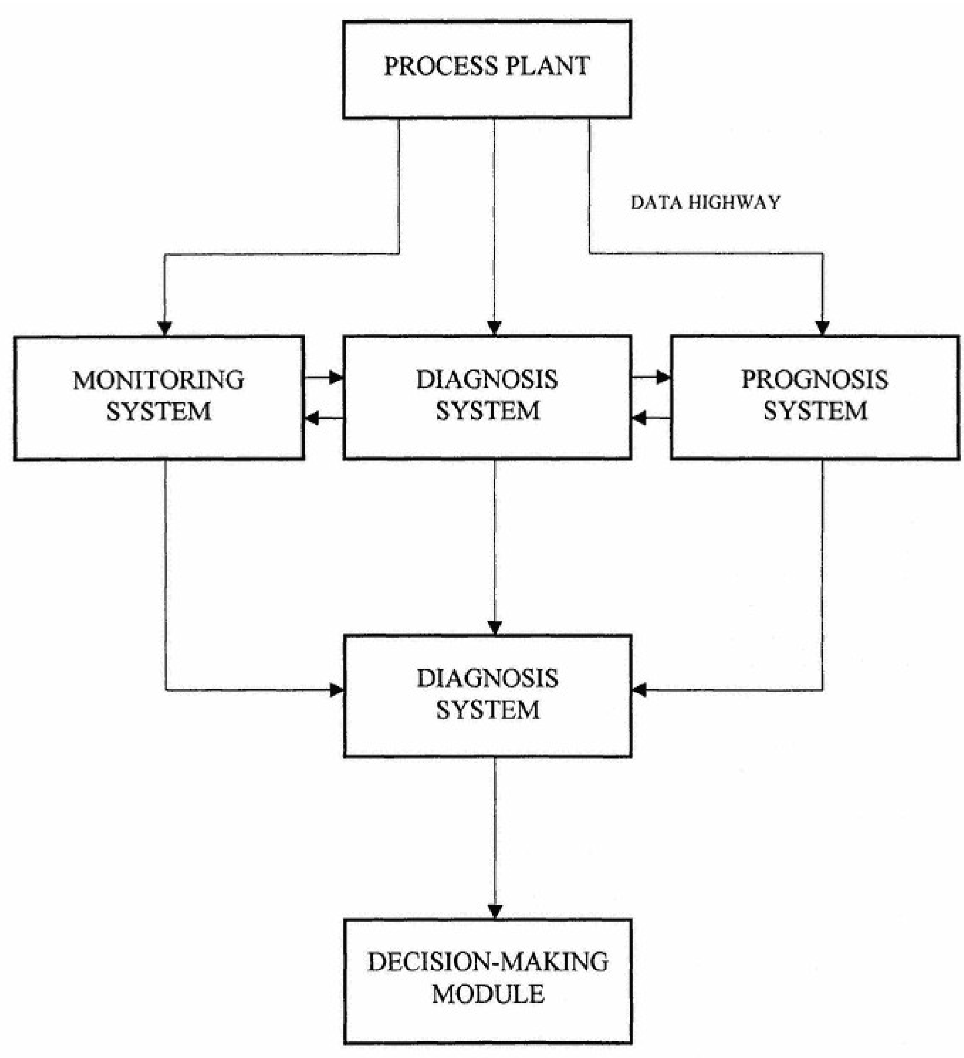

Figure 1
Schematic of an integrated plant monitoring diagnosis and prognosis system

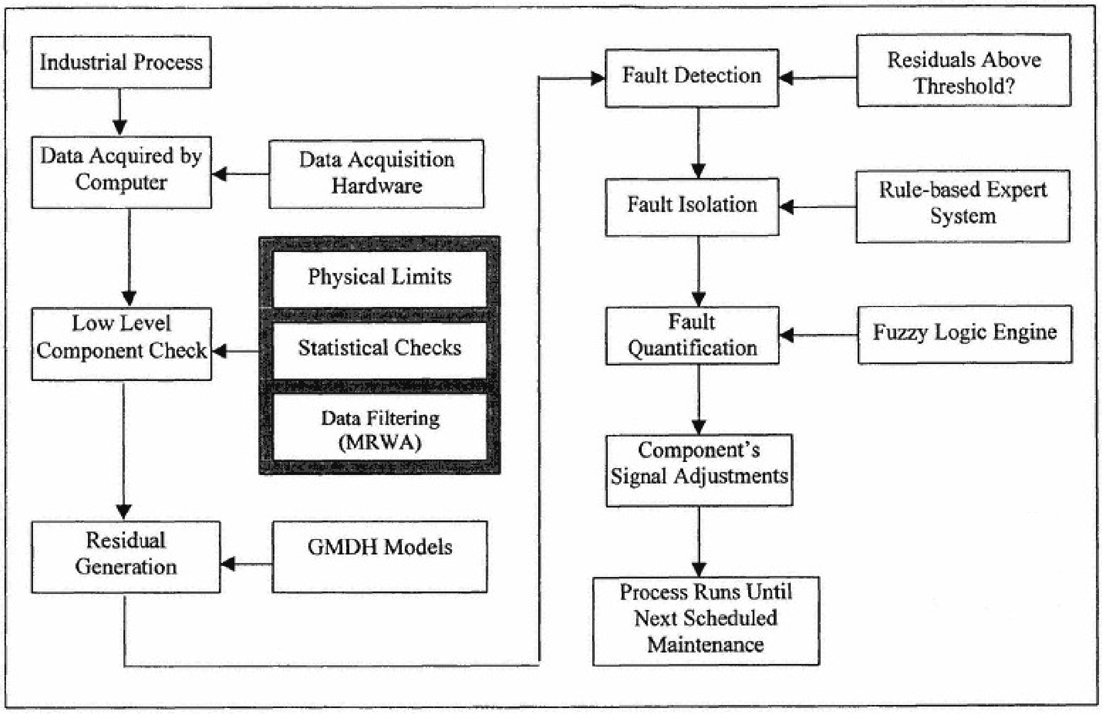

Figure 2
Steps in the implementation of a fault detection and diagnosis system (Ref. 13)

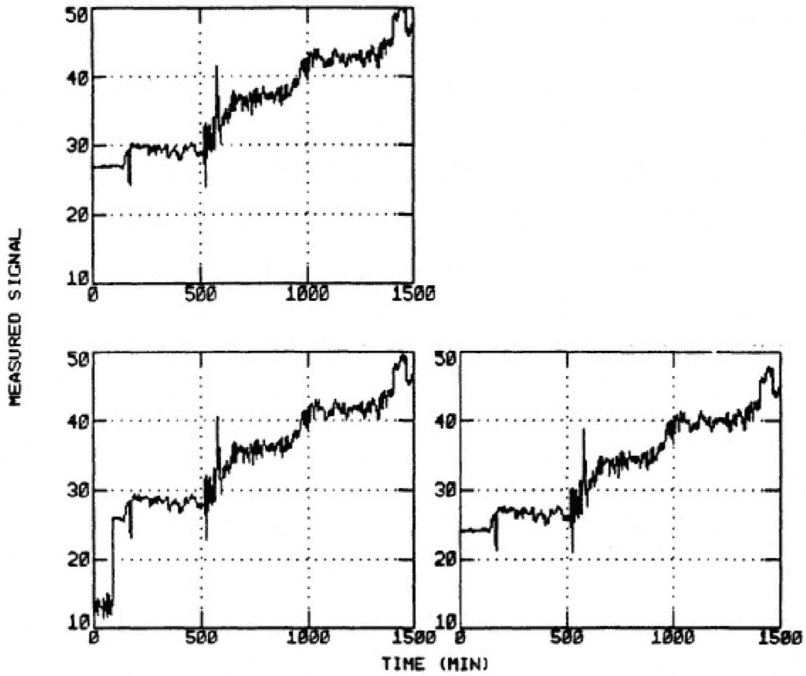

Figure 3
Three redundant pressurizer level measurements in an operating pressurized water reactor plant (Ref. 11).

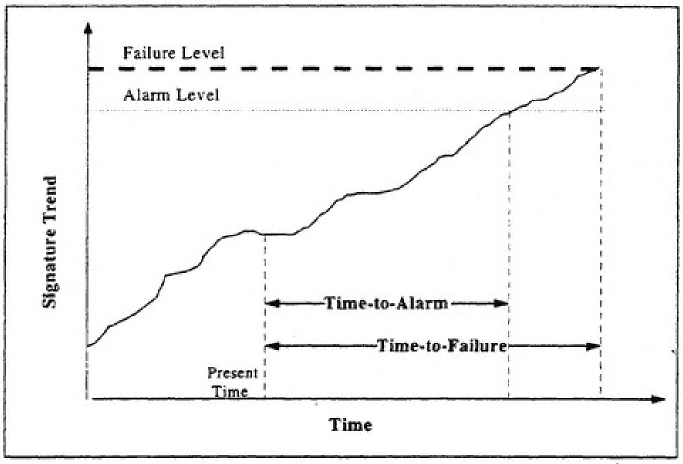

Figure 4
Definition of parameters used in estimating equipment operable lifetime

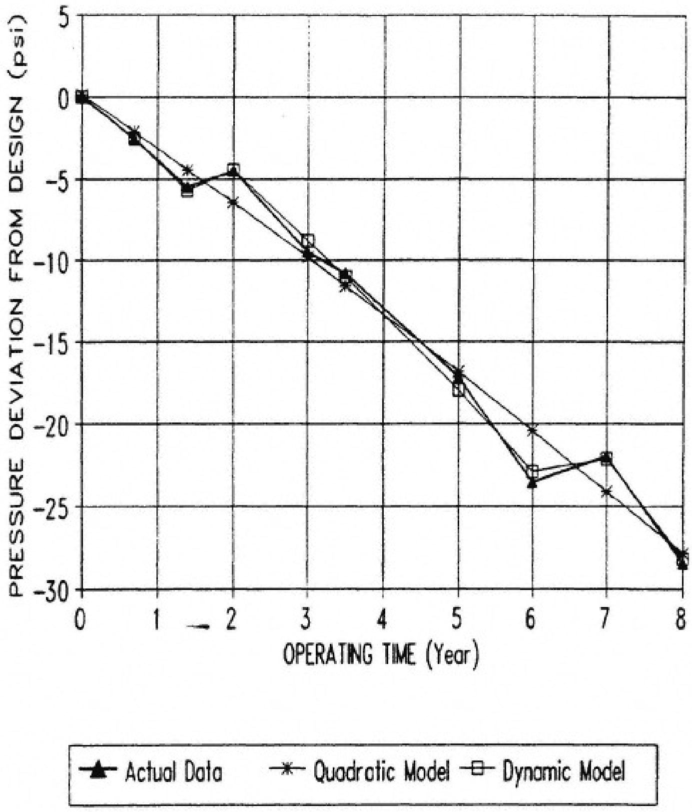

Figure 5
Prediction of steam generator pressure trend using a static quadratic model and a hybrid dynamic regression model (Ref. 12)

Chapter 65— A & E Perspective: Building in Power Quality

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Abstract

The purpose of this paper is to provide the Architect and Engineering firm's viewpoint on power quality. Power quality features can be incorporated into the initial design of a facility if the concept of power quality can be sold to the future building owner. In this paper, the reason for investing in power quality will be explored. Also to be discussed are the advantages gained by the A & E firm which promotes power quality features in initial building design.

Introduction

Power quality simply stated is having the proper voltage, current and frequency such that electrical equipment operates as intended in its environment. Voltages, currents, and electrical environments vary significantly. Power frequency, however, is relatively constant within the United States, but internationally even frequency varies. Add to this the fact that different equipment has varying levels of susceptibility to power quality disturbances. Then combine different equipment together in a process, and power quality quickly becomes a complex issue.

The ideal time to address power quality is when a new industrial facility or an expansion of an existing one is being considered. Power quality can be designed and built into the new facility or expansion thereby avoiding the associated costs and frustration of dealing with power quality problems after they arise.

What are the ramifications of not designing for or building in the appropriate quality of power? Who benefits from building in power quality? What is the role of the architect and engineering (A & E) firm, the utility, the industrial facility manager or client? Let's take a look. . . .

Ramifications of Not Building in the Appropriate Quality of Power

The ramifications are unfortunately quite well known to many industrial facility managers. Broken tools, molten plastic, and/or poor quality fibers are just a few of the obvious signs of poor power quality, but what are some of the less obvious signs? Adjustable speed drives mysteriously tripping, programmable logic controllers getting confused, relays and contactors dropping out are more subtle indications. All of these equals lost production, reduced profits, missed deadlines, possibly lost customers and certainly headaches for the industrial personnel in charge of the facility.

Everyone agrees that poor power quality has negative effects, but quantitatively, what are they? Below in Table 1 are costs for various industry segments for inadequate quality of power:

Table 1
Cost for Industry Segment [1]

Industry	Costs in $
Data Center	$10,000–$40,000 per sag event
Air Traffic Control—Airport	$15,000 per minute
Broadcast Facility	$100,000 per 0.5 hours
Paper Industry	$10,000–$30,000 per sag event
Large Semiconductor Manufacturer	$10,000–$50,000 per event
Plastics Industry	$10,000–$50,000 per sag event
Textile Industry	$10,000–$40,000 per event
Automotive Industry	$15,000 per event
Office Building	$22,000 per 500 kVA Critical Load
Industrial—Manufacturing	$75,000–$200,000 per event

Who Benefits from Building in Power Quality?

The answer is everyone.

