District Heating, Cooling, and Cogeneration

Technology Assessment

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THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

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EXECUTIVE SUMMARY

District heating and cooling/cogeneration (DHC/C) is the distribution of thermal energy (e.g. steam, hot water, and chilled water) from a central facility to multiple end-users in the surrounding area. The thermal energy usually is distributed through an underground piping system to the end-user, where it is used to heat and cool connected buildings. The central source can be a large conventional heating and cooling plant, or it can be a cogeneration plant where the thermal energy is produced as a by-product of electrical generation. Cogeneration is the ultimate achievement of DHC/C where fuel-use efficiencies of up to 80% are obtained. This efficiency gain, reflected in reduced fuel consumption, also has environmental and economic benefits.

This assessment evaluates the benefits and costs of DHC/C with and without cogeneration, estimates the New York State potential, and recommends actions to increase DHC/C use in the State. Specific tasks include:

- Reviewing DHC/C technologies;
- Quantifying energy, environmental and economic benefits;
- Estimating the potential for DHC/C development in New York State;
- Evaluating the role of technology research and development; and
- Recommending actions to increase DHC/C in New York State.

This assessment reviews major DHC/C system components including technology options for the central energy plant, distribution system, and the end-user interface. Cogeneration, the goal of a mature DHC/C system, can be derived from several technologies, including purchasing a specially designed turbine with heat-extraction capability; retrofitting an electric-only generating station; or installing a gas-turbine power plant. Technologies refined in Europe, where DHC/C is common, are now economical and available in this country.

Energy, environmental, and economic benefits of DHC/C are compared to individual heating and cooling plants. Increased fuel efficiency of centralized production and cogeneration benefits the environment and improves a community's economic competitiveness. By cogenerating heat and power, heat that would otherwise have been rejected to a river or the air is used to heat and cool buildings.

Cogeneration can reduce heat rejection to the environment from an electric generating station up to 60%. Reducing thermal discharges to New York's waterways can substantially limit aquatic mortality rates from processes such as impingement and entrainment. Environmental benefits are measured by externality values calculated for DHC/C and compared to on-site heat generation. Emissions of NO_x, CO_2, SO_2, particulates, and VOCs can be substantially reduced.

Dispersing and reducing air pollutants from a centralized facility with a carefully designed chimney and other appropriate air pollution controls can be performed more effectively than using many small chimneys that disperse pollutants in a localized area around the building. This is particularly important in an urban setting where building congestion coupled with vehicular traffic can create an unhealthy environment. Enforcing the 1990 Clean Air Act Amendment will mandate capital investments by certain end-users to control emissions, particularly NO_x. Legislation exists to limit release of CFC-based refrigerants commonly used in air conditioning systems. Future legislation will continue to mandate closer emission control, fuel-handling practices, and regulate other hazardous materials associated with the heating and cooling systems of individual buildings and industry. By establishing DHC/C in a community, the end-user is liberated from these issues because heating and cooling is the responsibilty of the district energy company. Because centralized production limits the number of emitting sources, environmental control is more effective.

Constructing DHC/C usually is capital intensive; however, identifying all life-cycle costs compared to on-site generation generally provides an economic justification for DHC/C. The price of DHC/C for the end-user is a function of the size of the system's heating and cooling load and its distance from the central source. This assessment develops a family of curves to indicate the effect of both load and distance on the price for DHC/C. The price for DHC/C includes a capital component for the central source and distribution to the end-user, an electric penalty where thermal energy is cogenerated at the expense of electric generation, auxiliary fuel, and a maintenance/operations component.

The assessment identifies the potential for expanding DHC/C in New York State in categories that include the retrofit of steam-turbine electric generating stations, incorporating cogeneration in existing systems and developing new community-based systems. Table S-1 shows New York State's potential for these categories. Potential fuel (energy) savings, environmental impact measured by externality cost savings, and economic impact estimated by employee earnings, and employee years achieved by constructing DHC/C are tabulated.

Table S-1
SUMMARY OF DHC/C POTENTIAL IN NEW YORK STATE

Comparisons	Convert Electric Plants to DHC/C	Convert Heat-Only DHC to Cogen	New DHC/Cogen Outside NYC	New DHC/Cogen in NYC	Total
DHC/C Heat Load Potential (MWt)	1,380	630	2,780	1,110	5,900
DHC/C Electric Load Potential (MWe)	-277	500	1,800	725	2,750
Annual Fuel Savings (Millions of barrels of oil equivalent)	2	3.1	3	1.3	9
Annual Externality Cost Savings ($ millions)	$15.90	$21.00	$23.50	$11.73	$72.13
Capital Expenditure ($ millions)	$472.00	$64.80	$949.00	$379.00	$1,860.00
Employee Earnings ($ millions)	$178.00	$24.40	$357.00	$143.00	$702.00
Jobs (Employee Years)	5,950	820	12,000	4,780	23,600

Recommendations to precipitate development include:

- Encourage high-efficiency power plants;
- Examine and modify the way New York does business; and
- Conduct research.

Specific actions are recommended in each category. Recommendations include a broad range of activities that may be difficult to implement. Further research is needed to prioritize the recommendations and quantify the benefits, costs, and time frames required for implementation.

Section 1

THE TECHNOLOGY

This section describes the technologies associated with the DHC/C industry, including technologies related to the thermal source, thermal distribution, and end-user.

THERMAL SOURCE

The thermal source for DHC/C can be selected from a variety of technologies including commercially available boilers and chillers, and cogeneration from steam turbine power plants and gas turbines. Since DHC/C development in the U.S has been limited, strategies have been devised to promote it in the U.S. energy market. DHC/C systems often develop from small clusters of buildings and then expand to capture a larger segment of the energy market. A typical strategy uses conventional heat-only boilers and chillers to initiate DHC, such as the Buffalo district heating system described on page 1-4 or A-2. As the system grows in thermal load, cogeneration is introduced either from a nearby electric power plant or by installing a new gas turbine. Developing a mature DHC/C system is exemplified by the Con Edison system in New York City where 82% of the thermal load is supplied by cogeneration. Con Edison uses a combination of specially designed extraction and backpressure turbines at five generating stations in Manhattan. Cogeneration is the ultimate goal of DHC/C to maximize fuel savings and reduce pollution.

Cogeneration from Existing Steam Boiler Electric Generating Stations

After steam turbine electric power plants convert about a third of the energy input to electricity, the balance is released to the environment. By cogenerating heat and power, this wasted energy can be substantially reduced, as shown in Figure 1-1, where 75% of the energy input is converted for useful purposes.

A single-purpose electric power plant is modified to cogeneration by extracting more steam from the turbine than generally is used for feedwater heating. The options include installing a new turbine designed specifically for cogeneration and modifying an existing turbine to provide extraction steam.

New Cogeneration Steam Turbine

A steam turbine designed at the factory for cogeneration enables the turbine to operate across the entire performance spectrum from maximum to zero heat extraction. The turbine has controls that stabilize operation in any mode while providing the usual safeguards to prevent turbine overspeed and water induction. The turbine design is only limited by boiler output and the extractions required for feedwater heaters.

Figure 1-1

ENERGY CONVERSION IMPROVEMENT WITH DHC/C

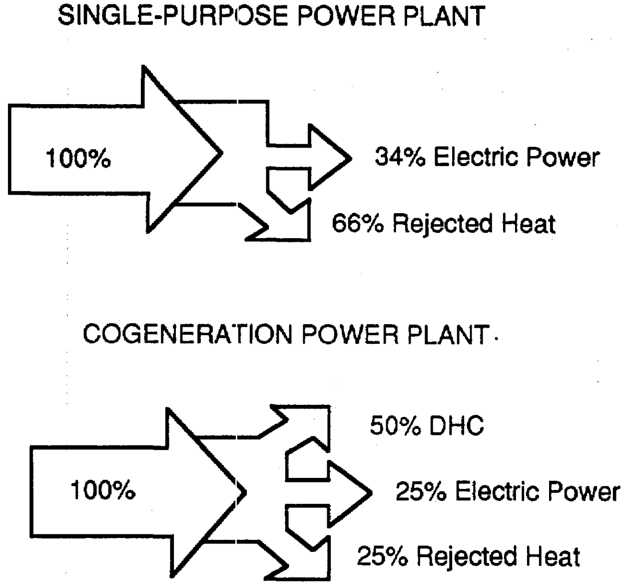
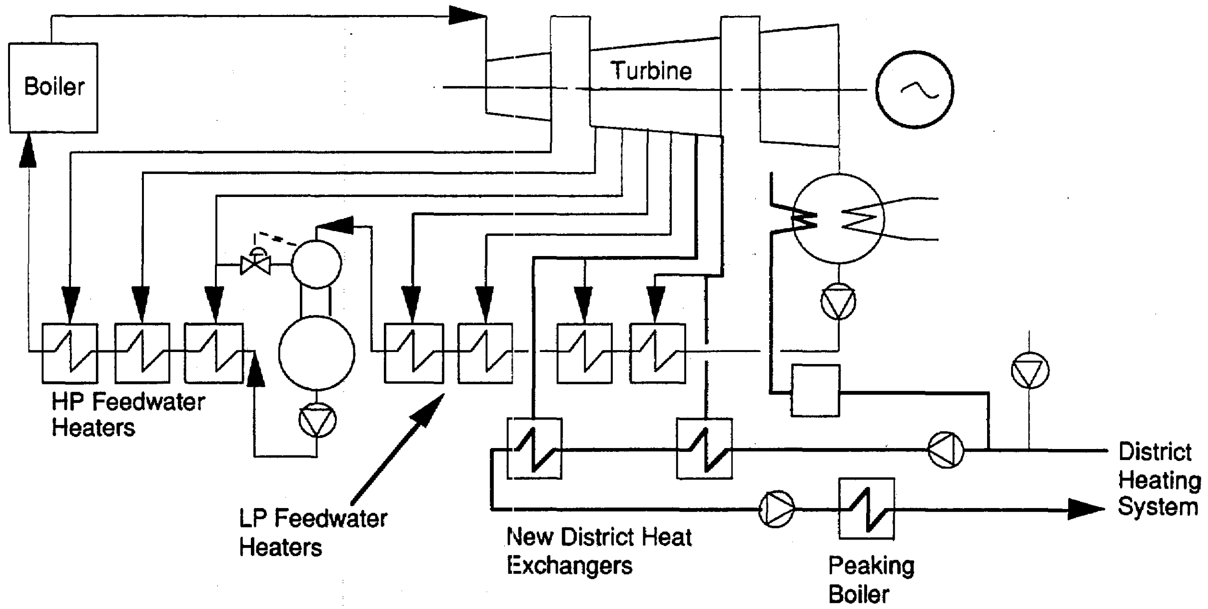


Figure 1-2

NEW COGENERATION TURBINE ARRANGEMENT



Cogeneration turbines designed for hot water production provide extractions from two pressure levels that provide staged heating of the district hot water for higher plant efficiencies. The two pressure condensers are arranged in series. The lower pressure steam is used to preheat the return while the higher pressure steam elevates the district water for either direct distribution to end-users or for further heating in a peaking boiler as shown in Figure 1-2.

Retrofit of Existing Steam Turbines

Steam extracted from existing steam turbines can be used in DHC/C. It is extracted at the lowest practical pressure to optimize efficiency and maintain electrical output. This pressure is a function of turbine design, location of extraction nozzles and the turbine's dynamic response to changes in steam distribution. Turbines must be retrofit in close cooperation with the manufacturer who is familiar with performance and mechanical constraints. Retrofit options include:

- Using the steam extracted for low-pressure feedwater heating. The extracted steam can be used directly (steam applications); in new district heat exchangers (hot water applications); or in existing feedwater heaters converted for DHC/C (hot water applications); This option may reduce steam available for low-pressure feedwater heaters so feedwater heating must be balanced at higher pressure extractions;

- Converting the turbine to backpressure operation where the last stage blades in the low-pressure cylinder of the turbine are removed. With fewer blades, the steam exits the turbine at a higher exhaust temperature to supply district heating. This option is very efficient; however, the district energy load must be constant most of the year;

- Extracting steam from external crossovers permits large quantities of steam to be extracted without internal modifications to the turbine. A special section and butterfly valve is installed in the crossover to divert steam from the crossover to the district heating system; and

- Low-temperature heat in the condenser may be used in applications such as hatcheries and greenhouses.

Jamestown Cogeneration Project

The district heating system in Jamestown, New York, is a prominent example of a single-purpose power plant retrofit for cogeneration. The Steele Street Power Station, operated by the Jamestown Board of Public Utilities, has four coal-fired boilers and two steam turbine-generator units. The 25-MW unit was selected for cogeneration. A blanked-off extraction point was opened for district heating supply. An auxiliary heat exchanger in the feedwater train can also be bypassed for district heating. The auxiliary heat exchanger is connected in series with the extraction heat exchanger to provide maximum heat output to the district heating system indicated in Figure 1-3.

Single purpose efficiency for Unit No. 6 is approximately 26.9%. By extracting a maximum of 7-MW_t for district heating, efficiency is increased to 32.5%, a 20% improvement.

Goudey Station Conversion Strategy to DHC/C

As another example, a single-purpose turbine retrofit to cogeneration capitalizes on the turbine design. One retrofit technique uses the external crossover between turbine sections as the point of extraction for district heating. For example, Goudey Station near Binghamton, New York, has two electric generating units and three coal-fired boilers and is operated by the New York State Electric & Gas Corporation. For this particular installation, the crossover pressure of the steam would be enough to produce district hot water, as shown in Figure 1-4. A diverter valve installed in the crossover would maintain pressure in the crossover to protect the turbine.

Conventional Heating and Cooling Plants

A community interested in developing DHC/C may have no electric generating station nearby. In these cases, conventional heating and cooling plants can initiate DHC/C. As the systems are expanded and their thermal load enlarged, a cogenerator is encouraged to build larger, more efficient plants that can be fueled by natural gas, oil, and coal or renewable sources such as refuse. If the community plans to build a waste-to-energy facility, linking it with DHC/C may be a real possibility.

Buffalo District Heating Project

For example, in Buffalo, New York, conventional gas-fired steam and hot water boilers were installed to start DHC/C. The plant supplies hot water and steam to several buildings near City Hall and Niagara Square. The new plant (Figure 1-5) was constructed to replace an old heating plant with excess capacity to enable the district heating system to grow.

Cooling-Only Plants

Cooling-only plants are becoming increasingly important to satisfy building cooling loads. The cooling technologies appropriate for district cooling applications include electric-driven centrifugal chillers, steam turbine-driven centrifugal chillers, and absorption chillers. One central cooling plant is shown in Figure 1-6.

District cooling can effectively level, reduce, or shift electric load. For example the central cooling plant in Albany for the Empire State Plaza burns gas to generate steam that is used for both district heating and cooling. Steam turbines drive chillers that produce chilled water which is distributed throughout the complex.

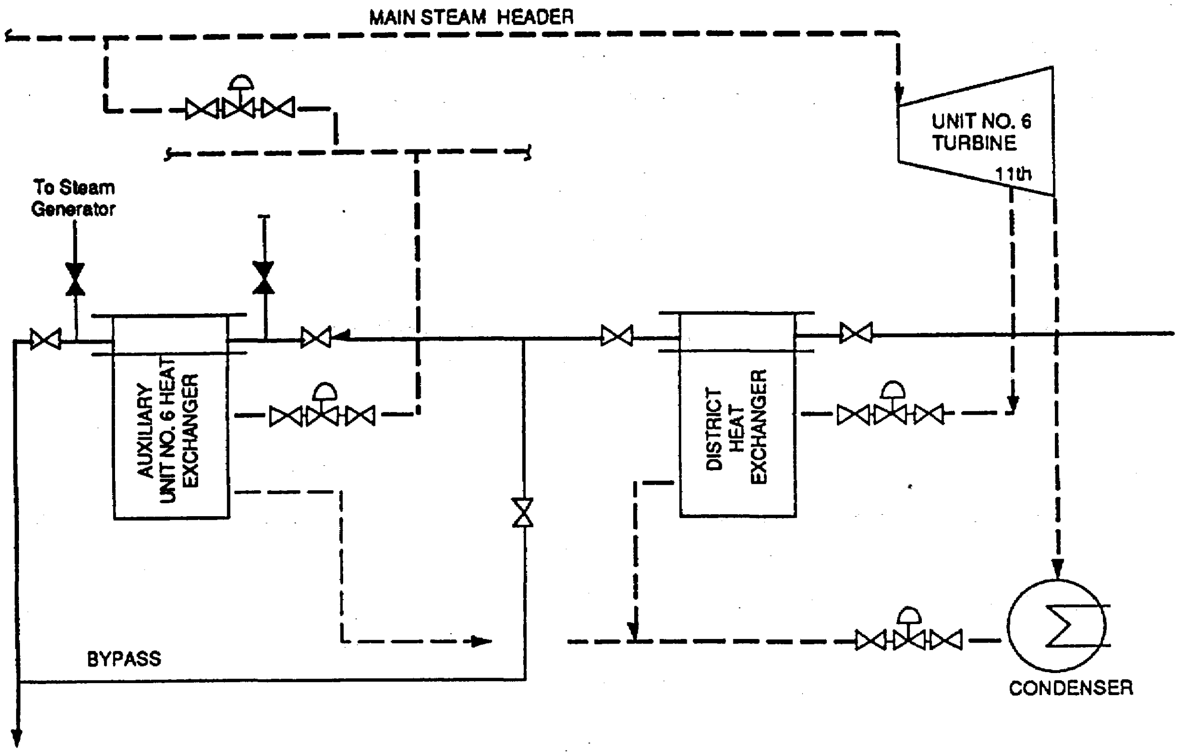


Figure 1-3. Jamestown Turbine Retrofit to Cogeneration

Figure 1-4

GOUDEY STATION RETROFIT TO COGENERATION

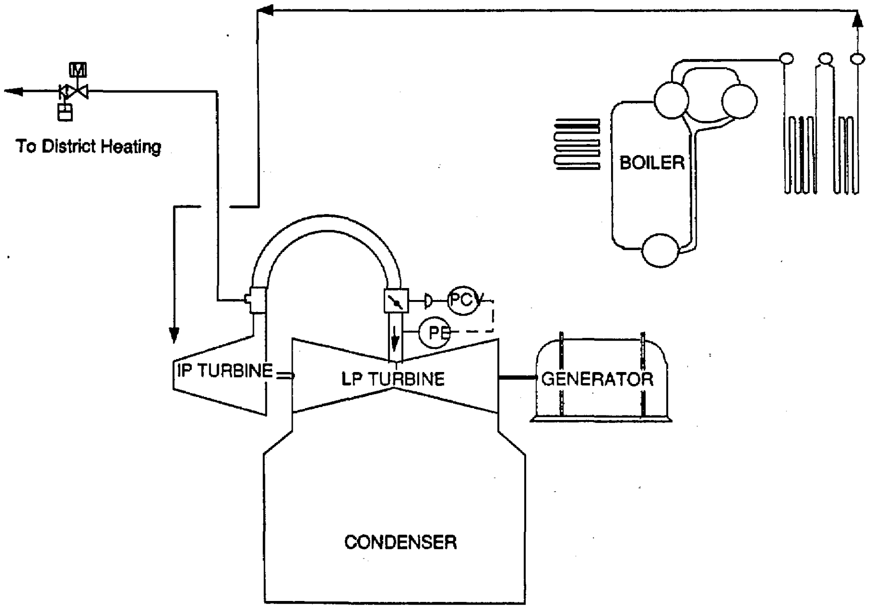
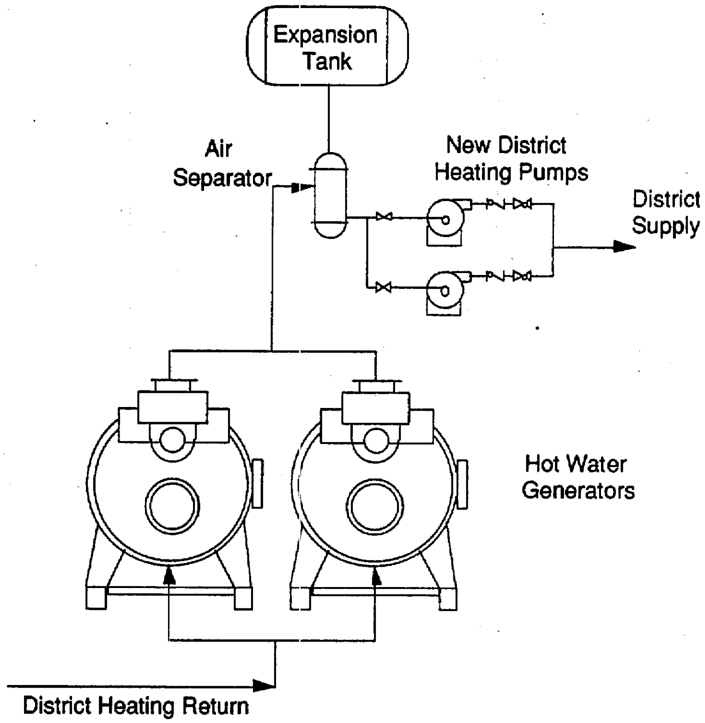


