A Study of the Feasibility of Utilizing Waste Heat from Central Electric Power Generating Stations and Potential Applications

July 2009

A Report By

The Connecticut Academy of Science and Engineering

For

The Connecticut Energy Advisory Board

A Study of the Feasibility of Utilizing Waste Heat from Central Electric Power Generating Stations and Potential Applications

A Report By

The Connecticut Academy of Science and Engineering

Origin of Inquiry:	The Connecticut Energy Advisory Board
Date Inquiry Established:	September 5, 2008
Date Response Released:	July 30, 2009

© Copyright, 2009. Connecticut Academy of Science and Engineering, Inc. All rights reserved

This study was initiated at the request of the Connecticut Energy Advisory Board on September 5, 2008. The project was conducted by an Academy Study Committee with the support of David Pines, PhD, Project Study Manager and Tom Filburn, PhD, Study Consultant. The content of this report lies within the province of the Academy's Energy Production, Use and Conservation Technical Board. The report has been reviewed by Academy Members Sten A. Caspersson and Robert J. Hermann, PhD. Martha Sherman, the Academy's Managing Editor, edited the report. The report is hereby released with the approval of the Academy Council.

Richard H. Strauss
Executive Director

MEMBERS OF THE STUDY COMMITTEE ON THE FEASIBILITY OF UTILIZING WASTE HEAT FROM CENTRAL ELECTRIC POWER GENERATING STATIONS AND POTENTIAL APPLICATIONS

Michael F. Ahern
Vice President, Utility Services
Northeast Utilities

Joseph F. Camean, PE
Vice President, van Zelm, Heywood & Shadford, Inc.

William H. Day, PhD
President, Longview Associates, LLC

A. George Foyt, ScD *(Academy Member)*
Manager of Electronics Research
United Technologies Research Center (ret.)

Joseph M. King, Jr.
UTC Power (ret.)

Lee S. Langston, PhD *(Academy Member), Chairman*
Emeritus Professor of Mechanical Engineering
University of Connecticut

Fred L. Robson, PhD
Principal Engineer
kraftWork Systems, Inc.

Septimus van der Linden
Principal, BRULIN Associates LLC

Leonard Wyeth, AIA
Principal, Wyeth Architects LLC

RESEARCH TEAM

STUDY MANAGEMENT TEAM

David Pines, PhD
Associate Professor and Chair of Civil, Environmental, and Biomedical Engineering
University of Hartford

Tom Filburn, PhD
Assistant Professor of Mechanical Engineering
University of Hartford

ACADEMY PROJECT STAFF

Richard H. Strauss, Executive Director
Ann G. Bertini, Assistant Director for Programs

EXECUTIVE SUMMARY

THE PURPOSE OF THIS STUDY

A significant by-product of power generation plants is rejected (or "waste") heat. Rejected heat resulting from inefficiencies of the power generating process is then rejected into the atmosphere or into bodies of water—Connecticut rivers and Long Island Sound. Large quantities of heat are rejected in Connecticut—enough energy to heat every building in the state.

The Connecticut Energy Advisory Board (CEAB) requested that the Connecticut Academy of Science and Engineering (CASE) investigate the feasibility of using the rejected heat rather than wasting it.

BRIEF STATEMENT OF PRIMARY CONCLUSION

Connecticut's power plants transform energy stored in nuclear and chemical fuels, with roughly one-third being converted into useful energy and two-thirds being rejected as heat. The total heat currently being wasted from Connecticut's power plants is an untapped resource that is roughly equal in value to all of the fossil fuels used for the state's residential, commercial, and industrial sectors for process and space heating.

Proven combined heat and power technologies can be utilized to capture rejected heat for useful purposes and will pave the path towards energy independence and security by reducing dependence on fossil fuels, while creating jobs and providing economic benefits, as well as improving the environment and energy efficiency. The challenge is to develop the policies and infrastructure necessary to utilize this valuable resource that is currently wasted.

The Study Committee concluded that there are several beneficial uses for the heat that is rejected into the environment by power plants in Connecticut. It is recommended that

- Rejected heat should be used to develop district energy (heating and cooling) systems in high population/employment areas;
- Waste heat enterprise zones should be created to encourage economic development; and
- To complement this effort, Connecticut should also explore the potential of growing algae for generating biofuel from fossil fuel stack gases, or cooling water reject heat.

Upside:

In general, the potential for using rejected heat from electrical generating facilities is significant. For example, the residential, commercial, and industrial sectors in Connecticut burned approximately $3.8 billion worth of fossil fuels for process and space heating in 2006 (Department of Energy (DOE) Energy Information Agency (EIA)). It is important to consider

that every BTU of fossil fuel burned in Connecticut involves dollars leaving Connecticut. Almost every BTU of rejected heat discharged into the environment is a resource that is entirely wasted. It is also important to consider that rejected heat discharged into the environment can have negative environmental impacts.

Downside:

Although the rejected heat is plentiful and readily available, it is not at conditions suitable for distribution and high value end use nor is it always conveniently located for use. These conditions are a result of striving for maximum electrical efficiency, a goal arising from current practices and regulations that is based on limited thinking of energy as disparate forms (electricity, natural gas and heating oil) rather than considering all forms of energy as an integrated whole. The realization of maximum economic and social benefits resulting from using the rejected heat will require current laws, practices and regulations to be modified to consider the larger energy perspective by desegregating the treatment of energy and by including land use planning and associated economic development.

Benefits:

- Reducing state's "exporting" of financial resources to purchase fossil fuels
- Creating in-state jobs to build the infrastructure needed to transport the waste heat
- Providing environmental benefits
- Creating incentives for durable manufacturing jobs in Connecticut
- Lowering energy cost to support economic development
- Increasing national security

STUDY DESCRIPTION

This report includes the following elements:

1. Operational and rejected heat characteristics of base load power plants of 65MW or larger.
2. Types and quantities of rejected heat available.
3. Domestic and foreign examples of productive and politically expedient uses for reject heat.
4. Investigation of successful industrial, institutional and municipal examples of combined heat and power (CHP—a power plant that produces two products, electric power and heat), also commonly referred to as cogeneration.
5. Investigation of successful industrial, institutional and municipal examples of district heating.
6. Review of potential uses for Connecticut's reject heat.

STUDY COMMITTEE CONSIDERATIONS

In general, electric power generated in central station power plants has been optimized for maximum electrical efficiency with the technology available at the time of construction, rather than optimized for maximum energy utilization. Rejected heat from these plants is usually available at relatively low temperatures (about 100°F).

The Study Committee considered technical viability, energy efficiency, economics, national security, environmental impact, and regulatory impact when examining potential uses for reject heat. For many of these applications, the heat may not be needed 24/7, 365 days a year. The seasonal needs of some applications were also considered.

Past Policies and Where We Are Now

- Deregulation has encouraged companies involved with electricity, natural gas or fuel oil supply for buildings to focus on their core commodity and sometimes on a specific aspect of the supply—for example, electric generation or energy transmission and distribution. They do not provide integrated energy generation and distribution services. For example, Dominion Resources, Inc (Dominion) and NRG are in the electricity generating business; Connecticut Light and Power and United Illuminating are in the electrical transmission and distribution business; and Connecticut Natural Gas, Southern Connecticut Gas and Yankee Gas are in the natural gas distribution business. This structure is not conducive to energy districts where the challenge is to realize the advantages that result from increasing the integration of thermal and electricity generation, transmission, and distribution.
- Environmental policy needs to be coordinated with energy policy. They can and do have shared interests. For example, the renewal of Millstone's National Pollution Discharge Elimination Systems (NPDES) permit may require the installation of cooling towers to minimize adverse environmental impacts from Millstone's cooling water intake structures. Dominion may be required to build cooling towers that could cost more than $1 billion to mitigate an environmental impact to the Niantic Bay and Long Island Sound. The cost would be passed on to the rate payers. In effect, this would move the reject heat from Long Island Sound to the atmosphere. Either way, it would be entirely wasted. Alternate use of the heat on a grand scale would solve the environmental impact and provide an energy resource to the area. The money for the cooling towers could be better used and the rejected heat can be viewed as an asset.

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Findings

A significant amount of energy is being wasted as rejected heat in the generation of electricity and it is possible to recover much of it to increase overall energy utilization.

USES FOR REJECTED HEAT

There are different categories of waste heat uses based primarily on the changes to power plants that are required to achieve them. They are

1. Applications which don't require any modification to the basic power plant and in which the equipment using the heat can be located at the power plant site;
2. Applications which require modifications to the power plant and which could be located at the power plant or remotely; and
3. New distributed generation power plants located near or co-located at sites using the heat.

I. Rejected Heat Applications That Do Not Require Significant Retrofit of Existing Power Plants

For existing power plants, the study first considered uses for rejected heat that did not require significant retrofit to existing facilities and minimal infrastructure to transport the heat to locations relatively near the plants. These include

- Algae Farms: Algae farms are a promising technology for utilizing waste gases and heat from stack gas for producing biofuel. Fuel production per acre is much higher than that for other biofuel sources and does not require use of land suited for agriculture. Currently, there are no existing commercial algae farms, but pilot testing of closed-system photobioreactors that utilize the carbon dioxide, nitrogen oxides, and waste heat from fossil fuel power plant stack gases have produced encouraging results. In the colder Connecticut environment, it may also be possible to use some of the heat currently rejected to cooling water. Because the biofuels would be produced using carbon dioxide from fossil plant stack gas, overall production of greenhouse gas would be reduced and Connecticut would have an indigenous supply of transportation fuels, improving energy security, increasing jobs and keeping some of its energy expenditures within the state. Estimated production of biofuel from the 850 MWs of base load fossil fuel generation plants in Connecticut is 30 million gallons per year, which is 15% of Connecticut's transportation fuel requirements. Use of power plant exhaust gases to produce this quantity of algae would reduce carbon dioxide emissions by 1.8 million tons per year for these same plants. Current estimates of total land required to achieve these results is 7,000 acres among the several base load plants, and technology to reduce this land requirement should be pursued.
- Industrial Ecology Parks: Industrial zones near power generating facilities could provide incentives to locate businesses and industries in Connecticut, creating durable jobs and strengthening tax bases. The waste heat is essentially free and available to stabilize heating and cooling costs as well as to provide readily available process water. Although the heat is at low temperature, there are some industrial processes which could use this heat.
- Greenhouses: Radiant floor heating for greenhouses could be designed to utilize 100°F water. Greenhouses may also be able to benefit from carbon dioxide in the exhaust of fossil fuel power plants. Connecticut currently has 300 commercial greenhouses, which primarily grow flowers, with total land area of less than 200 acres. Absorbing a significant portion of the heat produced by a plant such as Millstone would require 5,000 to 10,000 acres. Therefore, there is not sufficient greenhouse demand in Connecticut to alleviate environmental effects of once-

through cooling of this or other plants in Connecticut. However, should use of power plant heat and other factors make greenhouse food production attractive, this application may make a significant contribution to reducing the environmental effects of power plant cooling.

II. Rejected Heat Applications That Require Retrofit of Existing Power Plants

When rejected heat is available at higher temperatures, there are more potential uses for it. With modifications or retrofits to existing electricity generating facilities, the potential exists for CHP: two or more useful sources of power or energy. This is not a difficult technical challenge, but does increase the capital cost to utilize the reject heat.

Each of the following applications reduces power plant electrical efficiency by lowering the MW rating due to the diversion of steam that otherwise would have been used to generate electricity. The benefit of this modification, however, is higher overall thermal efficiency (i.e., more of base fuel's energy is utilized). These applications include

- Industrial Ecology Parks: Co-located industrial facilities could be used to absorb the heat. Several Connecticut generating facilities have available land adjacent to or near the existing plants. A search for industrial customers for "over the fence" heat could be conducted to determine whether the capital expense, heat cost and land availability are consistent with sale to industrial customers. The benefit of this approach is that a significant amount of thermal energy can be utilized with minimal amount of infrastructure cost needed for piping since the application will be near the source. This type of CHP has not been widely adopted in Connecticut, but successful examples of using a small portion of heat include AES Thames (Montville) and Algonquin Power (Windsor Locks). These facilities provide steam to one dedicated customer in addition to generating electricity.