Power quality can be addressed either proactively, built in, or reactively, addressed when the problem arises. The benefits of proactively building in power quality and thereby avoiding the loss of products, loss of profits, and loss of peace-of-mind seem obvious, but each year scores of industrial facilities experience power quality problems that could have easily been avoided. The detriments of reactively addressing power quality include not only the costs associated with the problem such as loss of productivity and profitability, but also the time and cost related to diagnosing and resolving the problem. Determining what is causing the problem often involves long term monitoring and sometimes involves more intensive testing, such as sag simulation, in order to provide the most economical solution.

There are multiple groups with a vested interest in ensuring that the appropriate quality of power is available. Equipment designers and suppliers are interested. If the equipment they sell does not operate properly when installed, the purchaser often assumes that the equipment is faulty. This certainly does not promote repeat business. Standards organizations are interested. They recommend what is acceptable or standard for the delivery voltage, current, and frequency as well as what is considered electrically safe. Utilities are interested. When the industrial facility manager or engineer has a problem with new equipment and is satisfied that the equipment is not faulty, he or she then turns to the utility suspecting poor power quality is being delivered to the facility. Organizations such as the Electric Power Research Institute (EPRI) are interested. EPRI supports electric utilities and is very active in power quality testing and education. The A & E firm is interested. Repeat business is critical and designing and integrating systems that do not work, does little for client retention. And last but certainly not least, the industrial facility manager is interested. It is difficult to maintain production and profitability if the process repeatedly shuts down.

It is everyone's responsibility to ensure power quality is built into the facility rather than addressed after losses have occurred. The A & E firm is responsible for working with the client to design the safest, most economical facility possible. The client is responsible for selecting and working with an A & E firm with the capability and experience to design in power quality. The utility is responsible for having the experience and expertise to provide the necessary data and assistance to the A & E firm and the client. The utility is also responsible for providing reliable service. Ultimately, it is a partnership between the A & E firm, the client, the utility, and others such as equipment designers and suppliers, standards organizations, and EPRI. Working together, everyone benefits.

A & E Firm's Role in Building in Power Quality

Let's take a closer look at the role of the A & E firm. There are different types of architect and engineering firms. One specializes in architecture and does minimal engineering work. Another specializes in engineering and to a lesser degree architecture. Perigon Engineering and Architectural Associates is an example of the later, offering engineering services such as:

Specifying equipment drives and programmable logic controllers, for example

Sizing motors

Sizing electrical panels

Developing construction drawings and specifications

Integrating systems

Overseeing start-up

Control system and HMI (human machine interface) design and development

Coordinating transient voltage surge suppression

Specifying uninterruptible power supplies and other mitigating equipment

To successfully design for power quality, A & E firms must consider many issues: which equipment or component of the equipment is susceptible to power quality disturbances; what equipment within the customer's process creates power quality problems for other equipment; and what are the most economical means of addressing power quality concerns.

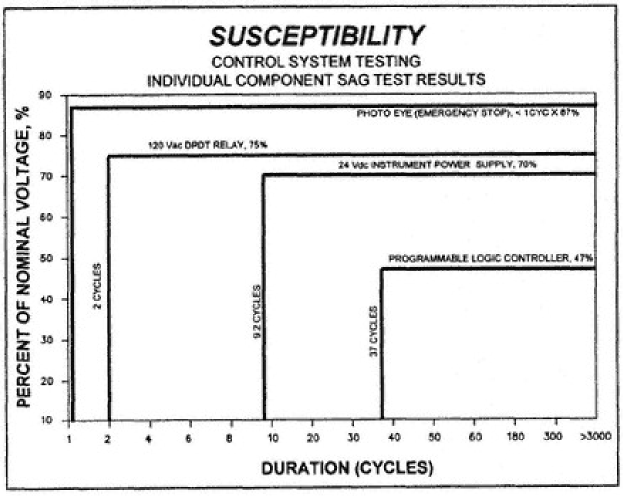

Figure 1
Graph of Equipment Susceptibility [2]

The A & E firm works with equipment suppliers to determine the susceptibility of equipment to common power quality disturbances and to specify the ride-through for each piece of equipment purchased. The A & E firm, if necessary, also works with the equipment supplier to specify testing of the equipment to ensure it meets the agreed upon specifications. All requirements should be included in the purchase contract. An example of a *Susceptibility Graph,* shown in Figure 1, is helpful when talking with suppliers and specifying ride-through.

Figure 1 shows the sensitivity of several pieces of equipment or components of equipment often found in industrial facilities. For example, the double-pole-double-through (DPDT) relay will cause the process to shut down if the voltage sags below 75% of nominal for longer than 2 cycles. The programmable logic controller, however, will not cause the process to shut down until the voltage sags below 50% of nominal for greater than 37 cycles.

Having the specifications for the equipment is not enough. The A & E firm must also have the characterization of the utility electrical service. In order to determine the level of reliability and power quality already available at the facility location, the A & E firm needs to work closely with the utility. There are some questions that the A & E firm will need to ask:

***Questions to Ask the Utility*[3]**

1. Will service be provided from the local transmission or distribution system?

2. How many sustained outages (>1 minute) has the proposed circuit experienced over the past 3–5 years?

3. Where is the closest utility office from which repair crews are dispatched and what is the expected response time in the event of an outage at my facility?

4. How many momentary interruptions (breaker and recloser operations) has the proposed circuit experienced over the past 3–5 years?

5. How many feeders are served from the same transformer bank as the proposed circuit? What types of customers (industrial, commercial, or residential) are on this system and how will these customers' systems affect my facility? How many sustained outages and momentary interruptions have they experienced over the past 3–5 years?

6. Is there a more reliable circuit available for service and, if so, how much will it cost to provide service from that circuit?

7. Is an alternate or spare feeder available for service? If so, what costs are involved and what transfer means are available?

8. Can the magnitude of voltage sags be predicted for a fault on nearby transmission lines?

9. Can computer modeling be performed and my "area of vulnerability" determined?

10. What is the number one cause for faults on the transmission/distribution circuit that will serve my facility? (Examples: lightning, trees, and equipment failure.) Do you have ongoing maintenance or specific programs aimed at reducing these occurrences?

11. Do you have measures and improvement goals for interruptions?

12. Do you have any guidelines or standards on power factor? Harmonics? Flicker?

13. Can you provide a *Characterization Contour Plot* of the electrical system serving the facility location? (See Figure 2.)

The Utility's Role in Building in Power Quality

Like A & E firms, utilities also vary. Some have a strong power quality focus and actively participate in EPRI projects such as the Distribution Power Quality or DPQ Study, which characterized power quality on distribution systems nationwide. These utilities offer a wide range of power quality services, some of which include:

- Power quality monitoring
- Wiring and grounding audits
- Problem diagnosis
- Recommendations for solutions
- Implementation of solutions
- Power quality consulting

Although utilities often separate reliability and power quality into different departments, the two work together to provide the necessary system information to the A & E firm and the client. If the utility has a *Characterization Graph* like the one shown below, for the utility service at the new facility location, it is extremely helpful.

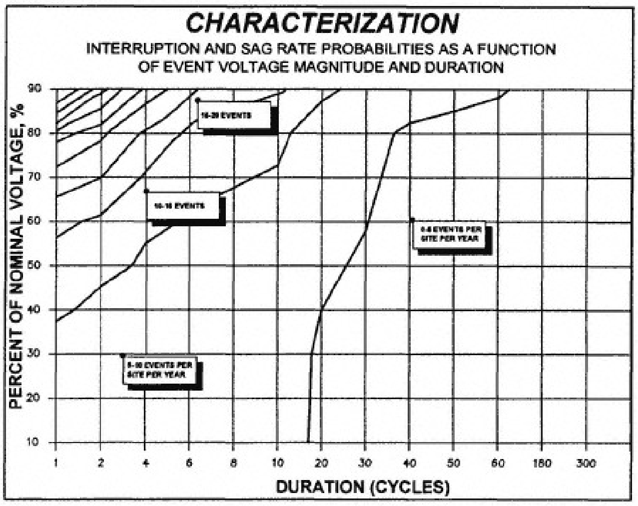

Figure 2
Characterization Graph [4]

Figure 2 represents information collected as part of EPRI's Distribution Power Quality Study. The graph contains contour lines, which represent the number of interruptions and sags a facility is likely to experience in a one-year period. For example, a voltage sag to 70% lasting 20 cycles would statistically occur 5–10 times per year.

The Client's Role in Building in Power Quality

The industrial facility manager or client must select an A & E firm with the experience and expertise to design a facility with the appropriate quality of power for the specific industrial process. To be very proactive, the client would work with the A & E firm and the utility during site selection to determine the levels of reliability and power quality provided by the utility and what if anything would need to be done to improve them to the required level.

Selection of the right A & E firm is critical. Below are some questions the client or industrial facility manager might ask when interviewing perspective A & E firms:

1. What are your standard services? What are your specific capabilities?

2. What is your experience incorporating power quality into the original facility design?

3. How do you ensure the equipment will ride through common voltage sags and interruptions? What do you include in the equipment specifications to ensure power quality?

4. How do you determine the reliability and quality of power provided by the utility at the facility site?

In order for the industrial facility manager to make a good business decision regarding the cost of improving power quality versus the benefits, it is necessary to have a good idea of the cost per event for the particular industrial process. Using data from another similar facility and the information below, it is possible to predict the cost of one process shut down.

Cost of Process Shut Down

1. Lost productivity = (number of employees affected) x (loaded wages per hour) x (down time and start-up time)

2. Equipment damage = cost of repairs, labor (including overtime), and parts

3. Lost revenue = (revenue per hour) x (down time and start-up time)

4. Penalties for late or missed delivery deadline = any costs associated with late or missed delivery of product

Considering the equipment susceptibility, the characterization of the utility electrical service, and the cost of a process shut down, the industrial facility manager working with the A & E firm and the utility must determine if the level of power quality is adequate. A *Compatibility Graph* such as the one in Figure 3 is a helpful assessment tool.

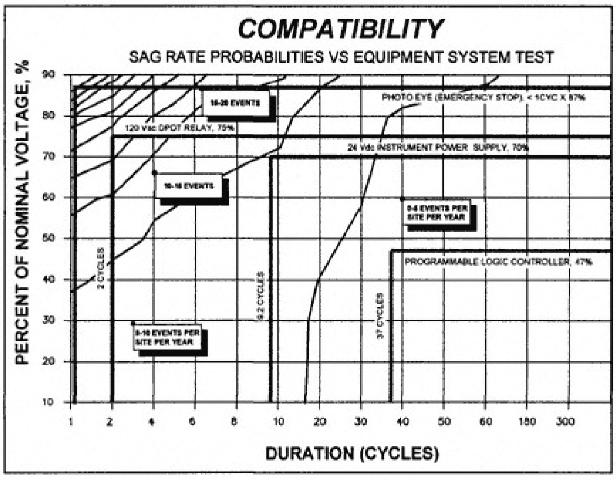

Figure 3
Compatibility Graph [5]

Figure 3 combines Figures 1 and 2. The DPDT relay which drops out when the voltage sags below 75% for longer than 2 cycles will probably take the entire process down between 20 and 25 times each year. The programmable logic controller, on the other hand, will only cause process shut down between 1 and 5 times a year.

Ultimately building in power quality requires a partnership. If the number of process interruptions is not acceptable based on the susceptibility of the equipment and the characterization of the utility service, the A & E firm, the industrial facility manager or client, and the utility must determine the most economically feasible way to decrease the number of interruptions. This can be accomplished on the utility system, inside the industrial facility, or both.

A Case Study

The following design case illustrates the importance of the A&E firm in including power quality in the design stages of a project.

An industrial manufacturing facility manager contacted Perigon to provide electrical engineering services for an iron reduction plant expansion project. The plant expansion consisted of adding an iron reduction unit to two existing ones. Perigon's scope of services included consulting at the preliminary engineering phase, then preparing complete electrical construction drawings and specifications in the detailed engineering phase. Perigon was selected for the project based on its capabilities with power system modeling. Perigon utilizes computer software to aid in power system analysis. This software analyzes voltage drop and system voltage effects due to motor starting inrush and high inertia loads.

Power for the plant was supplied from two utility-owned 37/50 MVA transformers with a secondary voltage of 13.2 kV. Upon completion of the project, the transformers would be loaded to nearly full capacity. The expanded plant would utilize a number of large (3000HP) 13.2 kV motors, a few 4.16 kV (2000HP maximum) motors, and a large number of 480V motors ranging up to 300 HP. The inertia loads on some of these motors would have made starting difficult.

Preliminary engineering included a power study to determine overall system stability once the third iron reduction unit was brought on line. System parameters such as voltages, load factors, transformer impedance, line impedance, X/R values, protective device settings, etc. were entered creating an electronic model of the plant's power system. Once the model was created, the initial analysis included running a voltage drop study with new and existing motors starting and running with the plant at full capacity. It was immediately obvious that voltage drops were unacceptable (up to 13%) at several busses throughout the plant. Several different tap arrangements were modeled on the main transformers and the step-down transformers. Once the plant model was complete, the software analyzed dozens of configurations of transformer tap arrangements. The optimum arrangement was a 5% boost for the main transformers, and a 2.5% boost for all of the plant transformers, except one 2000 KVA unit feeding an emergency MCC that was set at 5% boost. This final arrangement limited the maximum voltage drop to less than 5% for any point in the plant.