Figure 1-5

HOT WATER HEAT-ONLY PLANT



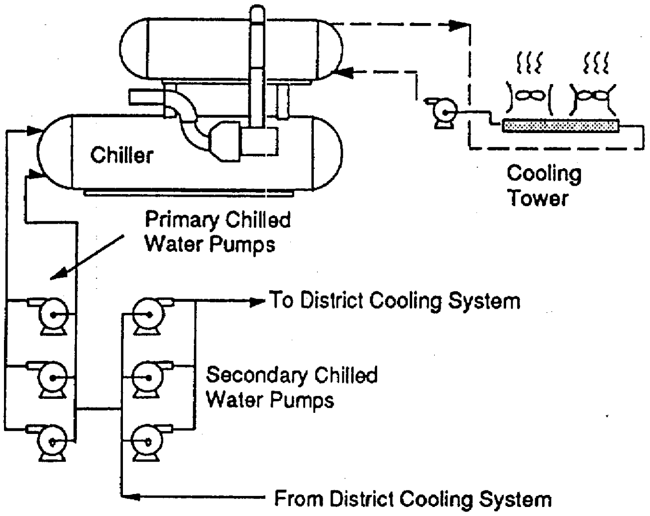


Figure 1-6. Central Cooling Plant

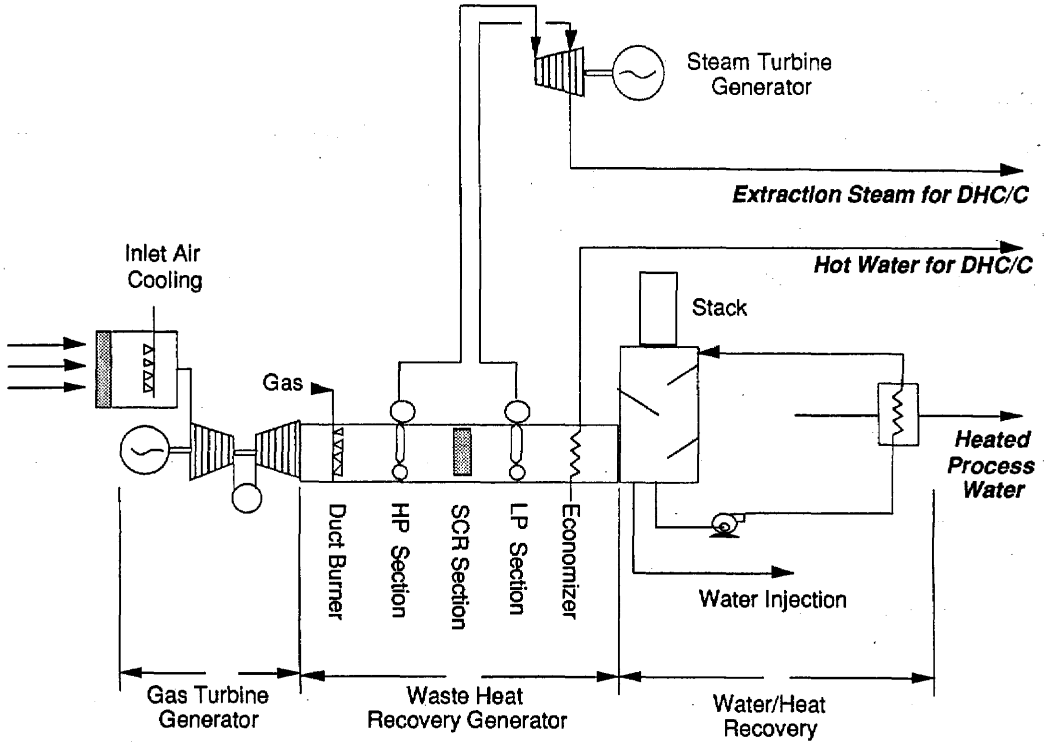
Cogeneration from a Stationary Gas Turbine

Gas-turbine cogeneration has flourished in the last 15 years. Major performance improvements have enabled cogenerators to meet PURPA requirements resulting in a proliferation of projects. The industry has grown in response to improvements in engine design and performance and the growth of independent power producers. Gas turbines linked with DHC/C conveniently qualify the facility under PURPA while efficiently using the waste heat available in the exhaust gas. Several technologies are used to meet efficiency and environmental standards. Figure 1-7 is a schematic of these technologies and their integration with the gas turbine plant.

To capture the substantial waste heat liberated by the gas turbine, a heat recovery steam generator (HRSG) is installed at the turbine exhaust. The generator usually has two or three steam pressure levels for efficient heat recovery from the turbine's exhaust gases. A duct burner is often installed at the entrance to the HRSG. The duct burner adds temperature to the exhaust gases at high combustion efficiency to provide superheat to the high pressure steam that can be generated, and provides the HRSG with a backup thermal source when the gas turbine is off-line.

Figure 1-7

COMBINED CYCLE PLANT WITH EFFICIENCY IMPROVEMENT



The high-pressure steam generated in the HRSG can be used for several purposes. It can be throttled to a steam turbine to generate electricity to add to that produced by the gas turbine; hence the term, combined cycle. It can also be injected in the steam turbine for power enhancement (STIG) or to control NO_x emissions. Steam generated in the low-pressure sections of the HRSG can be used to supplement the steam turbine or used for other process-related tasks. The steam turbine can be designed with extraction ports for DHC/C and other auxiliary loads. An economizer coil can be installed at the tail of the HRSG to preheat makeup water for a DHC/C system.

In some applications when water recovery is important, there are techniques to condense the water vapor in the exhaust gas, particularly when steam or water must be injected in the gas turbine for performance reasons and substantial makeup is required.

To account for the behavior of the gas turbine at high and low ambient temperatures, a heater and/or chiller is often installed to optimize the electric output of the gas turbine. This device is installed in the inlet air duct to the turbine. The heater element is supplied with low-pressure steam from the HRSG or the steam turbine extraction port. Many installations use chilled water for cooling, produced in electric or absorption chillers. In some cases the refrigerant such as ammonia is expanded directly in the cooling coil insert of the inlet air duct.

Nassau County Cogeneration Project

Trigen Energy Corporation commissioned a new 57-MW combined cycle power plant in Hempstead, New York, to provide steam, hot water and chilled water to two DHC/C systems. One system supplies the Nassau Veterans Memorial Coliseum, a portion of the Community College and the Marriott Hotel. This system had been supplied hot and chilled water from the County's Central Utility Plant (CUP) that Trigen purchased.

As part of the original proposal with the County, Trigen offered to construct a combined cycle plant adjacent to the CUP as part of a plan to reduce the County's energy costs while providing much needed electrical capacity to the Long Island Lighting Company. To spread operations and maintenance costs, the thermal load was expanded by adding the Nassau County Medical Center and Prison Complex which are approximately two miles distant.

The cogeneration plant consists of one 40-MW General Electric Frame 6 gas turbine with dual fuel capability and one 17-MW steam condensing turbine with a 250 psig extraction for DHC. The HRSG has supplementary firing. Air-cooled condensers are used to conserve water.

Syracuse University Cogeneration Project

An 80-MW gas turbine cogeneration facility was constructed in 1992 by Project Orange Associates, a limited partnership. The plant provides heating and cooling to non-university steam users, including nearby hospitals. The electric power is being sold to Niagara Mohawk Power Corp. The project pre-purchased a 16-year natural gas supply. The project consists of two General Electric LM5000 gas turbines.

Cool Storage

Cool storage is the production and storage of chilled water or ice made during periods of low-cost energy to meet an end users requirements when energy costs are higher. Since producing a cooling effect generally involves an electrically driven source, cool storage systems are prevalent, particulary in thermal storage applications due to the differences of on-peak and off-peak electricity costs. Thermal storage systems modify a cooling system's daily chiller load profile by shifting cooling production to off-peak hours to capitalize on the lower electric rates and demand charges as shown in Figure 1-8. Cool storage systems can be designed for partial or full storage capability when all or part of the peak hours cooling demand is supplied from storage.

Cool storage is an energy conservation measure for the cogenerator whose operation is dictated by electric demand. The electric and heating and cooling demand profiles usually do not match the corresponding outputs of the gas turbine at any given time. Assuming that the turbine is operated to meet an electrical dispatch schedule, excess heat will be generated in the HRSG that can not be absorbed by the connected end users at the same time. This excess heat can be converted to cooling and stored for future use. The primary advantages of cool storage include:

- Chilled water is generated at night at lower cost compared to meeting the full cooling demand during the day when electric rates are highest;
- Chilled water production efficiency increases at night when ambient temperatures drop;
- Efficient chillers are base loaded;
- Large cool storage systems have economies-of-scale;
- Chilled water and ice are environmentally benign; and
- The levelizing effect of storage systems promotes continuous operation of cogeneration systems.

Cool storage in the form of chilled water is often incorporated into DHC/C. For large systems, chilled water storage is generally more cost effective than its alternative, ice storage, from an economy-of-scale perspective. While several methods are used to control the charge and discharge of chilled water from the storage tank, the stratified tank is becoming prevalent. Special distributors are placed at the top and bottom of the storage tank to prevent mixing the warmed return water and the chilled water remaining in the tank. An example of a distributor design is shown in Figure 1-9, a design approach that can be applied to new tank installations or to a retrofit. One example, Hartford, Connecticut, demonstrates the latter; a 2.3 million-gallon fuel oil storage tank was converted to chilled water storage with a 19,000 ton-hours capacity.

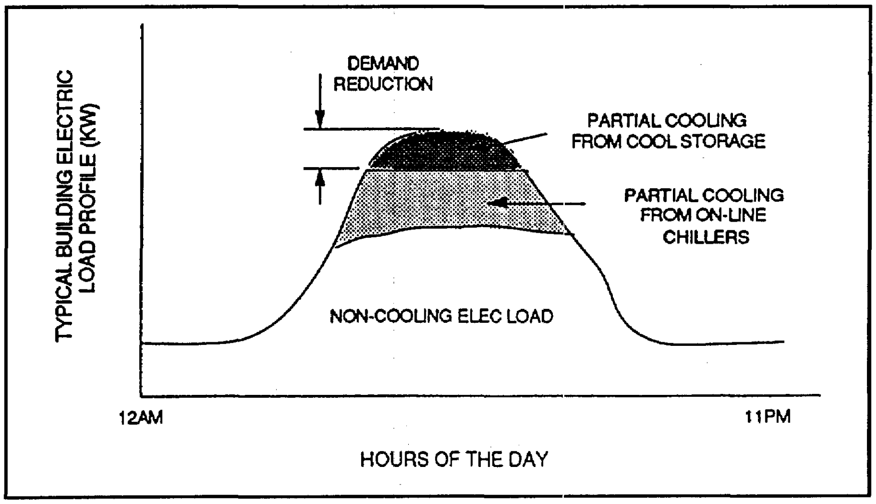


Figure 1-8. Contribution of Cool Storage to Demand Reduction

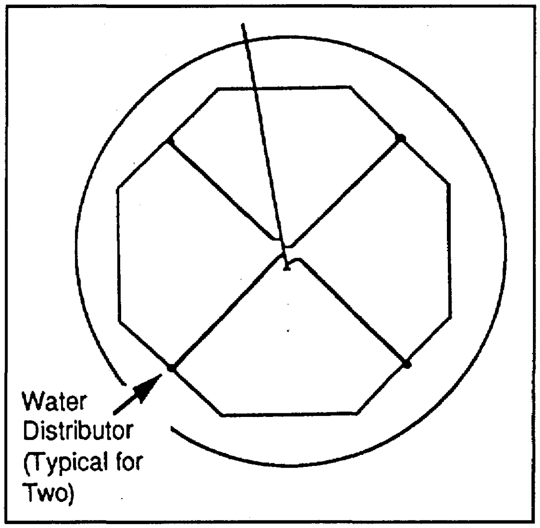


Figure 1-9. Plan View of a Thermally Stratified Chilled Water Tankton-hrs. capacity.

In another example for Cornell University near Ithaca, New York, adding new cooling capacity was investigated to compare installing a new mechanical chiller with constructing a chilled water storage tank. Capital and operating cost estimates were prepared for both alternatives. With the rebate from the local electric utility, the cost to erect a four million gallon storage tank was estimated at less than the cost required to install a new 3,000-ton chiller. Figure 1-10 shows the typical peak-day chilled water load for Cornell University. Two profiles are indicated, including the campus cooling load served by the district cooling system, and the chiller load used to meet this demand.

The chiller-load profile incorporates operating the cool storage tank which is evident if the chiller profile between the 10th and 18th hours is inspected. Note that the chiller load is substantially reduced in on-peak hours. In off-peak hours, the chiller load profile is above campus demand indicating that chillers are being used to charge the cool storage tank. Figure 1-10 shows the substantial on-peak electric load reduction during the day that accounts for a peak demand load reduction from 4 to 5-MW.

Ice Storage

Ice storage systems, successfully used in moderately sized DHC/C systems, require a tank volume from 15% to 20% that of a chilled water tank. These systems can be installed in less space, which may be important in congested urban areas. Several designs are commercially available. One design consists of multiple, cylindrical storage vessels filled with water. A compacted coil is inserted in the tank through which an ethylene glycol solution is circulated to freeze the water and subsequently melt the ice, as seen in Figure 1-11.

THERMAL DISTRIBUTION

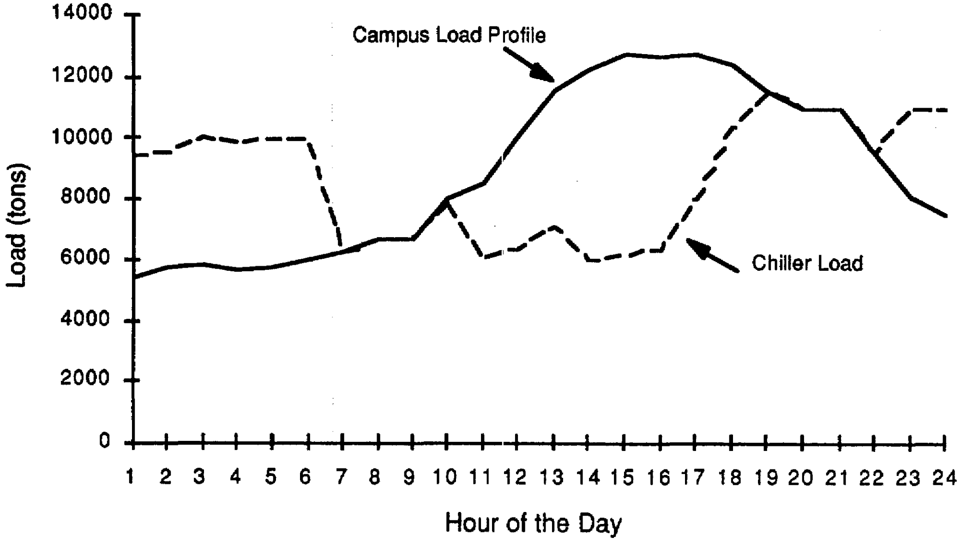
Steam Distribution

The usual steam or high temperature hot water district heating system uses a factory manufactured piping system prefabricated with an insulating layer, an air space, and outer casing that is usually steel with a tar-wrapped protective finish; however, other casing materials such as galvanized steel and fiberglass are used.

These systems generally conform to requirements for a drainable, dryable and air-pressure testable Class A heat distribution system. Piping systems are designed to allow for drainage and to dry out the insulation if the system is flooded. Sections of the system are anchored between manholes or at building penetrations to withstand thermal expansion. Within the manhole, the conduit section is finished by enclosing the air gap with end caps or gland seals that permit the casing to be air-tested at slightly above atmospheric pressure. This piping system is shown in Figure 1-12. For

Figure 1-10

PEAK DAY CHILLED WATER PROFILE AT CORNELL



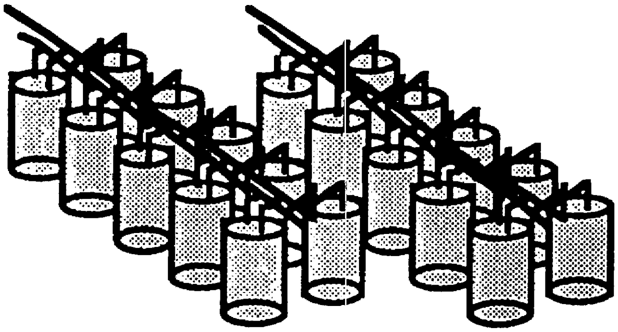


Figure 1-11. Manifolded Ice Storage Vessels

steam systems, condensate is returned in a similar conduit that parallels the steam main. The steel carrier is generally selected with a heavier wall thickness to allow for corrosion.

Hot Water Distribution

Contemporary practice is to distribute low-temperature hot water to end-users. The success of hot water district heating is apparent in West European cities. These systems use lower cost, superior performing prefabricated piping systems. A prefabricated low-temperature hot water system consists of a thin-wall steel carrier pipe, polyurethane insulation, and a polyethylene casing as shown in Figure 1-13. The conduit, a bonded system where all components of the system expand as a single system, has no air gap between the insulating layer and the outer casing.

These systems' use depends on the supply temperature from the central plant and is limited to about 250°F. Many systems in New York State and the U.S. have steam district heating systems. Therefore, incorporating new piping systems must integrate existing conditions with the ability to change the conditions of the heat supply and the form of heat demand. These systems could be introduced in stages when old systems or sections are replaced. With systematic planning, the district heating system could be gradually upgraded.

These systems offer advantages usually unavailable in high-temperature systems including:

- Reduced Installation Time:
  Since the system is prefabricated, welding, joint insulation and joint enclosure techniques are pre-engineered, reducing time in the field.

- Superior Protection from Water Ingress:
  With a durable polyethylene casing and advanced jointing, these systems provide lasting protection from ground water.

- Reliable Design:
  System components are designed to be installed and tested to reduce field errors and future problems.

- Thermal Compensation:
  By taking advantage of the elastic characteristics of the steel carrier pipe at these "low" temperatures, no expansion loops or expansion joints are required for this design that reduces component and installation cost.

