Burns & McDonnell
SINCE 1898

2001 No. 4

TechBriefs

Office Locations

Kansas City, Missouri
Atlanta, Georgia
Chicago, Illinois
Dallas, Texas
Denver, Colorado
Fenton, Missouri
Houston, Texas
Jacksonville, Florida
Los Angeles, California
Miami, Florida
Summit, New Jersey
Oak Brook, Illinois
O'Fallon, Illinois
Phoenix, Arizona
San Diego, California
San Francisco, California
St. Louis, Missouri
Tulsa, Oklahoma
Wichita, Kansas

TechBriefs is published quarterly by Burns & McDonnell. For more information, contact TechBriefs at **techbriefs@burnsmcd.com** For address changes, contact Kevin C. Fox, corporate marketing manager, at **kfox@burnsmcd.com**

Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114
(816) 333-9400

www.burnsmcd.com

Printed on recycled paper

In This Issue

> *"You may have to fight a battle more than once to win it."*
> **Margaret Thatcher**

Municipal Utilities and Distributed Generation:
A Project Solution

By Julie Coulter, P.E.

Municipal Utilities and Distributed Generation

A municipal utility has the challenging task of providing reliable electrical service to its customers at a low cost. Deregulation has changed competition for electric sales, occasionally making it more expensive to purchase electricity at wholesale levels. Buying electricity from the grid allows a utility to defer investing capital in generation equipment; however, it may pay inflated prices on the open market. Managing daily demand in a volatile market has compelled many municipal utilities to make use of distributed power generation as a solution to the problems they face.

The use of small-scale power generation technologies that provide electric power at locations closer to the load being served, known as distributed power generation, can provide numerous services to a utility, including:

- Baseload generation
- Standby generation
- Peak shaving capability
- System stability
- Reduced transmission line losses
- Sale of excess capacity during market price spikes
- Load management
- Power supply negotiating strength
- Fuel flexibility

Burns & McDonnell is currently serving as owner's engineer for a southeast Missouri public utility for the construction of a 19.8 MW power plant adjacent to the city's existing plant. Burns & McDonnell was responsible for preparing the request for proposal, evaluating bids, and is serving as the owner's representative throughout construction and plant startup.

A study completed by Burns & McDonnell in 2000 provided results showing economic benefit to the utility for adding generation. The study recommended a multiple unit installation consisting of either combustion turbines or medium speed reciprocating engines in the 16-20 MW range.

Installation Considerations

The reciprocating engines in the existing plant have the capability of running on either natural gas or fuel oil. Natural gas is the primary fuel with diesel fuel used as a backup source in case of an unforeseen emergency. The new plant's engines were specified in

CRITERIA	VENDOR A	VENDOR B	VENDOR C	VENDOR D
NO. OF UNITS	3	3	8	4
TYPE OF UNIT	RECIPROCATING	RECIPROCATING	RECIPROCATING	GAS TURBINE
LUMP SUM BID PRICE	$11,176,000.00	$14,220,000.00	$7,248,250.00	$15,125,180.00
ADDER FOR GAS COMPRESSOR (20 PSI MIN)	$319,000.00	$400,000.00	OMITTED FROM PROPOSAL	$31,500.00
TOTAL LUMP SUM PRICE	$11,495,000.00	$14,620,000.00	$7,248,250.00	$15,156,680.00
$/kW	715.26	737.82	453.02	869.82
NATURAL GAS				
GUARANTEED NET CAPACITY, kW	16,071	19,815	OMITTED FROM PROPOSAL	17,425
FUEL EFFICIENCY (HEAT RATE), Btu/kW-hr	8,505	8,924	N/A	12,448
PRODUCTION COST, $/MW-hr (1)	34.05	35.70	COULD NOT EVALUATE	49.79
NO. 2 FUEL OIL				
GUARANTEED NET CAPACITY, kW	17,039	19,815	16,000	17,525
FUEL EFFICIENCY (HEAT RATE), Btu/kW-hr	8,675	9,539	NOT PROVIDED	12,240
ALLOWABLE RUN HOURS PER YEAR ON NG	861	712	177 (FUEL OIL ONLY)	5,657
PER UNIT CAPACITY AND FUEL COSTS, $/MW-hr (2)	649.32	670.37	COULD NOT EVALUATE	798.01