Once the voltage levels were established, a number of motor starting models were done, with emphasis on the large inertia loads. A number of the large motors showed starting times up to 30 seconds to reach rated speed. The client confirmed these starting times were within tolerable limits for the process and protective device settings were adjusted accordingly, again through the software. While running the model, the engineer discovered a particular problem while trying to start one of the 480V, 300HP Quench Air Blower motors which drove a high inertia load. The motor was located a long distance from the motor control center from which it was fed. Upon starting, motor voltage dropped to 387 Volts, due to a large drop in the feeder cable. At that voltage, analysis indicated that the typical NEMA B motor would never bring the load up to rated speed. The model was run using the characteristics of a NEMA C design motor, which has a higher break away torque, this time showing a starting time of 18 seconds. Based on this data, it was recommended that the client purchase two NEMA C motors for the quench air blowers, one main and one in-line spare, instead of the NEMA B, which the client did.

By addressing voltage level and motor starting in the design, the client saved approximately forty thousand dollars in direct capital cost, which included the two NEMA Design B motors, freight charges, and labor. Savings attributed to avoiding process interruptions could reach a hundred thousand dollars or more. One further issue that should be considered is system performance after start-up is complete. Motor contactors, for example, are sensitive to voltage sags on the system. With the inertia many of these motors have, a voltage sag of 10 cycles, for example, should not adversely affect the motors. The motor contactor, however, senses this reduced voltage and opens. Devices are currently available (120–480 Volts) to hold the contactor "in" during short duration voltage sags.

Conclusion

Process interruptions due to power quality disturbances are costly and frustrating for industrial facility managers. These interruptions can be avoided. The best time to address power quality is in the early stage of planning a new facility or an addition to an existing one. Working with an A & E firm with power quality expertise, power quality can be built into the new facility thus avoiding the costs and headaches. In order to do so, it requires the industrial facility manager, the A & E firm, and the utility work together toward a common goal, building a new facility where equipment and processes function as intended.

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Chapter 66—
Continuous Process Improvement and Power Quality

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Abstract

The purpose of this paper is to evaluate the application of the principles of continuous process improvement to power quality. Electricity is itself a product and an input into the processes which customers employ to produce yarn, tires, computer chips, coax cable, and countless other products. Process requirements, feedback, performance gaps, process measures and process improvement are all ideas that have been discussed before, but have we put them all together when we talk about power quality? This paper will review the basics of process improvement and detail practical examples where these basics have been applied and power quality considered.

Introduction

Strategies for Continuous Improvement (CI) are commonplace in today's industrial environment. The need to constantly improve quality and/or reduce cost is essential to stay competitive in the world marketplace. Once a philosophy practiced only by the Japanese, continuous improvement has lead to a virtual revolution in quality standards, supplier evaluation, and procedures for cutting costs.

The quality of the incoming power has always been a factor in manufacturing—power outages and disturbances directly affect the ability of a producer to produce and deliver competitive products. Efforts have long been underway to improve and maintain the reliability of the electric utility system. Developments over the last couple of years have revealed economical means for making production equipment less susceptible to power quality problems.

The purpose of this paper is to explore the possibility of evaluating power quality using the tools of continuous improvement or continuous process quality improvement. The effort has certainly gone into improving power quality and the response of equipment to variations in the power, maybe it's time to look at it from another perspective.

Continuous Process Quality Improvement

Much of Japan's manufacturing capabilities were destroyed by the end of World War II and they suffered a horrible reputation for the quality of their manufactured goods. A product made in Japan was the "cheap stuff." With the assistance of people like Dr. W. Edwards Deming, Japan was able to roar back onto the competitive scene with products that in most cases exceeded existing product quality. Today, the rest of the world employs many of the same methods for producing top-quality products. You can't go to a library or a bookstore and not see scores of titles like *World Class Quality; Total Quality; Introduction to TPM; Cutting the Cost of Quality; Quality is Free* and/or *Quality Without Tears*. Many industries have gone through some form of awakening or rebirth as a result of continuous improvement—the most notable being the automotive industry. So why is continuous improvement important? Listed below are some of the benefits.

1. Products or services are of a higher quality.

2. Products or services cost less to produce resulting in a potential for higher profits.

3. Projects run smoother with less irritation or stress.

4. A better reputation or higher prestige can be gained in the marketplace.

5. Greater efficiency is gained which translates into increased productivity.

6. Possibilities for just-in-time service appear and thus smaller inventories can be held. [1]

The Japanese phrase *kaisen* which means making "small incremental improvements or refinements involving everyone on the organization without spending much money," [2] sums up the meaning of and much of the philosophy surrounding continuous improvement.

Before we leave this section of the paper, it's interesting to note that continuous improvement and "fire fighting" are not the same thing! Figure 1 depicts a Juran Trilogy Diagram, developed by Joseph M. Juran who is one of the leaders in the field of continuous improvement. Fire fighting is the act of addressing the spikes in poor quality—bringing the level back down to the quality before the spike. Continuous improvement, on the other hand, improves quality remarkably.

A Ten-Step Cycle for Continuous Process Improvement

Listed below are ten steps, which can be employed to ensure continuous process, quality improvement. These steps will be utilized in examples later in the paper.

1. Identify the major processes involved in the mission and vision of the group or unit.

The first step in making improvements is to first determine, in detail, what your business is all about. What are you trying to accomplish? Where do you see the group or unit five years from now? What are the processes involved in making that happen? Figure 2 illustrates a simply diagram defining the components of a process.

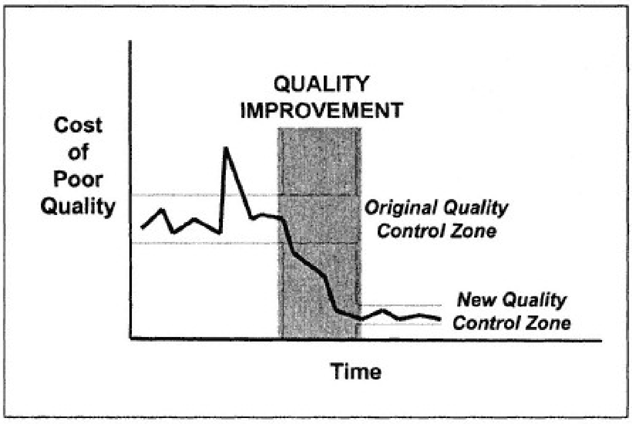

Figure 1
Juran Trilogy Diagram.[3]

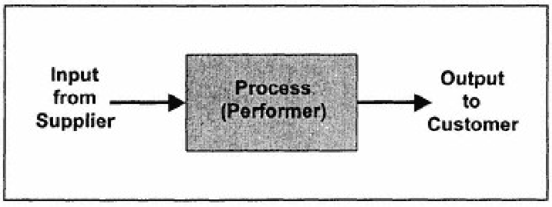

Figure 2
Defining the Components of a Process.

2. Identify the customers or clients of the processes and/or services, and ***their*** measures of quality.

It's important to realize that your measures of success and the measures used by your customers may not be the same. Realize that you will be successful if your customers are successful and look closely at their measures of success/quality.

3. Using tools of continuous quality improvement, analyze the processes, one at a time, to identify:

root causes of problems, and

opportunities for improvement.

4. List possible solutions, using team brainstorming and benchmarking of other similar organizations.

5. Evaluate potential solutions, again using tools of continuous quality improvement.

6. Select a solution based on criteria derived from the customer's definition of quality.

7. Gain acceptance and feedback from decision-makers.

8. Implement the solution, typically on a pilot or trial basis.

9. Measure and evaluate results, using the adopted measures of quality.

10. Repeat the cycle, by going back to Step 2, asking customers anew of their level of satisfaction with the services provided and suggestions for improvement.

A Simple Example

To illustrate the ten-step cycle to continuous process quality improvement, the simple example of a soft drink machine service is given. It seems that there are soft drink machines in every break room in every industrial plant, commercial building, school, etc. This example, therefore, should be one with which most can identify.

Have you ever thought about what goes on behind the scenes in bringing soft drinks to you? You insert your coins (or dollars) and magically, out comes a drink to quench your every thirst. Or does it?

The tools of continuous process improvement include control charts, fishbone or Ishikawa diagrams, histograms, capability studies, quality function deployment, failure mode and effects analysis, designed experiments, checksheets, scattergrams, project management, and benchmarking.[4] Of course to get started, the processes must first be identified and detailed in a process map (Step 1).

Figure 3 illustrates the process by which soft drinks are provided in a drink machine. All of the customers and clients have been identified as stipulated in Step 2. Using an Ishikawa diagram (shown in Figure 4), root causes are identified that would lead to a dissatisfied soft drink customer. An

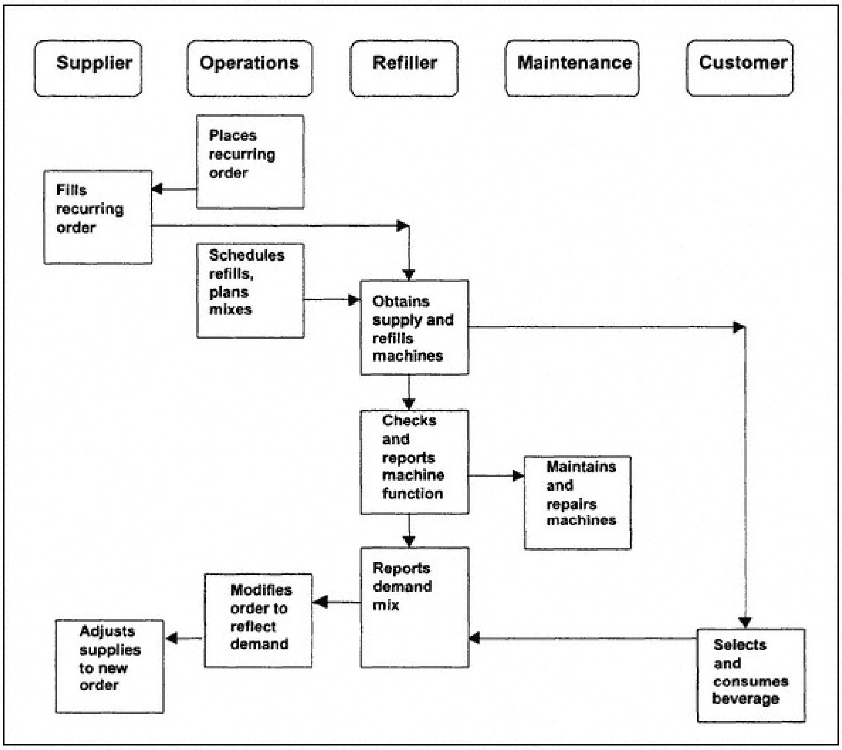

Figure 3
Flow Chart for Soft Drink Service

Ishikawa diagram is also known as a cause-and-effect diagram and indicates the direct causes of particular problems.

The diagram utilized in Figure 4 is probably the best continuous improvement tool to use for this simple example. Problems and causes are pretty straightforward. Opportunities for improvement in your business may be much more complex and require the use of some of the other tools listed above. *Control charts* are similar to the Juran diagram in Figure 1—they are used to chart the variation of a process and put it in terms of control. *Histograms* are bar charts used to display data by frequency. *Quality function deployment* details customer needs versus product specifications in a matrix. *Designed experiments* are a powerful continuous improvement tool that allows for the varying of process inputs and tests for optimum performance while identifying sources of problems. *Scattergrams* are plots of two variables to determine association or relationship between the variables. And *benchmarking* is a common tool used for comparing your products/service/operation to that of your peers.

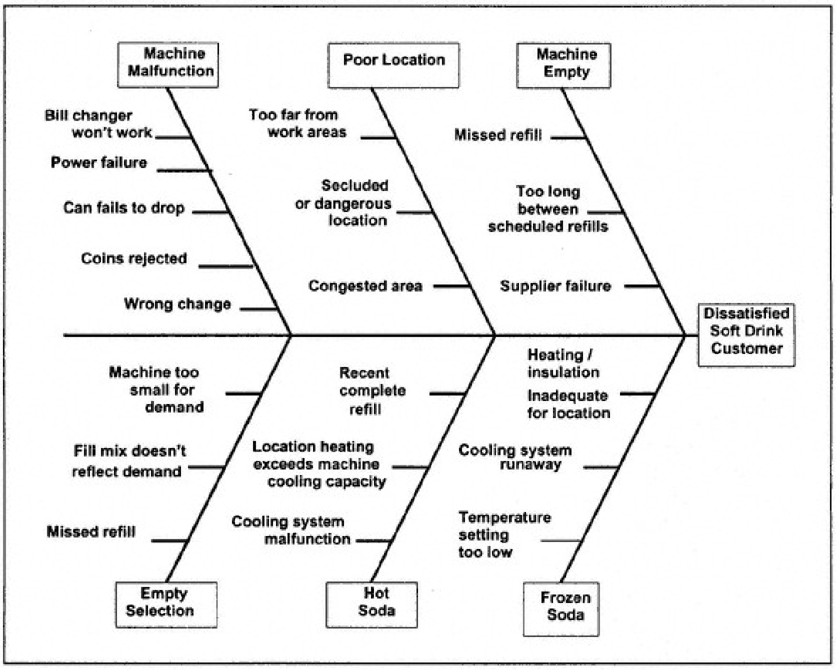

Figure 4
Ishikawa Diagram for Soft Drink Service

Continuous Improvement and Power/Power Quality

For the most part, all of us are customers of electric utilities. All of us have also probably experienced a power outage or a power disturbance that prevents us from operating our business as normal. "Power quality" is the customer's perception of the value of electrical energy at the end-use equipment. As with most products and services, different customers require different levels of quality. A power disturbance may cause you to reset the clock on your microwave at home, for example, but the same disturbance may have much more of an economic impact on your injection molding plant.