Figure 1-12

HIGH TEMPERATURE DISTRIBUTION PIPING SYSTEM

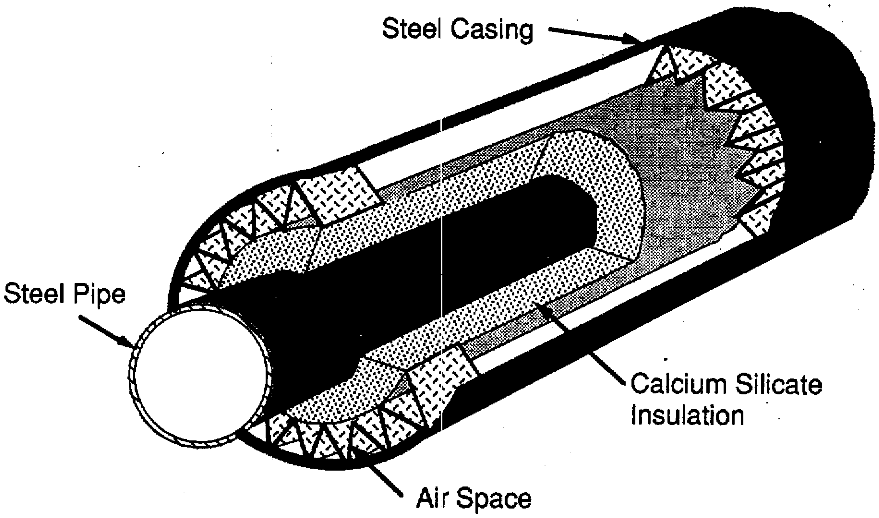
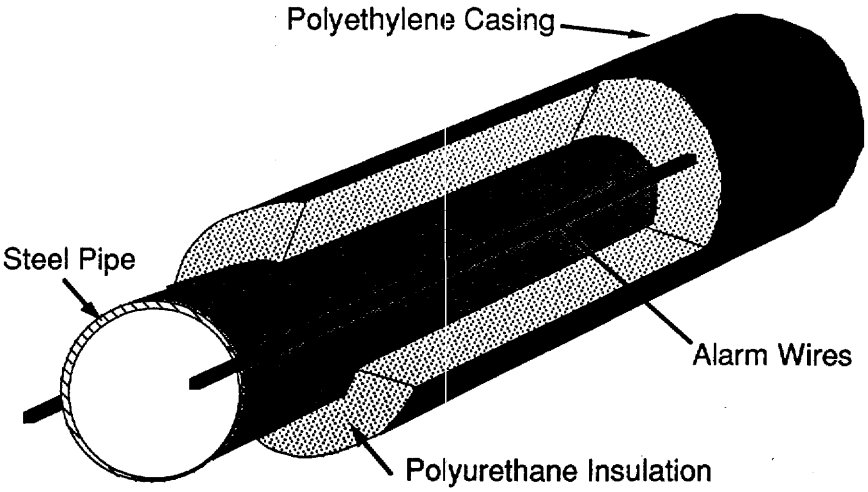


Figure 1-13

HOT WATER DISTRIBUTION PIPING SYSTEM



- Built-in Leak Detection:

  These systems have built-in leak detection and locator systems that indicate problems that need prompt repair. Leaks are located accurately, quickly reducing excavation time when searching for leaks.

Chilled Water Distribution

Since chilled water distribution temperatures are about 40°F, a variety of piping systems can be used. Plastic and fiberglass piping has been used with some success, but is usually selected in diameters less than 12 inches. If soil conditions permit, steel piping can be buried directly. The piping is insulated if the owners feel the economics are justified. In many parts of the country, ambient soil conditions approach the temperature of the chilled water system and insulation is considered unnecessary. The bonded conduit systems previously described for low temperature hot water systems have been used for chilled water distribution.

Since distribution of chilled water is similar to a municipal water supply, some district chilled water systems have used the same piping technology. When large diameters are required to supply the distribution system as in municipal supplies, ductile-iron pipe is economical. Fabrication in the field uses "push on" joints between sections as shown in Figure 1-14.

The pipe is highly resistant to ground-water corrosion and if properly constructed the joints are water-tight, the district cooling system requiring minimal makeup. Ductile-iron systems are generally not insulated and do not use leak detection systems.

Burial Techniques

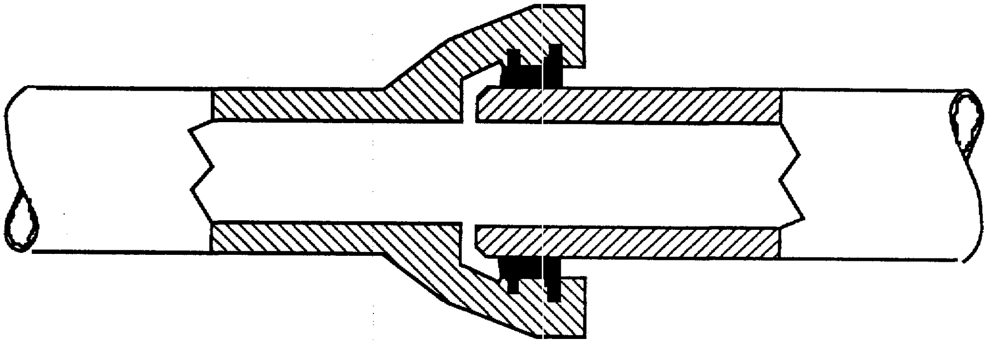
Several techniques are used to install distribution systems for DHC/C, primarily direct burial of the piping system and constructing concrete culverts or tunnels. Selecting the piping system often determines the installation technique. Piping systems such as the bonded prefabricated systems used for low temperature hot water or chilled water are designed for direct burial applications. These systems function with the soil to contain the system's thermal expansion. Similarly, ductile-iron piping systems that are impervious to the corrosive effects of groundwater are buried directly.

For bonded systems with plastic casings, special care must be taken during installation not to damage the casing. The pipe must be laid on a bed of rock-free sand and completely covered with sand so the casing will be protected from punctures, as shown in Figure 1-15.

Concrete culverts and tunnels are obviously more expensive to construct so their application is limited. Experience has demonstrated that high-temperature piping systems (steam and high-temperature hot

Figure 1-14

PUSH-ON JOINT FOR DUCTILE IRON PIPING SYSTEM



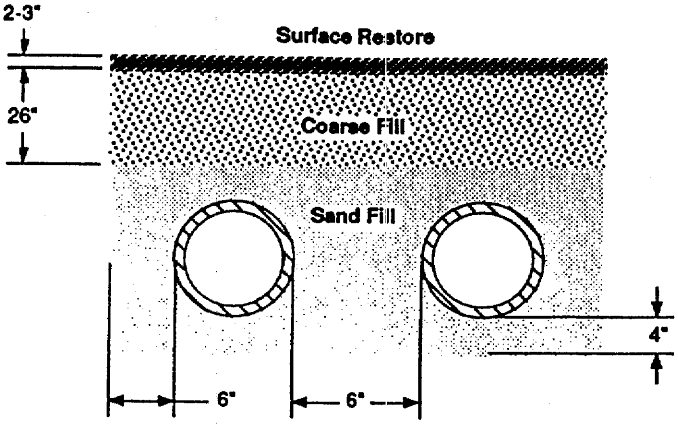


Figure 1-15. Direct Burial of Distribution Piping

water) are more likely to corrode from groundwater contact. Many systems are constructed in culverts to mediate this problem. Tunnels and culverts are also used to avoid disruption to the surface for maintenance, because tunnels allow access to the piping system without digging.

Some operators of high-temperature systems have switched to culvert systems to avoic the high failure rates of direct-buried systems. Culverts, while they promise to insure integrity of the piping system, must be carefully designed and installed. Failure to do so will create similar problems like water ingress, poor drainage,and saturation of insulation by groundwater. Concrete culverts can be precast and delivered to the site in sections or as is more popular, cast on-site. A cross section of a typical culvert is shown in Figure 1-16.

END-USER CONSIDERATIONS

Maximizing Energy Extraction from DHC/C

Issues that concern the end-user and affect the operation and efficiency of the DHC/C system include hydraulic stability, maximizing thermal exchange and energy metering. A primary concern for a DHC/C system is to insure that each customer will receive the proper amount of heat or cooling. In large systems this can often be a problem if customers at the far end of the system receive too little heat or cooling while those close to the source receive too much.

Improving energy use in the customers' buildings is important for efficient production and distribution from the central plant. For water-based DHC/C systems, the primary objective of the interconnection arrangement is to maximize the temperature differential between the supply and return to minimize the pumping power from the DHC/C plant. A typical end-user connection shown in Figure 1-17 indicates controls and energy measurement for a water-type DHC/C system.

To maximize energy extraction from a water-based DHC/C system, it is generally recommended to install a return temperature limiter as shown in Figure 1-17. Before the water is pumped back to the return side of the loop, a temperature-regulated control valve tests the water temperature to verify that the predetermined temperature differential is satisfied. If not, the water is recirculated through the building until the required temperature differential is reached when it is allowed to enter the return side of the loop and flow back to the central DHC/C plant.

The interface between the DHC/C system and the end-user is of prime importance. These considerations are often associated with this interface:

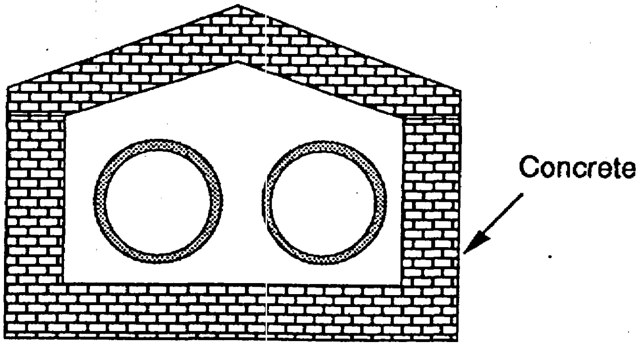
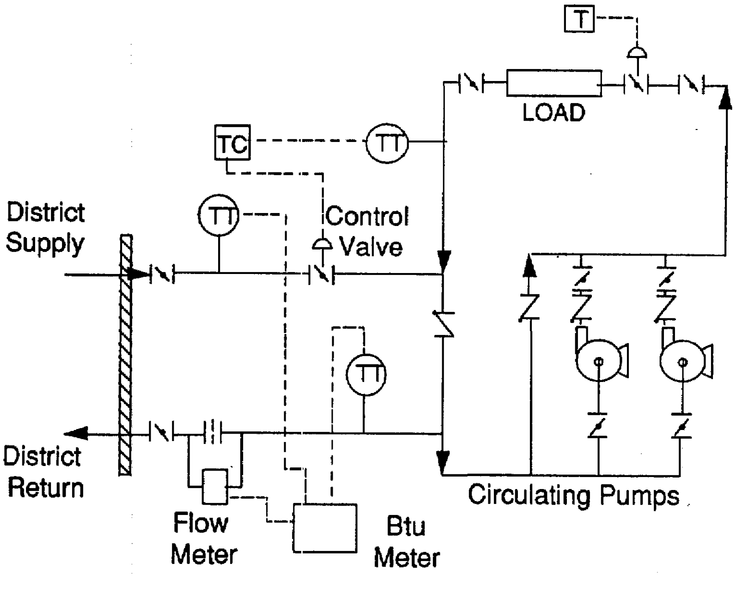


Figure 1-16. Tunnel or Culvert Installation of Distribution Piping

Figure 1-17

TYPICAL END-USER ARRANGEMENT FOR WATER DHC/C SYSTEMS



- The systems should be responsive to load diversity;

- Pumping interlocks between the central distribution pumps and the end-user circulating pumps (water systems) can cause unpredictable flows in the hot or chilled water supply line. The interface should be hydraulically stable;

- The central distribution system must be carefully designed to accommodate current loads and the potential for future growth;

- For satisfactory system performance, standards should be developed for the interface early in the project to insure that each end-user follow a consistent design philosophy; and

- The interface should contribute to optimizing energy use in the DHC/C system, and should maximize the temperature differential across end-user systems (water systems).

While the interconnection arrangement is vital to controlling the use of DHC/C, often the building systems need improvement. Modifying end-user systems can often accomplish higher temperature differentials through improved recirculation and more controlled hydronic balancing of individual subsystems within the building. Installing new terminal cooling units during renovation and new construction can significantly affect energy efficiency.

Direct vs Indirect Interface

Depending on the design of the DHC/C system, buildings can be interconnected to the DHC/C system with or without a heat exchanger. In a direct water-based DHC/C system, the district supply is blended directly with the building's circulating water. When the water has transferred its energy, it returns to the DHC/C system. In steam DHC/C systems, steam is delivered to the building at an elevated pressure. A pressure reducing station is usually installed to reduce the pressure of the incoming steam to a distribution pressure suitable for building use.

In an indirect system, a heat exchanger isolates the DHC/C water from that which is circulated through the building. While this is a more expensive alternative to a direct system, there are several advantages. When a heat exchanger is provided, the end-user is hydraulically isolated from the DHC/C system, usually improving control. Correct selection of the heat exchanger is paramount to the efficiency of thermal delivery between the system and the end-user. Heat exchangers are used in steam DHC/C systems for customers who require the steam to be converted to hot water circulation.

In many modern low temperature hot water DHC/C systems in Western Europe and in the U.S., plate and frame heat exchangers are used to maximize the temperature performance of the DHC/C system. The high efficiency that can be achieved with these units makes them particularly attractive for DHC/C where a primary objective is to maximize the temperature differential across the system. A typical unit is shown in Figure 1-18.

Energy Metering

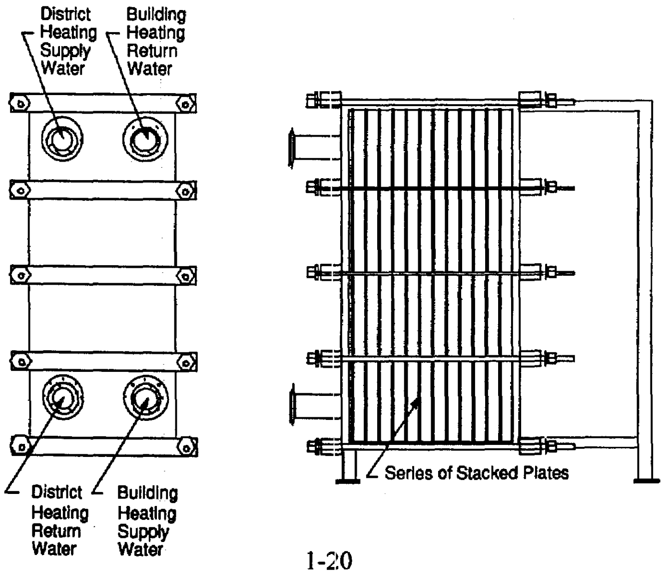
Accurate energy metering required for the end-user, is also essential for the system's financial stability. Through accurate metering, the costs to operate the system can be properly allocated among connected customers. More elaborate systems can measure daily peak demands that can liken a thermal rate structure to those used by electric and gas utilities. Many manufacturers of "BTU meters" can fulfill the accuracy and budget constraints of the DHC/C industry.

Billing end-users based on actual energy consumption will provide an incentive for the building owner to conserve energy, install energy-efficient controls, and insulate and upgrade windows. This step could be very significant to continually improve energy efficiency of the DHC/C system by allowing market conditions to dictate the economic advantages of energy conservation.

Energy metering systems depend on the type of thermal media used in the system; i.e., steam, chilled water or hot water and the anticipated swings in load. In steam systems, consumption is often measured using condensate turbine-type meters. Water-based systems commonly use turbine flow meters with an integrator function that measures inlet and outlet temperatures and computes energy consumption. A new feature with many meters is "peak value memory," which gives a monthly record of peak consumption. Ultrasonic meters are "top-of-the-line" and are usually affordable to accurately measure

Figure 1-18

PLATE AND FRAME HEAT EXCHANGER FOR DHC/C END-USERS



large flow rates. Some typical energy measurement devices used in the DHC/C industry are listed in Table 1-1.

Table 1-1

ENERGY-METERING DEVICES USED FOR DHC/C

Meter Type	Service	Accuracy	Advantages	Disadvantages	Maintenance
Turbine (full flow)	water, condensate	30 to 1 turndown, accurate to 2% of max flow	low cost in small sizes, most commonly used	subject to damage by debris	replace bearing 7-10 yrs
Turbine (partial flow)	water, condensate	30 to 1 turndown, accurate to 2% of reading	good low flow accuracy	subject to damage by debris	replace bearing 4-5 yrs
Vortex (differential pressure)	water, steam	10 to 1 turndown	low cost in large sizes, low-pressure drop	good only for steady flow	calibrate pressure sensors
Orifice plate (differential pressure)	water, steam	10 to 1 turndown	low cost	good only for steady flow	calibrate pressure sensors
Magnetic	water	30 to 1 turndown, accurate to 0.5% of max flow	low cost in large sizes, no moving parts, low-pressure drop	expensive in small sizes, special spool piece	calibrate every 3 yrs
Ultrasonic	water	30 to 1 turndown, accurate to 0.25% of max flow	low cost in large sizes, completely external to flow path, low-pressure drop	expensive in small sizes	calibrate every 7 yrs
Shunt	steam	10 to 1 turndown, accurate to 2% of reading	bypass arrangement allows small (lower cost) meter for measuring high capacities	high maintenance, not easy to calibrate	service is similar to orifice-type meters

Section 2

ENERGY, ENVIRONMENTAL, AND ECONOMIC BENEFITS AND COSTS OF DHC/C FOR NEW YORK STATE

Several thermal generation scenarios were used in the comparisons to develop energy and environmental benefits of DHC/C. The scenarios use a mix of fuels and technologies commonly encountered, and include cogeneration arrangements and heat-only options. The comparison quantifies the potential energy and environmental benefits of DHC/C compared with the end-user's generation of heat with on-site boilers. The scenarios used include:

DHC/C

- Cogeneration from a Steam Turbine Power Generating Station;
- Cogeneration from a Combined Cycle Gas Turbine Generating Station; and
- Heat-Only Gas-Fired Boiler.

On-Site Heat Only

- #2 Oil-Fired Boiler;
- #6 Oil-Fired Boiler; and
- Gas-Fired Boiler.

ENERGY BENEFITS FROM COGENERATION

The primary energy benefit of cogeneration is capturing heat that otherwise would have been rejected to the environment, either to the air via cooling towers or to the waterways. While heat rejection to the environment is reduced, heat must be extracted within the generating plant at a higher pressure and temperature than that which is rejected in the plant's condenser. The temperature of waste heat at the condenser is too low for use in most district heating applications. Extracting heat from the power plant at higher pressure and temperature causes a reduction in electrical generation, since the extracted heat is no longer available to produce electricity. Results of the energy requirement comparison to produce useful heat are presented in Table 2-1 and Figure 2-1. Incremental fuel required to produce 30,000 MWhr of useful heat is indicated for the steam turbine and the combined-cycle gas turbine. This incremental fuel can be compared to the fuel required to replace electricity lost during cogeneration.

The analysis considers the energy required to generate 30,000 MWhr of useful heat. The amount of heat required for cogeneration alternatives is a function of heat rate (efficiency) of the existing power plant and the amount of heat that can be generated for each kW of electrical loss. A heat rate of 10,000

Table 2-1

FUEL NEEDED FOR 30,000 MWhr OF USEFUL HEAT

	Incremental Fuel to Replace Electricity					
	Cogen Stm Turbine Power Plant DHC/C	**Cogen Comb. Cycle Gas Turbine DHC/C**	**Heat-Only Gas Boiler DHC/C**	**Heat-Only # 2 Oil Boiler End-User**	**Heat-Only # 6 Oil Boiler End-User**	**Heat-Only Gas Boiler End-User**
Fuel Input (MWhr)	17,600	14,100	37,500	46,200	46,200	46.200
Equivalent Barrels of Oil Saved Compared to End-User	16,250	18,240	4,940	0	0	0

Table 2-1 Assumptions:

a) Heat rate = 10,000 Btu/kWhr for steam turbine generating plant

b) Heat rate = 8,000 Btu/kWhr for combined cycle

c) Cogeneration factor = 5 kW_t/kW_e

d) DHC/C gas boiler efficiency = 80%

e) End-user boiler efficiency = 65%

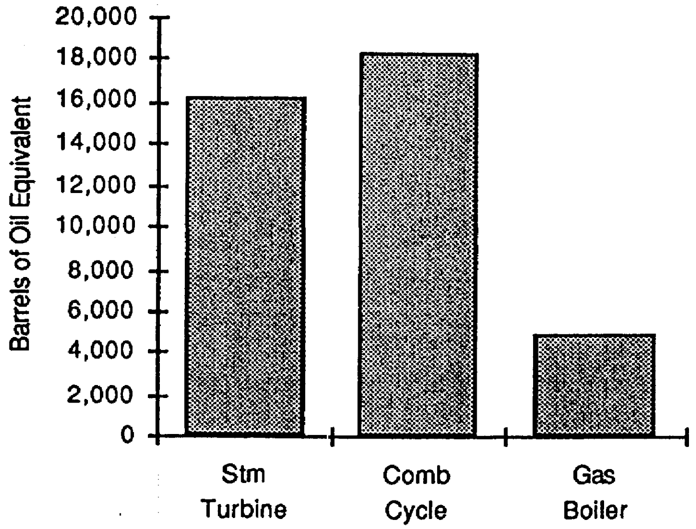


Figure 2-1. Barrels of Oil Saved with DHC/C for 30,000 MWHR of Useful Heat as Compared to the End-User

Btu/kWhr is assumed for the steam-turbine power plant and 8,000 Btu/kWhr for the gas-turbine combined-cycle. A cogeneration factor of 5 kW_t/kW_e, assumed for the cogeneration options, accounts for loss of electric generation that occurs during cogeneration of useful heat. To produce "useful" heat, steam is extracted from the turbine before it reaches the condenser, when it is considered "waste" heat. The actual loss in electric generation is a function of:

- Where the steam is extracted from the cycle;
- Operating parameters that govern the dispatch of the power plant; and
- Specific design limitations of the turbine and other primary equipment.