- District Heating and Cooling: District heating and cooling systems are not a new technology. In most northern European countries and Scandinavia, there is a high penetration of district heating and cooling. Furthermore, in the European Union, nearly every country also takes advantage of local biomass in the form of municipal waste, and these waste-to-energy power plants are incorporated into district heating and cooling systems. District heating requires comprehensive planning to ensure the proper density, distribution corridors and coordinated government action. Another viable example of an existing large-scale (although under-utilized) district heating and cooling system is Hartford Steam and the Hartford steam loop. The system serves the capital area, downtown, and south end (Hartford Hospital).

  Typically, hot water can be piped about 12 miles from the centralized generating facility. Chilled water loops also have advantages: they significantly reduce the summer peak electricity demand caused by electrical air conditioning. This would reduce the need for peaking electric generating units that only operate a few hours each year. Because of the lower temperature difference between the desired indoor air temperature and the chilled water, the typical distance that chilled water can be piped is about 4 miles.

  A dramatically successful example of distributed cogeneration as part of a countrywide energy strategy has been demonstrated in Denmark. Foreign oil dependence nearly devastated the Danish economy during the oil embargo of 1973.

The government moved quickly and decisively, as a matter of national security, to develop a strategy to change from foreign oil dependence to energy independence. By 2006, the Danish economy was no longer dependent on foreign oil and even exported some forms of energy. The transition increased national security, and created durable jobs and economic growth. Denmark's land area and population density is similar to Connecticut. The strategies, policies and technology used in Denmark can also work in Connecticut.

II. DISTRIBUTED CHP

In Connecticut, CHP systems providing space heat and cooling to a district loop are widely used on university and institutional campuses (e.g., University of Connecticut (UConn), Yale, etc.) where there is common ownership of land, power plant and buildings and where the university owns the electric distribution system (therefore no conflict exists with public utility law). Applications involving power plants located at, and supplying heat and power to, an individual building are another CHP approach in use in Connecticut and worldwide. Any and all new generation facilities planned for Connecticut should be considered as part of a statewide (and possibly region-wide) energy strategy.

Heat Utilization Implications

There are several non-technical implications to the use of heat rejected from power plants. They include capital requirements, current practices and regulations, business models and public education. The alternative—cooling towers—also has utilization implications.

Capital: To provide heat at higher temperatures, power plants would have to be designed appropriately and existing plants would require retrofit, reducing capacity and necessitating construction of new plants. Distribution of heat and cooling in district heating and cooling systems will require significant investment.

Current Practice and Regulation: As noted above, the current energy supply system is designed and operated around separate consideration of electricity, natural gas and fuel oil. For example, power plants are owned by non-utility organizations and regulated and operated with only electric power production being considered. Little or no consideration is given to industrial development or to land use planning which would be required to gain maximum use of heat at minimum distribution costs.

Planning for distribution of all utilities such as electricity, heat, telephone, cable, water and sewers is not integrated, so considerable expense is involved with opening streets multiple times for the individual services.

Electric power plants are operated on the basis of daily auctions. This would be unacceptable when the customer is dependent on heat from the power plant.

Business Models: Under deregulation, electric power plants are project financed and sell to one customer; in Connecticut the customer is the Independent System Operator for New England (ISO New England). Heat is sold to many customers, similar to the situation for electric power distribution utilities or gas utilities. A similar business structure would have to be developed for district heating and cooling systems.

Public Education: Since distribution of heat and cooling in a district heating system is limited to a 4 to 12 mile radius, this means power plants will be quite close to people. In

Europe, where high utilization of energy is an important societal goal, the power plants are accepted by the public.

Cooling Towers

Cooling towers serve to dump heat to the atmosphere. They are expensive to construct and operate, consuming electric power, water and treatment chemicals. These units are physically very large and often cause major public objection in siting. For a large power station, hyperbolic shaped natural draft towers as tall as a 40 to 50 story building emit vapor plumes visible from a radius of several miles.

Recommendations

To meet this challenge, the following first steps are suggested to begin the paradigm shift to integrate the state's electricity and thermal requirements.

1. Require that electricity and thermal generation be integrated into the design and operation of new facilities in request for proposals for new electricity generating capacity.
2. Thoroughly evaluate the connection of the CRRA South Meadows waste-to-energy units to the Hartford heating and cooling loop. This is likely the best opportunity in Connecticut for demonstrating the benefits of combining electricity generation with heating and cooling districts. The economic and societal benefits include increasing energy utilization of the CRRA South Meadows facility from about 25% to over 50%, reducing Connecticut's dependence on fossil fuels, and reducing air pollution, carbon dioxide emissions, and impact on fisheries.
3. Provide that facilities that convert to a CHP mode of operation or new CHP plants and utilities be allowed to pursue long-term purchase contracts for selling electricity to the grid or to each other.
4. Provide Class I or Class II renewable energy credits for use of rejected heat from electricity generating facilities that otherwise would have been disposed of to the atmosphere or a water body. This would incentivize energy districts for urban areas with high population densities by helping to offset the initial costs of retrofitting the electricity generating facility. Also, this would help increase the use of combined heat and power plants for individual buildings where centralized energy districts with district heating and cooling are not feasible.
5. Encourage major urban population areas to develop master utility plans so that utility upgrades (i.e., water, gas, electricity, cable, and phone) can be coordinated along with installation of district heating and/or cooling loops. This will provide a more efficient means for instituting energy districts and provide the data needed to determine the most cost-effective projects.
6. Develop a government or private organization to purchase power plant heat and distribute it to multiple customers as is done in many locations in Canada, Europe and the United States.
7. Develop Waste Heat Enterprise zones around existing and new generation facilities

to promote local development that utilizes the waste heat as part of a smart growth policy. Developers would likely be attracted to locations where only a connection is required to the heating and cooling loop, thereby eliminating the upfront capital costs for mechanical equipment such as boilers and chillers. Furthermore, this would make additional space available for income-generating purposes that otherwise would be occupied by mechanical equipment. US EPA, as required by the 2007 US Energy Independence and Security Act (EISA), is in the process of developing a survey of waste heat energy sources in order to create a registry that would provide companies with access to information for industrial and business development purposes, as well as serving as the basis for potential waste heat energy recovery projects to qualify for financial and regulatory incentives.

8. Initiate an algae farm demonstration project at the UConn CHP power plant. The study should evaluate the cost and yield of growing algae using the stack gases from a natural gas combined cycle power plant in comparison to an algae farm using nuclear power plant condenser reject heat with (1) carbon dioxide concentrated from the atmosphere via an air extraction process; and (2) from another non-fossil fuel CO_2 source such as waste water treatment plants. The results could then be used for determining the viability of using this type of process at a nuclear power plant, such as Millstone.

Benefits

The benefits to integrating electricity generation and thermal needs are

- Reduced energy consumption, since waste heat from all electricity generating facilities is about equivalent to the fossil fuels utilized by Connecticut's industrial, commercial, and residential sectors.
- Utilizing the waste heat will reduce the approximately $3.8 billion that is spent each year in Connecticut by the residential, commercial, and industrial sectors on fossil fuels imported from out of state and from outside the country.
- Current uses of fossil fuel in buildings in Connecticut generate amounts of carbon dioxide similar to that generated by electric power generation in Connecticut. Use of power plant waste heat to meet needs currently satisfied by separate burning of fossil fuel will reduce carbon dioxide and other emissions accordingly.
- Use of fossil fuel power plant exhaust to grow algae could generate biofuel which could supplant up to 15% of the transportation fuel used in Connecticut with attendant reductions in carbon dioxide emissions.
- Utility corridors that bundle all services in a common right of way could provide sound infrastructure that will serve Connecticut for many years, providing an incentive for in-state business development, job creation, and promotion of smart growth strategies.
- Reduced air emissions including carbon dioxide and nitrogen oxides by burning less fossil fuels.
- Increased national security by reducing dependence on imported fossil fuels.
- Reduced peak electricity demand resulting from the use of chilled water loops, thus

reducing the need to make investments in peaking units that run less than 50 hours a year.

CONCLUDING REMARKS

The challenges for implementing the committee's recommendations are not technical, but will require a paradigm shift in Connecticut's energy policy and planning—to consider all energy forms/sectors along with their impacts on the environment and economic development holistically. The potential for beneficial use of power plant rejected heat is significant. The benefits have been amply demonstrated in several metropolitan areas in the United States and Northern Europe, particularly Scandinavia, and can also be achieved in Connecticut. However, policy changes are needed to integrate electricity and thermal requirements, and more detailed analysis is suggested to determine the portion of rejected heat that can be practically utilized from Connecticut's power generation plants. The question can no longer be how do we best dispose of the waste heat, but how the facilities can be best designed (new or retrofitted) to beneficially use the rejected heat.

TABLE OF CONTENTS

EXECUTIVE SUMMARY v

TABLE OF CONTENTS xv

1.0. INTRODUCTION 1

2.0 ELECTRICITY GENERATION FROM HEAT ENGINES 3

3.0 ENVIRONMENTAL IMPACT OF HEAT REJECTION SYSTEMS 11

4.0 CONNECTICUT ELECTRICITY GENERATING SYSTEMS 15

5.0 POTENTIAL APPLICATIONS FOR UTILIZING WASTE HEAT 29

6.0. SUMMARY OF FINDINGS, RECOMMENDATIONS AND CONCLUDING REMARKS 55

ACKNOWLEDGEMENTS 73

APPENDIX A: Thermodynamics of Power Cycles 75

APPENDIX B: Electricity Generating Facilities Survey and Summary of Responses 89

APPENDIX C: Letter from Donald W. Downes, Chairman, DPUC 98

APPENDIX D: Summary of Waste Heat Applications That Do Not Meet the Near-Term Needs of Connecticut 100

1.0 INTRODUCTION

The Connecticut Energy Advisory Board (CEAB) requested that the Connecticut Academy of Science and Engineering (CASE) investigate potential beneficial uses of waste heat from the operation of central power generating stations. Specifically, the concern is with those facilities that utilize once-through cooling systems because they may be required to install new cooling technologies that minimize the facility's thermal releases and impact on fisheries, as required by the federal Clean Water Act. The objective of this study is to evaluate the trade-off between the cost of installing a new cooling water system versus using that investment to increase the thermal efficiency of the facility (i.e., reducing or utilizing waste heat) while at the same time reducing the overall environmental impact. For example, the renewal of Millstone's National Pollution Discharge Elimination Systems (NPDES) permit may require the installation of cooling towers to minimize adverse environmental impacts from Millstone's cooling water intake structures.

In general, the potential of being able to use the waste heat from electrical generating facilities is significant. In 2006, Connecticut consumed 238 trillion BTUs of fossil fuels in the residential, commercial, and industrial sectors at a cost of $3.8 billion. Also, in 2006, Connecticut's electric power sector consumed over 330 trillion BTUs of energy to generate over 100 trillion BTUs of electricity (32,000 million kW-hrs), thus generating more than 220 trillion BTUs of waste heat (Energy Information Administration, Department of Energy.) Therefore, the quantity of waste heat generated by power plants could approximately replace the fossil fuel usage of the residential, commercial, and industrial sector if it were technically and financially feasible to transport, store, and utilize the waste heat for these purposes. Currently, the waste heat is being "dumped" into the state's water bodies and the atmosphere.

To evaluate the potential of using waste heat beneficially, this study concentrated on reviewing the operation and waste heat characteristics of power plants that are 65 MW or larger, using surveys and on-site interviews. Concurrently, the types of activities that could benefit from the use of waste heat were screened to determine if their needs could be adequately met by the waste heat from electricity-generating facilities. These potential applications include increasing electrical efficiency, district heating and cooling, industrial ecology parks, greenhouses, fish farms, algae farms, liquefied natural gas (LNG) vaporization, and hydrogen production. As part of this task, the experiences of electricity-generating facilities that are beneficially utilizing waste heat were reviewed in order to determine if the same opportunities were applicable to Connecticut. In addition, power plant operators from facilities that only generate electricity as well as those from plants that both generate electricity and sell steam made presentations to the committee. Also, experts on potential applications including greenhouses, central heating districts, and forward osmotic processes for desalination and electrical generation made presentations to the committee.