As stated earlier, the quality of the incoming power is definitely a factor in manufacturing. While in the past it took a complete loss of power and often for an extended period of time to upset production, today's sensitive electronic equipment can shut down as the result of a 10% reduction in the voltage lasting only millionths of a second. In the past, the customer looked to the electric utility to reduce or eliminate the number of outages they experienced. This effort at utilities goes on today and they spend millions of dollars each year to maintain the transmission and distribution facilities that bring power to their customers. Unfortunately, much of the reliability of the electric system depends on forces that are outside the control of the utility. Lightning and other weather-related events, vehicle accidents, and vandalism are only a few of the causes of voltage sags and power interruptions. Though a utility may be able to reduce the number of such events, it is not economically feasible (for the utility or ratepayers) to build and maintain a system that is completely outage/disturbance-free. Therefore, at some point the customer or end-user must decide how many of these shutdowns can be considered acceptable. Enhancing the performance of process equipment has proven to be an economical method of reducing equipment downtime.

As the market for plastic products continues to become more price-driven and competitive, it is imperative that manufacturers increase throughput and maintain or reduce existing costs. While much of the attention of the electric utility industry (and the manufacturer) has been focused on reducing costs through cheaper electric rates, the use of energy efficient motors, adjustable speed drives, heating electrotechnologies, etc., throughput can be increased by considering power quality. Thus, there are two ways to look at power and power quality using the principles of continuous improvement:

1. the electric utility can be treated and certified as a supplier, or

2. increasing throughput can be examined as part of the production process.

Supplier Evaluation

It is interesting to examine how producer/supplier relationships have changed over the years. In Joseph Juran's book: *Juran on Leadership for Quality: An Executive Handbook,* he explains how these relationships have gone from adversarial to teamwork-oriented.

It is also interesting to note that not all of the elements given in Table 1 have applied to the electric utility as a supplier. In most cases there was only one supplier, the contract duration and prices were basically fixed, and there was no true evaluation of quality. The only way for a producer to change suppliers was to have on-site generation or physically relocate the plant! Of course, all that is about to change with the advent of deregulation in the electric utility industry. With so many questions still surrounding that topic, however, deregulation is not something that will be examined further in this paper. Suffice it to say that the relationship with electric utilities will change. The relationship will take on more of a traditional "supplier" look and, actually, that change has already begun. Some utilities and their large industrial customers have already partnered to evaluate power quality needs and performance. As deregulation unfolds and customers are allowed to choose their energy provider, methods of evaluation will be used to choose that energy provider. Philosophies of continuous improvement highly recommend supplier involvement and some type of assessment or certification. Figure 5 depicts a general supplier certification process which can be used for suppliers like the electric utility.

TABLE 1.
TRENDS IN SUPPLIER RELATIONS.[5]

Supplier Relations Practice Under:

ELEMENT	ADVERSARY CONCEPT	TEAMWORK CONCEPT
Number of suppliers	Multiple; often many	Few; often single source
Duration of supply contract	Annual	Three years or more
Criteria for quality	Conformance to specifications	Fitness for use
Emphasis of surveys is on:	Procedures, data systems	Process capability; quality improvement
Quality planning	Separate	Joint
Pattern of collaboration	Arms length; secrecy; mutual suspicion	Mutual visits; disclosures; assistance

Figure 5
Supplier Certification Process.[6]

A Power Quality Example

In producing plastic products using the process of injection molding, for example, many factors must be considered in order to produce a quality product in a timely fashion. The reliability and quality of the electric service is definitely a factor in this process. One injection molding company served by Duke Power indicated that they lose an average of $8,000 in "sales and value added" for every hour their operation is down. Momentary interruptions and voltage sags result in a restart time of approximately 2 hours while a "cold start" that occurs after an extended power outage (more than 2 hours) requires up to six hours. Some of the inputs into the process of making molded parts are illustrated in Figure 6.

Of the inputs shown in Figure 6, what are the root causes of problems in production and where are opportunities for improvement? Actually, ***all*** of the inputs can be examined for improvement. Having more than one source for resin may be a way to keep material prices down, for example. The focus of this paper, however, is on utilities or, more specifically, power quality.

It has already been noted that the electric utility can be treated and certified as a quality supplier. Furthermore, throughput can be increased by reducing the amount of power-related downtime. A partial Ishikawa diagram for process equipment downtime is shown in Figure 7. Although we will not go into the details in this paper, recent testing by Duke Power of several injection molding machines indicated that the pump motor contactor is one of the more sensitive components within the injection molding machine. In one case, the contactor opened when the voltage sagged to as little as 50% for 4 cycles. While the rest of the process including the pump motor would operate properly during a 4 cycle disturbance, the sensitivity of the contactor calls for the process to shutdown. If something could be installed such that the contactor could "ride through" a 4 cycle disturbance, for example, process

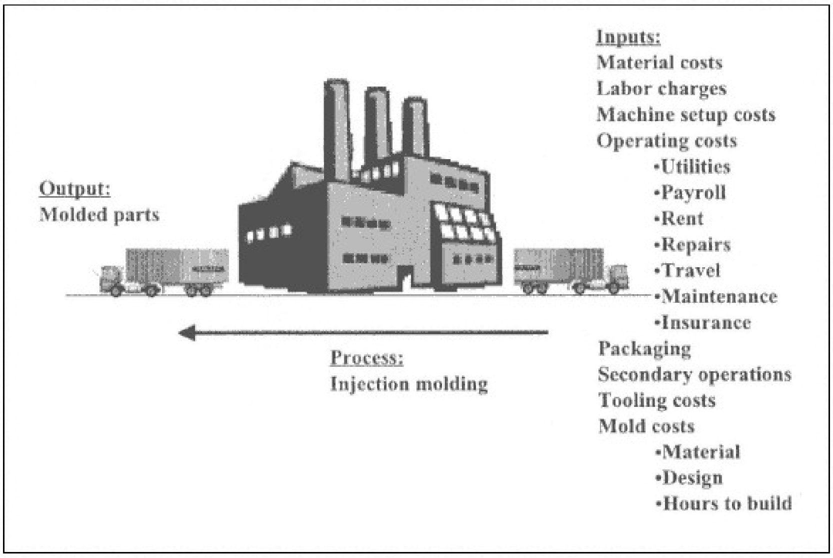

Figure 6
Making Molded Parts: Inputs and Output

downtime could be reduced. In fact, there are such retrofit devices available that improve the ride-through performance of contactors. There are also ways of improving the voltage sag ride-through performance of relays, programmable logic controllers, adjustable speed drives, and many other electrical components. If the process shuts down five times in a year after making ride-through retrofits, rather than 20 times a year without retrofits, throughput has been increased and process improvement has been achieved.

Conclusions

In order to stay competitive in the world market, manufacturers must continuously improve their operation. They must improve product quality and reduce costs of production. Philosophies of continuous process quality improvement have been successful in many industries such as the automotive industry. These same practices and tools can be applied to power and power quality—

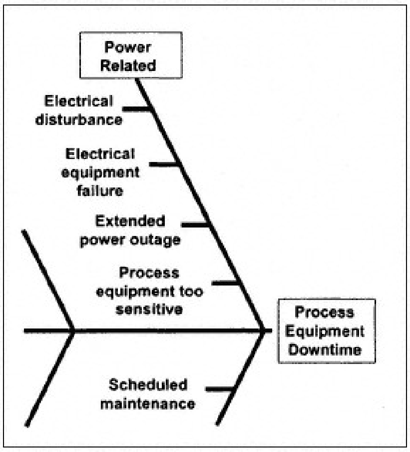

Figure 7
Partial Ishikawa Diagram for Process Downtime

treating the electric utility as a traditional supplier and treating the power quality as a factor in production. There are economical solutions available to improve the voltage sag ride-through of equipment components, thus reducing downtime and increasing production throughput.

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Biographies

J. William (Bill) Shelnutt is a Professor of Engineering Technology at UNC Charlotte and currently serves as a faculty associate in the Office of the Provost, where he coordinates university efforts in Distance Learning and Outcomes Assessment.

At UNC Charlotte for over 20 years, he has served as Chair of the Department of Engineering Technology and as coordinator of Manufacturing Engineering Technology. Previously he served as Chair of the Department of Mechanical Engineering Technology at the University of Cincinnati. He also held engineering positions in General Motors Corporation in Flint, Michigan and the Center for Manufacturing Technology in Cincinnati.

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Before joining the Power Quality group, Mr. Dougherty held several positions at Duke Power including Electric System Design Supervisor (Durham, NC), Supervisor of Engineering and Stores (Elkin, NC), and has held various other positions in the area of Distribution Engineering (Charlotte, NC). He began his career at Duke Power in 1983.

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Notes

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Chapter 67— New Technologies and Services in Power Quality: Improving Your Bottom Line

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Summary

As electric power markets are opening, and as electricity-using equipment has become more sophisticated, managers are turning their attention more and more to issues of power quality. Two of the most vexing issues in power quality are reliability of supply and electrical "pollution" in the form of harmonics. Each of these problems—the abrupt loss of operations due to a sag in purchase power, or the nagging and mysterious problems that elusive harmonics may cause—represent challenges for managers.

There are a number of technologies available to deal with harmonics, including harmonics-canceling transformers, chokes, and passive filters. Active harmonics filters, which are just now entering the market, offer a new and much more flexible way to deal with electrical distortion. In addition, facility managers are finding that reliability and harmonics problems are linked, particularly when different sources of power (such as standby generators) are used within a facility.

In addition to technical innovation in harmonics, smart facility managers are now taking steps to evaluate technologies to protect whole facilities from brief power sags or outages. This field has a number of new contenders, including new energy flywheel-based storage systems—featuring either conventional low-speed or composite high-speed flywheels—improved superconducting magnetic energy storage (SMES) technologies, and new strategies for conventional chemical batteries.

Managing Harmonics

Harmonics are voltage and current frequencies riding on top of the normal electrical voltage and current in office and facility power systems. This unwanted distortion is caused primarily by so-called "nonlinear" or " switching" loads like electronic equipment, computers, electric motor controls, and electronic lighting systems within end-users' facilities. Harmonics-causing loads create electrical system distortion because the electrical current they draw does not vary smoothly with voltage as with simple loads like resistive heaters or incandescent light bulbs. Each time these " switching" loads turn on and off, a current pulse is created, with each pulse containing many unwanted harmonic frequencies.

The main culprit in the harmonics drama is the ever increasing array of electronic gismos populating modern offices and manufacturing plants. The switching power supplies used in these systems draw a high percentage of their power in the form of electrical current harmonics. One or two of these devices do not usually cause harmonics problems in other systems. But, if you get too many of these electronics systems gathered together on one electrical circuit, their collective harmonics can add up enough to cause problems.

Unfortunately, from a harmonics standpoint, problems with harmonics are likely to get worse before they get better. An estimated 20 percent of all electric power in the U.S. today passes through "switching" electronic power semiconductors found in industrial and commercial office equipment, control systems and electrical power systems. But this is just the tip of an on-coming harmonics iceberg. The loads in new modern office buildings and automated manufacturing facilities are 50 to 90 percent "switching" systems, caused dramatic increases in the levels of harmonics and the problems they can cause.

While electrical harmonics exist in all offices and plants, problems usually manifest themselves gradually over time, if at all. Problems begin to occur not all-at-once, but gradually with the addition of more and more harmonics-causing electronic equipment (computers, printers, photocopiers, etc.) or with the addition of a new system that is particularly sensitive to harmonics—ironically, most often an electronic computer or control system that, in addition to contributing its share to the harmonics problem, also is confused by electrical system harmonic pollution. A noteworthy exception, however, to this normally gradual process is when different power sources are used, as discussed further below.

Dealing with Harmonics

Dealing with harmonics is no different than dealing with other electrical-system issues, in that it boils down to knowing how to work with the basic parameters of voltage and current. Classic concerns about voltage can essentially be addressed through two basic questions: Is there sufficient voltage? Is there too much voltage? In harmonics-rich environments, however, more questions need to be answered, such as does the electrical system voltage approach zero more often than the regular 120 times per second—a condition that can cause lights to flicker or cause clocks to run irregularly. The same kinds of questions can be asked for electrical current. The paramount issue for all electrical systems is whether there is too much current (which is why virtually all electrical circuits are protected by breakers). But harmonic-rich environments may have additional electrical current issues, including whether the peak levels of electrical current are too high.

Many power quality problems, including those resulting from harmonics, occur when new equipment is haphazardly added to older systems. The problems, however, do not require expensive solutions, but can be solved by fixing poor or nonexistent equipment and facility grounding, upgrading overloaded or marginally rated electrical transformers (usually mounted in supply cabinets or on concrete pads outdoors), and ensuring that wiring systems are adequate to carry the current of the new and old loads under all likely operating conditions.

In many electrical systems, however, these straightforward fixes aren't enough and direct mitigating measures are required to cancel or otherwise lessen the level of electrical harmonics. There are a number of technologies available to do this, each with its own advantages and pitfalls:

Harmonics-Canceling Transformers

While transformers are most often used in facilities to change a high voltage supply to a lower voltage (say, 480 volts to 120 volts), transformers can also be used to cancel harmonics. To do this, a special transformer is installed so that it feeds two "perfectly balanced" circuits—the transformer then uses the harmonics from one of the circuits to cancel the harmonics coming from the other (by using cleverly configured windings so that harmonics are phase-shifted and cancel when combined). This can work very well (and economically), but only if the two loads are truly identical at all times. Good examples are parallel water pumps, twin lighting systems, or redundant computer systems.

Isolation Transformers and Chokes

A technique most often used for reducing the amount of harmonics caused by a system, isolation transformers and inductive "chokes" try to smooth-out the electrical current drawn by harmonics-causing systems. This is a very low-cost, and low-tech, approach to reducing the impact of harmonics. Downsides include reduce the energy efficiency of the system and, in some cases, these systems can actually make voltage harmonics worse even if current harmonics are improved.