In the analysis, it is assumed that 1 kW_e is lost for every 5 kW_t of useful heat produced. The incremental fuel requirement indicated in Table 2-1 for the cogeneration options indicates the amount of fuel necessary to recover electricity that is lost during cogeneration to produce 30,000 MWhr of useful heat.

In addition to cogeneration, Table 2-1 shows the fuel requirements of heat-only options for DHC/C and the end-user. Fuel requirements for the heat-only alternatives are calculated by dividing the 30,000 MWhr of useful heat by the assumed annual boiler efficiency.

ENERGY BENEFITS FROM DISTRICT COOLING

District cooling offers several opportunities to reduce peak electric demand. At numerous sites in the United States, district cooling systems substitute alternate fuel sources for electrically driven equipment. In Indianapolis, Indiana, and Albany, New York, for example, district cooling is generated by turbine-driven chillers; the steam is supplied from waste-to-energy plants. In Albany, New York, and other sites, natural gas is used as the primary fuel. In Hartford, Connecticut, which uses turbine-driven chillers, the steam is generated by a gas turbine and gas-fired boilers. In these examples, the total cooling load in the system represents a reduction in the peak electric demand for the region.

Another opportunity implements cool storage to achieve peak electric reduction. District cooling systems usually implement chilled water storage to complement their chiller capacity. Cool storage offers additional on-peak capacity and the ability to reduce peak electric demand by avoiding operating electric-driven chillers during peak hours as defined by the utility. Table 2-2 indicates the range of peak electric reduction opportunity with chilled water storage. The table indicates that the magnitude of reduction is a function of temperature rise that can be achieved across the storage tank and the number of hours this discharge is maintained. Peak reduction is greatest when the hours of discharge are minimized, which can be compared to a cooling load profile with a sharp on-peak load.

Table 2-2

SHIFTED kW FOR EVERY MILLION GALLONS OF CHILLED WATER STORAGE

	Temperature Rise Across Tank (°F)			
Hours of Discharge	10	12	14	16
4	1400	1700	1900	2200
5	1100	1300	1600	1800
6	900	1100	1300	1500
7	800	1000	1100	1300
8	700	800	1000	1100
9	600	700	900	1000
10	600	700	800	900
11	500	600	700	800
12	500	600	600	700

Assumptions:

a) Storage efficiency = 80% (accounts for tank thermal losses and return mixing)
b) Chiller energy consumption = 1 kW/ton

ENVIRONMENTAL BENEFITS OF COGENERATION

DHC/C could have a significant impact on reducing air emissions, especially in New York's non-attainment areas as mandated by the Federal Clean Air Act Amendments (CAAA) of 1990. If New York State does not meet the requirements, it will be subject to penalties including fines exceeding $100 million annually and sanctions that could severely restrict economic development.

Environmental benefits were based on fuel requirements to produce 30,000 MWhr of useful heat, as shown in Table 2-1. Since incremental fuel required to replace lost electricity from the steam turbine power plant is assumed to be derived from the power pool, associated emission rates are those derived from the New York Power Pool average. Emission rates for gas-turbine combined-cycle and heat-only boilers were based on technology and fuel type. Emission rates for NO_x, CO_2, SO_2, particulates, and VOC were used in the analysis shown in Table 2-3.[1]

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[1] Hydro-Quebec Economic Study, NY State Energy Office and Dept. of Public Service, May 1992; PM and VOC based on 1990 DEC Emissions Inventory

Table 2-3

TONS OF EMISSIONS FOR 30,000 MWHR OF USEFUL HEAT

	Incremental Fuel to Replace Electricity					
	Cogen Stm Turbine Power Plant DHC/C	**Cogen Comb. Cycle Gas Turbine DHC/C**	**Heat Only Gas Boiler DHC/C**	**Heat Only # 2 Oil Boiler End-User**	**Heat Only # 6 Oil Boiler End-User**	**Heat-Only Gas Boiler End-User**
Fuel Input (MWhr)	17,600	14,100	37,500	46,200	46,200	46,200
SO_2	6.3	0.0	0.0	25.2	82.8	0.0
NO_x	1.2	0.5	5.1	11.0	29.2	110
Particulates	0.5	0.2	0.2	1.1	9.2	0.2
CO_2	2,340	2,810	7,490	12,800	13,300	9,220
VOC	0.06	0.07	0.06	0.08	0.39	0.08

Results from Table 2-3 are charted in Figures 2-2 through 2-6 for each of the tabulated pollutants.

Air Emission Externality Cost

Externality costs associated with emissions of NO_x, CO_2, SO_2, particulates, and VOC are applied to quantities of pollution produced by each of the technologies shown in Table 2-3.[2] Cost assumptions are given in Table 2-4. Externality values are a function of negative impacts on health and physical resources for society.

Table 2-4

AIR EMISSION EXTERNALITY COST ASSUMPTIONS

Emission	**Externality (\$/ton - nominal \$1992)**
SO_2	1,367
NO_x	6,524
CO_2	8.6
VOC	4,400
Particulates	3,642

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[2] Hydro-Quebec Economic Study, NY State Energy Office and Dept. of Public Service, May 1992

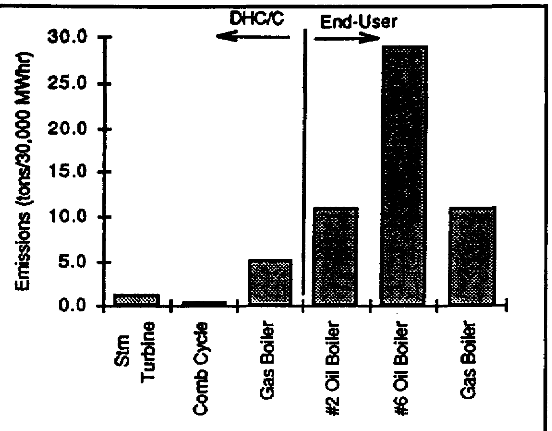


Figure 2-2. NO_x Emission Comparison

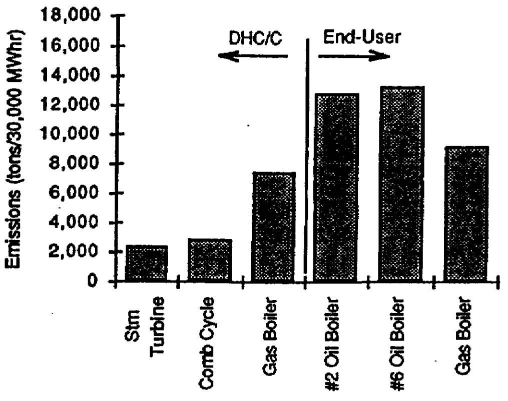


Figure 2-3. CO_2 Emission Comparison

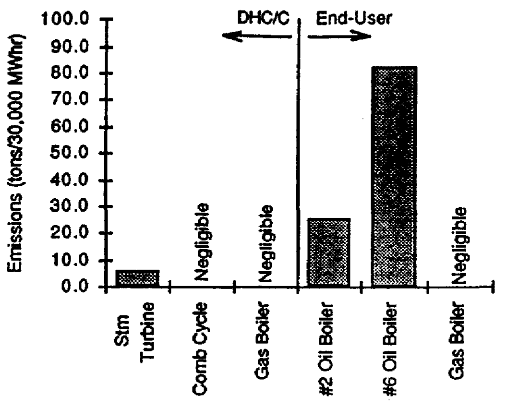


Figure 2-4. SO_2 Emission Comparison

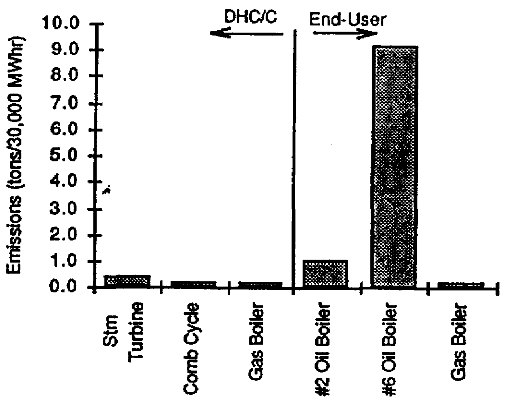


Figure 2-5. Particulates Emission Comparison

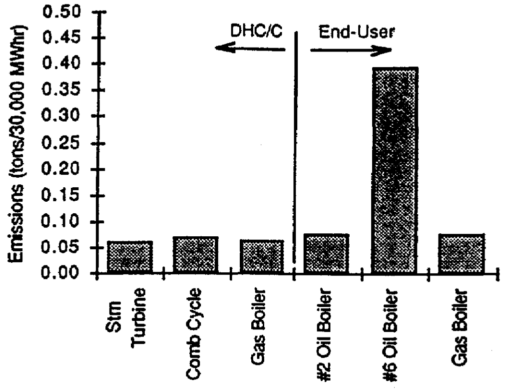


Figure 2-6. VOC Emission Comparison

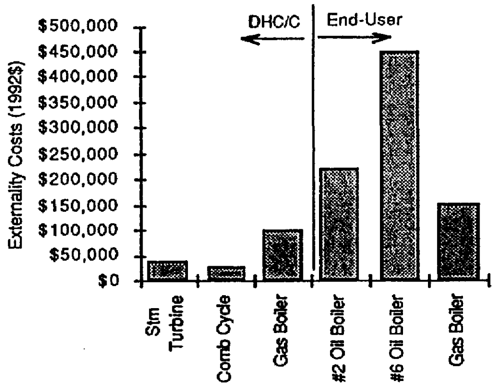


Figure 2-7. Externality Cost Comparison

Table 2-5

EXTERNALITY COSTS FOR 30,000 MWHR OF USEFUL HEAT

	Incremental Fuel to Replace Electricity					
(nominal $1992)	**Cogen Stm Turbine Power Plant DHC/C**	**Cogen Comb.Cycle Gas Turbine DHC/C**	**Heat Only Gas Boiler DHC/C**	**Heat Only # 2 Oil Boiler End-User**	**Heat Only # 6 Oil Boiler End-User**	**Heat Only Gas Boiler End-User**
SO_2	$8,620	$20	$52	$34,500	$113,000	$65
NO_x	$7,840	$3,140	$33,400	$72,000	$190,000	$72,000
Particulates	$1,640	$876	$699	$4,020	$33,600	$861
CO_2	$20,100	$24,200	$64,400	$110,000	$114,000	$79,300
VOC	$264	$318	$281	$347	$1,730	$347
Total Externalities	$38,500	$28,600	$98,800	$221,000	$452,000	$153,000

Externality cost assumptions in Table 2-4 expressed in $/ton are multiplied by quantities of each emission type produced to generate 30,000 MWhr of useful heat. Results indicated in Table 2-5 and displayed in Figure 2-7 show the dramatic reduction in total pollution and associated externality cost for DHC/C alternatives.

Reducing Thermal Discharge to the Environment with Cogeneration

Cogenerating heat from the steam turbine of a power plant reduces the quantity of heat rejected to the environment. Since steam flow to the condenser is reduced by the quantity of heat extracted for district heating, a relationship between the percent extracted compared to the heat rejected to the environment can be developed as a function of the size of the power plant, as approximated in Figure 2-8. Heat rejection to the environment can be reduced about 60% with cogeneration. Although reduced, heat is still rejected through the power plant's condenser; not all heat can be effectively captured. Figure 2-8 verifies that heat rejection is not reduced to zero at 100% heat extraction. Some steam must travel the full length of the low-pressure section to the condenser due to turbine design limitations. Figure 2-8 assumes that a full-condensing turbine is being converted to cogeneration (a power plant that has a condenser); it does not apply to a back pressure turbine where all the steam that leaves the turbine at an elevated pressure is used for DHC/C.

Reduction in thermal discharge to the environment can be represented as gallons of cooling water that can be saved as a function of the permitted temperature rise in the waterway as indicated in Figure 2-9.

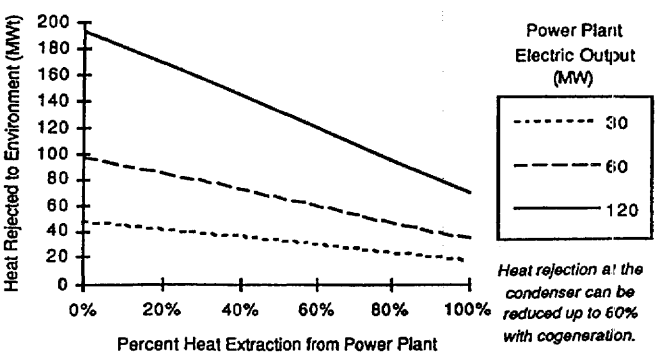
Ecological, Aesthetic and Economic Benefits from Reduced Cooling Water Use

Reductions in cooling water use can benefit aquatic life in affected New York State waters. Studies indicate that aquatic organism mortality from processes such as impingement and entrainment at power plants is related to the volume of cooling water used. As power plants withdraw large volumes of water for cooling, fish and other large aquatic organisms become impinged or trapped against screens used to protect the plant interior from debris. Organisms suffer physical damage and death from contact with intake screens and, if there is no way to return fish to the waterbody (as is often the case), they die.

The young life stages of fish (e.g. eggs, larve, and some juveniles) and other small aquatic biota (e.g. plankton) pass through the intake screen mesh, a process called entrainment. Entrained organisms suffer physical damage from changes in water pressure and collisions with pump blades and pipe walls, and thermal stress as the cooling water becomes heated (temperature increases from 8°F to 35°F are common).

Electric generating stations are required to use the best technology available to reduce impacts to aquatic biota from withdrawing cooling water. A commonly used technology in new facilities is closed-cycle cooling (i.e. cooling towers). Closed-cycle cooling can decrease the amount of new cooling water by 90% or more. DHC/C benefits aquatic resources through reductions in cooling water use and by using the waste heat rather than rejecting it to the atmosphere. DHC/C also reduces the potential aesthetic impact of large cooling towers and their plumes by reducing their size.

The economic impact to aquatic life by reducing cooling water use with cogeneration can be quantified by estimating the number of fish saved. An estimate was performed for the Dunkirk Power Generating Station in western New York State, which consumed approximately 167,200 million gallons for cooling use in 1987. Based on the number of "fish kills" estimated for approximately 10 species, the rate of economic impact was estimated from $13.50 to $20.50/million gallons of cooling water. Appendix B



Heat rejection at the condenser can be reduced up to 60% with cogeneration.

Figure 2-8. Reducing Thermal Discharge with Cogeneration

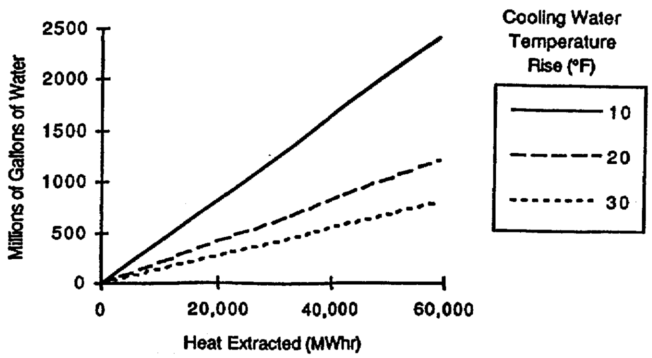


Figure 2-9. Cooling Water Saved with Cogeneration

page B-1 includes a detailed assessment of this calculation. The cooling water savings of Figure 2-10 are calculated for three temperature rises of 10°, 20°, and 30°F.

Temperature rise establishes the cooling-water flow rate; the smaller the temperature rise, the higher the flow rate required to pass an equivalent heat load. Higher flow rates mean more impingement and entrainment of aquatic life with a corresponding increase in mortality and economic impact. For each temperature rise there is a band of economic benefit based on the range previously cited. This economic impact range is applied to the amount of cooling water saved by cogeneration in Figure 2-9.

ECONOMIC BENEFITS OF DHC/C

Cost of Heat: Cogeneration Compared to Heat-Only Boiler

The economic viability of district heating is evaluated by comparing its equivalent unit cost to the end-user's current cost. For cogenerated heat, the cost includes those associated with production, distribution, and lost electric-generation penalty. Figure 2-11 compares heat from an existing electric power plant to DHC/C, and shows the effect of transmission distance from the power plant to the thermal load center. As thermal demand increases, unit cost to generate and distribute heat decreases.

In Figure 2-11, the cogenerated unit cost of heat is comprised of the cost to generate heat to the plant boundary plus the cost to distribute the heat to the end-user. Several transmission lengths are indicated, including customer loads that are one-half, one, two, and five miles from the power plant. For this analysis, production cost is determined to the plant boundary and includes a capital cost component (annualized by applying a capital recovery factor of 20%) for plant retrofit to cogeneration; an electric penalty that is a fuel component charged to district heating for reduced electrical output from the plant; peaking boiler fuel for use when the turbine is off-line; and an O&M component to account for incremental O&M. Production cost to the plant boundary is presented in Table 2-6.

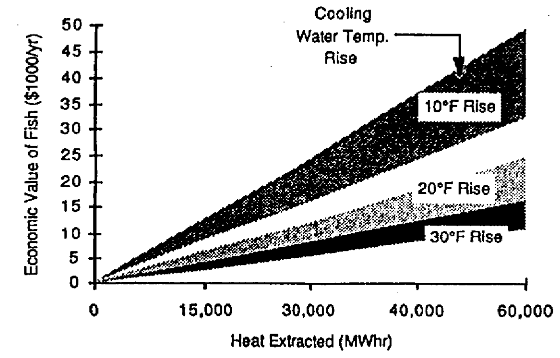


Figure 2-10. Economic Value of Fish Saved with Cogeneration (based on 1987 data from the Dunkirk Generating Station)

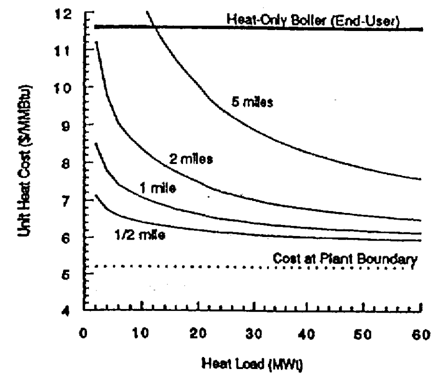


Figure 2-11. Cost of Cogenerated Heat vs Heat-Only Boiler

Assumptions:

a) Hot water distribution.

b) Cost at plant boundary is calculated in Table 2-6 for conversion of a steam turbine plant.

c) Cost of heat-only boiler (end-user) is calculated in Table 2-7.