The study scope provides an option for a Phase 2 study upon approval of the CEAB, if the preliminary analysis indicates that waste heat produced can be utilized for a useful purpose. The following, among other tasks to be determined based on study's recommendations, would be included as part of a Phase 2 project:

- Availability of on-site land that could be used for potential development
- Industries, businesses, and residences within about 12 miles of the plant that would be candidates for using the waste heat

A scenario analysis would then be conducted to further analyze the technical and financial viability of the potential waste heat application. For this phase of the project, separate analyses were performed for the retrofit of existing facilities and the integration of thermal and electrical generation into the design and siting of new facilities.

The report concludes with the CASE Study Committee's findings and suggestions as to how Connecticut should proceed in managing the waste heat from electrical generating facilities.

2.0 ELECTRICITY GENERATION FROM HEAT ENGINES

2.1 HEAT ENGINES

Electric power generated in Connecticut is based on turning an energy resource such as fossil fuel, nuclear heat or biomass fuel into electric power through the use of an energy conversion system. Except for fuel cells, hydroelectric, solar and wind power, these systems are based on one of two thermodynamic cycles. These two cycles use a portion of the energy in the fuel to power a mechanical device that drives an electric generator. The fraction of the fuel energy that can be usefully turned into power is limited by the fundamental laws of thermodynamics. These laws state that higher temperature heat addition and lower temperature heat rejection generally provides for higher efficiency, and that not all of the energy can be used for electricity production. A corollary to these laws also states that the energy not used for electricity production must be rejected as heat. The overall efficiency of these power plants is directly related to the temperature at which the heat is supplied and rejected. Power stations using older equipment or those using nuclear fuel (simple cycle) typically reject about 65% of their input energy, while newer plants using a combination of equipment (combined cycle) typically reject less than 50% of the input energy as heat. What this means is that for every kilowatt of electricity generated, between one and two kilowatts of input energy are rejected into the surroundings—the atmosphere or a body of water. This rejected heat is therefore "wasted."

The two major thermodynamic heat-engine cycles that are used to generate electric power are the Rankine cycle (named after William Rankine, a Scottish engineer, 1820-1872) and the Brayton cycle (named after George Brayton, an American engineer, 1830-1892). Both of these cycles use the combustion of a fossil fuel or the heat of a nuclear reaction to heat a fluid to a high temperature. They differ in the fluid used in the heat engine and how this high temperature heat is used to convert mechanical energy to drive the electric generator.

For all heat-engine cycles—Rankine cycle, Brayton cycle or other thermodynamic cycle—the efficiency of the cycle (essentially the ratio of the useful work produced to the energy put into the cycle) is dependent on the highest and lowest temperature of the working fluid. The higher the temperature at which the heat is added and the lower the temperature at which the heat is rejected, the better (more efficient) the cycle. Thus, the temperature of heat rejection is a very important factor, affecting not only the efficiency but also the amount of heat "wasted."

The following are brief descriptions of the three primary cycles used; detailed descriptions are provided in Appendix A.

> **Rankine cycle.** The Rankine cycle uses water as the working fluid. Liquid water is pumped to high pressure and heat from a boiler or nuclear reactor is used to convert the water to steam, which is then expanded through a turbine to low pressure. The turbine rotates a generator to generate electricity. After the turbine, the water is condensed and returned to the pump. The maximum and minimum temperatures of the Rankine cycle are shown in Table 1.

Brayton cycle. The Brayton cycle uses air as the working fluid. Air is compressed and then a fuel is combusted with the air before the combustion products are passed through a turbine, which rotates a generator to generate electricity. The maximum and minimum temperatures of the Brayton cycle shown in Table 1 are considerably higher than those of the Rankine cycle.

Combined cycle. A combined cycle uses the exhaust heat of a gas turbine Brayton cycle to raise steam for the turbine of a Rankine cycle. By combining the higher heat addition temperature of the Brayton cycle with the low temperature heat rejection of the Rankine cycle, much higher efficiencies can be obtained. The maximum temperature of the combined cycle is the same as the Brayton cycle while the minimum temperature is the same as the Rankine cycle, giving the combined cycle a much higher efficiency (see Table 1).

TABLE 1: COMPARISON OF OPERATING TEMPERATURES AND EFFICIENCY FOR RANKINE, BRAYTON, AND COMBINED CYCLES

cycle	High Temperature (°F)	Low Temperature (°F)	Efficiency
Rankine	1,000	100	28%–35%
Brayton	2,600	1,100	40%
Combined	2,600	100	50%–58%

There are several other modifications to the Rankine cycle and Brayton cycle which alter the working fluid in some way. These alternative cycles include the Kalina cycle, Organic Rankine cycle and Cheng cycle. These cycles can be useful when added to existing gas turbine plants (i.e., Brayton cycle) to make them more efficient combined cycle plants if they were needed for base load operation, or when a lower temperature source of heat such as reject heat from an industrial process or geothermal heat is available. However, they don't offer any improvement to the efficiency or heat rejection characteristics of a Rankine or combined cycle when the low temperature is 100°F. These cycles are also described in Appendix A.

2.2 HEAT REJECTION SYSTEMS

2.2.1 Once-through Cooling

As previously described, all of the Rankine (steam) electric power plants have a fundamental requirement to reject heat at some point in the cycle operation. This heat rejection occurs in the turbine exhaust where the steam is condensed to liquid water. This condensation process allows liquid to be pumped (much more easily than steam or a steam/liquid mixture) to the boiler. Therefore, all of the conventional (Rankine cycle) steam electric plants in Connecticut need to convert large quantities of low pressure steam into liquid water. Historically, large electric generating plants have been located near large bodies of water or on rivers. Locating these electric power plants close to

these water sources allowed the generating plant to reject its heat (condensing steam to liquid water) using these water sources. The cheapest and simplest method for achieving this steam-to-liquid phase change is via a once-through cooling system.

Once-through cooling systems circulate water from a river, reservoir, lake, or ocean. This water is pumped through very large pipes into a heat exchanger located below the exhaust duct of the steam turbine. The heat exchanger in these once-through cooling systems most frequently consists of multiple tubes arrayed below the steam exhaust duct. The steam leaving the turbine flows over the outside of the tubes. Ocean, river or lake water (at the local ambient temperature) is pumped through the inside of the tubes. The low temperature of the cooling water extracts heat from the exhausted steam, causing it to condense, and adds heat to the cooling water, increasing its temperature by about 20°F. Figure 2.1 below shows a flow schematic for these types of heat exchangers in which cold water flows inside the tubes and steam is condensed on the outside.

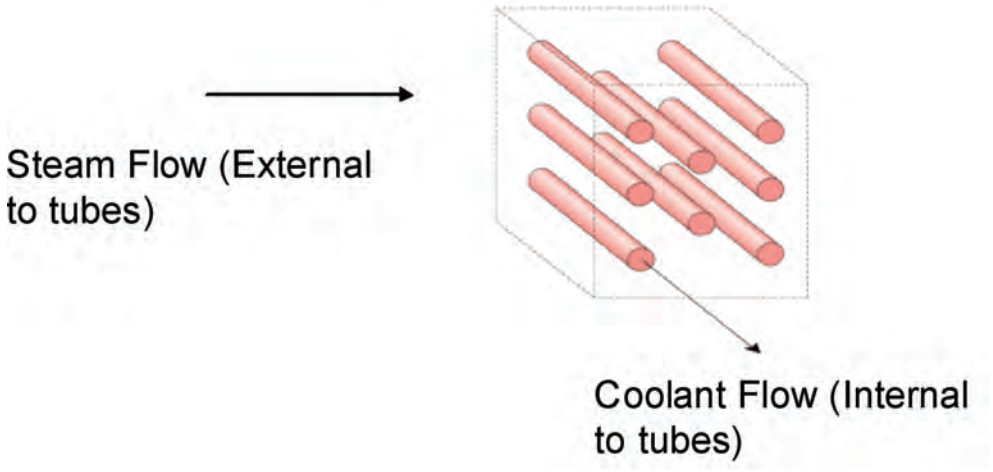


FIGURE 2.1: ONCE-THROUGH COOLING STEAM CONDENSER (TYPICAL)

There are several advantages to once-through cooling systems. They are simple, require the least amount of power to operate, and are also the least expensive to build. One disadvantage of these types of systems is the need to locate them near a large body of water (depending on the size of the power plant and therefore the magnitude of the energy to be rejected). A second disadvantage is the approximately 20°F temperature rise in the cooling water, along with the large quantity of water that must be removed and returned to the local ambient. Both the temperature rise and the physical act of pumping the water through the steam condenser can have a negative affect on biological systems.

2.2.2 Wet Cooling Towers

There are alternatives to once-through cooling systems which rely on local bodies of water. Not all power plants are located on the ocean or near rivers and lakes. Even if located on a river or other waterway, the large quantity of heat to be rejected may produce too great an increase in overall fluid temperatures and have a negative influence on biological activity.

All power plants reject heat, and larger power plants—especially nuclear-fueled or older fossil-fueled plants—reject approximately 66% of their input energy. It is impossible to locate all of these power plants on large bodies of water or on the coast. Therefore, alternative cooling mechanisms, generally using cooling towers, have been incorporated to allow these power plants to generate electricity and reject the heat necessary for their fundamental operation.

Figure 2.2 shows one potential implementation of a recirculating wet cooling tower. Recirculating wet cooling towers can be either mechanical draft or natural draft. In natural draft towers, airflow is induced by density differences (such as in a chimney) so the structures need to be much larger and taller than mechanical draft towers (typically 350 to 425 feet compared to 65 feet for mechanical draft towers). However, they are less expensive to operate. For smaller steam condensation loads (e.g., less than 250 MWe on steam), mechanical draft towers typically have a lower life-cycle cost.

A wet cooling tower uses the latent heat of the water, which is approximately 1,000 BTU per pound (7,500 BTU per gallon) to reduce the amount of water required. In comparison, once-through cooling with a 20°F temperature rise only absorbs 20 BTU per pound of water (150 BTU per gallon). This reduces the water withdrawal rate from the 500 to 750 gpm/MWe required for once-through cooling to 10 to 15 gpm/MWe for a recirculating wet cooling tower.

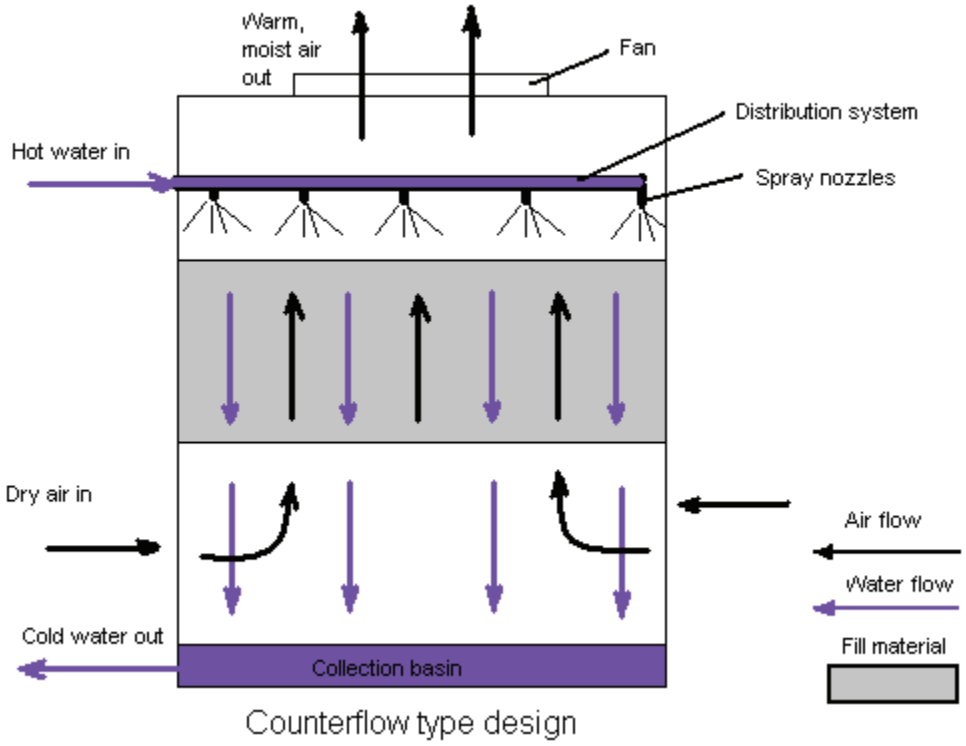


FIGURE 2.2: RECIRCULATING WET COOLING TOWER (WIKIPEDIA)

A cooling tower reduces the temperature of water through evaporative cooling. In Figure 2.2, warm water circulates to the top of the cooling tower immediately below

the induced draft fan. This warm water is injected (countercurrent) into the rising air flow through the spray bars shown. These spray bars ensure that the water is injected in small droplets. The combination of small water droplets and the possibility of louvers or trays within the cooling tower ensures intimate contact between the water and the circulating air. About 1%–2% of the recirculating water will evaporate based on the inlet water temperature, the inlet air temperature and the relative humidity (dew point) of the inlet air stream. Evaporation (phase change liquid water to steam) will produce a drop in the water temperature along with contact heat transfer between the air and water droplets. When the water is collected at the bottom reservoir, it will be cooler and ready for recirculation to the condenser or other power plant heat exchanger equipment.