Passive Filters

Passive harmonics filters consist of carefully selected and matched electrical components (capacitors and inductors) that, when used in concert, will redirect harmonic currents to flow through the passive filter itself, away from the rest of electrical system. Passive filters have successfully used in a wide range of facilities. The principal challenge to using them has been the extensive engineering required to identify the right combination of electrical components needed for the application, and the follow-up engineering or monitoring required to ensure that no changes have occurred that would cause the passive filter to behave poorly. If the electrical system does change (addition of a new manufacturing line or a significant number of new computers or lighting systems, for example) it is mandatory to re-check the filter to ensure that it will continue to function as specified. If not, then the filter may have to be redesigned or additional passive filters added. The costs for passive filters are in the range of $20-$40 per kVA.

Active Filters

A new technology that is just entering the harmonics mitigation market are intelligent harmonic filters. These systems, unlike their passive filter counterparts, are able to adapt "on the fly" to changes in facility electrical systems. These systems, while 2–5 times more expensive to purchase initially than passive filters, are often less expense to actually apply because they require only minimal engineering to specify, and they don't require the detailed follow-up evaluations that passive filters do. There is also a lot of manufacture activity for active harmonics filters, as nine active harmonics products are just beginning to enter the North American harmonics-mitigation market. The costs for active harmonics filters are in the range of $125–$150 per kVA.

Harmonics and Separate Generation Sources

The world of harmonics is confusing enough, but it is beginning to get much more complicated as more and more enterprises are moving to implementing redundant and back-up electrical supply sources. In particular, undesired interactions between adjustable-speed drives and back-up generators have created new headaches for facility managers. For one of the authors, this problem was experienced first hand at a waste water treatment plant where special harmonics filtering was required to facilitate operation from standby power.

Protecting Facilities from Voltage Sags and Power Outages

Facility-class uninterruptible power systems—technologies that allow facilities to ride through brief voltage sags or power outages—are emerging in a lucrative new service market that is estimated will be worth well over $1 billion per year. Central to these power protection techniques are extremely fast energy storage systems that can, in the blink of an eye, switch on to keep an industrial or commercial facility operating until the power supply returns to normal, saving the huge cost of lost production and labor that can often result from short-duration power interruptions.

Power Problems Are Common and Costly

The consistency and quality of electrical power is extremely important for facilities with sensitive manufacturing processes. For some, a single sag or outage lasting only one-tenth of a second can cost over $1 million in scrap production alone, not to mention the time and resources lost in getting manufacturing going again. Many facilities are hit by hundreds of short power glitches each year, creating a huge market for power system protection products, ranging from small office surge protectors to facility-wide protection systems.

The sags or outages caused by short power disturbances are expensive. One 1989 paper looking at the costs of power interruptions to U.S. industry estimated losses at $13.3 to $25.6 billion per year. While utilities have worked diligently to eliminate longer-term sags or outages, short-term anomalies—most often brief voltage sags—continue to present a costly problem for customers. Many suffer from numerous sags or outages over the course of a year, most lasting less than a second. It is the challenge of modern ride-through systems to isolate facilities from these short-term sags or outages, with the potential to improve the quality of standard utility electric power from a typical 99.7 percent integrity today to the 99.98 percent level.

What is a Facility-Class Uninterruptible Power System?

All facility-class ride-through systems comprise two basic subsystems: an electronic control and power conversion component and an energy storage component.

<u>Electronic controls and power conversion</u>. Although methods for storing energy in ride-through systems are very different (ranging from rotational energy in a flywheel to chemical or electrical storage in batteries or SMES), the controls and power electronics used in these systems are quite similar. In each design, there are electronic components for taking in three-phase electric power from the utility and complementary electronics for reconverting the stored energy back to three-phase power for the end user. In addition, all ride-through systems have similar control electronics to decide when the storage device should be charged, and when to allow it to discharge to feed the end user's facility. Although most manufacturers of storage devices are heavily specialized, many manufacturers of ride-through electronics make them for several kinds of energy storage media.

Two basic configurations of ride-through systems exist: series and shunt. In a series configuration, all power from the utility is rectified, stored, extracted, and finally converted back to three-phase AC electrical power for use by the facility. The advantage to this approach is that all power going to the facility is conditioned by the ride-through system, providing some isolation between the utility and the facility, and affording the opportunity to clean up harmonics or power factor. A disadvantage is that a failure of one of the ride-through components could itself cause a power interruption, making a quick bypass circuit necessary.

In the shunt-connected configuration, the facility normally draws power directly from the utility, with the ride-through system only providing energy when utility power is temporarily unavailable. The advantage of the shunt configuration is that the power electronics for charging can be simpler, and failure of the ride-through system should have no immediate effect on plant operation. A disadvantage is that in the event of an abrupt utility interruption, a high-speed switch must disconnect the utility grid before power from the ride-through system can flow to the plant. Fortunately, using common solid-state switches, this disconnection usually happens extremely quickly, in under four milliseconds, or less than one-quarter of a normal power cycle.

Energy storage. Energy storage devices suitable for uninterruptible power applications are designed for high power rather than for storing lots of energy. Most ride-through energy storage devices will hold, at most, a few kWh of energy, but they are able to release it very rapidly. What differentiates these technologies from other energy storage systems (such as pumped or thermal storage, or even stand-by generation) is the requirement that they begin delivering at full power within milliseconds after a utility interruption is detected—something more conventional bulk energy storage methods are incapable of doing economically.

For SMES-based systems, the rate of power delivery is almost entirely limited by the power electronics used to reconvert the stored DC electric current to more useful three-phase AC power. Electromechanical batteries are expected to have very fast response, again limited primarily by the size and sophistication of their power electronics. Chemical batteries have inherent internal resistances that must be overcome when drawing large currents, causing significant heating. Regardless of which storage technology is used, however, additional storage modules can usually be added, where necessary, when higher power or more energy storage is desired.

A Summary of Ride-Through Technologies

A number of emerging energy storage technologies are vying in the whole-facility ride-through marketplace.

Low-Speed Flywheel Technology

One of the oldest forms of human-made energy storage is the rotating mass, dating back to ancient times with the first pottery wheel, and advancing over time to the large, high-inertia steel and concrete versions used on steam engines and water wheels.

High inertia flywheels have historically been directly coupled to their supported loads, and used for two primary purposes: to smooth torque and motion in otherwise jittery systems (e.g.: conveyers or elevators), and to provide modest energy storage for systems that might experience very abrupt changes in load (e.g.: rock crushers, mining drag lines, etc.). While these flywheel systems performed their functions very well, they had to be significantly oversized as very little of the energy stored in the conventional flywheel was actually available for work—speed reduction of only a few rpm, at most, was tolerable.

Most modern low-speed flywheel systems have solved this problem by configuring low-speed flywheels such that 80 percent or more of the energy stored in the flywheel can be extracted. This is achieved by changing the interconnection between the flywheel and the supported load from an inflexible mechanical one to a highly dynamic electrical one.

Low-speed flywheels energy storage systems use a fixed or variable speed motor to spin a conventional forged steel flywheel up to 10,000 rpm. When power is interrupted, the flywheel's energy is used to drive a generator. Because the flywheel's speed begins to decay proportional to the square-root of the energy extracted, the frequency output of the generator is "wild" and typically will be rectified and inverted to provide a consistent output voltage and frequency.

Low-speed flywheel systems are commercially available in sizes ranging from 30 kW up to around 2 MW, for durations of 1–2 seconds, up to 30 seconds depending on the load. Costs for these systems can range from $100 to $350 per kVA.

High-Speed Flywheel Technology

The flywheels used in modern electromechanical battery (EMB) systems are light and spry compared to their low-speed competitors. They take in electrical energy and convert it to mechanical energy in the form of a high-speed rotating weighted shaft that is held in place by high-efficiency bearings. The more energy stored in a flywheel, the faster it rotates, with maximum speed typically on the order of 90,000 rpm. Permanent magnets mounted on the flywheel allow " touch-free" transfer of energy into and out of the spinning flywheel. To keep friction losses to a minimum, the flywheel spins in a near-perfect vacuum, down to one ten-millionth (10E-7) of an atmosphere.

In many respects, a modern flywheel can be thought of as a rotor in a high-tech permanent magnet motor: electrical energy is fed to an electronic adjustable-speed drive (ASD) that then powers the flywheel " motor," causing it to turn faster and faster until it reaches its maximum speed. To extract energy from the flywheel, the ASD acts like a regenerative brake, taking energy out of the flywheel motor and converting it to electrical current that flows back onto the power grid.

In the past, using high-speed flywheels for energy storage has held a degree of danger because some older flywheel designs have been known to fail explosively. However, modern high-performance EMBs have incorporated two fundamental improvements: their rotating shafts are made of lightweight, brittle composite materials that tend to shatter on impact, and new housings made of strong composites and steel completely enclose the rotating members. Destructive testing of modern flywheels, in which they are accelerated until they suddenly fly apart, has shown that composite flywheels abruptly turn into a high-tech version of "spaghetti" that flows like a liquid, and is readily contained by properly constructed and sealed steel and composite housings.

The technical "know-how" to make high-performance flywheel-based EMBs has been around for over two decades. Many of the earliest conceptual and technical breakthroughs are attributed to Dr. Richard Post of Lawrence Livermore National Laboratory, and a number of patented developments have come recently from long-time flywheel developer American Flywheel Systems of Bellevue, Washington. Although EMB technology is well understood, what has limited its commercialization is the system integration and exhaustive engineering necessary to integrate all the high-performance components and subsystems into a whole that performs efficiently, reliably, and—perhaps most importantly—in a way that competes with alternative technologies.

The evolution of high-performance flywheel technology has been driven by advances in other contributing technologies, primarily composite materials, magnetic materials, power electronics, and control technology. All of these have been advanced by non-flywheels-directed research (mostly aerospace and defense related), and their technical and cost improvements have helped to make flywheels technology more competitive.

Composite materials. The evolution of composite materials is particularly illustrative of how advances in component technologies have benefited EMBs. Over the last thirty years, the tensile strength of graphite composite materials has increased some five-fold, while the cost per pound has dropped over 90 percent.

The development 20 years ago of Kevlar marked the seminal materials breakthrough that contributed to early EMB development. More recently, T1000 graphite composites with tensile strengths up to a million pounds have enabled flywheels to approach 100,000 rpm, dramatically increasing their energy storage capacity.

Magnetic materials. Magnetic materials have seen a marked improvement in recent years with the development of rare earth magnets such as samarium cobalt-17 in the mid-1970s and neodymium-iron-cobalt (NdFeB) in 1983. The latter, in particular, has been developed extensively by the automotive industry for use in alternators. Materials costs for NdFeB are also quite low, as neodymium is the third most common "rare earth" element, and cobalt is used only in small alloying amounts.

Controls and power electronics. Controls and power electronics technology have developed at a rapid pace in recent years, with the component cost dropping yearly, and the sophistication of feedback and control algorithms riding the wave of ever faster processor speeds.

Bearings. Bearings technology is perhaps the "final frontier" for flywheel development, as it is extremely important to have absolute stability and very low frictional losses when a flywheel is rotating at peak speed. Magnetic bearings seem an obvious solution because they cause a flywheel's rotating shaft to float, with no surface-to-surface contact. Most previous magnetic bearing research has come out of the large rotating machinery developers, and has focused on high-power active magnetic bearings that use too much energy to be practical for most EMB systems. Attention now is on hybrid magnetic bearings that use permanent magnets to do most of the work, and provide correction and stability with much smaller and more energy efficient electronic components. Alternatives to expensive magnetic bearings are also available, such as ceramic bearings that provide nearly frictionless rotation, despite the surface-to-surface contact inherent in their design.

Because of their high level of sophistication, high-speed flywheels today are quite expensive, over $1,000 per kVA.

Superconducting Magnetic Energy Storage

SMES technology—storing electrical power in a coil of superconducting wire submerged in liquid helium—is a strong technical contender in both the ride-through and energy storage markets. In fact, since research began into this technology in the late 1960s, over 20 SMES projects have begun, with some spectacular results. While storing huge amounts of energy in a SMES is technically feasible, its ability to deliver extremely high bursts of power make it very attractive for facility-class ride-through systems.

SMES is the only viable energy storage technology today that directly stores electrical energy without intermediate conversions to mechanical or chemical energy. The SMES energy storage mechanism consists of a superconducting magnetic coil immersed in liquid helium (4.2K, or –455.5F), causing its resistance to DC current to fall to zero. In this state, huge amounts of electrical current can be pumped into the coil, where the current circulates without any losses, until it is eventually diverted from the coil to the facility's power system. To maintain its extremely cold temperatures, SMES technology requires continuously operating cooling systems. The operating costs of SMES systems include the energy used by the cooling systems—about 25 kW for a moderately sized SMES that stores about 0.28 kWh—at a typical cost of about $18,000 per year at 8¢/kWh.

The leader in SMES technology, Superconductivity, Inc. has been in the business for over eight years, and shipping commercial systems since mid-1992, with over a dozen working SMES ride-through systems currently installed. Since the company's acquisition in April of 1997 by American Superconductor, further enhancements have been made to the company's "MicroSMES" PQVR design. The addition of high-temperature superconducting leads to the PQVR's cryostat has significantly reduced internal heating and, thereby, the energy required to keep the system cool. Sizes range from 0.75 to 2.5 MVA. Costs for these systems have come down significantly in recent years, from over $1,600 per kVA just 3–4 years ago, to about $400 per kVA today.