Table 2-6

COST OF HEAT AT THE COGENERATION PLANT BOUNDARY

Components of Unit Heating Cost		Unit Heat Cost ($/MMBtu)
Capital Component		2.3
Power Plant Retrofit Cost ($/kWt)	$200	
Capital Recovery Fact	0.2	
Electric Generation Penalty		2.0
Replacement Cost ($/kWe)	0.04	
Cogen Efficiency (kWt/kWe)	5	
Peaking Fuel Component		0.5
Annual Efficiency =	85%	
Unit Fuel Cost ($/MMBtu)	3	
Operating Duration/year =	15%	
O&M		0.4
Annual Cost based on 3% of Capital Cost		
Total		5.2

The cost to generate an equivalent heat load with heat-only boilers typical for most end-users also is indicated in Figure 2-11; a capital component to cover costs associated with on-site heat production, fuel, and O&M is included. O&M costs include on-site labor cost, on-site maintenance and service contracts, related utility costs including electric, water and sewer, chemical treatment, insurance, and taxes. Production cost for the end-user is presented in Table 2-7. The results in Figure 2-11 suggest substantial savings for the end-user in most cases.

Figure 2-12 graphically estimates potential end-user savings with DHC/C. By determining the ratio between cost offered for district heating and current cost using heat-only boilers, and approximating current seasonal efficiency, anticipated savings for the end-user can be estimated. Costs include capital investment, fuel, and O&M for both the DHC/C option and the end-user. The unit cost for district heating is based on energy supplied to the building. The unit cost for the end-user is based on energy of the fuel consumed by their on-site boilers.

For example, assume that DHC/C is offering heat at $8/MMBtu and that the customer consumes fuel on-site at a cost of $10/MMBtu. The "Ratio of District Heat/End-User Unit Cost" is equal to:

$$\frac{\text{District Heat}}{\text{End-User}} = \frac{8\$/\text{MMBtu}}{10\$/\text{MMBtu}} = 0.8$$

Table 2-7

COST OF HEAT FOR THE END-USER WITH HEAT-ONLY BOILERS

Components of Unit Heating Cost		Annual Cost ($)	Unit Heat Cost ($/MMBtu)
Peak Heat Load (MMBTU/hr) =	1		
Annual Heating Hours =	1,500		
Annual Heat Load (MMBtu)=	1,500		
Capital Component	$44,800	$4,600	3.1
Replacement Cost for New Boiler= Capital Recovery Based on 8% interest, 20 year loan =	0.102		
Fuel Component		$11,500	7.7
Annual Efficiency =	65%		
Unit Fuel Cost ($/MMBtu)	5		
O&M		$1,300	0.0
Annual Cost based on 3% of Capital Cost			
Total		$17,400	11.6

Enter Figure 2-12 on the horizontal axis at 0.8 and move vertically until the estimated seasonal efficiency of the end-user's on-site plant is reached, 60% is used in the example. The point of intersection between the horizontal and vertical lines estimates the savings the end-user can expect; for this example, 50% energy cost savings with DHC/C.

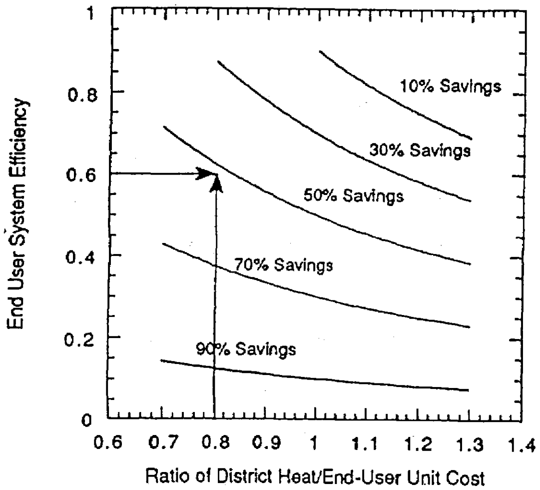


Figure 2-12. End-User Savings with District Heating

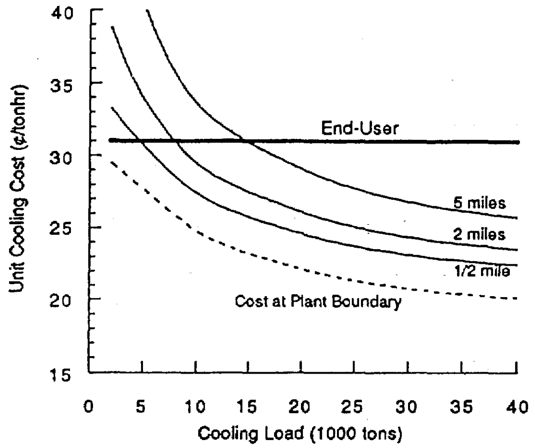


Figure 2-13. Cost of District Cooling vs End-user Chiller

Assumptions:

a) Chilled water distribution.
b) Cost at plant boundary is calculated in Table 2-8.
c) Cost of customer cooling is calculated in Table 2-9.

Table 2-8

COST OF DISTRICT COOLING AT THE PLANT BOUNDARY

Components of Unit Cooling Cost		Annual Cost ($)	Unit Cooling Cost ($/MMBtu)
Peak Heat Load (MMBTU/hr) =	10,000		
Annual Heating Hours =	1,000		
Annual Heat Load (MMBtu)=	10,000,000		
Capital Component		$1,530,000	15
Cost forChiller ($1200/ton)=	$15,000,000		
Capital Recovery Based on 8% interest, 20 year loan =	0.102		
Fuel Component		$480,000	5
Steam Cooling Efficiency(lb/tonhr) =	8.00		
Steam Cost ($/MMBtu)	6		
O&M		$450,000	5
Annual Cost based on 3% of Capital Cost			
Total		$2,460,000	25

Cost of Cooling: District Cooling Compared to On-Site Chillers

The economic viability of district cooling also is evaluated by comparing its equivalent unit cost to the end users current cost. This comparison is presented in Figure 2-13.

Among the cooling technologies available to implementating district cooling systems are absorption and mechanical vapor-compression cycles. Both technologies offer opportunities to use alternative fuel sources. Absorption cooling can use natural gas, waste heat, steam, and hot water to generate cooling. Mechanical cooling systems can use steam turbines, gas turbines, and electric motor drives. For purpose of the comparison, steam turbine drives coupled with centrifugal chillers are assumed for generation of district cooling. The steam for the turbine can be produced on-site or imported from another plant, as is done in Albany. The example assumes that steam is imported to the cooling plant for $6/MMBtu.

In Figure 2-13, the cogenerated unit cost of cooling is comprised of the cost to generate cooling at the plant boundary plus the cost to distribute cooling to the end-user. The cost to the plant boundary is assumed to decrease at larger cooling loads since economy-of-scale assumptions appear to drive construction of central cooling plants. Several transmission lengths are indicated, including customer loads that are half, one, two, and five miles from the power plant. Figure 2-13 shows the effects of transmission distance from the district cooling plant to the load center. As cooling demand increases,

Table 2-9

COST OF COOLING AT THE END-USER

Components of Unit Cooling Cost		Annual Cost ($)	Unit Cooling Cost (¢/tonhr)
Peak Heat Load (MMBTU/hr) =	1,000		
Annual Heating Hours =	1,000		
Annual Heat Load (MMBtu)=	1,000,000		
Capital Component		$153,000	15
Cost forChiller ($1000/ton)=	$15,000,000		
= Capital Recovery Based on 8% interest, 20 year loan =	0.102		
Fuel Component		$480,000	11
Annual Cooling Efficiency(kW/ton) =	1.20		
Unit Electric Cost ($/MMBtu)	0.09		
O&M Annual Cost based on 3% of Capital Cost		$45,000	5
Total		$306,000	31

the unit cost to generate and distribute cooling decreases. The production cost is determined to the plant boundary, and includes a capital cost component for the cooling plant, steam purchase, and an O&M component. Production cost for the base cooling plant at the boundary is indicated in Table 2-8. The results reflect the cost of production at one point (e.g. 10,000-ton cooling load) on the "cost at plant boundary" curve shown in Figure 2-13.

The cost to generate an equivalent cooling load for the end-user, presented in Table 2-9 and indicated in Figure 2-13, includes a capital component to cover the costs associated with the chiller plant, fuel, and O&M. Capital cost assumes that the model end-user has a peak cooling load of 1000 tons and that the cooling plant is sized at a minimum of 50% excess. O&M costs include on-site labor cost, on-site maintenance and service contracts, related utility costs including electric, water and sewer, chemical treatment, insurance, and taxes. The results indicated in Figure 2-13 suggest substantial savings for most end-users largely due to the lower production cost of district cooling as seen in Tables 2-8 and 2-9.

Economic Benefits in Jamestown, New York

The economic performance of the Jamestown district heating system is evaluated by comparing the cost of DHC/C and the cost that would have been incurred had customers generated their own heat on-site. Figure 2-14 presents a total cost comparison between DHC/C and the average cost of on-site heating for nine years of district heating in Jamestown. The total district heating cost for each year is based on recorded annual sales. Total on-site cost was computed based on an average system efficiency of

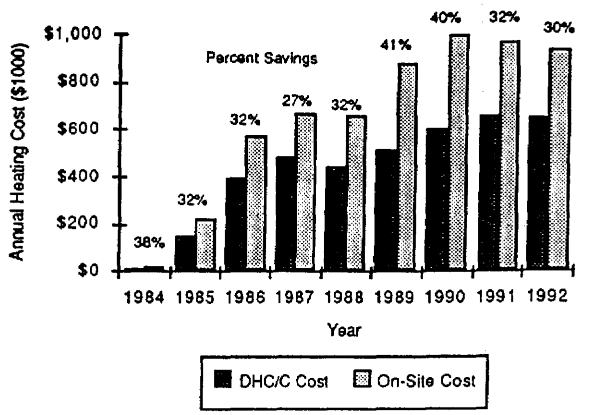


Figure 2-14.
DHC/C vs On-site Total Cost Comparison for Jamestown

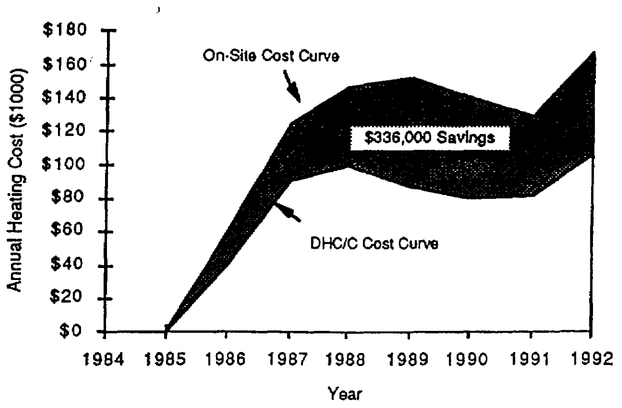


Figure 2-15. Cost Comparison for Jamestown High School

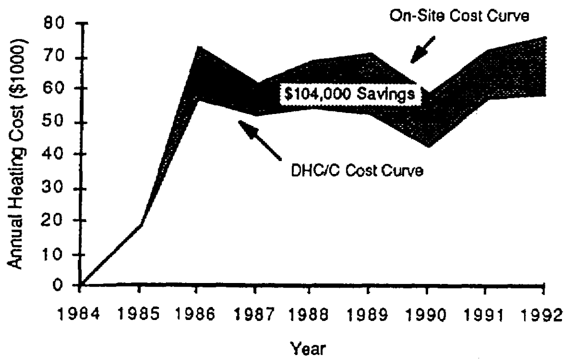


Figure 2-16. Cost Comparison for Jamestown Hotel

approximately 60%, natural-gas fuel for all customers, and actual gas prices for the respective years. Corresponding percentage cost savings with DHC/C are indicated in Figure 2-14 for each year. Results indicate that customers save from 30% to 40% on their heating bill.

Savings for two major DHC/C customers are shown in Figure 2-15 for Jamestown High School and Figure 2-16 for Hotel Jamestown. The Jamestown High School has saved some $336,000 in heating costs since converting to DHC/C in 1985. It was originally a steam-heated complex of buildings using natural gas. The school's interconnection with DHC/C meant converting the heating system from steam to hot water and retiring the steam boilers.

The Hotel Jamestown is a 10-story apartment building (assisted housing for the elderly) with business offices and retail shops on the mezzanine and lobby levels. The original heating was accomplished with low-pressure steam generated by two old gas-fired boilers in the basement. Converting this building involved a retrofit of the internal heating system from steam to hot water. The total energy savings since its interconnection to the DHC/C system in 1984 is estimated at $104,000.

Energy savings for both these customers and others in the system were achieved by efficiency gains from the steam to hot water conversion, an efficiency gain by eliminating inefficient boilers, and low-cost energy from cogeneration at the municipally owned coal-fired electric generating station.

Additional Economic Benefits

There are other economic benefits in addition to the reduced cost of energy to the end-user. Recent tax proposals have included an energy tax that would be calculated as a Btu tax, carbon tax, or oil tax. Reduced energy consumption would lessen the end user's tax burden. Developing the State's DHC/C potential would have a positive economic impact. The next section looks at how constructing DHC/C in New York State could provide a lasting economic impact as measured by growth in jobs and employee earnings.

Section 3

ESTIMATE DHC/C POTENTIAL IN NEW YORK STATE

This section analyzes three data categories to estimate the potential for district heating and cogeneration in New York State. These categories include an inventory of steam turbine power plants in New York State, an estimate of the building inventory on college campuses, and communities with populations exceeding 20,000. The DHC/C potential is quantified in terms of heat load that can be supplied from DHC/C and the electric output for new cogeneration systems. Fuel requirements and externality cost comparisons among DHC/C and end-user technologies are compared. The capital cost requirements to construct the DHC/C system and retrofit the end-user is used to estimate the economic impact to the State, measured by employee earnings and jobs measured in employee years.*[1]

DISTRICT HEATING POTENTIAL FROM POWER PLANTS

Steam Turbine Power Plants

A list of steam turbine power plants was developed, noting capacity and fuel type.[2] Table 3-1 lists coal-fired plants; Table 3-2 lists oil-fired plants; and Table 3-3 lists natural gas-fired power plants.

To estimate the "maximum" district heating potential, a factor of 1.17 MW_t output / MW_e (installed capacity) was multiplied by the installed capacities listed in the tables. The factor is a conservative estimate of the thermal output from the retrofit of single-purpose steam turbines.

District heating potential is summarized in Table 3-4 based on estimates in Tables 3-1, 3-2, and 3-3. A total "maximum" district heating potential of 20,000 MW_t of cogenerated heat is estimated, based on the electric capacity of the listed power plants. Associated with using waste heat from the steam turbine for DHC/C is the loss of electric capacity from the unit, also shown in Table 3-4.

Not all power plants may be economically retrofit for cogeneration either because of physical constraints involving turbine design and operation or how the unit is dispatched in the power pool. If the plant is located in a remote area away from existing heat loads, a new energy user (i.e., an industrial park) would need to be constructed near the power plant to economically tap the district heating potential.

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* An employee year is an employee working one year.

[1] Hydro-Quebec Economic Study, NY State Energy Office and Dept. of Public Service, May 1992

[2] Inventory of Power Plants in the United States 1991 (Energy Information Administration, 1992)

Table 3-1

"MAXIMUM" DISTRICT HEATING POTENTIAL FROM COAL-FIRED POWER PLANTS

Utility	Plant	Unit ID	Capacity (MWe)	Unit Type	Fuel Source	District Heating Potential (MWt)
Central Hudson	Danskammer (Orange)	3	134	ST	BIT	157
Central Hudson	Danskammer (Orange)	4	235	ST	BIT	275
City of Jamestown	S.A. Carlson (Chautauqua)	5	25	ST	BIT	29
City of Jamestown	S.A. Carlson (Chautauqua)	6	25	ST	BIT	29
NYSEG	Goudey (Broome)	7	45	ST	BIT	53
NYSEG	Goudey (Broome)	8	84	ST	BIT	98
NYSEG	Greenridge (Yates)	3	55	ST	BIT	64
NYSEG	Greenridge (Yates)	4	108	ST	BIT	127
NYSEG	Hickling (Steuben)	1	36	ST	BIT	42
NYSEG	Hickling (Steuben)	2	51	ST	BIT	60
NYSEG	Jennison (Chenango)	1	35	ST	BIT	41
NYSEG	Jennison (Chenango)	2	39	ST	BIT	46
NYSEG	Kintigh (Niagara)	1	686	ST	BIT	804
NYSEG	Milliken (Tompkins)	1	157	ST	BIT	184
NYSEG	Milliken (Tompkins)	2	161	ST	BIT	189
NMPC	CR Huntley (Erie)	S68	190	ST	BIT	223
NMPC	CR Huntley (Erie)	67	185	ST	BIT	217
NMPC	Dunkirk (Chautauqua)	ST4	204	ST	BIT	239
NMPC	Dunkirk (Chautauqua)	1	90	ST	BIT	106
NMPC	Dunkirk (Chautauqua)	2	90	ST	BIT	106
NMPC	Dunkirk (Chautauqua)	3	195	ST	BIT	229
Orange & Rockland	Lovett (Rockland)	4	181	ST	BIT	212
Orange & Rockland	Lovett (Rockland)	5	204	ST	BIT	240
RG&G	Rochester 3 (Monroe)	12	80	ST	BIT	94
RG&G	Rochester 7 (Montore)	1	47	ST	BIT	55
RG&G	Rochester 7 (Monroe)	2	65	ST	BIT	76
RG&G	Rochester 7 (Monroe)	3	65	ST	BIT	76
RG&G	Rochester 7 (Monroe)	4	80	ST	BIT	94
TOTAL			3552			4164

Existing DHC/C source

District heating potential based on 1.17 MW_t output / MW_e installed.

Table 3-2

"MAXIMUM" DISTRICT HEATING POTENTIAL FROM OIL-FIRED POWER PLANTS

Utility	Plant	Unit ID	Capacity (MWe)	Unit Type	Fuel Source	District Heating Potential (MWt)
Central Hudson	Roseton (Orange)	1	600	ST	FO6	703
Central Hudson	Roseton (Orange)	2	600	ST	FO6	703
Central Hudson	Asotria Queens)	ST5	369	ST	FO6	433
Con Edison	East River (New York)	5	134	ST	FO6	157
Con Edison	East River (New York)	6	134	ST	FO6	157
Con Edison	East River (New York)	7	175	ST	FO6	205
Con Edison*	Hudson Avenue (Kings)	10	44	ST	FO6	52
Con Edison	59th Street (New York)	14	16	ST	FO6	19
Con Edison	59th Street (New York)	15	19	ST	FO6	22
Con Edison	74th Street (New York)	10	65	ST	FO6	76
Con Edison	74th Street (New York)	11	36	ST	FO6	42
Con Edison	74th Street (New York)	9	65	ST	FO6	76
LILCO	Far Rockaway (Queens)	4	115	ST	FO6	135
LILCO	Northport(Suffolk)	ST1	367	ST	FO6	430
LILCO	Northport (Suffolk)	2	377	ST	FO6	442
LILCO	Northport(Suffolk)	3	371	ST	FO6	435
LILCO	Northport (Suffolk)	4	380	ST	FO6	445
LILCO	Port Jefferson (Suffolk)	ST1	46	ST	FO6	54
LILCO	Port Jefferson (Suffolk)	2	44	ST	FO6	52
LILCO	Port Jefferson (Suffolk)	3	193	ST	FO6	226
LILCO	Port Jefferson (Suffolk)	4	198	ST	FO6	232
NMPC	Oswego (Oswego)	ST1	90	ST	FO6	105
NMPC	Oswego (Oswego)	ST5	850	ST	FO6	996
NMPC	Oswego (Oswego)	ST6	841	ST	FO6	986
NMPC	Oswego (Oswego)	2	90	ST	FO6	105
NMPC	Oswego (Oswego)	4	90	ST	FO6	106
Orange & Rockland	Bowline Point (Rockland)	1	605	ST	FO6	709
NYPA	Charles Poletti (Queens)	6	825	ST	FO6	967
TOTAL			7739			9070

Existing DHC/C source

District heating potential based on 1.17 MW_t output / MW_e installed.