(1) BASED ON FUEL COSTS OF $4.00/MMBTU
(2) BASED ON 112 HOURS OPERATION AT FULL LOAD

Table 1
Bid Evaluation

a like manner to allow this flexibility and in accordance with the client's wishes.

Many factors were taken into consideration when preparing the criteria for equipment and installation selection:

- The noise would be limited to 65 dB at the city's property line.
- The new building would reflect and match the existing architecture.
- The new work was specified to generate 13.8-kV electricity to match the existing voltage of the power supply bus. New electrical equipment would include a new 69-13.8 kV transformer, main switchgear, auxiliary transformer, MCC, local control panels, and DC system.
- A modified air permit was obtained for the additional engines.
- A gas compressor or extensive natural gas pipeline modifications would be required for either prime mover.
- The units would be on line in less then one year from contract award.
- The project was to be bid as a design-build project.

Proposal Evaluation

The customer received four bids for this project. Three of the four bids met the intent of the request for proposal documents. All three bidders had the capability of providing a quality power plant that would fulfill the city's needs well into the future. Equipment prices as well as factors that influence equipment performance were evaluated. Table 1 provides a comparison of the four bids received against various evaluation criteria.

The fourth bid received was unsolicited from a high-speed engine manufacturer. Although their proposal was for less money and could be on-line in a shorter time, the bid was judged non-compliant for the following reasons:

- Per manufacturer's literature, medium speed (720 rpm) engines will require less maintenance on a $/kW-hr basis than higher speed (1800 rpm) engines. In addition, the city staff is experienced in maintaining and trouble shooting medium speed engines.
- Eight, two-megawatt high-speed engines were proposed, compared to three or four from the other bidders. The fewer prime movers, the fewer moving parts, which reduces operations and maintenance costs.
- The high-speed engines were not dual fuel capable – diesel fuel only.
- Without additional exhaust gas treatment (selective catalytic reduction), the exhaust emissions were more than ten-fold higher for the high-speed engines, lowering the allowable operating hours per year.
- The warranty on the high-speed engines terminated at 500 hours of operation.

The project was awarded to Vendor B (see Table 1) after evaluation of the proposals and in accordance with the client's wishes.

Summary

Municipal utilities that utilize power generation technologies to provide electric power at locations closer to the load being served can provide numerous benefits to both the utility and its customers. For this Midwest municipal utility, medium speed reciprocating engines provided the solution.

Julie Coulter, P.E., *is a senior mechanical engineer in Burns & McDonnell's Energy Group in the St. Louis office. She has a bachelor's degree in mechanical engineering from the University of Missouri-Columbia, and nearly nine years of experience in the design of power and process facilities.*

Loading of Power Transformers:

Reducing Costs Without Affecting Reliability

By Bill Strongman, P.E., and
Kiah Harris, P.E.

Introduction

In the past, normal utility practice has been to load power transformers to no more than the nameplate rating (e.g. OA / FOA / FOA) for normal peak operation, and to some limit above nameplate for emergency operation. The *IEEE Guide for Loading Mineral-Oil-Immersed Transformers* (Std C57.91-1995) suggests that transformers can be loaded beyond nameplate rating during peak hours of operation, provided they are loaded below nameplate rating during non-peak times. This assumes a willingness to accept an accelerated loss of life for a short duration given that the transformer life will be extended during low load hours.

In today's competitive environment, utilities need to review ways to reduce costs without affecting reliability. By using the methodology presented in the *Guide* to determine allowable transformer loading, the utility can defer transformer upgrades and thus reduce overall costs while keeping reliability the same. The intent of this article is to provide a discussion and example of how the *Guide* might be applied to utility substation transformers.