Chemical Batteries

Relying on a common technology—most often the tried-and-true lead-acid battery—chemical-battery-based ride-through systems are now available commercially. Battery technology, while continuing to evolve, has been stable for some time, offering a well understood and proven source of energy storage that is widely available on the commercial market today.

There are a number of factors that can affect battery life and application:

Number of charge/discharge cycles. When lead acid batteries are regularly "deep cycled" to 80 percent or more of full discharge, their life is typically limited to less than 600 charge/discharges. When the application requires only shallow discharge, using a third or less of the battery's full capacity, the number of charge/discharge cycles can climb to over 10,000. For facility-class ride-through applications, where discharges are relatively infrequent (typically less than 100 per year) and of short duration (not requiring complete discharge), the cycle-life of the batteries should be of little concern.

Calendar life. Most chemical batteries must be replaced, regardless of their application, at least every six to seven years. This presents an eventual replacement and disposal cost that must be factored into project economics. The U.S. Environmental Protection Agency places requirements on battery manufacturers to dispose of spent batteries, and some battery salvagers reportedly remove old batteries "free of charge" because of the valuable lead or other metals that can be recovered.

Weight and portability. Battery systems, in general, are able to store a lot of energy per unit weight, but are quite heavy relative to the amount of power they can deliver. Although modular construction can make battery systems movable, systems requiring significant power delivery are almost always very heavy, typically weighing several tons.

One manufacturer of chemical-battery-based ride-through systems—AC Battery of East Troy, Wisconsin—has been shipping its PM250 product since 1993. Based on sealed, maintenance-free automotive batteries (modified with thicker lead plates and higher electrolyte levels), one common configuration can provide 250 kW for 10 seconds . A larger 10-MW, 10-second configuration is available for an initial purchase price of about $700,000, or $350/kW, not including any subsequent battery replacement or disposal costs.

Another battery system manufacturer, Liebert Corporation of Irvine, California, makes large battery-based ride-through systems (100 kVA and up), with over 6,000 systems installed since 1971. A typical 1-MW system will consist of 240 lead-acid cells weighing 46,000 pounds and capable of delivering 1,800 amps for five minutes, with full output achieved within two milliseconds of a utility power interruption. System costs for typical 1-MW installations range from $350,000 to $500,000.

UltraCapacitors. Ultracapacitors (UCs) store energy in a polarized liquid layer that forms when a potential exists between two electrodes immersed in an electrolyte. They operate like high power, low energy capacity batteries, but store electric energy as an electrostatic charge, as opposed to the battery technique of storing energy in chemical reactions. The technology boasts a much higher power density than does a chemical battery (as much as ten times as high), but one-tenth the energy density (about 1 to 10 Wh/kg compared to 10 to 100 Wh/kg for batteries), with a long life capability of hundreds of thousands of deep cycles. Until recently most of the efforts with the technology had gone into automotive applications, where they would provide pulses of power when a vehicle needs to accelerate, such as pulling away from a stoplight or merging onto a highway.

Maxwell Technologies, a leading developer of UC technology recently launched a Power Electronics Systems Division to package UC s for UPS type applications. The initial configuration features DC output up to 650 V for ride-through capabilities aimed at adjustable speed drives (ASD), which are notoriously sensitive to power fluctuations, or other UPS-type applications. The system is connected directly to the DC link. Trickle recharge off the DC bus is set at 20 to 30 minutes.

Cost for today's ultracapacitor systems run in the range of $350 to $450 per kVA.

HiTec System: flywheel-inertia storage with backup generation. The HiTec dynamic diesel continuous power supply (DDCPS) system integrates low-speed flywheel technology with a synchronous generator to protect facilities from power sags or outages 2 to 3 seconds in duration, with a diesel or natural gas engine taking over for protection from longer power sags or outages. The HiTec system is installed in about 300 facilities worldwide, and over a dozen are currently operational in the U.S.

The technology behind the DDCPS system was developed by the HiTec Power Protection Group in the Netherlands over two decades ago. Employing an intriguing motor within a motor design concept, the system uses a 3,600-rpm induction motor, with a stator (the outer portion, which is normally bolted down) that rotates and is mechanically attached to the rotor of an 1,800-rpm synchronous motor/generator. Under normal conditions, when both motors are operating at full speed, the rotor of the induction motor actually spins at 3,600 + 1,800 rpm to achieve an overall rotating speed of 5,400 rpm and acts as an energy storage flywheel. During the first moments of an electric power interruption, the induction motor is instantly reconfigured to operate as an eddy (electrical) clutch—transferring energy from itself to keep the generator's shaft at full speed.

These systems are available in sizes ranging from 100 to 2,200 kVA, the DDCPS system costs about $700 per kVA for a 1-MW system.

Chapter 68— Pressing New Technology into a 100 Year-Old Electrical Infrastructure Application Challenges Are Obvious, Educational Challenges Are Daunting

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Abstract

According to a mid-1990's EPRI study, approximately 70% of the power utilized in the United States will be non-linear. Also, it would be safe to estimate that 50% of all electrical devices now contain some form of digital control or computer. Non-linear devices like switching power supplies, uninterruptible power supplies (U.P.S.'s), adjustable speed drives, and solid state ballasts are power conversion devices that utilize power electronic switches to convert supplied AC voltage to DC (and often return it to a controlled AC) for specialized use. Computer controlled electrical equipment like smart switches, lighting, appliances and building control systems and their respective communication and interface networks are connected to the same electrical supply. Such products are relatively new, when compared to the age of the electrical distribution infrastructure that supplies them and the generation and traditional practices that support it. For example, the adjustable speed AC drive for use with AC motors became commercially viable and reliable approximately 15 years ago. Since then, more than 1 million drives have been installed in the United States, however, only 9% of electric motors yet are controlled by a drive[i], which points towards continued increases in the use of drives. Conversely, electric motors, which are linear devices, have been in existence and operating for 100 years, though they are fundamentally unchanged in their method of operation.

The emergence of non-linear devices and computer-based control equipment in dramatic numbers has created new challenges for users and energy providers that are yet, not entirely resolved. The process of interfacing these devices has spawned entirely new market segments, like the area of Power Quality; and new targeted products, like the U.P.S. and power conditioning devices. Perhaps the most important impact of this change is that plant engineers, consulting engineers, facility managers, providers of non-linear and controls products and utility energy engineers now must all become proficient in new areas, and must begin to view their specific area of interest within a broader system. Companies, governments, educators and associations have identified this issue, and are, in some cases, addressing it with new human resource and education strategies, but with limited results. For instance, one provider of industrial products has elected to hire only degreed electrical engineers for it's front-line sales staff. Other companies have developed specialized technical training resources to increase the technical knowledge base of salespeople historically strong in negotiation or promotion. This paper will explore the challenges and opportunities in training and communications in the face of rapid change. It will highlight key attributes of the people and companies involved in the markets of electrical and electronic products and in the delivery and use of electricity to power that equipment. Finally, it will explore methods for quick, but effective education using innovative means.

The Traditional Roles and Attributes of Engineers

Traditionally, engineers are inventors and designers, systematic and precise. Their step-by-step approach is deliberate and paced. According to the United States Bureau of Labor Statistics, "Engineers apply the theories and principles of science and mathematics to research and develop economical solutions to practical technical problems". The Bureau continues, "Most engineers specialize in a particular area[ii]". In fact, recent graduates are more particular than ever. Specialties like power generation, transmission or distribution, communications or computers or subdivisions of electrical equipment like robotics or aviation are common. Most engineers graduate with a broad understanding of their field, with a particular area of study, and then in practice, further isolate and refine their specialty.

In fact, this career-long refinement process resulting in specialization is one of the factors that entice young students to engineering. In a recent survey of 200 design and application engineers in the power electronics industry, the most common answers to the question "Why did you choose to become an engineer?" were:

1. Stability and security

2. Ability to see results

3. Personal interest in specific area of work

Engineers are precise, organized, sequential thinkers. For example, in developing a new communication interface card, an engineer would first identify precise functionality and performance characteristics, understand them, and then would design and test components, assemble them, evaluate, refine, and evaluate again.

Through research, John Brekke, Executive Coach, has defined a person's thinking as squarely parked in one of two dimensions: *simultaneous* or *sequential.* He contends that people operate in one dimension, and it is unlikely that they will "cross over" to the other. Simultaneous thinkers, he says, "need to know where they are in space first, and then act. They think spacially, and conceptually.[iii]"

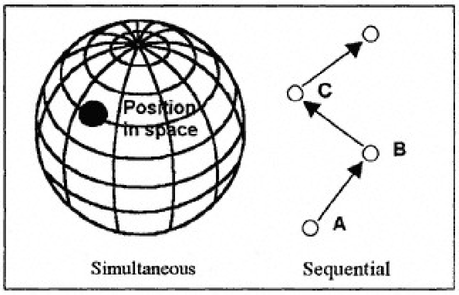

Figure 1
Representation of Thinking Dimensions

Sequential thinkers, on the other hand, think one step at a time, and operate that way too. They start at point "A", proceed to point "B", and then move to point "C". They are never out of order, and are without concern for the route from point "A" to point "C" or where they are in space during their travels. Most of us are fixed in our natural dimension. We are held there by years of influence from parents and educators, and by the comfort that exists in staying in our place. However, he continues, "effective [people] are those who are aware of their natural thinking dimension, but who can operate in the other dimension for a period, and return."

Applying Brekke's research, it would be safe and logical to say that engineers in general are sequential in thinking, and in the processes that they follow in their work. However, the most productive are likely those who can think and operate simultaneously too.

The new, rapidly changing electric distribution infrastructure makes Brekke's ideas even more poignant. More today than ever, engineers that have resided within, and further honed a special expertise are being asked to broaden their understanding of larger, systems issues as they work.

Fast Changing Operating Environment Adds to Complexity

Agility and flexibility are not adjectives often used to describe the electrical power infrastructure in the United States, and the organizations and enterprises that participate in it and are dependent on it. Since Misters Westinghouse and Edison argued about whether to transmit AC or DC many years ago, the network that is electrical power delivery and consumption has grown massive, cumbersome, bureaucratic, and dead-set on strict rules of engagement to play. The players include generators, transmitters, regulators, governments, large users, lobbyist, big industry and financiers. It is an arena largely lacking in visionary leadership and cohesiveness, but one that has tremendous influence over quality of life and economic health.

At the same time, the electrical power infrastructure is undergoing revolutionary changes. Deregulation, a far greater dependency on global suppliers for energy resources, and pressures created by environmental concerns have thrust change upon it. In addition, the emerging use of new types of high-technology equipment has forced power suppliers to consider new variables, develop a more detailed user perspective and in some cases, scrap traditional application engineering practices for completely new ideas. Asking a beached overweight turtle to spin on a dime is futile.

The most challenging aspect of this situation, however, may not to be the immovability of the marketplace, or specific engineering challenges in it. Instead, consider that the run of the mill maintenance man is now obliged to understand high voltage power transmission engineering; or that the controls salesperson must be fluent in three or four programming languages and understand electro-magnetic phenomenon; or that the field support engineer for the local utility must be able to solve a user's downtime problem on equipment that represents a tiny fraction of the total load for which he/she is responsible. Traditional roles have been tossed out. In this new arena, all players must be able to grasp broad concepts that are outside of their chosen specialty. Sequential thinkers must think simultaneously (or spatially), and vise versa.

A Real-World Application

There is a manufacturing company in Ohio. This mid-sized, privately held firm produces automotive parts using machinery that extrudes plastic parts. They spend as much as $120,000 a month for electricity to power the machinery and equipment in the plant, and annual energy bills account for as much as 7% of total revenues. For them, energy costs total more than employee health insurance or debt service. The company has been in business for more than 30 years, started by it's current CEO, and run by his two sons. They employ 65 people. A 28-year employee directs plant and facility operations. He is not an engineer. He has a background in maintenance and a team of two servicemen. From a dusty office in the back of the building, they monitor, manage and service everything from bathroom cleanliness to OSHA-regulated air quality to the operation of sophisticated machine controls. They also work with the local utility to monitor and attempt to manage energy usage.

In the early '90's the local power provider instituted a program of penalties and incentives designed to promote efficient use of energy, inclusive of penalties for poor power factor and discounts for operation during off-peak periods. The plant operations manager, faced with a new $27,000 penalty reached out for help from the utility's customer service team of power engineers, and was convinced of the financial benefits of a large switching capacitor bank for power factor correction. Of course, it immediately changed the distribution system in ways that caused catastrophic failure of control equipment, critical to the manufacturing of plastic products and revenues. The application engineers of the control equipment provider where called upon to correct the downtime. They were charged with delivering a localized solution for each of their devices that considered the new power delivery environment, and which was only marginally successful. In the end, a series of hardware providers and specialists lined up with various solutions, and after three attempts, the system was finally made operational with a combination of changes to the power factor gear and Band-Aids placed throughout the plant. The plant manager footed a $60,000 bill, before he saved a dime in relieved penalties.

In this gross, almost circus-like case, no one was playing in an arena in which they were qualified. The plant manager was not an energy efficiency expert, the utility's power engineers were not aware of the needs of sensitive control equipment and the controls engineers were asked to play the area of power transmission. Ironically it was an educator, a Ph.D. professor of engineering and a generalist with strengths in control and power, who delivered the final applied solution.

Referring again to recent reports from the Bureau of Labor Statistics: "It is important for engineers, like those working in other technical occupations, to continue their education throughout there careers because much of their value to their employer depends on their knowledge of the latest technology." It is clear though, that in addition to developing an understanding of the latest technologies, electronics and electrical engineers must also develop more than a basic understanding of areas outside of their specialty. This requires that engineers also challenge themselves to operate outside of their natural thinking dimension, and that the education provider and mechanisms deliver the material in ways that are conducive to the both thinking dimensions.