Cooling towers are advantageous when large bodies of water are not feasible for rejecting heat. However, cooling towers have several drawbacks that make them less desirable than once-through cooling systems.

1. Cooling towers are more expensive than once-through cooling. Depending on the magnitude of the cooling required, cooling towers can be extremely large structures that have high capital cost.
2. Except in dry, cool climates, cooling towers cannot reach the low coolant temperatures found in large bodies of water. Lower coolant temperatures almost always improve power plant efficiencies
3. Mechanical draft cooling towers increase station electric loads. Power plants can have station service loads (parasitic power loss) to operate the fans, pumps and instrumentation of the power plant that reach 5% of the generator output. Cooling towers will increase this parasitic loss, reducing the electricity available for the grid.
4. Wet cooling towers exhaust humidified air, which shows up as a humid plume.
5. Unlike once-through cooling systems, wet cooling towers have a net consumption of water of 8 – 12 gpm/MWe, which is not returned to the body of water from which it is taken.
6. Wet cooling towers require chemical treatment programs to minimize bio-growth and the water must be treated before it can be discharged back to a water body.

2.2.2. Dry Cooling Towers

One alternative to mechanical draft wet cooling towers is a dry system, in which heat rejection to the environment is achieved with air-cooled heat transfer equipment. These systems discharge heat directly to the atmosphere by heating the air. Dry systems are generally one of two types: direct or indirect. In direct systems, a duct carries the steam to air-cooled condensers (ACCs). ACCs can use either mechanical or natural draft to create the required air flow for the steam condensing. Indirect systems condense the steam in water-cooled surface condensers, from which the heated water is pumped to air-cooled heat exchangers where it is cooled and then re-circulated to the steam condenser.

Dry cooling towers have the lowest water consumption and withdrawal requirements, but they have the following disadvantages:

- Highest capital costs (1.5 to 3 times the cost of wet cooling towers)
- Highest operating costs
- Highest efficiency penalty
- Load limitations on the hottest days
- Space requirement (about twice that of wet cooling towers)

2.2.2 Hybrid Wet/Dry Systems

Hybrid wet-dry systems contain both wet and dry components that can be used separately or simultaneously. Studies have indicated that there is from 30%–98% reduction in water consumption with wet-dry systems compared to wet recirculating systems.

2.2.3 Comparison of Cooling Water Technologies

A comparison of once-through cooling to wet cooling, dry cooling condensers, and hybrid wet-dry systems is presented on the following page in Table 2.1.

TABLE 2.1. COOLING SYSTEM TRADE-OFFS
(FROM *COMPARISON OF ALTERNATE COOLING TECHNOLOGIES FOR CALIFORNIA POWER PLANTS - ECONOMIC, ENVIRONMENTAL AND OTHER TRADE-OFFS*, 2002 AND *AQUATIC POLLUTION* BY EDWARD A. LAWS, 2000)

Trade-off	**Cooling System Type**		
	Once-Through	**Wet Mechanical Draft**	**Dry Air-Cooled Condenser**
Water Consumption	Minor	8 to 12 gpm/MWe	~0%–<5% of wet tower
Capital Cost of Heat Rejection System	Base	2 to 4x	8 to 12x
O&M Cost	Pump Maintenance, condenser cooling	Highly site specific; fan/pump power; water treatment; tower fill/ condensate cleaning	Finned surface cleaning; gearbox maintenance; fan power
Performance Penalty	Base	Highly site specific; dependent on ambient air temperature and humidity; increase in parasitic power loss	Highly site specific; 5%–20% capacity shortfall on hot and windy days; increase in parasitic power loss
Water Withdrawal	500 to 750 gpm/ MWe	10 to 15 gpm/MWe	None
Discharge	500 to 750 gpm/ MWe; thermal plume and residual chlorine issues	2 to 5 gpm/MWe	None
Drift	None	Negligible; <0.001% of circulating water flow	None
Plume	None	Visible plume on cold, humid days	None

3.0 ENVIRONMENTAL IMPACT OF HEAT REJECTION SYSTEMS

The cooling water intake and discharge of electrical generating facilities are regulated by Section 316(a) and 316(b) of the federal Clean Water Act. Section 316(a) regulates heated discharges and Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. These adverse environmental impacts are due to impingement and mortality of organisms, primarily fish, on screens that protect the intake system, and through entrainment and mortality of small organisms, primarily fish eggs and larvae, that pass through those screens and through the plant's entire cooling system.

The requirements of Section 316 of the Clean Water Act are enforced in Connecticut as part of the National Pollutant Discharge Elimination System (NPDES) permit program and are issued in accordance with Section 22a-430 of Chapter 446K of the Connecticut General Statutes. The thermal component of the discharge must meet Water Quality Standards adopted pursuant to Section 22a-426 of the Connecticut General Statutes and the location, design, construction, and capacity of the cooling water intake structure must be consistent with Section 316(b) of the Clean Water Act.

Development of new regulations for Section 316(b) is taking place in three phases. They are

- Phase I: Applies to new facilities and was enacted in late 2001;
- Phase II: Consists of regulations applicable to existing large facilities (> 50 million gallons per day (mgd) cooling water flow) and was issued in February 2004; and
- Phase III: Consists of regulations applicable to small existing facilities (<50 MGD)

These new federal regulations must be incorporated into the NPDES permits, which must be renewed every five years. For example, in August 2006 the Connecticut Department of Environmental Protection (CT DEP) published a tentative decision to renew the water discharge permit for Millstone Power Station that would allow discharge of 2.28 billion gallons of water per day from its once-through condenser cooling water system. Ecological monitoring over the last 30 years by previous owner Northeast Utilities and current owner Dominion Resources Inc. (Dominion) shows that the discharge of water from Millstone has not had an adverse impact on Long Island Sound because of the strong tidal currents in the area that average 78 billion gallons per day. However, there are concerns that the operation of the facility has contributed to the estimated 80% decline of winter flounder in the waters of southern New England due to impingement and entrainment. With this finding, the tentative decision contained the following requirements for better protection of winter flounder and other aquatic life in Long Island Sound:

- Installing by December 31, 2009, new technology to reduce the intake of cooling water by 40% during the optimal spawning season of winter flounder, which is typically early April to mid-May

- Conducting a feasibility study of the potential benefits of installing fine mesh screens to reduce the mortality rate of winter flounder larvae
- Conducting a detailed study to determine the steps needed to augment the natural reproduction of Niantic River winter flounder

In January 2007, the US 2nd Circuit Court of Appeals decided in Riverkeeper, Inc., v. EPA that many parts of the Phase II rule were invalid or needed to be reevaluated by the Environmental Protection Agency (EPA). Thus, as of March 20, 2007, the Phase II rule was suspended. This action caused the CT DEP to stop the public hearings on Millstone's tentative permit and required that Dominion conduct a detailed evaluation of all available technologies, including closed-cycle recirculation, so as to minimize adverse environmental impact in addition to the steps outlined above to address the issues relating to better protection of winter flounder and other aquatic life. The results of this detailed evaluation will be used by CT DEP to determine the best available technology to be installed at Millstone in accordance with the Clean Water Act and Riverkeeper II court decision.

Most recently, on April 1, 2009, the US Supreme Court issued its decision on whether Section 316(b) of the Clean Water Act authorizes EPA to compare costs with benefits when determining the best available technology available for minimizing adverse environmental impact at intake of cooling water structures. The court found that it is permissible to use cost-benefit analysis and to allow site-specific variances to those standards as applied to existing power plants. This decision reverses the previous decision by the US 2nd Circuit Court of Appeals that significantly limited the ability of EPA to consider costs in its determination of best available technology, and means that CT DEP can now use cost-benefit analysis for determining the best available cooling technology for Millstone. The same process now will be followed by CT DEP for renewal of NPDES permits for all electricity generating facilities in Connecticut.

While replacement of once-through cooling systems with wet or dry cooling towers will reduce the adverse impact on fisheries, it will also have economic, energy efficiency, and environmental impacts. Wet cooling systems reduce the electrical efficiency of the power plant, resulting in higher fuel consumption and greater air emissions. Also, these systems have environmental impacts including water consumption, wastewater discharge, drift (small droplets entrained in the air that are carried out of the tower), and visible plumes; they also can be visually obtrusive (e.g., natural draft towers are about 400 to 500 feet tall). Examples of the visual impact of a natural draft and mechanical draft cooling tower are shown in Figures 3.1 and 3.2, respectively. Dry cooling towers do not have any impact on fisheries, but require about twice the land area of mechanical draft cooling towers. They can also have more visual impact than mechanical draft cooling towers because they need to be raised off the ground in order to provide sufficient air flow. Dry towers also reduce the plant's efficiency due to higher backpressure; this impact is greatest during the hottest periods of the year when demand for electricity is the greatest. As with wet towers, the reduced efficiency results in higher fuel consumption with correspondingly higher emissions. In addition, more electricity generating capacity is needed because of the reduced efficiency on peak demand days.

FIGURE 3.1. SINGLE 400 FT. NATURAL DRAFT COOLING TOWER AT A EUROPEAN NUCLEAR POWER PLANT
(FROM HTTP://WWW.NUCLEARTOURIST.COM/SYSTEMS/CT.HTM)

FIGURE 3.2. MECHANICAL DRAFT COOLING UNITS AT THE 813 MW CALEDONIA COMBINED-CYCLE PLANT LOCATED NEAR COLUMBUS, MISSISSIPPI
(FROM HTTP://WWW.TVA.GOV/SITES/CALEDONIA.HTM#)

4.0 CONNECTICUT ELECTRICITY GENERATING FACILITIES

The focus of this project was to identify beneficial uses of waste heat at large electricity generating facilities, which were defined to be greater than 65 MW. There are 16 existing electricity generating facilities and five additional facilities approved by the Connecticut Siting Council that meet this criterion. The electrical generating facility, owner, location, fuel type, and summer MW rating are listed in Table 4.1 and shown on the map in Figure 4.1. The population density is also shown on the map, to illustrate the potential users for the facility's waste heat. For example, the power plants that are located in high population centers are:

- Waterside (Stamford)
- Norwalk Harbor
- Bridgeport Energy and Bridgeport Harbor
- New Haven Harbor
- South Meadows (Hartford)

Some facilities, such as Millstone, are near population centers (~3 miles southwest of New London), where piping waste heat may still be a possibility (about 4 miles is typically the maximum distance for chilled water and about 12 miles for hot water/steam loops). Other facilities, such as Lake Road, are likely located too far from a population center to make installation of heating and cooling residential loops economically feasible. In these cases, development incentives would need to be provided to encourage an industrial and/or business application that could utilize the waste heat to locate near the generation facility.

Locations that have a high concentration of office buildings and industry are also good candidates for having users that could beneficially utilize the waste heat. To gain some preliminary insight into these locations, the businesses that have greater than 15 employees are shown in Figure 4.2 along with the electrical generating facilities and population density. These employers tend to follow the population density map, with the majority of employers located on the coast and up through the middle of the state.