Explanation of Theory

Transformer nameplate rating is based on life expectancy, which in turn is based on insulation loss of life. Deterioration of insulation is a time function of temperature. The expected life of a 65˚ C rise transformer is based on a continuous hot-spot temperature of 110˚ C. That is, for each hour that the transformer is operated at a hot-spot temperature of 110˚ C, the life is reduced by 1 hour. The *IEEE Guide* assumes a normal life of 180,000 hours.

The *Guide* provides a methodology for determining acceptable loading levels beyond the 110˚ C hot-spot limit. The underlying concept is that the additional aging for hot-spot temperatures above 110˚ C is offset during periods when hot-spot temperatures are much lower. The *Guide* discusses the concepts of Normal Life Expectancy Loading, Planned Loading Beyond Nameplate Rating, Long-time Emergency Loading, and Short-time Emergency Loading, which are defined as follows:

- Normal Life Expectancy Loading (NLE): Normal life expectancy occurs when a transformer is operated at 110˚ C continuously. The *Guide* recommends allowing the hot-spot temperature to reach 120˚ C for a short period during the day, provided the transformer will be operated for longer periods below 110˚ C.
- Planned Loading Beyond Nameplate (PLBN): Where transformers do not carry steady continuous loads, which is the more typical utility operation, loading can be such that the hot-spot temperature can rise to 120-130˚ C. This operating scenario is intended for planned repetitive loads.
- Long-time Emergency Loading (LTE): In situations where a transformer is expected to carry emergency loads, the hot-spot temperature can rise to 120-140˚ C. This is not a normal operating condition and is expected to cover a prolonged outage (from several hours to several months) to some system element (single contingency outage). Expectation is that these types of events will occur only two or three times over the life of the transformer.
- Short-time Emergency Loading (STE): For highly unlikely conditions (second and third contingencies) the hot-spot temperature can be allowed to go as high as 180˚ C. This would be expected to occur for a short period (two to three hours) and only once or twice over the life of the transformer.

Other factors that must be taken into account when applying the above loading levels, especially for Short-time Emergency Loading, include:

- Evolution of free gas due to heating of winding and lead conductors may reduce dielectric strength.
- Operating at high temperatures will cause reduced mechanical strength of both conductor and structural insulation; however, this is normally more of a concern during transient over-current conditions.
- Thermal expansion of conductors, insulation or structural parts at high temperatures may result in permanent deformation that could contribute to mechanical or dielectric failure.
- Pressure build-up in bushings could result in leaking gaskets, loss of oil, and ultimately dielectric failure.
- A build-up of oil decomposition products at the contact point can increase resistance in the contacts of tap changers.
- Auxiliary equipment internal to the transformer may also be subject to risk.
- Top oil temperatures above 105˚ C can cause oil expansion that might be greater than the holding capacity of the tank, which can result in

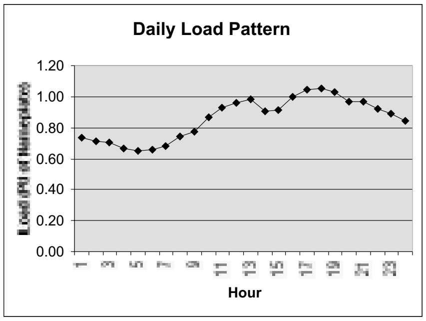


Figure 1

operation of the pressure relief device and subsequent loss of oil.

- Rating of connected equipment may limit the ability to load the transformer beyond nameplate.

Determination of Allowable Loads

The *Guide* provides a calculation of the "Aging Acceleration Factor," which can be interpreted as the number of hours the insulation ages for one hour at a given hot-spot temperature. The hot-spot temperature rise is a function of the transformer heating characteristics such as top-oil temperature rise above ambient and hot-spot rise above top-oil temperature. These temperature rises are added to the ambient to determine the final hot-spot temperature.