Emerging Technology Providers Feel the Training Pinch

For example, in the business of selling and applying AC Drives, which mix leading edge power switching devices, sophisticated control, monitoring, management and communications electronics and electro-magnetic technologies in one box, and which have critical operational interdependence on the AC line and the motor, engineers must be well versed in all arenas. But who is delivering the education to those engineers and those that use their products? As we discussed earlier in this paper, this market is still relatively new. In addition, the speed of technological advancement and the pressure to find new applications has kept traditional educators out of the field, or at least on the fringes. Manufacturers are required by their customers to provide what resources that they can to educate, but are constrained by the high costs of doing so. Some progressive utilities have identified an educational need in the area, and are providing basic training services, but these programs are usually rough and lightly attended. Independent consultants and value-adding resellers are trying to train too. They usually offer limited fundamental training in the interest of focusing on some proprietary and specialized technology. Associations like the IEEE (The Institute of Electrical and Electronics Engineers) and EPRI (Electric Power Research Institute) have developed detailed and comprehensive training resources, but limit them to members only. (As we have seen in our example, some of the players in this marketplace are not provided access to the training resources made available through associations when those associations require specific qualifications for entry.) Clearly, no one entity has taken responsibility for, nor has the resources to apply to the task of effective training in this niche marketplace.

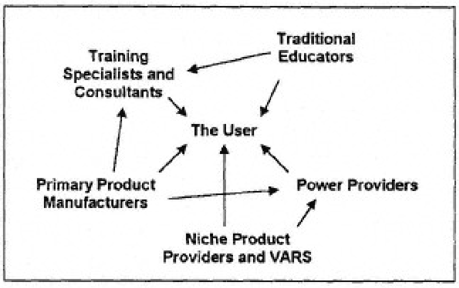

Figure 2
Traditional Training Model

New Opportunities in Interconnectivity among Providers May Hold the Key

The explosive growth of the Internet may provide a platform for developing cost-effective, up-to-date, training programs for markets like the one that we have used as an example. Web-enable, software driven training programs are available that allow a user to specify an area of interest, and then view topical, targeted materials complete with links to related areas, when they are relevant. In addition, interactivity can be monitored, ensuring successful training results. Well-designed, real-time updated application guides allow diverse thinkers to capture fundamental principles, regardless of traditional thinking processes. But this interconnected web of resources implies the existence of a high level of cooperation between complimentary product and service providers. This concept is best explained using the example provided to us by the innovators who brought is the Internet to begin with.

Internet visionaries like Michael Dell of Dell Computer Corporation and Andy Grove of Intel realized early that a general population, barely proficient in the use of personal computers at the time, would flock to a convenient and inexpensive virtual gathering place *if trained in its use.* They cooperated and invested heavily and early in simple tools to spread a basic knowledge regarding the use of the Internet, often using the Internet for delivery. It is widely known that when it became clear to Bill Gates of Microsoft that the Internet was real, he shifted most of his development (engineering) resources towards "making Microsoft an Internet company." The result of this broad strategic alliance among providers was improved ergonomics in software and hardware, more intuitive tools for interface with the web, and seminar after seminar, book after book and website after website, all designed to train us to be Internet and computer users. Mr. Dell, Mr. Grove and Mr. Gates clearly identified a gap in user education, and implemented sweeping organizational, resource and even cultural changes within their companies to be able to make the Internet real to even the least skilled computer user. They gave us simple instructions and real training, regardless of our qualifications or thinking dimensions. Whether for profit or power, philanthropy or the greater good, these leaders clearly recognized the connection between education and value during the early stages of the market, and provided one to create the other. The result has been jet-fueled economic growth based on a combination of knowledge and technology.

Who Will Provide the Content and the Mechanism to Educate in Electrical Products and Power Markets?

To explore this question, we should return to the sample niche market area of AC drives. Who, in this area, is best qualified to provide the content and the mechanism of training? Certainly, the manufacturers themselves have massive application libraries that represent a real training resource. Those resources, in a highly competitive market, are guarded and reserved for key customers.

As deregulation of the power providers continues, and providers jockey for a new value position, it may be that training resources will be made available from them too. Power providers are the best suited to offer broad, system training to participants at all levels. However, whether real resources are applied to training is dependent entirely on whether the training provides customer value and creates revenue for the provider. A utility with new financial pressures may pull back on an investment in training if the return is not clear.

Training specialists and traditional educational channels will also play. They will likely focus their services and curriculum towards select students and clients, and they will usually be slightly behind the leading technological edge.

In order to offer real value to the end customer, who is the power and product user, the process of training needs coordination and cooperation from all of these players. Manufacturers must compliment utilities who must compliment traditional educators and all must stay globally, spatially focused, and on the forefront of technology.

The Internet Model for User Education Should be Used in the Electrical Marketplace

Michael Dell, Andy Grove and Bill Gates created just the type of complementary, agile, education-focused environment that is needed in the electrical marketplace. Companies like GE, ABB, Siemens, and their suppliers and value-added resellers (VARs), providers like Northern States Power, Consumer's Power and Duke Power and traditional educators would be well served to pool their existing training investments and recreate a market-oriented, high value alternative. This alternative should be easy to use, inexpensive, self-directed, interactive and online. It should be financially self-sufficient and self-governed. It should compliment targeted resources provided by IEEE and EPRI and other associations. It should be user and system focused, but specific enough to satisfy the most detailed specialist.

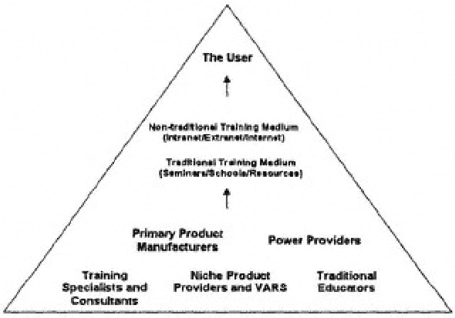

Figure 3
Customer-Focused Training Model

Conclusion

As new technology is pressed harder and faster into and onto the electrical distribution system, the need for intensive targeted training of engineers, providers and users increases. Traditional cultures and infrastructures have widened gaps in tangible, effective education in the electrical marketplace. Combining the power of the Internet with strategic alliances in the creation of new training resources should be a primary strategy for anyone who might benefit from increased productivity or greater efficiency in the use of electrical energy.

Footnotes and References

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Chapter 69—
Understanding how OSHA's new Powered Industrial Truck Training Regulations Affect Employers

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Abstract

This paper explains the requirements of new OSHA regulations (1910.178 (1)) on powered industrial truck training. The paper explains who this regulation applies to and what employers must do to comply.

Introduction

The Occupational Safety and Health Administration (OSHA) of the US Department of Labor released new regulations December 1, 1998 requiring companies using powered industrial trucks to provide their operators with classroom and hands-on training by a trained, knowledgeable, and experienced instructor (29 CFR 1910.178 (L)). These new regulations are effective March 1, 1999, from which time employers must be actively working towards full compliance by December 1, 1999. State regulatory authorities must also respond to this new regulation in the next six months, ensuring that their local standards comply with the Federal Regulations at minimum. (Note however that many State Regulations surpass the federal guidelines).

Who and What Does This Apply To? (Scope)

This new rule applies to all industries (general industry (1910), construction (1926), shipyards (1915), marine terminals (1917), and longshoring operations (1918)), with the exception of agricultural operations. This means employers from the small corner store to the international warehousing and/or manufacturing plant that use any kind of "mobile, power-driven vehicle . . . to carry, push, pull, lift, stack or tier [product or] materials" must provide their operators with adequate training.

The new regulations apply to any equipment covered by the specific industry standard. These include, but are not limited to, the following powered industrial trucks (regardless of their name):

- fork trucks
- tractors (tow, yard, etc.)
- platform lift trucks (order pickers)
- motorized hand trucks (powered pallet jacks)
- industrial crane trucks
- combination vacuum lifts
- guided industrial vehicles
- container top handlers
- container reach stackers
- semi-tractors/utility vehicles

straddle carriers

hustlers

top loaders

side handlers

and other specialized industrial trucks powered by electric motors or internal combustion engine.

NOTE: Earth moving and over-the-road haulage vehicles are excluded. Even earth moving equipment modified to accept forks.

Who Must Be Trained? (Paragraph 1-i & 2-i)

Each and every operator. This means that full-time, part-time, seasonal, substitute, and occasional operators—regardless of experience—must be trained. In other words, you cannot legally allow any one of your operators—even experienced operators—to operate a powered industrial truck until they have successfully passed the required training and evaluation by a qualified instructor. OSHA feels that experienced operators who have learned through trial-and-error and have not had the benefit of safety training likely do not employ consistent safe driving habits and must therefore be trained.

The only exception to this requirement is during the training process itself, under supervision of a qualified trainer, and when the operation does not endanger any person.

Is a Video or CD Rom Adequate? (Paragraph 2-ii)

No, not by itself. A video or CD ROM can be an excellent training aid, but it is only an aid. By itself, it is not a complete training program and does NOT meet these new OSHA regulations. Employers must provide "a combination of . . . formal instruction (e.g. lecture, discussion, interactive computer learning, video tape, written material); practical [hands-on] training (demonstrations performed by the trainer and practical exercises performed by the trainee); and evaluation of the operator's performance in the workplace."

Who Must Do the Training and Evaluation? (Paragraph 2-iii)

"A person [employee or external contractor] who has the knowledge, training and experience to train powered industrial truck operators and evaluate their competency" (OSHA). Although OSHA does not apply the title of "instructor" it is clear in the preamble to the Final Rule, that the "person trained to train" must be a qualified instructor.

To clarify, this Rule requires that the person teaching be trained as an instructor. An experienced operator—without training in how to teach and without the theoretical knowledge of safety hazards and how to avoid them—is not adequate.

Recommendations were made during the final discussions on the new regulations to include a requirement that instructors get accredited by OSHA. OSHA felt that they should not get in the business of "certifying" trainers. It would be overwhelming and burdensome. OSHA felt that professional safety and health organizations [like Ives & Associates] have been successfully certifying people for years and taking on such a task would be equivalent to "reinventing the wheel."

Is General Training Adequate? (Paragraph 3)

No. Your training must be site- and equipment-specific. There are too many differences with equipment and too many variables with each site to address your specific safety issues in a general training program.

In other words, you cannot allow an operator who has been trained on one type of equipment to operate another type of equipment. Likewise you cannot let an operator who has been trained in one area of your plant to work in another area of your plant if different working conditions exist. If you need to move operators to different types of equipment and different work areas, they must be trained in those areas before you can let them operate the equipment.

What Must the Training Program Include? (Paragraph 3)

A combination of formal (classroom-type) and hands-on training in a series of truck and workplace related topics (see below) must be provided by a trained, knowledgeable and experienced instructor. All subject matter must be taught along with all the other requirements of this regulation, except where employers can demonstrate that such need for training does not exist or does not apply to their workplace.

We suggest that if you feel that your situation requires an exception, you should gain written acknowledgement from an OSHA representative.

1—
Truck Related Topics

a. All operating instructions, warnings, and precautions for the types of trucks the operator will be authorized to operate

b. Differences between the truck and the automobile

c. Controls and instrumentation: location, what they do and how they work

d. Engine or motor operation

e. Steering and maneuvering

f. Visibility (incl. restrictions due to loading)

g. Fork and attachment adaptation, operation, and use limitations

h. Vehicle capacity

i. Vehicle stability

j. Vehicle inspection (maintenance too, if required of operator)

k. Refueling or charging, recharging batteries

l. Operating limitations

m. Any other operating instruction, warning or precaution listed in the operator's manual for the type of vehicle which the employee is being trained to operate.

2—
Workplace Related Topics

a. Surface conditions where the vehicle will be operated

b. Composition of loads to be carried and load stability

c. Load manipulation, stacking, unstacking

d. Pedestrian traffic in areas where vehicle will be operated

e. Narrow aisles and other restricted places of operation where vehicle will be operated

f. Operating in hazardous (classified) locations

g. Operating the truck on ramps and other sloped surfaces that could affect the stability of the vehicle

h. Operating the vehicle in closed environments and other areas where insufficient ventilation could cause a buildup of carbon monoxide or diesel exhaust

i. Other unique or potentially hazardous environmental conditions that exist or may exist in the workplace

Do I Only Have to Do the Training Once? (Paragraph 4)

Re-evaluation and retraining is required. You must have a trained, knowledgeable and experienced person (evaluator) conduct performance evaluations a minimum of every 36 months to ensure that the operator retains the necessary knowledge and skills.

OSHA does not want the evaluation to be overly burdensome to the employer. The evaluation can be brief, informal and not interrupt the production process. OSHA suggests a combination of observation and questioning. (Use the training program content requirements as your guide). To protect yourself from liability, you should keep documentation of the hands-on evaluations and theory tests that you conduct.

Then you must provide retraining when any one of the following conditions exist:

the operator has been observed to operate the vehicle in an unsafe manner.

the operator has been involved in an accident or near-miss incident.

the performance evaluation reveals that the operator is not operating the truck safely.

the operator is assigned a different type of truck.

workplace conditions change [e.g. different paving] which could affect the safe operation of the lift truck.

NOTE: Employers only need to retrain operators in those areas where they demonstrate deficiency.

What If My Existing or New Operators are Already Trained? (Paragraph 5)

OSHA provides a clause for the avoidance of duplicate training: "If an operator has previously received training in a topic [see previous contents list], and such training is appropriate to the truck and working conditions encountered, additional training in that topic is not required if the operator has been evaluated and found competent to operate the truck safely."