TABLE 4.1. CONNECTICUT ELECTRICITY GENERATING FACILITIES GREATER THAN 65 MW

Facilities	Owner	Town	Fuel	Summer MW
AES Thames	AES Thames, Inc.	Montville	Coal/Oil	181
Bridgeport Energy	Bridgeport Energy LLC	Bridgeport	Gas	445
Devon 10	NRG Energy, Inc.	Milford	Oil	14.4
Devon 11	NRG Energy, Inc.	Milford	Gas/Oil	29.3
Devon 12	NRG Energy, Inc.	Milford	Gas/Oil	29.2
Devon 13	NRG Energy, Inc.	Milford	Gas/Oil	30.0
Devon 14	NRG Energy, Inc.	Milford	Gas/Oil	29.7
Bridgeport Harbor #2	PSEG Power, LLC	Bridgeport	Oil	131
Bridgeport Harbor #3	PSEG Power, LLC	Bridgeport	Coal/Oil	383
Bridgeport Harbor #4	PSEG Power, LLC	Bridgeport	Oil	15.4
New Haven Harbor #1	PSEG Power, LLC	New Haven	Oil/Gas	448
Cos Cob 10	NRG Energy, Inc.	Greenwich	Oil	19.5
Cos Cob 11	NRG Energy, Inc.	Greenwich	Oil	16.9
Cos Cob 12	NRG Energy, Inc.	Greenwich	Oil	18.5
Cos Cob 13	NRG Energy, Inc.	Greenwich	Oil	19.2
Cos Cob 14	NRG Energy, Inc.	Greenwich	Oil	19.6
Lake Road #1	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	246
Lake Road #2	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	251
Lake Road #3	Lake Road Generating Co., L.P.	Killingly	Gas/Oil	255
Middletown #2	NRG	Middletown	Oil/Gas	117
Middletown #3	NRG	Middletown	Oil/Gas	236
Middletown #4	NRG	Middletown	Oil	400
Middletown #10	NRG	Middletown	Oil	17.1
Montville #5	NRG	Montville	Oil/Gas	81
Montville #6	NRG	Montville	Oil	407
Montville #10 and #11	NRG	Montville	Oil	5.3
Norwalk Harbor #1	NRG	Norwalk	Oil	162
Norwalk Harbor #2	NRG	Norwalk	Oil	168
Norwalk Harbor #10	NRG	Norwalk	Oil	11.9
Milford Power #1	Milford Power Company, LLC	Milford	Gas/Oil	260
Milford Power #2	Milford Power Company, LLC	Milford	Gas/Oil	261
Millstone #2	Dominion Nuclear CT, Inc.	Waterford	Nuclear	877
Millstone #3	Dominion Nuclear CT, Inc.	Waterford	Nuclear	1137

Facilities	Owner	Town	Fuel	Summer MW
Pierce	CMEEC	Wallingford	Oil	73
South Meadow #5	CRRA	Hartford	Solid Waste	25.6
South Meadow #6	CRRA	Hartford	Solid Waste	27.1
South Meadow #11	CRRA	Hartford	Oil	35.8
South Meadow #12	CRRA	Hartford	Oil	37.7
South Meadow #13	CRRA	Hartford	Oil	38.3
South Meadow #14	CRRA	Hartford	Oil	36.8
Waterside Power	Waterside Power	Stamford	Oil	71.2
Wallingford 1	PPL Wallingford Energy, LLC	Wallingford	Oil	42.9
Wallingford 2	PPL Wallingford Energy, LLC	Wallingford	Oil	40.1
Wallingford 3	PPL Wallingford Energy, LLC	Wallingford	Oil	42.9
Wallingford 4	PPL Wallingford Energy, LLC	Wallingford	Oil	42.5
Wallingford 5	PPL Wallingford Energy, LLC	Wallingford	Oil	41.2
Facilities Approved by Council – Not Yet Constructed or Under Construction				
Devon #15-18	Devon Power LLC	Milford	oil/gas	200
PDC-EL Paso Meriden, LLC	Meriden Northeast Generating	Meriden	gas/oil	544
Kleen Energy Systems, LLC	Kleen Energy Systems, LLC	Middletown	gas/oil	620
Towantic Energy, LLC	Towantic Energy, LLC	Oxford	gas/oil	512
Waterbury Generation	Waterbury Generation LLC	Waterbury	gas/oil	96

FIGURE 4.1: CONNECTICUT ELECTRICITY GENERATION PLANTS GREATER THAN 65 MW WITH POPULATION DENSITY

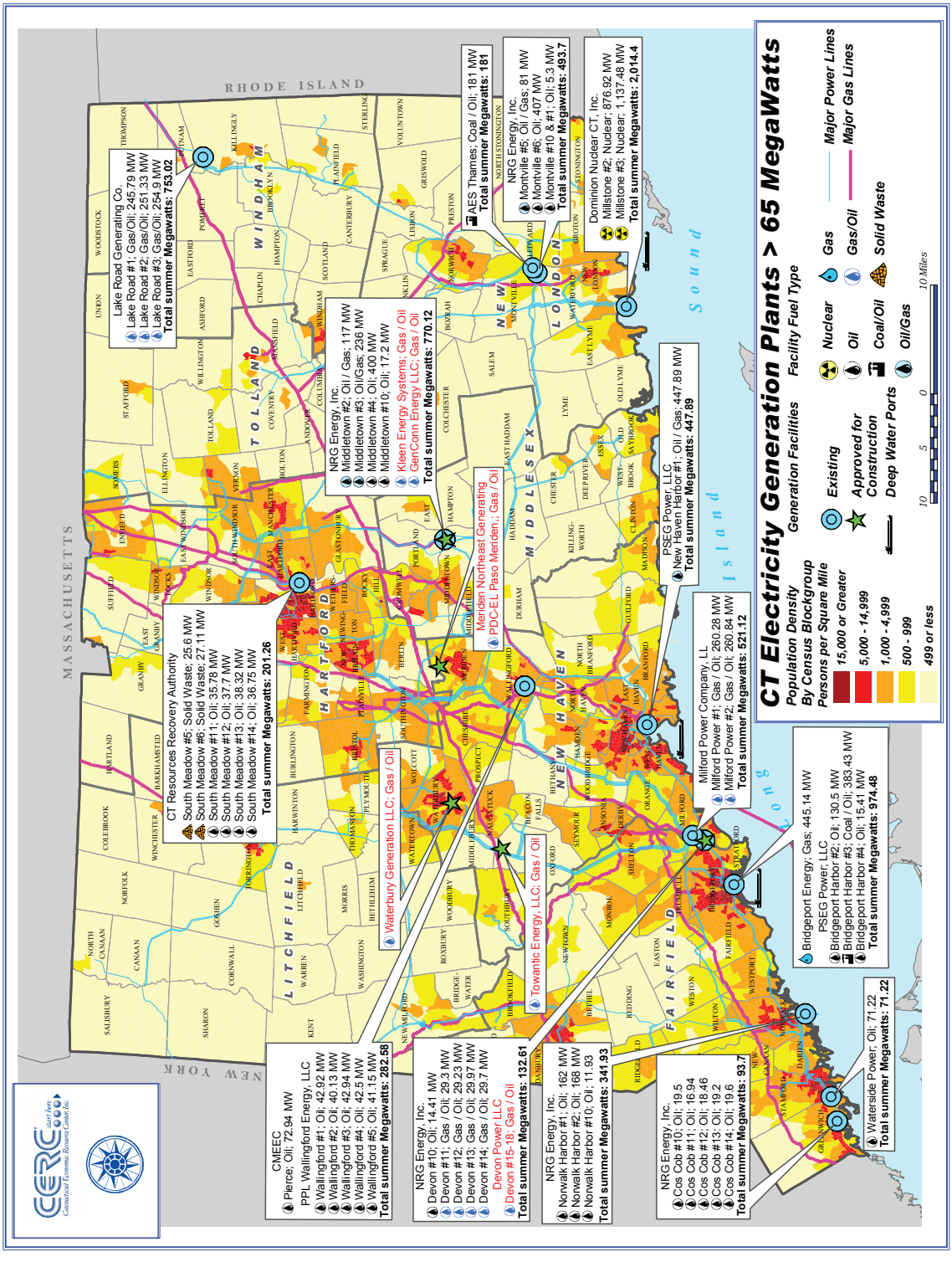
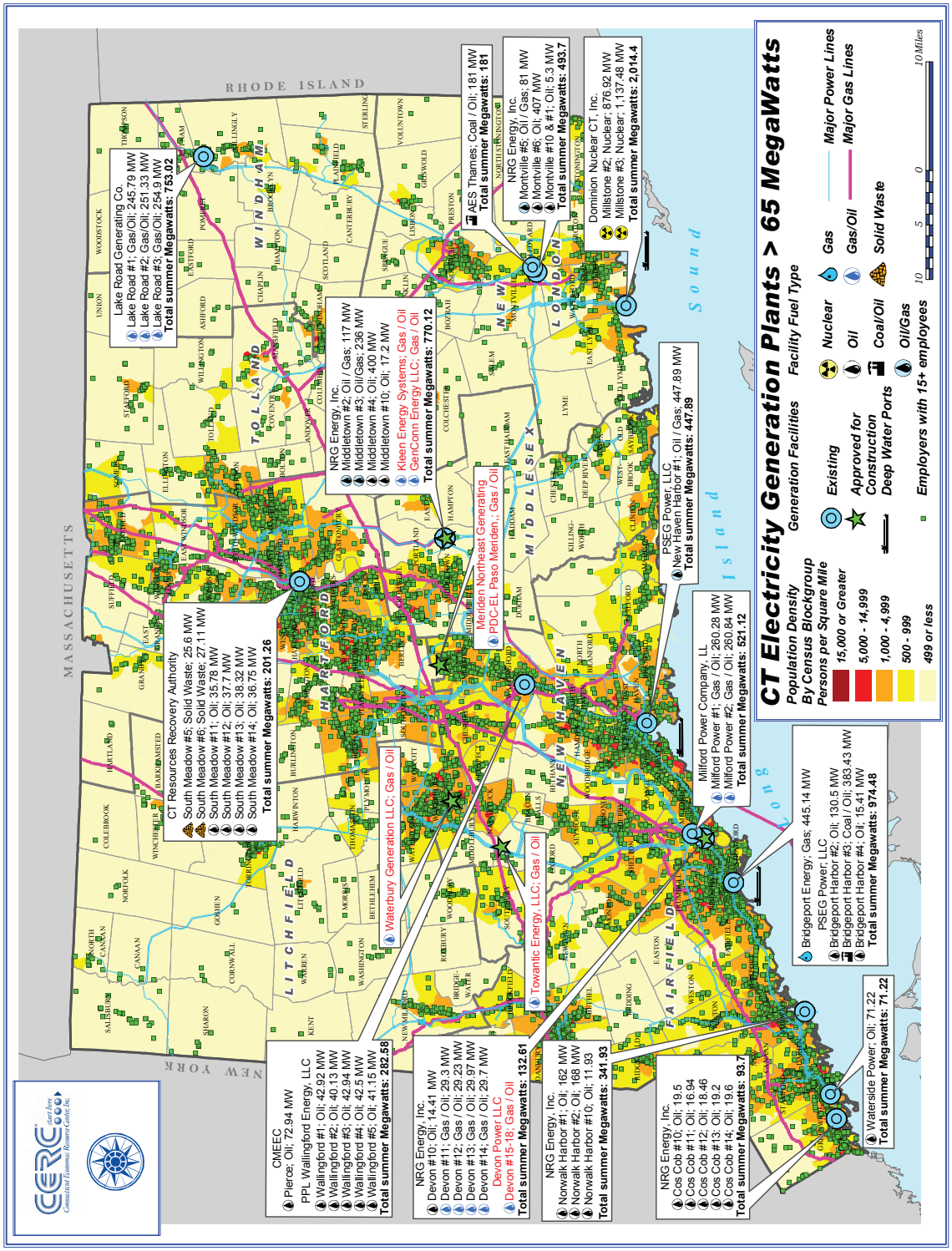


FIGURE 4.2: CONNECTICUT ELECTRICITY GENERATION PLANTS GREATER THAN 65 MW WITH POPULATION DENSITY AND EMPLOYERS WITH GREATER THAN 15 EMPLOYEES



The Study Committee developed a survey to learn more about the operation of these facilities in order to be able to further analyze the facilities that are the best candidates for utilization of the waste heat. The survey was divided into three sections. Questions in the first section were targeted at learning more about past and current efforts by the facility to utilize the waste heat. The second section dealt with the operation of the facility, including typical hours of operation, type of cycle, nominal heat rate, and identification of any capital improvements that are planned over the next 24 months. The final section explored system cooling operation, stack gas exhaust temperature, and working fluid characteristics. The complete survey is in Appendix B.