As a transformer is loaded, the hot-spot temperature increases. The intent is to load the transformer as high as possible without exceeding the allowed hot-spot temperature. The following presents an example of how the calculations in the *Guide* might be used to determine the allowable load on an hourly basis for the various loading levels above. For the purpose of this article, the allowed hot-spot temperatures for each load level are:

	Hot-spot Temp
NLE	120˚ C
PLBN	130˚ C
LTE	140˚ C
STE	180˚ C

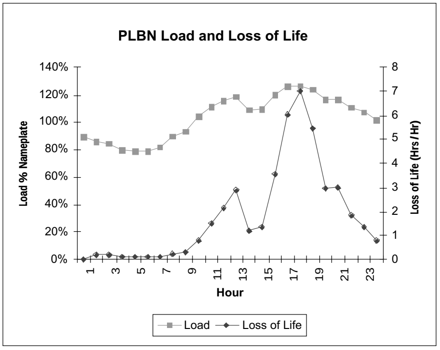


Figure 2

The resulting loading levels for given hot-spot temperatures are a function of both load patterns for the substations and the transformer characteristics. The load patterns were taken as typical summer loads for a utility in the Midwest, as shown in Figure 1. The transformer characteristics were assumed to be:

- Top-oil rise over ambient at rated load: 35˚ C
- Hottest-spot rise over top-oil temperature, at rated load: 45˚ C
- Ratio of load loss at rated load to no-load loss: 6.5
- Oil thermal time constant at rated load: 1.25
- Exponent of loss function vs. top-oil rise: 1.0
- Exponent of load squared vs. winding gradient: 1.0

These values are taken from the 1981 *IEEE Guide to Loading Mineral-Oil-Immersed Power Transformers* (C57.92-1981) as being reasonable assumptions where actual data is not available.

For this example, the nameplate rating of the transformer is 6250 kVA and the ambient temperature is assumed to be 40˚ C.

Table 1 presents the load, temperature and Age Acceleration Factors for one day assuming the transformer is to be loaded at Planned Loading Beyond Nameplate. The table shows the main components of the calculations. There are intermediate steps in the calculations to arrive at the final hot-spot temperature. The reader is directed to the *Guide* for these steps. The peak allowable load is found by setting the maximum allowed hot-spot temperature at 130˚ C and using the "Goal Seek" function in Excel to find the maximum peak one-hour load.

Again, the intent is to load transformers beyond the nameplate ratings without adversely reducing the life of the transformer. The aging is shown in the last two columns. As can be seen, the accumulated aging of the transformer over a 24-hour period for this scenario is about 43 hours. The loads and age acceleration factor from Table 1 are presented graphically in Figure 2.

The loading and loss of life for the other three loading levels were also calculated. The following are the results of the analyses:

Allowed Hot-Spot Temperatures	NLE	PLBN	LTE	STE
	120˚ C	130˚ C	140˚ C	180˚ C
Peak Allowable Loading				
	117%	127%	135%	170%
Loss of Life Over Peak Hour				
	2.5 hrs.	7 hrs.	17 hrs.	424 hrs.
Loss of Life Over Day				
	18 hrs.	48 hrs.	96 hrs.	480 hrs.

On an annual basis, the loss of life for a transformer is considerably lower than shown above. This is due to two factors 1) the ambient temperatures are much lower for the majority of the year and 2) loads are much lower than the peak for the majority of the year. Aging can be as low as 0.1 hours over a 24-hour period. For example, the accumulated aging was calculated to be 0.116 hours for a 24-hour period assuming an ambient of 20˚ C and a load of 100% of nameplate.

The above analysis is based on assumed transformer heating characteristics. It should be noted that the hot-spot temperature, and subsequently the loss of life, is sensitive to the input assumptions used for the transformers. A 1˚ C decrease in the top-oil rise over ambient, or the hot-spot rise over top oil results in a 1% increase in the allowable loading. The values used in this study are considered to be conservative.