Table 3-3

"MAXIMUM" DISTRICT HEATING POTENTIAL FROM COAL-FIRED POWER PLANTS

Utility	Plant	Unit ID	Capacity (MWe)	Unit Type	Fuel Source	District Heating Potential (MWt)
Central Hudson	Danskammer (Orange)	1	63	ST	NAT.GAS	74
Central Hudson	Danskammer (Orange)	2	59	ST	NAT.GAS	69
Central Hudson	Arthur Kill (Richmond)	2	350	ST	NAT.GAS	410
Central Hudson	Arthur Kill (Richmond)	3	501	ST	NAT.GAS	587
Central Hudson	Astoria (Queens)	ST1	175	ST	NAT.GAS	205
Central Hudson	Astoria (Queens)	2	175	ST	NAT.GAS	205
Central Hudson	Astoria (Queens)	3	361	ST	NAT.GAS	423
Central Hudson	Astoria (Queens)	4	369	ST	NAT.GAS	433
Con Edison	Ravenswood (Queens)	1	390	ST	NAT.GAS	457
Con Edison	Ravenswood (Queens)	2	381	ST	NAT.GAS	447
Con Edison	Ravenswood (Queens)	3	972	ST	NAT.GAS	1140
Con Edison	Waterside (New York)	14	58	ST	NAT.GAS	68
Con Edison	Waterside (New York)	15	70	ST	NAT.GAS	82
Con Edison	Waterside (New York)	5	37	ST	NAT.GAS	43
Con Edison	Waterside (New York)	7	57	ST	NAT.GAS	67
Con Edison	Waterside (New York)	8	47	ST	NAT.GAS	55
Con Edison	Waterside (New York)	9	47	ST	NAT.GAS	55
LILCO	E.F. Barrett (Nassau)	ST1	192	ST	NAT.GAS	225
LILCO	E.F. Barrett (Nassau)	ST2	193	ST	NAT.GAS	226
LILCO	Glenwood (Nassau)	4	104	ST	NAT.GAS	122
LILCO	Glenwood (Nassau)	5	111	ST	NAT.GAS	130
NMPC	Albany (Albany)	1	100	ST	NAT.GAS	117
NMPC	Albany (Albany)	2	100	ST	NAT.GAS	117
NMPC	Albany (Albany)	3	100	ST	NAT.GAS	117
NMPC	Albany (Albany)	4	100	ST	NAT.GAS	117
NMPC	Oswego (Oswego)	3	75	ST	NAT.GAS	88
Orange & Rockland	Lovett (Rockland)	2	14.5	ST	NAT.GAS	17
Orange & Rockland	Lovett (Rockland)	3	68	ST	NAT.GAS	80
Orange & Rockland	Bowline Point (Rockland)	2	605	ST	NAT.GAS	709
Orange & Rockland	Lovett (Rockland)	1	16.8	ST	NAT.GAS	20
TOTAL			5891			6905

Existing DHC/C source

District heating potential based on 1.17 MW_t output / MW_e installed.

Table 3-4

SUMMARY OF "MAXIMUM" DISTRICT HEAT POTENTIAL FROM EXISTING POWER PLANTS

Fuel	Existing Electric Capacity (MW$_e$)	Electric Penalty (MW$_e$)	DHC/C Potential (MW$_t$)
Coal	3,600	840	4,200
Oil	7,700	1,800	9,100
Gas	5,900	1,400	6,900
Total	17,500	4,040	20,200

To assess DHC/C potential from steam turbine-type power plants, each power plant's location was superimposed on a map of New York State population centers. Plants located within an approximate five-mile radius from a population center of more than 20,000 people were selected for further analysis, as shown in Table 3-5. This assessment incorporates data from previous NYSERDA studies of DHC/C potential in the vicinity of power plants, as listed in Appendix A, to estimate heating loads and capital cost.

Potential heat loads projected during the studies for DHC/C systems were compared to the "maximum" potential calculated for each plant. The ratio of DHC/C heat load to the maximum potential was calculated when information was available. Most studies were conducted in less congested areas, therefore, the ratio determined is probably conservative. An average ratio (0.17) was calculated and applied to the balance of power plants listed in Table 3-5 to more realistically estimate the peak heat load. The annual heat load is estimated based on 2000 full-load hours.

The analysis in Table 3-5 estimates the DHC/C heat load potential and compares cogeneration from steam turbine power plants with typical end-users, usually oil- or gas-fired boilers. Section 2 results for fuel requirements and externality costs are correlated to the estimated heating load from each power plant, then compared to the end-user. Fuel requirements for cogeneration from steam turbine power plants assume a heat rate of 10,000 Btu/kWhr and cogeneration conversion factor of 5 kW_t/kW_e to generate the annual heat loads in Table 3-5. End-user fuel required assumes average annual fuel-conversion efficiency of 65%. Fuel savings are expressed in equivalent barrels of oil.

Externality costs for each heat-producing technology (Table 2-5) are applied to fuel requirements estimated for each DHC/C site and the end-user listed in Table 3-5. The result is an estimated $16 million in externality cost savings when comparing cogeneration with end-user technologies.

Table 3-5
DHC/C POTENTIAL IN NEW YORK STATE FROM STEAM TUBINE POWER PLANTS

Site Data		***Energy Requirements***			***Technology***		***Annual Fuel Requirement Comparison***			
Power Plant Location	**Electric Output Capacity (MW)**	**Electric Penalty (MW)**	**Peak Heat Load (MWt)**	**Annual Heat Load (MWhr)**	**End User**	**DHC/C**	**End User Technology (MWhr)**	**DHC/C Technology (MW hr)**	**Savings with DHC/C (MW hr)**	**Savings with DHC/C (Equiv. Barrels of Oil)**
Arthur Kill	850	33	167	333,000	Oil Boiler	Gas Stm Turb	510,000	200,000	310,000	176,000
Astoria	1,080	42	212	423,000	Oil Boiler	Gas Stm Turb	650,000	250,000	400,000	227,000
Astoria	369	14	72	145,000	Oil Boiler	Oil Stm Turb	220,000	80,000	140,000	80,000
Jamestown	50	2	10	19,600	Gas Boiler	Coal Stm Turb	30,000	10,000	20,000	11,000
Ravenswood	1743	68	342	683,000	Oil Boiler	Gas Stm Turb	1,050,000	400,000	650,000	369,000
Waterside	316	12	62	124,000	Oil Boiler	Gas Stm Turb	190,000	70,000	120,000	68,000
Easte River	443	17	87	174,000	Oil Boiler	Oil Stm Turb	270,000	100,000	170,000	97,000
Hudson Avenue	44	2	9	17,300	Oil Boiler	Oil Stm Turb	30,000	10,000	20,000	11,000
59th Street	35	1	7	13,700	Oil Boiler	Oil Stm Turb	20,000	10,000	10,000	6,000
74th Street	166	12	59	117,000	Oil Boiler	Oil Stm Turb	180,000	70,000	110,000	62,000
Glenwood	215	8	42	84,300	Oil Boiler	Gas Stm Turb	130,000	50,000	80,000	45,000
Port Jefferson	481	3	15	29,300	Oil Boiler	Oil Stm Turb	50,000	20,000	30,000	17,000
Far Rockaway	115	5	23	45,100	Oil Boiler	Oil Stm Turb	70,000	30,000	40,000	23,000
Albany	400	5	26	52,800	Gas Boiler	Gas Stm Turb	80,000	30,000	50,000	28,000
Oswego	75	3	15	29,400	Gas Boiler	Gas Stm Turb	50,000	20,000	30,000	17,000
Oswego	1,961	6	29	58,600	Gas Boiler	Oil Stm turb	90,000	30,000	60,000	34,000
Poletti	825	18	88	176,000	Oil Boiler	Oil Stm Turb	270,000	100,000	170,000	97,000
Goudey	130	9	44	87,900	Gas Boiler	Coal Stm Turb	140,000	50,000	90,000	51,000
Huntley	375	9	47	92,800	Gas Boiler	Coal Stm Turb	140,000	50,000	90,000	51,000
Dunkirk	579	3	15	29,300	Gas Boiler	Coal Stm Turb	50,000	20,000	30,000	17,000
Rochester	80	3	16	31,400	Gas Boiler	Coal Stm Turb	50,000	20,000	30,000	17,000
Totals	10,300	275	1,380	2,770,000			4,270,000	1,620,000	2,650,000	1,500,000

Table 3-5
DHC/C POTENTIAL IN NEW YORK STATE FROM STEAM TURBINE POWER PLANTS

Site Data		**Externality Cost Comparison**			**Capital Expenditure for DHC/C**			**Economic Impact Potential**	
Power Plant Location	Electric Output Capacity (MW)	End User Technology	DHC/C Technology	Annual Savings with DHC/C	End-User Retrofit	DHC/C System	Total	Employee Earnings	Employee Years
Arthur Kill	850	$2,450,000	$427,000	$2,020,000	$17,100,000	$39,800,000	$56,900,000	$21,400,000	720
Astoria	1,080	$3,120,000	$543,000	$2,580,000	$21,700,000	$50,600,000	$72,300,000	$27,200,000	910
Astoria	369	$1,070,000	$186,000	$884,000	$7,400,000	$17,300,000	$24,700,000	$9,300,000	310
Jamestown	50	$101,000	$25,200	$76,000	$1,000,000	$2,300,000	$3,300,000	$1,200,000	40
Ravenswood	1743	$5,030,000	$877,000	$4,150,000	$35,000,000	$81,600,000	$116,600,000	$43,900,000	1,470
Waterside	316	$913,000	$159,000	$754,000	$6,300,000	$14,800,000	$21,100,000	$7,900,000	270
Easte River	443	$1,280,000	$223,000	$1,060,000	$8,900,000	$20,700,000	$29,600,000	$11,200,000	370
Hudson Avenue	44	$127,000	$22,200	$105,000	$900,000	$2,100,000	$3,000,000	$1,100,000	40
59th Street	35	$101,000	$17,600	$83,000	$700,000	$1,600,000	$2,300,000	$900,000	30
74th Street	166	$862,000	$150,000	$712,000	$6,000,000	$14,000,000	$20,000,000	$7,500,000	250
Glenwood	215	$621,000	$108,000	$513,000	$4,300,000	$10,100,000	$14,400,000	$5,400,000	180
Port Jefferson	481	$216,000	$37,600	$178,000	$1,500,000	$3,500,000	$5,000,000	$1,900,000	60
Far Rockaway	115	$332,000	$57,900	$274,000	$2,300,000	$5,400,000	$7,700,000	$2,900,000	100
Albany	400	$273,000	$67,800	$205,000	$2,700,000	$6,300,000	$9,000,000	$3,400,000	110
Oswego	75	$152,000	$37,700	$114,000	$1,500,000	$3,500,000	$5,000,000	$1,900,000	60
Oswego	1,961	$303,000	$75,200	$228,000	$3,000,000	$7,000,000	$10,000,000	$3,800,000	130
Poletti	825	$1,300,000	$226,000	$1,070,000	$9,000,000	$21,000,000	$30,000,000	$11,300,000	380
Goudey	130	$454,000	$113,000	$341,000	$4,500,000	$10,500,000	$15,000,000	$5,700,000	190
Huntley	375	$485,000	$120,000	$365,000	$4,800,000	$11,200,000	$16,000,000	$6,000,000	200
Dunkirk	579	$151,000	$37,600	$113,000	$1,500,000	$3,500,000	$5,000,000	$1,900,000	60
Rochester	80	$162,000	$40,300	$122,000	$1,600,000	$3,700,000	$5,300,000	$2,000,000	70
Totals	10,300	$19,500,000	$3,550,000	$15,900,000	$142,000,000	$331,000,000	$472,000,000	$178,000,000	5950

The estimated capital expenditure to develop DHC/C potential is indicated in Table 3-5. Capital costs are tabulated to construct the DHC/C system and retrofit end-users. The cost to construct the DHC/C system, which includes the cost of the power plant retrofit and underground piping, is based on an average cost of about \$240,000/MW_t, derived from Appendix A. The cost for building retrofits is based on an average cost of about \$102,000/MW_t, also derived from Appendix A.

Economic impacts are based on capital expenditures for DHC/C system construction, as discussed in the preceding paragraph. The potential economic impact for New York State in employee earnings and employee-years is shown in Table 3-5. Earning impacts were based on an estimate that \$593,700 of earnings are generated in New York State for every million dollars spent on capital construction.[3] Employment impacts were based on an estimate that 21 employee-years are created in New York State for every million dollars spent on capital construction.[4]

Existing Independent Power Producers

DHC/C potential from existing power plants has focused on traditional electric utility generating stations using the boiler/steam turbine combination of the Rankine thermodynamic cycle. Independent power producers, however, are primarily responsible for introducing PURPA machines to the electric generating mix, usually gas turbines and/or combined cycles as derived from the Brayton thermodynamic cycle. As prescribed by PURPA, the potential contribution of independents to increasing the DHC/C growth in New York State beyond minimum requirements is considered insignificant, as they are usually distant from population centers. Independents have contracts to sell generated electricity and are more likely to decline entering the DHC/C business when electric generating losses will occur. Traditional utilities are aggressively studying DHC/C as a complementary business to keep customers and satisfy their energy needs, which is why the potential contribution of independents is included.

DEVELOPING NEW DHC/C SYSTEMS

To estimate the potential of new district heating sites in New York State, a list of communities with populations of more than 20,000 was compiled (Table 3-6)[5] that includes land area and district heating

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[3] Appendix 5, Table V-53, Hydro-Quebec Economic Study, NY State Energy Office and Dept. of Public Service, May 1992

[4] Appendix 5, Table V-52, Hydro-Quebec Economic Study, NY State Energy Office and Dept. of Public Service, May 1992

[5] 1992 County and City Extra Annual Metro, City and County Data Book (ed. by C Slater & G Hall, 1992)

potential. To analyze the potential magnitude of the district heating load, population densities were calculated for each community.

NYSERDA's previous district heating study results were used to estimate the relationship between district heating loads and population density, as shown in Figure 3-1. The graph indicates significant data scatter; however, to make a broad estimate, data were curve-fit, as shown by the dotted line in Figure 3-1. The curve fit was then applied to the population densities for each city in Table 3-6 to determine district heating potential. A total peak heat demand of 2,780 MW_t is estimated. The annual heat load of 5.6 million MWhr was based on 2000 full-load hours.

The fuel requirement, externality cost comparison, and economic impact are shown in Table 3-7. The assessment was performed for two scenarios of DHC/C supply including a heat-only gas boiler and a gas-turbine combined-cycle cogeneration plant. For both scenarios, the end-user technology was assumed to be heat-only gas boilers. Capital costs to construct DHC/C, which includes the cost of the generating source, underground piping, and end-user retrofits, were estimated based on averages developed from previous NYSERDA studies listed in Appendix A. The cost to construct the DHC/C gas-turbine combined-cycle is estimated at $\$240,000/\text{MW}_{t;}$ a the DHC/C heat-only boiler is estimated at $\$205,000/\text{MW}_t$. The average cost for a building retrofit is based on $\$102,000/\text{MW}_t$.

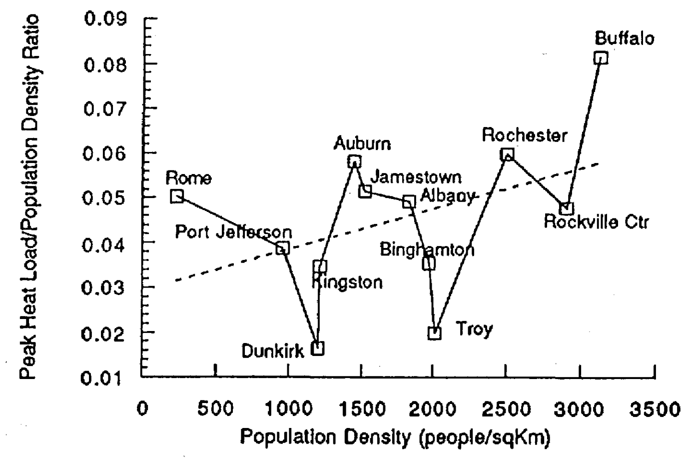

Figure 3-1. District Heating Potential Based on Population Density

Table 3-6
DEVELOPMENT OF NEW DISTRICT HEATING SYSTEMS

Location	Population	Land Area (Sq. Km.)	Population Density (Pop/Sq. km)	DH Potential Peak (MWt)	DH Potential Annual (MMBtu)
Albany	101082	55.4	1825	25	168000
Amsterdam	20714	15.4	1345	16	112000
Baldwin CDP	31258	21	1440	18	123000
Bayshore CDP	22719	4	2989	50	339000
Binghampton	21279	7.6	1553	20	136000
Brentwood CDP	45218	13.7	1971	27	187000
Brighton CDP	34455	26.9	1732	23	157000
Buffalo	328123	26.1	859	9	64000
Centereach CDP	26720	20.6	1297	16	107
Central Islip	26028	15.2	1712	23	154000
Cheektowaga CDP	84387	65.9	1281	15	105000
Commack CDP	36126	31.2	1158	14	93000
Coplague CDP	20769	8.3	2502	38	262000
Coram CDP	30111	35.7	843	9	63000
Cortland	19801	10.1	1960	27	186000
Deer Park, CDP	28840	16.1	1791	24	164000
Dix Hills, CDP	25849	41.3	626	6	44000
Dunkirk	13989	11.7	1196	14	97000
East Massapequa CDP	19550	9	2172	31	214000
East Meadow CDP	36909	16.3	2264	33	227000
East Northport CDP	20411	13.2	1546	20	135000
East Patchogue CDP	20195	21.5	939	10	71000
Elmira	33724	19	1775	24	162000
Elmont CDP	28612	8.9	3215	55	378000
Franklin Square CDP	28612	8.9	3215	55	378000
Freeport Village	39894	11.9	3352	59	403000
Garden City Village	21686	13.8	1571	20	138000
Glen Cove	24149	17.2	1404	17	119000
Harrison Village	23308	43.6	535	5	37000
Hauppauge CDP	19750	28	705	7	51000
Hempstead Village	29543	95	5206	117	802000
Hicksville	40174	17.6	2283	34	230000
Holbrook CDP	25273	17.7	1428	18	121000
Huntington Station CDP	28247	14.1	2003	28	191000
Irondequoit CDP	52322	39.2	1335	16	111000
Islip CDP	18924	14	1352	17	113000
Ithaca	29541	14.1	1095	30	204000
Jamestown	34681	22.9	1514	19	131000
Kingston	23095	19.1	1209	14	98000
Lackawanna	20585	15.9	1295	16	107000
Levittown CDP	53286	17.8	2994	50	340000
Lindenhurst Village	26879	9.7	2771	44	304000

Table 3-6

DEVELOPMENT OF NEW DISTRICT HEATING SYSTEMS

Location	Population	Land Area (Sq. Km.)	Population Density (Pop/Sq. km)	DH Potential Peak (MWt)	DH Potential Annual (MMBtu)
Lockport	24,426	22.1	1105	13	87,000
Long Beach	33,510	5.5	6093	152	1,037,000
Lynbrook Village	19,208	5.2	3694	68	467,000
Massapequa CDP	22,018	9.6	2294	34	231,000
Medford CDP	21,274	26.1	815	9	60,000
Merrick CDP	23,042	10.9	2114	30	206,000
Middletown	24,160	12.8	1888	26	176,000
Mount Vernon	67,153	11.4	5891	144	981,000
Newburgh	26,454	9.9	2672	42	288,000
New City CDP	33,675	40.4	833	9	62,000
New rochelle	67,265	26.8	2510	39	263,000
Niagara Falls	61,840	36.4	1699	22	153,000
North Bellmore CDP	19,707	6.8	2898	48	324,000
North Tonawanda	34,989	26.2	1335	16	111,000
Oceanside CDP	32,423	13	2494	38	261,000
Ossining Village	22,582	8.3	2721	43	296,000
Oswego	19,195	19.8	969	11	74,000
peekskill	19,536	11.2	1744	23	158,000
Plainview CDP	26,207	14.8	1771	24	162,000
Plattsburgh	21,255	13.1	1623	21	144,000
Port Chester Village	24,728	6.1	4054	79	539,000
Poughkeepsie	28,844	13.3	2169	31	214,000
Rochester	231,636	82.7	2801	45	308,000
Rockville Centre Village	24,727	8.5	2909	48	326,000
Rome	44,350	184.1	241	2	15,000
Ronkonkoma CDP	20,391	21.2	962	11	74,000
rotterdam CDP	21,228	18	1179	14	95,000
Saratoga Springs	25001	72.6	344	3	22,000
Schenectady	65,566	28.1	2333	35	237,000
Seiden CDP	20,608	12.1	1703	22	153,000
Shirley CDP	22,936	28.2	813	9	60,000
Smithtown CDP	25,638	30.6	838	9	62,000
Spring Valley Village	21,802	5.4	4037	78	536,000
Syracuse	163,860	65	2521	39	265,000
Tonawanda CDP	65,284	45	1451	18	124,000
Troy	54,269	27	2010	28	192,000
Uniondale	20,328	6.9	2946	49	332,000
Utica	68,637	42.3	1623	21	144,000
Valley Stream Village	33,946	8.9	3814	72	490,000
Watertown	29,429	22.5	1308	16	108,000
West BAbylon CDP	42,410	20	2121	30	207,000
West Islip CDP	28,419	16	1776	24	162,000
West Seneca CDP	47,866	55.4	864	9	65,000
White Plains	48,718	25.4	1918	26	180,000
Yonkers	188,802	48.8	3854	73	498,000
TOTAL					19,038,000