The survey was emailed to the contact person identified by the Department of Public Utility Control (DPUC); this individual had previously been notified about the study via a letter sent by DPUC Chairman Donald W. Downes (see Appendix C). The initial email was followed up with a phone call to answer any questions and to increase the survey completion rate.

Based on initial Study Committee discussions, it was concluded that survey efforts should concentrate on base load facilities, since the continuous operation of these systems is likely to provide the best opportunities for finding end users for the rejected heat. For the purpose of this study, those facilities that operate greater than 70% of the time based on 2008 operation were considered base load facilities. These facilities are shown in Figure 4.3 and include:

- AES Thames (Unit A and B)
- Milford Power #2
- South Meadows Units 5 and 6 (refuse burners)
- Bridgeport Harbor Unit 3
- Millstone Unit 2 and 3

Kleen Energy Systems, which is under construction, is included since it has been given a contract by DPUC to provide base load power for the next 20 years. Review of annual capacity factors identified several other facilities that provide base load and are also shown on Figure 4.3. They are:

- Algonquin Power (56 MW summer rating)
- Pratt & Whitney, East Hartford (23 MW summer rating)
- Refuse Burning Facilities
    - o Bridgeport Resco CRRA (58 MW summer rating)
    - o Preston RRF SCRRF (16 MW summer rating)
    - o Bristol RRF Ogden Martin Systems (13 MW summer rating)
    - o Lisbon RRF Rile Energy Systems (13 MW summer rating)
    - o Wallingford RRF CRRA (6 MW summer rating)

Figures 4.4 and 4.5 on the following pages show the location of electricity generating facilities that have peaking units (i.e., gas turbines and/or internal combustion engines that can start, sync, and load in under 10 minutes from a cold start) and those that operate intermittently as needed, respectively. While their current mode of operation is not well suited for supplying thermal energy, these facilities might have characteristics (e.g., location, land availability, system configuration) that would allow them to operate more efficiently as a cogeneration facility. Further discussion of these potential applications is in Chapter 5.

FIGURE 4.3: CONNECTICUT BASELOAD FACILITIES WITH OPERATING FACTOR GREATER THAN 70%

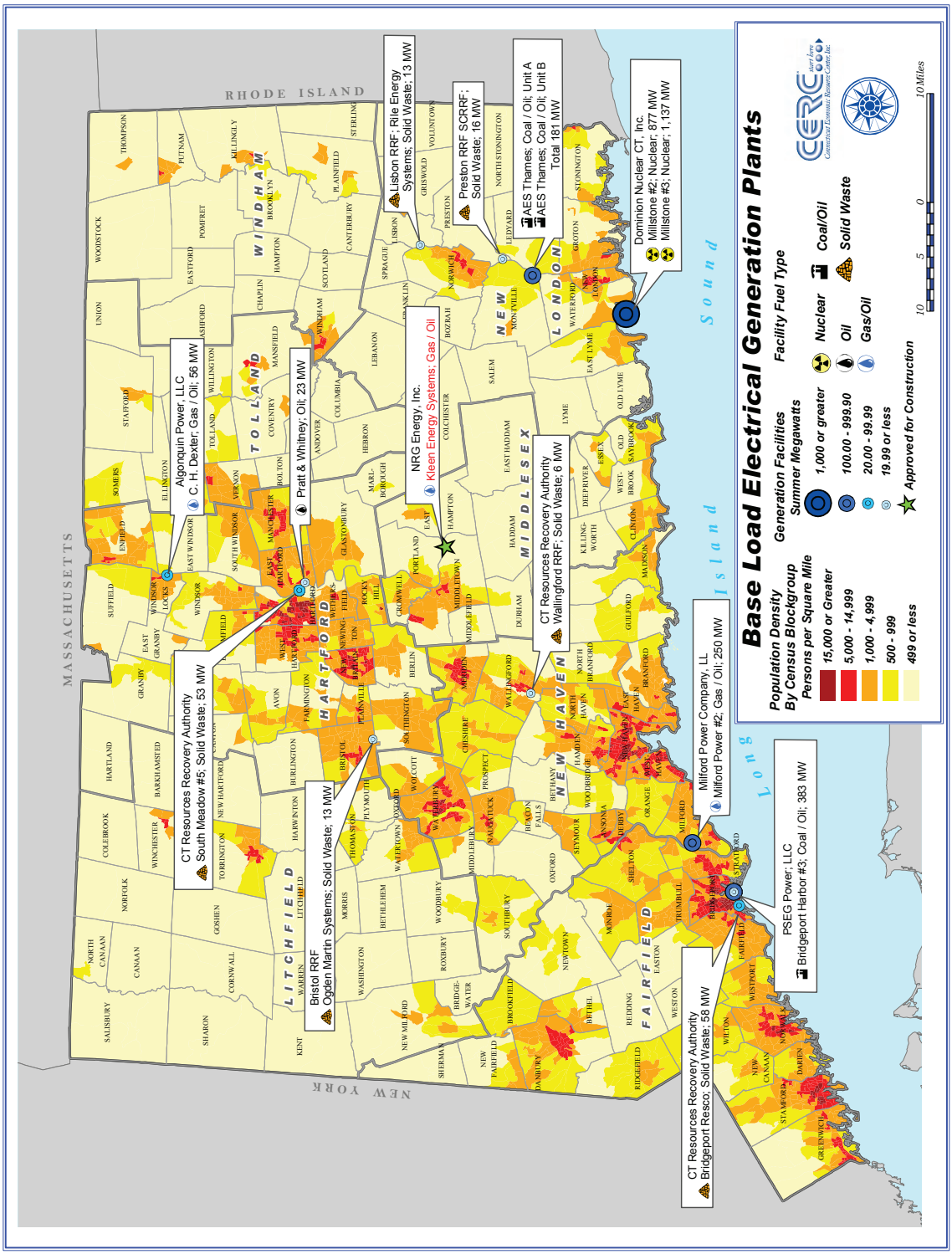


FIGURE 4.4: CONNECTICUT PEAKING UNITS

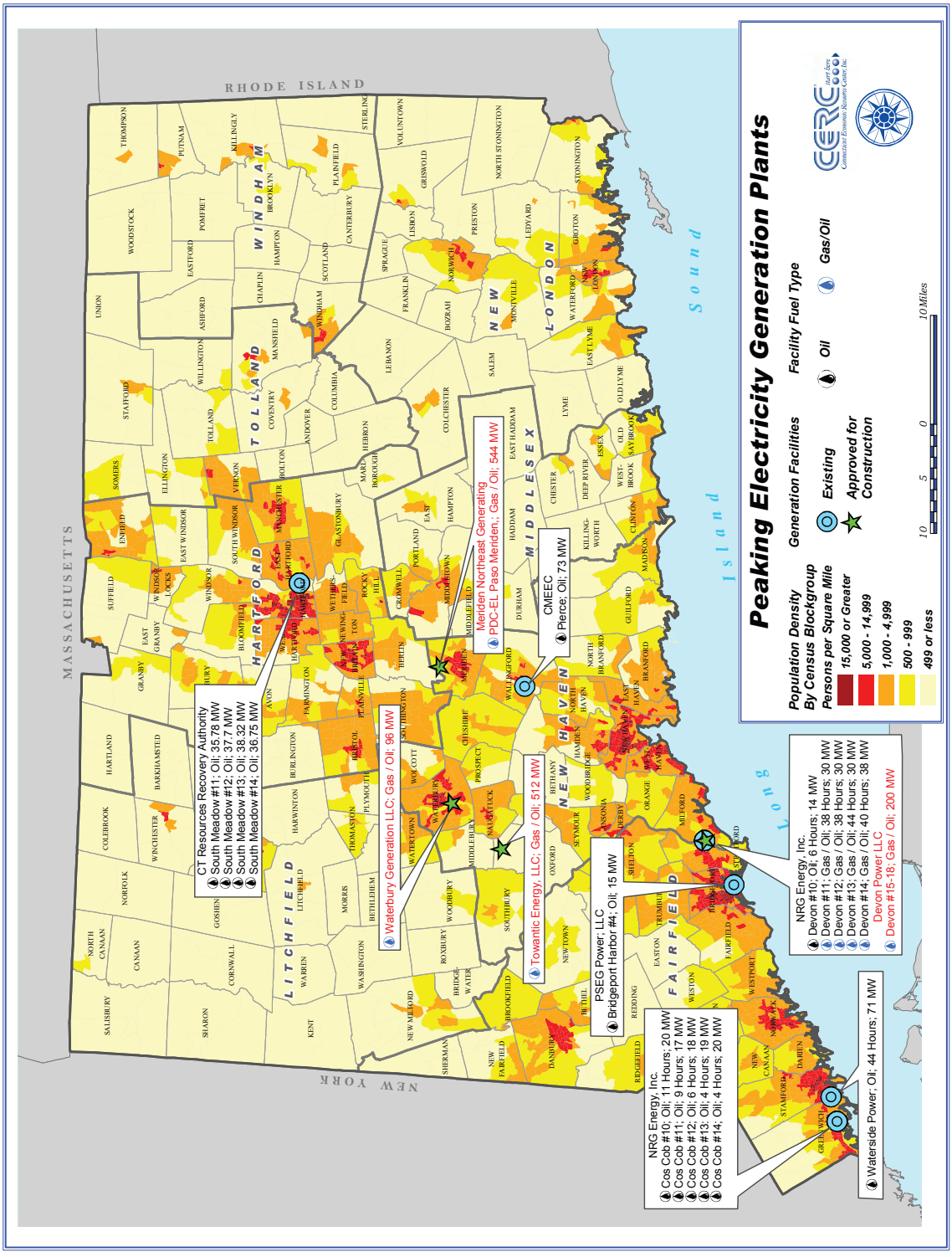
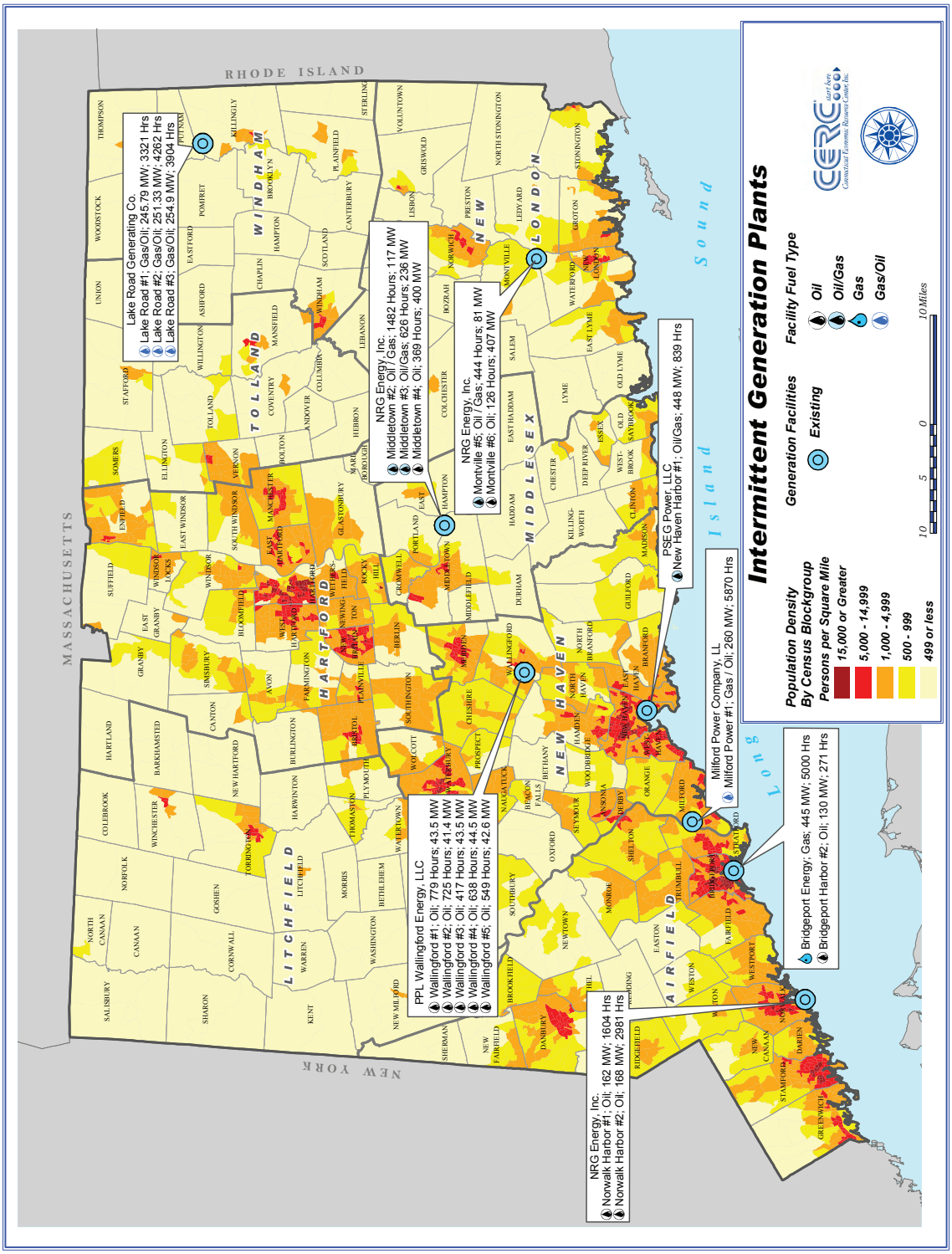