If your existing operator or new operator has already been trained, compare his/her previous training with these new requirements. You may want to check that . . .

all relevant subject matter was covered

the operator was trained by a trained, knowledgeable and experienced instructor

he/she was trained on the same type of equipment

he/she was trained in the same type of environment

he/she has adequate experience

that experience is relatively recent

the training program materials and course outline used are proven to be thorough and comprehensive.

Once you have checked that your operator's previous training meets all the new regulations, you must then conduct a performance evaluation. If your previously trained operator successfully passes a theoretical evaluation and performs all required operations successfully, then you may certify him/her. OSHA notes, however, that "some training on the site-specific factors of the new operator's workplace is likely always to be necessary."

What about Certification? (Paragraph 6)

In addition to training your operators, you must also certify them as having successfully passed their training. OSHA doesn't specify what is a passing grade, except requires that the operator perform all the required operations safely. OSHA leaves the level of competency on the theoretical and hands-on evaluation to the discretion of the trainer. However, the industry generally agrees that 70–85% correct answers would be acceptable.

According to OSHA, certification consists of proof—in other words documentation showing—that the training and evaluation was conducted by a trained, knowledgeable and experienced instructor, in a formal classroom and hands-on environment, on the specific equipment and work area, and covering all the applicable subject matter. Proof should also consist of "the name of the operator, the date of the training, the date of the evaluation, and the identity of the person(s) performing the training or evaluation."

Though OSHA does not require employers to maintain copies of the training program materials and course outline, they do recognize that these records provide a "good means of measuring compliance with a standard."

When Do I Have to Comply? (Paragraph 7)

You are expected to work actively towards compliance beginning March 1, 1999. By December 1, 1999, you must be in full compliance no exceptions.

Note however that the old regulations which require that you provide adequate training are still in existence. You cannot let any untrained operator drive any one of your powered industrial trucks. But by March 1, 1999, this requirement includes hands-on and formal (classroom) training and evaluation by a qualified trainer.

We suspect that OSHA will continue to conduct safety inspections in the following priority: when an accident or near miss occurs, when a complaint is made, if you are in a high risk industry, and during random checks.

Why Should I Comply?

Costly Damages: Improper Lift Truck operation is the major cause of warehouse and plant damages. One study from a major commercial property insurer found that the cost of 280 losses over a ten year period totaled $87 million! (Factory Mutual Engineering & Research)

Loss of Life and Limb: Powered industrial truck accidents cause approximately 85 fatalities and 34,900 serious injuries each year. (OSHA)

Lost Productivity: Employers loose an estimated 20,000 work days annually due to lift truck accidents. (Bureau of Labor Statistics)

Risk of Litigation: Employers spend up to $42 million annually in accident-related litigation and settlements. (OSHA) If you have an accident, a complaint by an employee, or a random visit by an inspector, you could be cited for the infraction and have to pay a substantial fine.

In addition, statistics also show that "operator training can reduce lift truck related accidents by as much as 70%" (NIOSH).

Compare the costs of accidents to OSHA's projected cost of compliance being 0.0002 percent of sales and you might conclude that compliance will actually save you a substantial amount of time, money, and effort.

What Should I Do?

OSHA recommends that you use either an "outside qualified training organization that can provide evidence that the employee has successfully completed the relevant training topics, both classroom and practical. [Or] have an employee(s) [with the necessary training, experience and knowledge to train powered industrial truck operators] perform the training, which would allow the employer to certify that the employee has successfully completed the training." Note, however, that if you hire an outside trainer to train your operators, you will likely have to provide your operators with further site-specific training.

If you hire an outside trainer(s), be sure to check their qualifications. Have they been trained in a classroom and hands-on environment? Do they know how to safely operate a powered industrial truck? Have they successfully passed a detailed evaluation by a non-bias, outside third party? Do they have proof (or Certification) showing that they are competent and qualified?

The same rule applies when you are searching for a train-the-trainer program to teach your employees. Does the program not only tell your would-be instructors what to teach, but also show them how to teach and how to put these new teaching skills into practice in a real-life setting. Does it evaluate your would-be instructors' ability to train your operators thoroughly as required by these new regulations? Does it provide you with proof—in other words "certification"—showing that your instructors are qualified and competent?

If your instructor is not proven—in other words "certified" —to be qualified and competent, you could be opening yourself to a myriad of potential liabilities.

DISCUSSION: How the regulations affect you. Legal implications of noncompliance. Issues you face in complying. Exploring solutions.

HANDOUT: Compliance Checklist with detailed Special Report.

PHOTO: You can download a high-resolution photo from our website at www.ives-associates.com.

Chapter 70— Ergonomics a Productivity and Quality Improvement Process

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Introduction

Ergonomics is typically viewed as a safety issue. Cumulative trauma disorders, repetitive motion injuries, back injuries, and carpal tunnel syndrome are common phrases encountered with the implementation of an ergonomics program. This article will discuss the benefits where an ergonomics process will not just focus on "safety issues" but rather on improving the overall business and thus bottom-line profitability. That is the business advantage of an ergonomics program.

Ergonomics is an excellent example of moving the safety profession into a better strategic direction by helping the business improve its overall objective.

Ergonomics—The Business Management Perspective

Many times, business management views ergonomics as a safety program. Very little is seen in terms of the overall business benefit with these types of programs. Other issues may involve the reasons for the cumulative trauma disorders, such as fraudulent claims, poor medical management of claims, workers not properly trained. These are actually symptoms that the management process needs to be improved, not just the ergonomic aspects of a task. The safety professional will best be able to assist the business and have more success in implementing ergonomic controls when these controls are put into the context of the business process. Dr. Steven Covey states, "seek first to understand then to be understood." His concept tells us that we should first understand the management process within the business and then determine how the ergonomic issues are affecting the business. For example, business management as reported by *Industry Week* magazine is concerned with three primary issues: product quality, controlling health care costs, and controlling production costs. If you ask business management what their primary concerns are, the majority would state production, quality, and thus, overall bottom-line profitability. The safety professional needs to understand that safety is not first, but the key is to understand how safety and ergonomic issues affect production and quality, and over-all bottom-line profitability. That is the advantage of a business ergonomics process.

Regulatory Issues

Too many businesses have only a compliance-based safety culture. These cultures will never be truly effective in providing a quality safety program. In these organizations, safety is viewed as strictly a compliance-based issue and not seen as a true advantage to the business. Companies that only aspire to a compliance-based safety program also do not understand the total quality management process. From a regulatory point of view, we look at OSHA having been in place for approximately the past 30 years. Since that time, the number-one work place injury for the past, present, and foreseeable future has been low back injuries. However, when we review the OSHA regulations, we see no regulation and/or standard addressing the number-one work place injury. My point is not to blame OSHA for this but only to demonstrate that the OSHA regulations do not even address our number-one work place injury. More importantly, why do businesses wait for OSHA to tell them how their businesses should be run? They key is to look at the ergonomics process and view it as a business advantage, and implement a continuous improvement process that will control cumulative trauma disorders.

Ergonomics:
Benchmarking

Typically, the need and effectiveness of an ergonomics program are based upon traditional benchmarking. Injuries are reviewed and analyzed, and from there decisions are made based upon these priorities. For example, workers' compensation injuries: OSHA first reports of injuries, reported incidents are reviewed, and from there the frequency and severity is determined in which priorities are then established to implement the ergonomics process. Whereas, this is a good way to involve the ergonomics program, there are many other business opportunities that may have even more of a need for the ergonomic process. For example, the safety professional in the desire to become more business focused should also expand the ergonomics process when determining priorities and look at the following areas:

Product Development and Liability

If and when an ergonomics standard is implemented in this country, then plaintiff attorneys would have a strong basis for liability suits. For example, assume that the NIOSH-recommended weight limit under ideal lifting conditions is 51 lbs. If a product is bagged in 50-lb. bags, and an employee is lifting this product from the plant floor thus making the RWL 25 pounds, would not there be a possibility of a product liability suit given the "hazardous product?" The theory can also involve product development costs since ergonomic principles will need to be provided in the development of new products to minimize the product liability issue.

In implementing an ergonomics process, safety professionals should work with their human resources department in reviewing turnover and absenteeism records. The primary reason why people "turnover" from jobs is that the jobs are not enjoyable. The primary reasons for many turnover problems are ergonomic issues. This is because the match between the work and the worker is not in a user-friendly process, and thus, the end result is employee dissatisfaction, and thus, turnover will result. Reviewing turnover records is very important in prioritizing the needs for the ergonomics process. These records should also be compared with the injury reports.

Productivity, quality and how the company benchmarks the production process should be reviewed. First, the safety professional should talk the language of business. For instance, where are the higher error rates within the plant? Are there any bottleneck areas? Does the current business plan involve planned higher productivity for a particular product? Where is the number-one production headache within the plant? Where is the highest error rate? The safety professional should use the ergonomics process to improve all of these areas. For example, the primary reasons why productivity, error and quality problems occur are once again the poor relationship between the work and the worker.

Safety professionals are very familiar with the 300 to 30 to 1 relationship. This "pyramid" explains how there will be unsafe acts and many near misses long before the actual serious injury will occur. The same holds true with a cumulative trauma disorder. The "CTD" pyramid shown in Figure 1 should be reviewed.

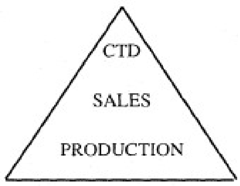

Figure 1
CTD Pyramid

As the pyramid clearly demonstrates, productivity and quality issues will occur which will reduce sales possibly.

Case Studies

The following are two actual case studies which demonstrate the business advantage of an ergonomics process. These are actual examples involving the related production and injury costs.

Metal Manufacturer

This customer operates a metal fabrication shop that provides parts for automotive manufacturers. Two employees work at a punch press machine. One employee manually picks up and places 23-lb. plates, similar to automotive bumpers, into the punch press machine. After the punch press works on the product, the second employee removes the product from the punch press and places it in a bin for transportation to the warehouse department. Over a two-year period, there were two serious back injuries with direct accident costs at approximately $30,000.

The turnover for this job has been high. The plant manager has requested that "lifting training" be provided to this area to reduce the back injury problem.

At this time, please think about the overall issues with this process. Notice that the plant manager is focusing on the "back injury problem." The challenge to the safety professional is to go beyond the traditional safety and ergonomics issue and look at how this process is affecting the overall business.

In discussions with the plant manager, it is learned that the process produces 1200 parts per day. The plant manager would like to increase this number to at least 1600 parts per day and, in reality, the market potential in terms of how much product can be sold is approximately 2800 parts per day. Thus, the safety professional should use this information to look at the "big picture" when designing and recommending controls for this process.

After the ergonomic analysis is complete, the primary exposure is with the low back injury potential to both workers. This is due to the poor workstation heights, and the bending, repetitive lifting, and overall poor postures and forces generated with this task.

On a short-term basis the safety professional recommends adjustable lift tables and mechanical handling equipment as well as improvements to the punch press to eliminate the majority of manual stress with this task. The overall process changes cost approximately $5,000. The safety professional working with the plant ergonomics team also looks at the productivity issue, and it is decided that robotics be reviewed to speed up the process so that the 3200 parts per days in production can be achieved. The plant manager quickly agrees to the short term implementation and with the mechanical handling equipment, the production quota of 1600 parts per day is obtained and the employees are much happier, less fatigued, and there have been no reported injuries and/or complaints with the use of these new changes. Approximately one year later, robotics were installed which have increased the productivity to 2800 parts per day and the two employees have become "process controllers" which is much less physical fatiguing upon the employees. As a result, the plant manager is a firm believer in the ergonomics process and has implemented the ergonomics team to include looking at these issues as part of their overall safety activities.

The second example involves a wooden door manufacturer, which has two plants. Plant #1 has had $128,000 in low back injuries over the past two years. This involves a total of seven employees working at a process which produces 300 doors per day. One employee oversees the door manufacturing machine and manually handles the doors onto one of three similar nailing tables. At each of these three nailing tables, there are two employees. These employees produce 100 doors per day per nailing table and then place the doors on a cart for shipping.

At plant #2, the same productivity requirements call for 300 doors per day to be produced. However, there are only five employees at this process. There is one employee at the door manufacturing machine, and only two nailing tables with two employees at each table. Thus, each of these nailing tables produces 150 doors per day. As you would imagine, the main difference is that the second plant has mechanical handling equipment and a more "use-friendly" work environment. Also, plant #2 has had no reported back injuries in the last two years.

The primary focus of the manager of plant #1 is to provide "lifting training." The safety professional needs to look beyond these issues and the overall business process and thus discuss the overall business impact with the back injury problem. As you can see, there are much higher labor and production costs associated with plant #1 as well as a much higher injury cost problem. As a result, the president of the corporation also reviews this issue, and determines that an ergonomics process is needed to look at "best practices" for the corporation. In implementing an ergonomics team with the company, many of the best practices within plant #2 are incorporated in plant #1 which has reduced production costs, injury costs and thus had a major positive impact on overall bottom-line profitability. Once again, this "first victory" with the ergonomics process has given full management support and commitment for the ongoing efforts of the "best practices team"

Summary

Many safety professionals focus on the ergonomics analysis and not on the improvements. The safety professional needs to go beyond the "safety issues" and look at the overall business issues and the true benefit of an ergonomics process. Also, unless the ergonomics process is included as part of the quality management process, a total quality management program does not exist. How can you have a continuous improvement process when you don't evaluate the primary interface between the work and the worker?

Safety professionals need to go beyond looking at injury accident data and get into the actual business process which is the true advantage of a common sense business oriented ergonomics process.