Benefits

There are three benefits that need to be considered. First, for substations with single transformers, the loading for expected system peaks can go to 125% of the nameplate rating. This could delay transformer change-out by five or six years. Second, where substations are strongly interconnected through the distribution system, the load from an outaged transformer can be transferred to the remaining transformer(s) provided the loading on any of the remaining transformers does not exceed 135% of nameplate. Finally, where there are two transformers operated in parallel in the same substation, the loading on the remaining transformer for an outage to the other transformer can go to 160%, provided the loading is only for two to three hours.

Conclusions & Discussion

Utilities can take advantage of the ability of transformers to safely handle over-peak conditions to reduce installation costs and maintain system reliability. Utilities should consider loading transformers to the PLBN levels (in the order of 115-125%) for distribution substations that have one transformer. For distribution substations that have two transformers, the STE rating of 160% could be used for short duration loading situations. For substations where loads can be moved to other substations, the LTE rating of 135% could be used.

It is very important that, in considering the above loading levels, the utility obtain data on the transformer. The transformer temperature characteristics are especially important in the calculations, and thus the utility should search its records or check with the manufacturer to determine the characteristics. Also, especially for older units, the utility should check with its maintenance group to determine if there are any problems that would preclude a unit from being loaded above nameplate.

HOUR	KVA Load	PU Load	Top Oil Delta C	Hot Spot Delta C	Hot Spot Temperature C	Age Acceleration Factor (hrs)	Accumulated AAF (hrs)
100	5549	0.89					
200	5356	0.86	47.09	7.81	94.90	0.20	0.20
300	5264	0.84	46.06	7.60	93.66	0.17	0.38
400	5001	0.80	43.53	7.00	90.53	0.12	0.50
500	4913	0.79	42.55	6.80	89.35	0.11	0.61
600	4918	0.79	42.30	6.81	89.12	0.10	0.71
700	5114	0.82	43.75	7.26	91.01	0.13	0.84
800	5595	0.90	47.87	8.38	96.25	0.23	1.07
900	5812	0.93	49.80	8.90	98.70	0.30	1.38
1000	6501	1.04	56.87	10.65	107.52	0.77	2.15
1100	6970	1.12	62.16	11.91	114.06	1.51	3.66
1200	7201	1.15	65.00	12.54	117.55	2.13	5.79
1300	7396	1.18	67.56	13.09	120.65	2.89	8.68
1400	6779	1.08	60.38	11.39	111.77	1.20	9.87
1500	6844	1.10	61.29	11.56	112.85	1.34	11.21
1600	7495	1.20	69.38	13.37	122.76	3.53	14.74
1700	7833	1.25	74.07	14.35	128.42	6.03	20.77
1800	7909	1.27	75.43	14.57	130.00	6.98	27.76
1900	7724	1.24	73.35	14.03	127.38	5.47	33.23
2000	7286	1.17	68.08	12.78	120.87	2.95	36.18
2100	7287	1.17	68.30	12.78	121.08	3.01	39.18
2200	6928	1.11	64.15	11.79	115.94	1.82	41.00
2300	6714	1.07	61.74	11.22	112.95	1.35	42.35
2400	6320	1.01	57.34	10.18	107.53	0.78	43.13

Table 1
Load, Temperature, Age Acceleration Factors

Bill Strongman *is a senior planning engineer in Burns & McDonnell's management services group. He has over 25 years experience in the electric utility industry, ranging from generation planning to distribution design. He has a bachelor's degree in electrical engineering and a master's degree in business administration, both from the University of Alberta.*

Kiah Harris *is a principal in the management services group. He has over 25 years experience in the planning, design and construction of electrical engineering plants, transmission and substation facilities, and system dispatch centers. He has a bachelor's degree and master's degree in electrical engineering from the University of Missouri.*

Navigating a Turbulent Energy Marketplace:

New Choices in Central Plant Design

By Kenneth M. Clark, P.E., and Edward R. Mardiat

For owners of energy-intensive facilities, deregulation of electric utilities brings increasing uncertainty. While owners used to be able to depend on their local power companies for long-term contracts and reliable generation and delivery of electricity, the reorganization of electric utilities makes the possibility of dramatic price fluctuations and interruptions of electric service a growing concern.