FIGURE 4.5: CONNECTICUT'S INTERMITTENT GENERATING FACILITIES BASED ON 2008 CAPACITY FACTORS



4.1 SURVEY RESULTS

Surveys were returned by four of the base load facilities that were identified by DPUC (AES Thames, Milford Power, South Meadows, and Millstone). Bridgeport Energy and Lake Road also completed and returned the survey. Bridgeport Energy typically operates about 16 hours each day and shuts down at night for economic reasons. In 2008, the annual capacity for the two units was 53% and 61%, or slightly below the study's cut-off of 70% for a facility that is considered a base load generator. The three Lake Road units had annual capacity factors between 38% and 49% in 2008, but were staffed and prepared to operate continuously. Pierce Station also returned a survey but is not included in our analysis because it is currently used solely as a peaking unit. The survey responses are tabulated in Appendix B. The following sections summarize the survey results.

4.1.1 Past and Current Efforts at Utilizing Waste Heat

AES Thames and Algonquin Power were the only facilities of the eight surveyed that sell steam in addition to generating electricity. AES Thames supplies 100,000 lb/hr steam to Smurfit-Stone Container Corporation (SSCC) for recycling 155,000 tons/yr of corrugated cardboard and Algonquin Power supplies 100,000 lb/hr steam to Ahlstrom Fiber Composites. Except for South Meadows, the other facilities have focused on their core objective of optimizing the electricity generating cycle, thereby having only very low-grade waste heat available for other applications. The primary objective of the South Meadows facility is the management and burning of solid waste from 70 towns, but they have investigated the possibility of supplying steam to the Hartford Steam Loop.

The major barrier to utilizing and/or selling the waste heat is the low quality of the steam. In some cases, it would not be possible to supply waste heat continuously because the facility does not generate electricity on a continuous basis. The primary barriers to modifying the steam cycle so as to have a higher quality of steam available are the cost of the required modifications and the lost revenue from the downtime needed to make the modifications. Bridgeport Energy summarized the issue very well by stating that "the value of modifying the steam cycle would have to be offset by both the value of keeping the steam in the cycle and cost of infrastructure to transport it to that other use."

The availability of unused land at a site or at contiguous properties was site specific with no clear trends observed from the limited number of surveys. The range of conditions is summarized in Table 4.2.

TABLE 4.2: UNUSED LAND AT SITE OR AT CONTIGUOUS PROPERTIES

Facility	Unused Land at Site	Unused Contiguous Land
AES Thames	Leases 100% of land from SSCC	Land owned by SSCC
Bridgeport Energy	7.5 acres, with 1.5 acres often used for laydown space	None
Lake Road	31 acres of the 57 acres available	17 acres owned by Town of Killingly as part of the Killingly Industrial Park is currently undeveloped
Milford Power	Only a small area is available on the 28-acre site	Number of undeveloped industrial sites available around the site
South Meadows	About 55 acres of the 85-acre site are unused, but containment area for large jet fuel tank would have to be relocated to make it usable	CL&P has 3 acres of land available

4.1.2 Facility Operation

The facilities that returned surveys are prepared to operate 24 hours per day and 7 days per week, but market conditions govern their annual capacity factor. To supplement the responses from facilities, data in Appendix B also includes 2008 hours of operation that was obtained from the US EPA Clean Markets Air Data (http://camddataandmaps.epa.gov/gdm/). As indicated previously, the base load facilities are considered those units that have annual capacity factors of greater than 70% as shown in Figure 4.3.

Most of the facilities can operate at other than full load with operation down to 60% being possible for Milford Power. One exception is AES Thames, which either operates at full load or at 45% of load when on standby.

The facilities operate using either a combined or Rankine cycle. As expected, the nominal heat rate is dependent on the cycle. (Heat rate is the amount of energy needed to generate one kW-hr of electricity. A more efficient power plant would thus have a lower heat rate.) For example, combined cycle plants have heat rates between 6,900 and 7,200 BTU /kW-hr; Millstone (Rankine cycle) has a heat rate of about 10,000 BTU/kW-hr; and the South Meadows waste-to-energy plant (Rankine cycle) has a heat rate of about 12,000 to 13,000 BTU/kW-hr. In one case, this information was reported as confidential. In general, the heat rate increases as load is reduced and as ambient temperature increases.

None of the facilities have planned capital improvements related to using waste heat.

4.1.3 System Cooling Operation, Stack Gas Exhaust Temperature, and Working Fluid Characteristics

The primary and backup fuel types are shown in Table 4.1. These range from natural gas for Bridgeport Energy, Lake Road, Milford Power, and Algonquin Power to coal for AES Thames and Bridgeport Harbor to nuclear for Millstone.

Except for Lake Road, which has air cooled condensers, the other facilities use once-through cooling from rivers (e.g., Connecticut, Housatonic, or Thames) or from Long Island Sound. In general, the cooling water being discharged is about 20°F higher than the inlet source water temperature. In some instances, the water is filtered through a coarse traveling screen (e.g., 3/8 in. mesh) to remove debris ahead of the circulating water pumps. Also, all of the power plants except for South Meadows add sodium hypochlorite (i.e., chlorine) to the water to minimize fouling. Typically, the dosing of chlorine is for less than two hours per day. The concentration and duration depends on what is allowed by the facility's NPDES permit.

Stack exhaust temperatures range from 200°F to 270°F. The outlet temperature depends on the load and ambient temperatures. Further extraction of heat is limited by the corrosiveness of the stack exhaust gas.

The facilities were also asked about their working fluid operating temperatures. In general, maximum steam temperature was between 1,000°F and 1,050°F with the steam turbine exhaust temperature of about 100°F, depending on the backpressure.

5.0 POTENTIAL APPLICATIONS FOR UTILIZING WASTE HEAT

5.1 INCREASING ELECTRICITY EFFICIENCY

While adding gas turbines to existing steam plants or steam turbines to existing gas turbine plants to turn these plants into more efficient combined cycles would increase efficiency and reduce cooling requirements per MW, this would not necessarily be cost effective, because the plants may not be needed for the base load operation that would justify the added capital expense. The Kalina, Organic Rankine and Cheng cycles described in Appendix A would not provide any efficiency gain beyond that of combined cycle power plants.

Also included in Appendix A is a description of an osmotic heat engine that utilizes the waste heat from a power plant to increase electricity efficiency. This technology is currently in the conceptual phase and is presently not applicable to a commercial power plant.

5.2 DISTRICT HEATING AND COOLING

Two different and not interchangeable terms will be used in the following sections: District Heating and Cooling and Combined Heat and Power (CHP).

- District Heating and Cooling refers to sites that rely on a central source of heat and public distribution. The steam lines that heat many college campus buildings from a central steam plant are an example of district heating. While steam is the preferred heat transfer media for district heating, chilled water is commonly used in district cooling. District heating and cooling systems require separate lines for both fluid loops. The greater temperature difference available in generating steam versus the low temperature limit found in chilled water (32°F) means that district cooling pipes are frequently larger and require more flow.
- Combined Heat and Power (CHP) refers to systems that have a central electric generating plant that also conveys steam or hot water to buildings in its vicinity.

District heating and/or cooling offers improvement in efficiency through an economy of scale. CHP systems offer large increases in fuel utilization and a commensurate drop in waste heat.

Previous sections have provided detailed information on the low efficiencies found in conventional single-cycle electric generating plants. Both steam Rankine and gas Brayton cycle plants rarely have net efficiencies over 40%. This efficiency is a measure of the utilization of the energy available in the fuel. However, combining a population center's need for heating and cooling with electricity generation can push fuel utilization efficiency to 60%–80%, 1.5 to 2 times greater than that found in pure single-cycle electric power plants. This fuel utilization rate is the highest rate found and represents a large increase over that found in pure electrical generating plants.

The economic and business practicality of district heating and cooling systems depends on careful planning with regard to distribution of the heat and cooling as well as establishment of customer agreements consistent with the requirements of favorable return on the plant capital investment. Distribution requires laying piping systems across a broad geographic area surrounding a central plant which provides electricity, heating and cooling, as illustrated by the case studies described below. Providing the heat at useful temperatures requires that the plant be optimized for this purpose, which means a reduction in electric generation efficiency and electric capacity. While use of waste heat increases overall energy utilization, the economic value of the heat at current market conditions is less than that of the electricity. For example, at average prices for electricity in Connecticut and average prices for thermal energy in Connecticut, a simplified analysis could examine energy costs only. If only half of the waste heat from a Rankine cycle power station could be utilized, displacing fuel-fired heating at a current value of $10.00/ million BTU, and half of this savings was credited to the electric station input fuel, it would decrease the price of electricity by at least 20%.

5.2.1 Case Studies

University of Connecticut Storrs Campus

The University of Connecticut's (UConn) Cogeneration Plant is the "poster child" for power plant waste heat utilization in Connecticut. This 25 MW CHP, combined cycle plant, which went online in 2006, supplies all the electricity, heat and air conditioning needs for the 18,000-student campus in Storrs.

The heart of the plant is three 7 MW Solar Taurus gas turbines burning natural gas, with fuel oil as a backup. These drive water-cooled generators to produce up to 20-24 MW of electrical power distributed throughout the campus.

Gas turbine exhaust waste heat (at about 900°F) is then used to generate up to 200,000 pounds per hour of steam in heat recovery steam generations (HRSGs). The HRSGs provide high pressure steam (600 psi) to power a 5 MW steam turbine-electrical generator set, and medium pressure steam (150 psi) for campus heating.

The waste heat from the steam turbine contained in medium pressure turbine exhaust steam is combined with the HRSG medium pressure steam output for campus heating. Thus, careful waste heat engineering and management allows three energy usages (gas turbines, steam turbine and campus heating) for only one unit of gas turbine fuel.

During the warmer months, when heating is only needed for some campus kitchens and laboratories, the waste-heat–produced, medium-pressure steam (from both the steam turbine and the HRSGs) is used to power medium pressure steam turbines which drive three refrigeration compressors that supply up to 6,000 refrigeration tons of chilled water. The chilled water is distributed to campus buildings for air conditioning. A small part of the chilled water output can also be used to cool inlet air to the gas turbines on hot days, thereby maintaining high gas turbine efficiency and electrical power output. Thus, careful waste heat management provides campus cooling and the maintenance of high electrical power needs during hot summer months.