Table 3-7

DHC/C POTENTIAL IN NEW YORK STATE FOR COMMUNITIES WITH POPULATIONS GREATER THAN 20,000 (EXCEPT NYC)

	DHC/C Gas Heat-Only Boiler	DHC/C Gas Turbine Combined Cycle
Energy Requirements		
Peak Heat Load (MWt)	2,780	2,780
Annual Load (MWhr)	5,600,000	5,600,000
Electric Generation Potential (MWe)	0	1,800
Technology		
End-User	Gas Boiler	Gas Boiler
DHC/C	Gas Boiler	Cogen C/C
Fuel Requirements		
End-User Technology (MWhr)	8,620,000	8,600,000
DHC/C Technology (MWhr)	7,000,000	2,630,000
Savings with DHC/C (MWhr)	1,620,000	5,970,000
Savings with DHC/C (equivalent barrels of oil)	920,000	3,390,000
Externality Cost		
End-user Technology	$28,900,000	$28,900,000
DHC/C Technology	$18,400,000	$5,400,000
Savings with DHC/C	$10,500,000	$23,500,000
Capital Cost for DHC/C		
End-User Technology Results	$285,000,000	$285,000,000
DHC/C System	$569,000,000	$664,000,000
Total	$854,000,000	$949,000,000
Economic Impact Potential		
Employee Earnings	$322,000,000	$357,000,000
Jobs (Employee Years)	11,000	12,000

RETROFIT OF HEAT-ONLY DHC SYSTEMS TO COGENERATION

Defining the number of existing district heating systems in New York State is not limited to community-based systems, but for colleges, hospitals, and military bases as well. The analysis considers cogeneration potential on college campuses that have the largest number of district heating systems in the State. Due to centralized operations and planning, a college campus has a more realistic opportunity to construct a district heating system. The economics of introducing cogeneration to a campus may justify the expense of constructing an associated district heating system. Results for the cogeneration potential on college campuses are then extrapolated to include the potential for other heat-only systems such as hospitals and shopping malls.

The college campus cogeneration potential was estimated from the square footage of the campus building inventory in New York State by applying an average value for electrical demand. Data for this estimate, as shown in Table 3-8, were provided by the Association of Physical Plant Administrators.

Average gross building areas were provided including educational, general and auxiliary structures for six categories of university types. The data also included the number of such university types in New York State. Based on these averages, the building inventory of college campuses consists of some 540-million square feet. Based on an average of two watts/sqft for average electrical demand, the total electric load is estimated at 1,080 MW_e with a peak heating load of 4,700 MW_t and an annual heating load of more than 9.4 million MWhr.

Table 3-8

BUILDING ELECTRIC AND HEATING LOADS ON COLLEGE CAMPUSES

	Average Building Gross Square Feet for Each Type of University			New York State Estimate				
Type of University	Educational & General	Auxiliary	Total	No.	Total Building Square Footage	Average Peak Electric Load (MWe)	Peak Heat Load (MWt)	Annual Heat Load (MWhr)
Research	5,700,000	3,200,000	8,900,000	11	98,000,000	196	860	1,720,000
Doctoral	2,200,000	1,300,000	3,500,000	11	39,000,000	78	340	680,000
Comprehensive	1,200,000	540,000	1,700,000	59	100,000,000	200	880	1,760,000
Liberal Arts	400,000	300,000	700,000	32	22,000,000	44	190	380,000
Two-Year	600,000	60,000	700,000	90	63,000,000	126	550	1,100,000
Specialized	2,000,000	410,000	2,400,000	91	218,000,000	436	1900	3,800,000
Total	12,100,000	5,810,000	17,900,000	294	540,000,000	1,080	4,720	9,440,000

Based on previous NYSERDA studies, it is estimated that approximately half the peak electric demand (540 MW_e) is available for gas turbine combined cycle cogeneration. At this electric demand, the cogeneration facility can operate continuously during the year supplying approximately half the heating requirements for the campus. The cogeneration potential considers the energy requirements and associated impacts to supply half of the total heating load, that which is supplied directly from the cogeneration plant.

Not all universities are suited for cogeneration, and some may have already constructed such plants. Consequently, this figure is probably high for cogeneration potential on universities. Therefore, the results developed in Table 3-8 are used to determine a total cogeneration potential from existing heat-only DHC/C systems in the State of New York, including candidates like college campuses, hospital systems, and shopping malls. Fuel requirements, externality costs, and the potential economic impact are shown in Table 3-9. Installation of a new cogeneration plant and heat-only boiler assuming natural gas fuel and conventional technology used by existing DHC/C systems are compared.

Table 3-9

COGENERATION POTENTIAL FROM HEAT-ONLY DHC/C

	DH Gas-Heat Only Boiler	**Gas Turbine Combined Cycle**	**Savings with Cogen**	**Savings with Cogen (Equiv. Barrels of Oil)**
Cogeneration Potential				
Electric Capacity (MWe)		540		
Electric Penalty w/Cogen (MWe)		40		
Net Electric Capacity (MWe)		500		
Energy Requirements				
Cogen Heat Supply (MWt)	630	630		
Annual Load (MWhr)	5,064,478	5,064,478		
Annual Fuel Requirement (MWhr)	7,800,000	2,400,000	5,400,00	3,100,000
Annual Externality Cost Comparison ($)	$25,800,000	$4,800,000	$21,000,000	
Capital Cost for Cogen ($)		$64,800,000		
Potential Economic Impact				
Employee Earnings		$24,400,000		
Job (Employee Years)		820		

NEW YORK STATE'S POTENTIAL

DHC/C potential in New York State, its costs, and benefits are summarized in Table 3-10. The summary includes technology comparison between DHC/C and the typical end-user associated with converting single-purpose electric generating plants to cogeneration, converting existing heat-only DHC systems to cogeneration, and developing new community DHC/C systems.

The case for converting electric generating plants considers only those plants within a five-mile radius of population centers. The results incorporate incremental fuel required to replace lost electricity and subsequent emissions associated with the New York Power Pool, which are then compared to end-users. Converting heat-only DHC systems to cogeneration entails installing a gas turbine combined cycle plant to replace gas boilers. Developing new DHC/C systems assumes installing a gas turbine combined cycle to replace end-user gas boilers.

Table 3-10

SUMMARY OF DHC/C POTENTIAL IN NEW YORK STATE

Comparisons	Convert Electric Plants to DHC/C	Convert Heat-Only DHC to Cogen	New DHC/Cogen Outside NYC	New DHC/Cogen in NYC	Total
DHC/C Heat Load Potential (MWt)	1,380	630	2,780	1,110	5,900
DHC/C Electric Load potential (MWe)	-277	500	1,800	725	2,750
Annual Fuel Savings (millions of barrels of oil equivalent)	2	3.1	3	1.3	9
Annual Externality Cost Savings ($millions)	$15.90	$21.00	$23.50	$11.73	$72.13
Capital Expenditure ($millions)	$472	$64.80	$949	$379	$1,860
Employee Earnings ($millions)	$178	$24.40	$357	$143	$702
Job (Employee Years)	5,950	820	12,000	4,780	23,600

Section 4

EVALUATE THE ROLE OF TECHNOLOGY R&D

Research and development is being conducted to improve the economical distribution of DHC/C from the central source to the end-user in areas that include reducing pumping costs due to friction, ice slurries, reinsulating old systems, and improving the accuracy of end-user energy consumption. While modern technologies have made DHC/C competitive with conventional alternatives, results of this research and development effort will not quickly revolutionize the industry and induce rapid growth. Industry growth will depend more on the recommendations presented in Section 5. Recent DHC/C research and development has focused on several areas.

ADVANCED FLUIDS

This research is aimed at reducing friction losses in fluid circulation and improving heat transfer characteristics. It has been estimated that capital investment in distribution systems for DHC/C could be reduced up to 30% and pumping costs could be reduced up to 50%. Using heat transfer additives will enable the installation of smaller-diameter pipes and allow systems to increase capacity through existing distribution pipes.

DISTRICT COOLING TECHNOLOGIES

The emphasis in this area has been to implement phase-change materials, including ice slurries, to increase distribution capacity. Associated improvements in ice production and end-user equipment to effectively implement such systems also are being investigated. This research is required to decrease the cost of constructing district cooling systems, especially distribution costs. Other developments include testing an advanced absorption chiller suitable for making ice slurry using 120°C water or steam as the heat source.

DISTRIBUTION SYSTEM COMPONENTS

This research investigates improved materials, components, and equipment, including developing a new Btu meter that promises to be simple, inexpensive, and reliable. Other areas include using plastic piping for hot-water applications and three-pipe systems where two pipes are dedicated for hot and chilled water supply with one common return.

Another effort is reinsulating old distribution systems. A technique is being developed to inject insulating foam into the outer casing of prefabricated piping systems. The technique assumes that, while the original insulating layer in the outer casing has disintegrated, it is intact enough to undergo the procedure. The operation is performed from the surface and does not require exposing the buried system.

AMMONIA-BASED CHILLING WITH COGENERATION

Innovations also are associated with the combination of existing technologies providing new, viable approaches to DHC/C. Application of ammonia-based chilling equipment generally has been limited to industrial applications. Emphasis on the CFC issue, resource planning, and DSM has spurred introducing alternative cooling technologies that can be applied effectively in the district cooling industry.

The concept of coupling a gas turbine to an industrial-type ammonia screw compressor became reality in early 1992 with the installation of two such units at two district cooling systems in Oklahoma, one in Tulsa and the other in Oklahoma City. The systems are owned and operated by Trigen Energy Corporation, a leading developer of district energy systems in the U.S. Trigen will install the same type of system at a new site in Chicago. These are good examples of how new innovations are being applied to expand the DHC/C market place.

Figure 4-1 gives a schematic of the equipment arrangement with these primary features:

- 1200 kW industrial gas turbine using natural gas fuel;
- 520 kW induction motor/generator;
- Inlet air cooling with a direct-expansion ammonia coil that maintains gas turbine output at 1050 kW at temperatures above 55°F; and
- Heat-recovery steam generator capable of generating 6,000 lbs/hr of 150 psig steam for the district heating system.

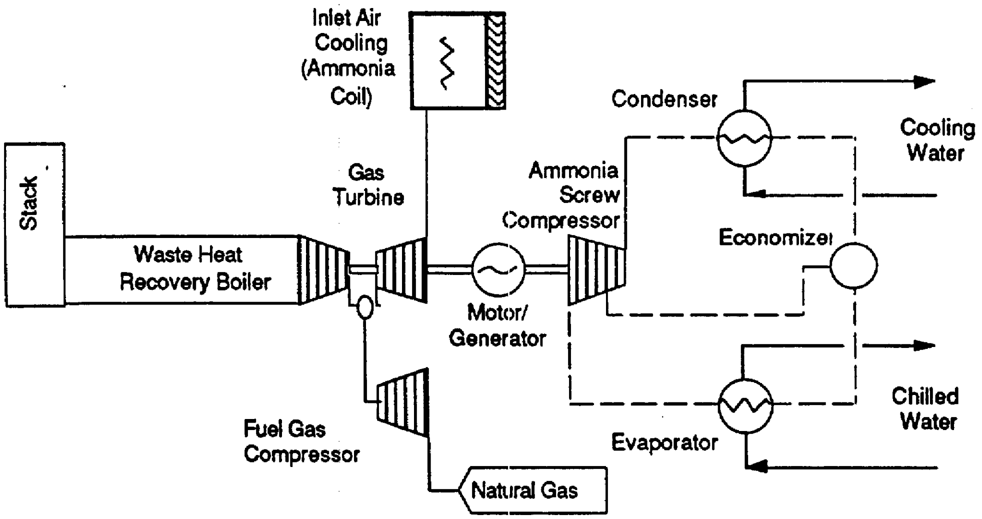

Figure 4-1. Schematic of the Ammonia Chilling Equipment Arrangement

A 1200 kW aeroderivative gas turbine is coupled to an induction motor that is, in turn, coupled to the ammonia chiller's screw compressor for chilled-water production. The gas turbine shaft is fit with a reduction gear box to maintain a speed of 3600 rpm that matches the screw compressor. Since the ammonia screw compressor can attain high compression ratios, water temperatures less than the nominal 40°F can be easily generated.

Cycle efficiency to near 85% is achieved by capturing the hot exhaust gas exiting the gas turbine in a waste heat steam generator capable of generating 6000 lbs of 150 psig steam for the district heating system.

An inlet air-cooling coil to reduce the temperature of combustion air to the gas turbine is installed to maintain turbine power output during periods of high ambient temperatures in the summer. The direct-expansion type cooling coil uses ammonia refrigerant to maintain inlet air temperature of about 55°F under most operating conditions. The effect of inlet air cooling is to limit the drop in gas turbine power output to approximately 1050 kW.

An electric induction motor that permits the gas turbine to operate at full load on a continuous basis is mounted on the turbine shaft, as shown in Figure 4-2. Gas turbine output decreases with increased ambient temperature. The reverse is true for electrical requirements of the screw compressor that needs more power at higher ambient temperatures. This opposing effect is solved with the induction motor/generator. When the compressor's power demand exceeds output from the turbine, the machine operates in the motor mode. When the output from the turbine exceeds the power requirement of the compressor, the machine operates in generator mode. Compressor electrical demand, however, is limited to the combined capacity of both gas turbine and induction motor/generator.

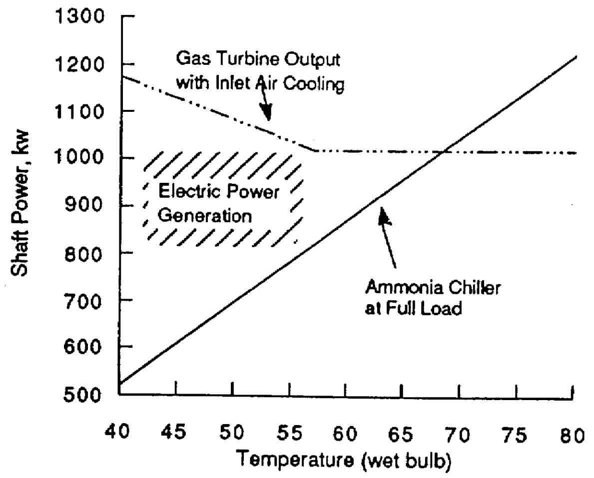

Figure 4-2. GT Production / Ammonia Chiller Consumption

Section 5

RECOMMENDATIONS TO ACCELERATE IMPLEMENTING DHC/C IN NEW YORK STATE

The following recommendations are based on NYSERDA's experience conducting feasibility studies at 18 sites across New York, of which six resulted in capital construction to build or refurbish DHC/C systems.*

Recommendations are in three major categories: encourage high-efficiency power plants; examine and modify how New York State does business; and conduct research. Specific actions are recommended in each category. The recommendations include a broad range of activities that may be difficult to implement. Further research is needed to prioritize the recommendations and quantify the benefits, costs, and time frames to implement them.

ENCOURAGE HIGH-EFFICIENCY POWER PLANTS

The following recommendations are directed toward encouraging power generation from high-efficiency plants so New York State can take advantage of energy savings, emissions reductions, and other benefits associated with high-efficiency power generation.

Increase Efficiency Requirements

RECOMMENDATION: Raise efficiency standards for new power plants higher than levels mandated by PURPA.

DISCUSSION: In 1978, the Public Utilities Regulatory Policy Act (PURPA) changed the power-generation industry by allowing organizations not controlled by regulated utilities to generate power without being subject to regulation under the Federal Power Act. PURPA required the cogeneration plant to meet efficiency and thermal-use criteria that have not changed since 1978.

In the ensuing 15 years, most new generation was built under PURPA rules. Gas turbine installations were constructed across the country and gas turbine performance improved, resulting in a need to connect smaller thermal loads to meet the efficiency requirements specified by PURPA.

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* The recommendations also reflect the interaction of Dr. Fred V. Strnisa with the DHC/C industry on the national and international level, most recently as Chairman of the National Planning Committee for District Heating, Cooling and Cogeneration. The planning Committee led an industry effort to produce the National Action Plan for District Heating Cooling and Cogeneration in March, 1992, and implemented several near-term recommendations called for in the Action Plan that were summarized in a July 1993 Progress Report.

Today's contemporary cogeneration plants usually are built to maximize electricity production and revenues while supplying minimum heat required by PURPA. The 1992 reform of the Public Utility Company Holding Act (PUCHA) allows wholesale generation of electricity with no heat recovery and provides even less motivation to recover thermal energy from power-generating plants.

A few cogeneration developers, however, have demonstrated that high-efficiency generation is possible and profitable. Trigen, for example, operates a plant in Trenton, New Jersey, that generates electricity and recovers heat to heat and cool buildings in downtown Trenton with an annual efficiency exceeding 70%. Con Edison supplies about 4000 MW_t of steam to Manhattan, 82% of which is produced by cogeneration plants operating at an annual efficiency of about 85%.

Without a mandate to increase efficiency, future electric production will come from installations meeting the minimum heat-recovery provisions of PURPA or the electric-only plants allowed by PUCHA.

Mandate Set-Aside for High-Efficiency Power Plants

RECOMMENDATION: Mandate the State's electric utilities to procure 300 MW_e of electric capacity by 2000 from sources using fuel at a minimum seasonal efficiency of 65%, where seasonal efficiency is the annual energy content of the fuel divided by the sum of the useful electric and thermal output.

DISCUSSION: This mandate is one way to implement the previous recommendation. The set-aside would be similar to the 300 MW_e set-aside for power generated by renewable resources. The rationale and benefits of such a set-aside are nearly identical to those for renewables. The mandate would demonstrate the costs, benefits, and implementation considerations to secure electric capacity from high-efficiency sources.

Adopt Efficiency-Based Emission Standards

RECOMMENDATION: Develop emission standards that reward efficient power production.

DISCUSSION: Emissions are currently regulated based on pounds of pollutant per unit energy input. This tends to discourage efficiency by putting a premium on minimizing fuel input without recognizing that high efficiency often requires using more fuel to produce both electricity and useful heat. Additional fuel is used at the power plant; however, total fuel use is reduced as plant efficiency increases and thermal energy is provided to heat-users who no longer burn fuel.

Although emission standards in the forms of pounds of pollutant per unit energy input are likely to remain essential for establishing a baseline for facilities, emission standards that address the energy efficiency of generation systems need to be considered. Current standards minimize pollution from the power plant but produce more pollution in the community. An efficiency-based pollution standard might increase emissions from the plant but reduce total emissions.

Give Tradeable Credits for Reduced Emissions from Efficient Power Plants

RECOMMENDATION: Give high-efficiency power plants tradeable credits for reducing emissions.

DISCUSSION: As this assessment confirms, DHC/C can reduce total emissions by replacing many on-site boilers with a more efficient, well-regulated supply of heat and electricity. Giving developers of high-efficiency power plants tradeable credits for reducing emissions would provide a small but significant investment incentive.