However, utility deregulation also brings new opportunities. With increased competition in the electricity marketplace, consumers can negotiate rates with power suppliers. They can also cut energy costs by adapting their load profiles to take advantage of variable rates for power during different periods of the day. In addition, concerns about the reliability and quality of grid-connected power are fueling development of systems that can provide consumers with new alternatives for meeting their energy needs.

The challenge for facility owners is to find ways of minimizing the impact of power outages and rising rates on their operations while maximizing potential to take advantage of the opportunities for cost savings deregulation presents. The solution can be found in new, innovative designs for central utility plants. Hybrid chiller plants, combined heat and power (CHP) systems, and building cooling, heating and power (BCHP) systems offer owners potential to mitigate the risks and seize the opportunities presented by today's turbulent energy marketplace.

The Hybrid Chiller Plant

As demand for air conditioning has risen, the central plant has become increasingly important in meeting the cooling needs of office complexes, college campuses, airport terminals, manufacturing plants and other large facilities. In the vast majority of these plants, electrically driven chillers provide cooling. Historically low electric rates and abundant supplies of electric power, combined with a lower initial cost for electric chillers than for other types, have made electric chillers the most economical and reliable choice. However, as deregulation continues to impact the electricity marketplace, the hybrid chiller plant is becoming a more attractive alternative.

While a traditional plant relies on a single source of energy, a hybrid plant is powered by a combination of energy sources. The most basic configuration for a hybrid chiller plant is a combination of individual chillers with one or two electrically driven centrifugal chillers and one or two additional absorption or steam-turbine-driven centrifugal chillers.

Another alternative is to provide an engine-driven generator to match the load of an electric centrifugal chiller. With this configuration, the chiller can operate on electricity or can be connected to the generator powered by natural gas (or fuel oil). The cost of this configuration (electric-driven chiller in combination with a gas engine / generator set) is comparable to the cost of an absorption chiller and provides the flexibility of operating on two energy sources. In addition, the engine / generator set could be used to supply other electrical loads in an emergency.

The cost savings and energy source flexibility of the hybrid chiller plant can be amplified with the use of thermal energy storage. When a chilled-water thermal energy storage tank is used in combination with a chiller plant fueled by both electricity and gas, the chilled water stored during off-peak cooling periods can be generated by either energy source. This will double the alternative energy source's capacity to provide cooling. This would work particularly well in systems in which the primary energy

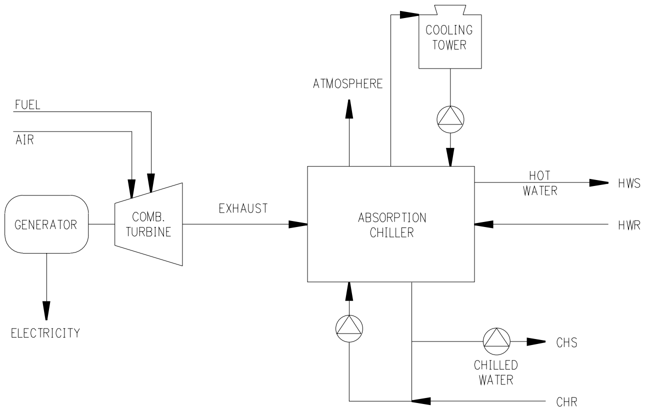


Figure 1
Basic Combined Cycle, Electricity & Chilled Water (Hot Water Optional)

source is gas and the alternative energy source is electricity. The electric chiller could operate at night when electricity may be less costly, more readily available, and less subject to demand charges. The stored capacity could then be used during peak cooling periods when electricity rates might be much higher.