EXAMINE STATE POLICIES

The following recommendations are aimed at examining and altering State policies to encourage the developing of DHC/C.

Life-Cycle Cost Policy for NYS Facilities

RECOMMENDATION: Require state-controlled facilities to use life-cycle cost criteria when evaluating energy supply and use options. Adopt a uniform procedure that incorporates all legitimate factors including capital, O&M, environmental, and fuel.

DISCUSSION: A project in Binghamton, New York, reflects a common occurrence in the negotiations between the district-heating utility and the customer. In this case, a university received a proposal from the local utility to supply it with heat for a given number of years at a given price. The campus would have been supplied with hot water cogenerated at the utility's nearby electric power plant. As part of its offer, the utility proposed a comparison of capital, operation, and maintenance, and fuel costs of district heating with on-site generation. The university considered avoided fuel costs the sole criteria when evaluating purchasing heat rather than generating it on-campus. Costs of on-site boiler-plant upgrades, labor, maintenance, supplies, and costs to meet future environmental requirements were not seriously considered by the university.

Examine Impact of Tax Policy on Energy Decisions

RECOMMENDATION: Examine the effects of tax policy on energy decisions and periodically confirm that the effects on energy use are consistent with overall State policy.

DISCUSSION: In many cases, district-heating systems are subject to local franchise fees, gross receipt taxes, and other taxes that are not imposed on customers who directly purchase and consume fuel. This is particularly true for tax-exempt facilities such as hospitals and universities, which are ideal candidates to use heat from a district heating plant.

This tax differential often erodes the price advantage that district heating could offer the customer. For example, in one case in New York City, the tax differential would have added 17% to the cost of district heat compared to that which individual building owners would have had to pay. This additional burden contributed to the decision to drop the project.

Price Regulation

PRICE REGULATION: Examine the effect of price regulation on developing DHC/C in New York State.

DISCUSSION: District-heating developers would prefer their prices to be regulated by contract with the customer rather than by government regulations. Contract regulation means providing a specified quantity and quality of heat, at an agreed price, for a definite time. The price usually incorporates the cost of capital to build the plant and distribution system, and formulas to deal with the cost of fuel and O&M over the contract period. DHC/C is not a monopoly. With the abundance of gas, oil, and electric as alternate-heating options, regulatory protection for customers is best done by contract. The customer enters a contract to purchase heat with open eyes and if things don't work out can return to on-site heat production.

RESEARCH AND DEVELOPMENT

NYSERDA intends to encourage implementing DHC/C in New York State. Several research areas are being considered.

Policy-Oriented Research

- Implications of increasing efficiency requirements for power generation, and mandating a set-aside for high-efficiency power generation;

- An appropriate efficiency-based emission standard and how it would be integrated into the existing regulatory framework;

- Pollutants that should be included in emissions trading and how tradeable credits are established and verified;
- The impact of taxes on energy decisions;

- Appropriate life-cycle cost procedures to evaluate energy supply and use options; and
- Appropriate price-regulation schemes for district heating systems that provide incentives and protection for the seller and buyer.

Feasibility Studies

NYSERDA will continue to support feasibility studies that promote this technology. Its program has been cost-effective in helping to develop this technology. For a net cost of about $2.1 million, NYSERDA has been instrumental in bringing New York 140 MW_e of new cogeneration capacity, $300 million in local investments, a 20 to 40% reduction in fuel use and energy costs, and 2500 construction-job years.

Power Plant Conversion

Site-specific factors associated with converting existing steam generating stations to cogeneration will continue to be investigated. This technical assessment has identified 1200 MW_t of realistic potential for DHC/C by converting existing steam-generating stations to cogeneration. NYSERDA will work directly with utilities to investigate site-specific factors associated with DHC/C at those sites.

Converting of Existing District Heating Systems to Cogeneration

NYSERDA will investigate site-specific factors associated with developing cogeneration potential at existing DHC/C sites in New York. This assessment estimates 600 MW_t of potential from universities and hospitals in New York State.

Appendix A

SUMMARY OF NYSERDA'S DHC/C PROGRAM

Albany

Participants	NYSERDA, U.S. HUD, City of Albany, Albany County
Results	Study demonstrated the feasibility of low-temperature hot water, steam, and chilled water to heat and cool buildings in downtown Albany.
Technology	Conventional heating and cooling plant and steam extraction from gas-fired boilers (Sheridan Avenue Plant)
Fuel	Natural gas
Capacity	Peak heating load for the customers was estimated at 26 MW_t Peak cooling load for the customers was estimated at 11,000 tons
Capital Costs	$6 million ($1991) for conventional heating and cooling plant and $5 million ($1991) for a system using steam from the Sheridan Avenue Plant; both costs include underground distribution piping for district heating and cooling for three phases of implementation.
Financing	100% debt financing was studied
Owners	Private and municipal ownership options were investigated
Thermal Customers	After screening, 21 buildings were selected for the project
Electric Customers	not applicable
Permits	not applicable

Auburn

Participants	NYSERDA, City of Auburn
Results	Study demonstrated the feasibility of low temperature hot water district heating.
Technology	Conventional heating plant (excess heat from Auburn Correctional Facility)
Fuel	Natural gas
Capacity	Peak heating load for the customers was estimated at 25 MW_t Peak cooling load for the customers was estimated at 1000 tons
Capital Costs	$1.5 million ($1992) for conventional heating plant Costs include underground distribution piping for district heating for three phases of implementation.
Financing	100% debt financing was studied
Owners	Municipal ownership was investigated
Thermal Customers	Memorial Hospital, Holiday Inn, assisted housing and other buildings for a total of 9 customers
Electric Customers	not applicable
Permits	not applicable

Binghamton

Participants	NYSERDA, Broome County
Results	Study demonstrated the feasibility of low temperature hot water and steam district heating.
Technology	Option 1: Downtown Binghamton, Conventional heating plant (new hot water boilers) initially, then construct gas turbine cogeneration and
	Option 2: Kirkwood Industrial Park, waste to energy recovery
Fuel	Natural gas
Capacity	Peak heating load for Option 1 and 2 approximately at 35 MW_t
Capital Costs	$7 million ($1988) for Options 1 and 2 Costs include thermal source and underground distribution piping for district heating for seven phases of implementation.
Financing	100% debt financing was studied
Owners	Municipal and private ownership was investigated
Thermal Customers	Option 1: 115 downtown buildings
	Option 2: 7 industrial sites in Kirkwood Industrial Park
Electric Customers	not applicable
Permits	not applicable

Buffalo

Participants	NYSERDA, City of Buffalo
Results	Construction of the pilot project commenced in September of 1986 with startup in January of 1987 to supply 5 downtown buildings with a customer heating load of approximately 7.5 MW_t. Approximately 3000 ft of pipe was installed for hot water and steam.
Technology	Conventional steam and hot water boilers
Fuel	Natural gas
Capacity	20 MW_t of boiler capacity installed
Capital Costs	$1.5 million for pilot system construction
Financing	Municipal bonds
Owners	City of Buffalo
Thermal Customers	City Hall, Buffalo Athletic Club, fire headquarters, court buildings
Electric Customers	not applicable
Permits	city construction permits were required

Dunkirk

Participants	NYSERDA, City of Dunkirk, Wilmorite, Niagara Mohawk
Results	Study demonstrated the feasibility of low temperature hot water district heating and chilled water district cooling to the designated service area.
Technology	Options included conventional heating and cooling plant, gas turbine cogeneration and steam extraction from an electric generating station (Niagara Mohawk Dunkirk Station).
Fuel	Natural gas, coal
Capacity	Peak heating load for the customers was estimated at 6 MW_t. Peak cooling load was estimated at 540 tons. A 1200 kW gas turbine was studied.
Capital Costs	$3 million ($1987) for cogeneration from Dunkirk Station and $5 million ($1987) for gas turbine cogeneration plant. Both costs include underground distribution piping for district heating and cooling for two phases of implementation.
Financing	100% debt financing was studied at rates corresponding to private and municipal ownership.
Owners	Municipal and private ownership options were studied.
Thermal Customers	Harbor Front Redevelopment Project, Brooks Memorial Hospital, Steger Towers and other public and private buildings
Electric Customers	not applicable
Permits	not applicable

Jamestown

Participants	NYSERDA, City of Jamestown, Manufacturer's Association
Results	Construction commenced in 1984, was significantly expanded in 1985 and continues to expand now supplying 33 downtown buildings. To date, more than 30,000 feet of underground piping has been installed with a customer heating load of approximately 20 MW_t.
Technology	Cogeneration from a coal-fired electric generating station
Fuel	Coal
Capacity	20 MW_t heat load connected to system
Financing	Municipal bonds
Owners	Jamestown Board of Public Utilities
Thermal Customers	33 downtown customers both public and privately owned
Electric Customers	not applicable
Permits	city construction permits were required

Kingston

Participants	NYSERDA, City of Kingston, Benedictine Hospital
Results	Study demonstrated the feasibility of low temperature hot water district heating to the designated service area.
Technology	Conventional heating plant (initially use excess capacity at Benedictine Hospital)
Fuel	Natural gas
Capacity	Peak heating load for the customers was estimated at 12 MW_t.
Capital Costs	$2.3 million ($1991) for retrofitting the existing heating plant and underground distribution piping for district heating for two phases of implementation
Financing	100% debt financing was studied
Owners	Benedictine and/or Kingston Hospital
Thermal Customers	Benedictine Hospital and eight other buildings including three schools
Electric Customers	not applicable
Permits	not applicable

Nassau County

Participants	NYSERDA, Trigen
Results	Project demonstrated the feasibility of integrating new cogeneration with an existing DHC system.
Technology	Cogeneration from a combined cycle gas turbine power plant
Fuel	Natural gas
Capacity	Peak heating load for the system is estimated at 25 MW_t and 3,000 tons of peak cooling load.
Capital Costs	$80 million project for the cogen plant and underground steam distribution to new customers
Financing	Private financed with equity and loans directly from Trigen
Owners	Trigen Energy Corporation
Thermal Customers	Nassau Veterans Memorial Coliseum, Community College, Marriott Hotel, the Nassau County Medical Center and Prison Complex, the latter two of which are approximately 2 miles away from the plant.
Electric Customers	Long Island Lighting Company
Permits	local building permits

New York City

Participants	NYSERDA, Con Edison, City of New York
Results	Study demonstrated the feasibility of low temperature hot water district heating to two hospitals in the vicinity of Con Edison's 74th Street Station in Manhattan. District cooling was also investigated.
Technology	Cogeneration from an electric generating station
Fuel	Natural gas
Capacity	Peak heating load for the two hospitals was estimated at 60 MW_t
Capital Costs	$3.5 million ($1985) for station retrofit and underground distribution piping for district heating
Financing	Financing mix (provided by Con Edison) and pure debt financing were studied
Owners	Ownership options included Con Ed, a private developer, and a private non-profit tax exempt cooperative
Thermal Customers	New York Hospital/Cornell Medical Center and Rockefeller University
Electric Customers	not applicable
Permits	not applicable

Onondaga County

Participants	NYSERDA, U.S. DOE, Syracuse-Onondaga County
Results	Study demonstrated the feasibility of expanding an existing DHC/C plant to serve new loads. Project went into construction to serve Convention Center Complex.
Technology	Cogeneration from steam turbine plant, including steam absorption chilling, steam and hot water DHC/C, and ice storage
Fuel	Natural gas, #2 oil backup
Capacity	Peak heating capacity of the expanded plant is about 25 MW_t for heating and 6000 tons for cooling.
Capital Costs	Total project cost for the expansion is estimated at $11 million.
Financing	100% debt financing through a bond issue approved by the County Legislature
Owners	County ownership
Thermal Customers	Public and private buildings in downtown Syracuse
Electric Customers	not applicable
Permits	local building permits

Port Jefferson

Participants	NYSERDA, U.S. DOE, Village of Port Jefferson
Results	Study demonstrated the feasibility of low temperature hot water district heating to two hospitals and several other customers both with and without cogeneration.
Technology	Options included both cogeneration from a gas turbine and conventional boilers.
Fuel	Natural gas
Capacity	Peak heating load for the customers was estimated at 15 MW_t. A 1100 kW gas turbine was studied.
Capital Costs	$3 million ($1987) for conventional boiler and $5 million ($1987) for cogeneration plant Both costs include underground distribution piping for district heating for three phases of implementation.
Financing	100% debt financing was studied
Owners	Private, hospital and municipal ownership options were investigated
Thermal Customers	Two hospitals (St. Charles and Mathers), a nursing home, several schools and other public buildings
Electric Customers	not applicable
Permits	not applicable

Rochester

Participants	NYSERDA, Rochester District Heating Cooperative (RDH), City of Rochester, Monroe County, RG&E
Results	Study demonstrated the feasibility of continued operation of the RG&E steam system by a customer cooperative. Established RDH which purchased steam system and plant from RG&E. Also demonstrated feasibility of district cooling as an addition to the existing district heating service.
Technology	Conventional heating and cooling plant, cool storage
Fuel	Natural gas
Capacity	Peak cooling load for the customers was estimated at 8000 tons.
Capital Costs	$10 million ($1985) to purchase and refurbish steam system $10 million ($1989) for conventional cooling plant with storage Costs including underground distribution piping for district cooling and three phases of implementation.
Financing	100% debt financing was studied
Owners	Rochester District Heating Cooperative
Thermal Customers	44 steam heated buildings in downtown Rochester and 16 cooling customers potential
Electric Customers	not applicable
Permits	not applicable

Rockville Center

Participants	NYSERDA, Village of Rockville Center
Results	Demonstrated the technical feasibility of cogenerating from the municipal power plant.
Technology	Cogeneration from an existing power plant (8 diesel engines)
Fuel	2/3 natural gas, 1/3 oil
Capacity	Peak heating load was estimated at 10 MW_t.
Capital Costs	$930,000 for power plant modifications, $1,000,000 underground piping systems
Financing	100% debt financing was studied.
Owners	Village of Rockville Center
Thermal Customers	various buildings in village
Electric Customers	not applicable
Permits	not applicable

Roosevelt Island

Participants	NYSERDA, NYC Public Utilities Service, Health and Hospitals Corporation, Roosevelt Island Operating Corporation
Results	Study demonstrated the feasibility of installing gas turbines for cogenerating heat and power for selected customers on Roosevelt Island. District heating, steam and hot water were considered.
Technology	Gas turbine cogeneration
Fuel	Natural gas
Capacity	Peak heating load for the proposed service area was estimated at 25 MW_t. 30, 50, 80 MW_e gas turbine options were studied.
Capital Costs	$115 million ($1993) for installation of 80 MW_e gas turbine option
Financing	Dept to Equity Ratio: 75% / 25%
Owners	Private ownership
Thermal Customers	NYC Public Utilities Service, Health and Hospitals Corporation, local commercial properties
Electric Customers	Roosevelt Island Operating Corporation, housing units on the island, wheeling to off-island customers
Permits	not applicable

Syracuse University

Participants	NYSERDA, University of Syracuse, North Canadian Oils Limited
Results	Study demonstrated the feasibility of installing gas turbines for cogenerating heat and power for steam customers at Syracuse University and local hospitals.
Technology	Gas turbine cogeneration
Fuel	Natural gas
Capacity	Two GE LM5000 gas turbines (80 MW_e)
Capital Costs	$205 million for installation of gas turbines, which includes a prepay of $88 million for natural gas.
Financing	Private
Owners	Private ownership (limited partnership)
Thermal Customers	Selected buildings at Syracuse University and local hospitals
Electric Customers	Niagara Mohawk Power Corporation under a 40 yr power purchase agreement
Permits	local building permits

Troy

Participants	NYSERDA, City of Troy, Russell Sage College
Results	Study demonstrated the feasibility of low temperature hot water district heating.
Technology	Conventional heating plant
Fuel	Natural gas
Capacity	Peak heating load for the customers was estimated at 12 MW_t.
Capital Costs	$2 million ($1992) for conventional heating plant Costs include underground distribution piping for district heating for three phases of implementation.
Financing	100% debt financing was studied
Owners	Private and municipal ownership options were investigated
Thermal Customers	Russell Sage College and other private and public buildings downtown
Electric Customers	not applicable
Permits	not applicable

where:

- Others #1: Includes minor species components, conservatively estimated at a minimum of $.08/fish.
- Others #2: Fish not included in original abundance estimates composed of primarily small E. Shiner and R. Smelt, collected from screenhouse No. 2.
- Others #3: Fish estimated from screenhouse No. 1, not included in original abundance estimates, based on numbers collected from screenhouse No. 2.

Appendix B

VALUE OF FISH KILLED
AT DUNKIRK POWER GENERATING STATION IN 1987

Table B-1 indicates the economic value of the fish destroyed as a result of cooling water used from Lake Erie at the Dunkirk Generating Station.

Table B-1
VALUE OF FISH KILLED AT DUNKIRK IN 1987

Species	**Abundance**	**Dollar Replacement Value/ Individual**[1]	**Total Replacement Value ($)**
E. Shiner	7,326,000	.08	586,000
R. Smelt	4,293,000	.08	343,000
G. Shad	2,726,000	.08-.35	218,000-954,000
Alewife	162,000	.14-.68	23,000-110,000
W. Bass	95,000	.15-1.80	14,000-172,000
W. Perch	84,000	.11-1.32	9,000-111,000
Spt. Shiner	60,000	.08	5,000
Y. Perch	43,000	.28-1.88	12,000-80,000
Fw. Drum	21,000	.11-.52	2,000-11,000
Tr. Perch	20,000	.08	2,000
Others #1	26,000	.08	2,000
Others #2	8,000,000	.08	640,000
Others #3	5,000,000	.08	400,000
Totals	27,856,000		$2,256,000-3,415,000

Cooling Water Volume: 167,000 million gallons/year

Rate of Impact: $13.50-$20.50/million gallons of cooling water used.

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[1] 1992 American Fisheries Society Values for replacing fish killed based on collected values from 135 federal, state, provincial and private agencies and hateries. Ranges reflect differences per size of fish.

Appendix C
GLOSSARY

TERMS

Absorption Chiller	refrigeration cycle that uses an external energy source (steam, hot water, waste heat) to change the energy level of the refrigerant (usually water) by using an absorbent (usually lithium bromide) to alternatively absorb heat at a low temperature level and reject it at a high temperature level by means of a concentration-dilution cycle.
Backpressure Steam Turbine	exhaust steam is used for a process or heating purpose
Centrifugal Chiller	a chiller that uses the principle of mechanical vapor compression, driven by either an electric motor, steam turbine or gas turbine
Cogeneration	simultaneous generation of electric power and useful heat
Combined Cycle	exhaust from the gas turbine is used to generate steam to drive a steam turbine
Cool Storage	storing of useful energy, specifically, cooling energy, for later use
DHC/C	district heating and cooling/ cogeneration
District Heating and Cooling	centralized production and distribution of thermal energy (e.g. steam, hot water, chilled water) to multiple end-users
End-User	the receipient of the heat distributed by the DHC/C system (e.g., industries and residential, commercial, government and institutional buildings)
Extraction Steam Turbine	partly expanded steam is extracted from the turbine for an external process or heating purpose
Gas-Turbine Combined Cycle	power generating station consisting of a gas turbine, waste heat boiler, and steam turbine

Power Plant	- power generating station consisting of fossil-fueled steam boiler(s) and steam turbine(s) as defined thermodynamically by the Rankine cycle
Single-Purpose Steam Turbine	- a steam tubine used only for electric generation
Turndown Ratio	- defines the range over which the instrument (specifically, BTU meter) can measure (i.e., 10 gpm to 100 gpm is a 10 to 1 turndown ratio)

CONVERSIONS

1 kilowatt-hour (kWhr) = 3,412.14 Btu
1 ton of refrigeration = 12,000 Btu/hr
1 boiler horsepower = 33,475 Btu/hr
1 megawatt-hour (MWhr) = 3,412,000 Btu
1 ton of refrigeration = 12,000 Btu/hr

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