CHP and BCHP Systems

Uncertainty in the energy marketplace is also making combined heat and power (CHP) systems more attractive. CHP, or co-generation, is the simultaneous production of electricity and useful heat from the same fuel source. This process captures the waste heat generated during the production of electricity and uses it to provide process steam, space heating, hot water and other thermal needs. Waste heat can also be used to satisfy cooling needs. For example, electricity might be generated by a natural gas-driven combustion turbine. The exhaust gases from the turbine could then drive an absorption chiller (see Fig. 1) or be run through a heat recovery steam generator (HRSG) and produce steam to drive a steam-turbine-driven centrifugal chiller.

While co-generation is not new in industrial settings, systems are now being developed to bring the benefits of CHP technology to smaller facilities with different energy needs. Building cooling, heating and power (BCHP) systems integrate on-site power generation equipment with heating, cooling and humidity control equipment to provide commercial, institutional and multi-family buildings with air conditioning, heat and hot water.

In a volatile energy marketplace, CHP and BCHP systems can provide tremendous benefits to facility owners. As electric utilities move toward real-time pricing, owners who are capable of producing their own electricity during peak demand periods can realize dramatic savings. They also have the ability to power their operations during power outages and brownouts. These systems also have societal benefits: In addition to reducing the demand on the nation's electrical transmission grid, they have a high level of efficiency that can help to reduce our consumption of energy resources. During the production of electricity at conventional power plants, two-thirds of the energy is wasted through lost heat. By making productive use of lost heat, CHP and BCHP systems can achieve efficiencies of 80 percent or more. As a result, the Environmental Protection Agency is promoting these systems as a means of reducing air pollution and greenhouse gas emissions.

The benefits of CHP and BCHP systems are highlighted in the recent report by the National Energy Policy Development Group, which recommends that the federal government "encourage the use of these cleaner, more efficient technologies" by easing restrictions and by providing nationwide permitting standards. In support of this goal, the Department of Energy (DOE) is partnering with industry in the research and development of BCHP systems that can be offered as comprehensive energy packages for commercial and institutional facilities.

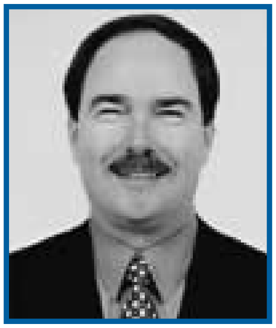
As a participant in this program, Burns & McDonnell is leading one of the teams selected by the DOE to pioneer development of BCHP systems. Currently under development is a system that will combine a natural gas-fired turbine with absorption chillers to provide electricity, cooling, heating and hot water to a facility such as a university, hospital, large office building, corporate campus or server farm. By actively promoting the development of this technology, the DOE hopes to double the nation's CHP capacity by 2010 and to make BCHP systems the preferred method of energy utilization in buildings by the year 2020.

Conclusion

In the wake of recent blackouts and battles over electric rates in California, the nation's attention has been focused on the negative aspects of deregulation. However, deregulation is opening up new choices for facilities owners about how to satisfy their energy needs. With innovative central plant designs, owners can position themselves not just to survive but to thrive in tomorrow's energy marketplace.

Portions of this article previously appeared in the August 2001 issue of Consulting-Specifying Engineer.

Kenneth M. Clark, P.E., *is a project manager for Burns & McDonnell with more than 36 years of experience in the design and construction of central plants and HVAC systems. He received his bachelor's degree in mechanical engineering from the University of Kansas, and is an ASHRAE fellow.*



Edward R. Mardiat *manages facility energy projects for Burns & McDonnell. He works with industrial, commercial and institutional clients to help them understand the impact of utility deregulation on their facilities, mitigate risk and take advantage of new energy market opportunities.*