UConn's cogeneration thermal efficiency is about 80%. A cogeneration plant's thermal efficiency (more accurately called an energy utilization factor) is calculated as the sum of the electrical power output and the useful heat produced divided by the fuel energy supplied. Other measures show that under a demand rate of 25 MW of electricity and 200,000 pounds/hr of steam, UConn's cogeneration plant uses only 52% of the fuel consumed by conventional non-cogeneration means. Careful utilization of power plant waste heat yields a large payoff for the user, and for the environment.

District Energy in Hartford

The City of Hartford has numerous buildings served by District Energy. The system is unique in providing winter heating and chilled water cooling service to the customer buildings, and it was the first large-scale commercial district cooling system in the United States. Most urban downtown district energy systems are served with steam service only, affording winter heating and sometimes steam-driven, in-building chillers for summer cooling.

Hartford's system was conceived in the 1950s by the then-Hartford Gas Company, and was a planned element of their goal to assist and increase their gas sales as part of the redevelopment of Hartford's downtown in the 1960s. Hartford Steam developed largely because Hartford Gas wanted to convert from manufactured gas to pipeline natural gas, to assure summer season demand for natural gas toward return on investment for the new infrastructure.

The motivation for deploying district heating and cooling was achieving capital and operating cost avoidance. The benefit to developers of office tower buildings was that they did not have to invest capital in their own large heating and cooling plants. The two anchor customers were Constitution Plaza and Travelers Insurance.

The original system was focused around an energy center on Columbus Boulevard between the present-day convention center and the I-91 Capitol Split exit ramp. This central plant originally had a bank of steam boilers and steam-driven water chillers. In the 1980s the central plant building was expanded and two GE LM2500 gas turbines and a steam turbine were added, providing approximately 50 MW of CHP capability. The project was motivated by an attractive power sale contract offered by Northeast Utilities (NU). In the 1990s, NU bought out the power contract with a condition that the CHP assets would be removed from their service territory (the LM2500s were sold and reused at a facility in Mexico). The plant subsequently had electric chillers added, and a former fuel oil storage tank was converted to provide 2.1 million gallons of chilled water cool storage.

All chillers reject their heat to the Connecticut River in the summer, and the river water is used for rejection of heat from year-round cooling customers. A small 3.5 MW gas turbine CHP system, including a supplemental gas-fired heat recovery steam boiler, is currently being added.

Note: Hartford Steam has seen a number of customer buildings, i.e., Constitution Plaza and One State Street, disconnect from their system after constructing in-building, stand-alone

heating and cooling plants, driven by positions that the service costs were not competitive. When the Connecticut Convention Center was developed abutting the Columbus Boulevard plant, it was decided to develop a stand-alone heating and cooling plant rather than become a customer of Hartford Steam.

Recently, Hartford Steam's parent holding company, EnergyEast, was acquired by Iberdrola, an energy conglomerate from Spain.

There are three districts of service within the City of Hartford, summarized as follows:

- **Downtown District**

  Began operation in 1962 providing steam and chilled water service; now serving 47 buildings. The largest building on the system is City Place I building, which receives both heating and cooling service. District area is generally bounded on the north by I-84, the south by Charter Oak Avenue, the west by Bushnell Park and the east by I-91. The chilled water system is interconnected to the Capitol Area System via piping underneath Bushnell Park.

Buildings Served:	
1. Senior Citizens Residential Tower 2. Hartford Steam Company 3. GSA Building 4. Hartford Public Library 5. City Hall 6. Metropolitan District Commission 7. Wadsworth Atheneum 8. Phoenix-38 Prospect Street 9. Travelers-50 Prospect Street 10. Bushnell South 11. Bushnell West 12. Bushnell East-MCI 13. The Hartford Club 14. 700 Main Street-Travelers 15. 740 Main Street-Travelers 16. 750 Main Street 17. Phoenix-56 Prospect Street 18. Phoenix-One American Row 19. WFSB 20. Downtown Fitness 21. Connecticut River Plaza 22. 55 Trumbull Street 23. Bank of America 24. Old State House	25. TheaterWorks 26. 111 Trumbull Street 27. 100 Pearl Street 28. Northeast Plaza 29. Travelers Training Center 30. Goodwin Square Tower 31. Goodwin Square Hotel 32. City Place I 33. City Place II 34. 150 Trumbull Street 35. City Steam Brewery 36. Metro Center 37. St. Patrick's Church 38. Hartford Civic Center Coliseum 39. Hartford Civic Tower Complex 40. 99 Pratt Street 41. 242 Trumbull Street 42. 280 Trumbull Street 43. Hilton Hotel 44. 915 Main Street 45. 950 Main Street-Capital Community College 46. 960 Main Street 47. Talcott Plaza

- **Capitol Area District**

  Began operation in 1987 providing low-temperature hot water and chilled water service; now serves 16 buildings. The largest building on the system is the state office building at 25 Sigourney Street, which receives both heating and cooling service. The area is generally bounded on the north by Farmington Avenue, the south by Russ Street, the west by Laurel Street, and the east by West Street. The chilled water system is interconnected to the Downtown System via piping underneath Bushnell Park.

Buildings Served:	
1. United Way	9. State Library
2. Underwood Towers	10. 165 Capitol Avenue
3. 25 Sigourney Street	11. Bushnell Memorial Hall
4. Aetna	12. 18/20 Trinity Street
5. 470 Capitol Avenue	13. 30 Trinity Street
6. State Armory	14. 10 Clinton Street
7. Legislative Office Building	15. 79 Elm Street
8. Connecticut Education Association	16. 75 Elm Street

Note: CDECA system was developed in combination with the Capitol District Energy Center Associates power plant, a 63 MW (GE Frame 6B and 25 MW GE Steam Turbine) gas and steam turbine combined cycle plant on Capitol Avenue, intended to serve most or all of the state-owned buildings in the Capitol area. The CDECA plant was intended to be base loaded but is now not competitive, operating as an intermediate/peaking unit; hence, source energy for the CDECA system is largely from boilers and chillers only. Though the decision to employ a four-pipe, low-temperature hot water and chilled water system was a progressive move, many of the state buildings were exclusively steam heated, incapable of accepting hot water heating, and most had little or no centralized (chilled water) cooling systems. Building conversions required considerable investment in modernizing building HVAC systems. A reduced number of buildings were connected to the system, and there were cost issues associated with Hartford Steam's efforts to recover their full investment. One building that was slated for district energy was 165 Capitol Avenue; when its aged steam heating boilers failed, Hartford Steam was contracted to replace and operate the boilers rather than initiating a conversion of the building from steam to hot water.

It is reported that the state is seeking to or has acquired part of all of the Capitol District distribution assets.

- **South End District**

Began operation in 1999 and now serves eight buildings. The largest building on the system is Hartford Hospital. The area is generally bounded on the northwest by Jefferson Street, the southwest by Broad Street, and the east by Maple Avenue. Hartford Steam also provides electricity to Hartford Hospital from the CHP power plant embedded in Hartford Hospital, contracted to Hartford Steam in the aftermath of the divestiture of the plant by a prior third party owner.

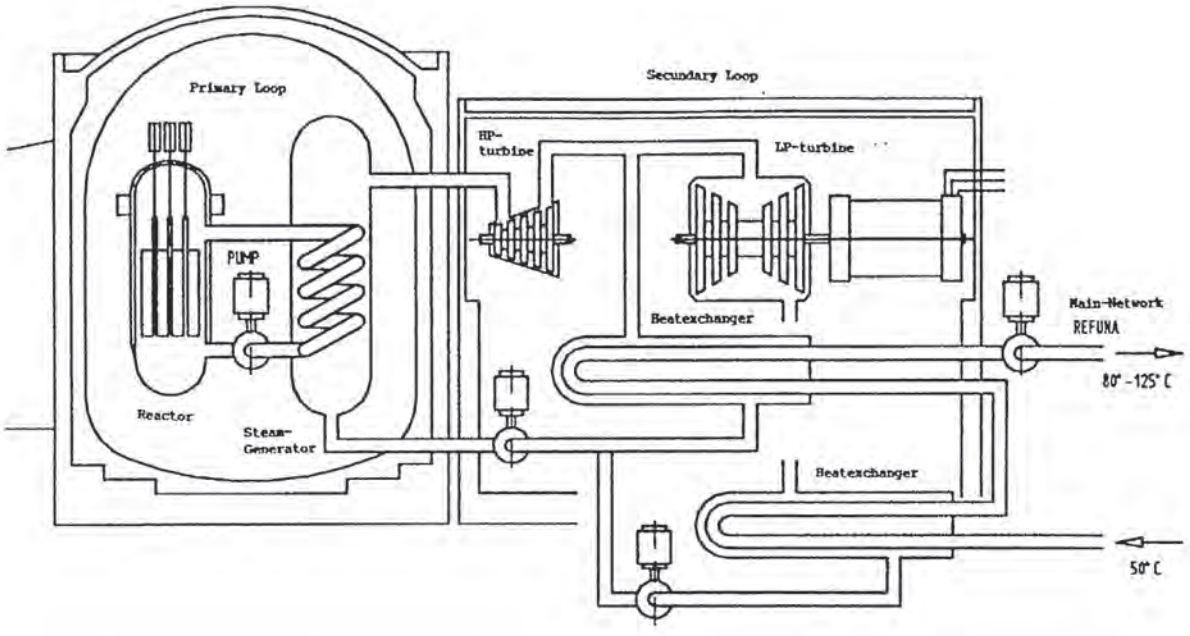
Buildings Served:
1. Hartford Hospital 2. Institute for Learning 3. The Learning Center

Note: Hartford Hospital is reportedly in negotiation to regain control of the CHP plant.

Switzerland

Beznau is a city about 25 miles northwest of Zurich. It is one of the few western European locations that uses a nuclear power plant for combined heat and power. Common in Russia and Eastern Europe, these plants are rare in Western Europe.

While average citizens may be concerned at the thought of a nuclear power plant supplying their domestic heat, it is important to remember that the steam or hot water circulating through this type of nuclear power plant does not enter the reactor and therefore is not exposed to radiation. Figure 5.1 shows the Pressurized Water Reactor used to create steam for electricity and for heating buildings.



Cascaded Heatextraction for REFUNA:
Between the HP- and the LP-turbine, steam of 128 °C
is extracted.
Extraction steam at 85 °C from the LP-turbine is
taken for preheating.

FIGURE 5.1: BEZNAU NUCLEAR ELECTRIC GENERATING AND DISTRICT HEATING PLANT

The Beznau plant is a twin reactor (1,130 MWTh 2,260 MW total) that generates 730 MWe. This same power plant could transmit up to a maximum of 75 MW of thermal energy (via steam and hot water) to the surrounding community for space heating or other process needs (e.g., industrial uses). The combination of this thermal load and the electricity production would produce a fuel efficiency rate 35.6% better than a nuclear power plant, which typically has an efficiency of about 33%. Unfortunately the Beznau region does not contain a high urban concentration, with a regional population of only 20,000 citizens and few industries that would require a large volume of steam for processing and operation.

A technical paper written by the International Atomic Energy Association in 1998 found that the technical performance of the Beznau system was flawless, but the economic return was not as positive. The article noted that the high capital costs of connecting 20 miles of piping and the low concentration of users (with most of the connections being from one- and two-family homes) was more expensive than conventional oil-fired heat systems.

Finland

In Finland, a new nuclear power station is being developed that will become the primary heat source for a district heating system. In the event that Connecticut needs to revise the nuclear component of its generation mix, this project warrants serious examination.

Denmark

Denmark is a model for implementing CHP systems. Denmark's former dependency on oil for centralized electricity generation and domestic heating made their national economy vulnerable to severe stress during the oil crisis of the 1970s. To protect themselves from this type of external threat and manipulation in the future, they made a large investment in CHP technology as a means to reduce their dependence on foreign oil. This investment has proven to be extremely effective. Figure 5.2 shows the increase in electricity production and district heating within Denmark from 1980 to 2007. This dramatic increase allowed Denmark to reduce CO_2 emission growth and increase efficiency in fossil fuel consumption.

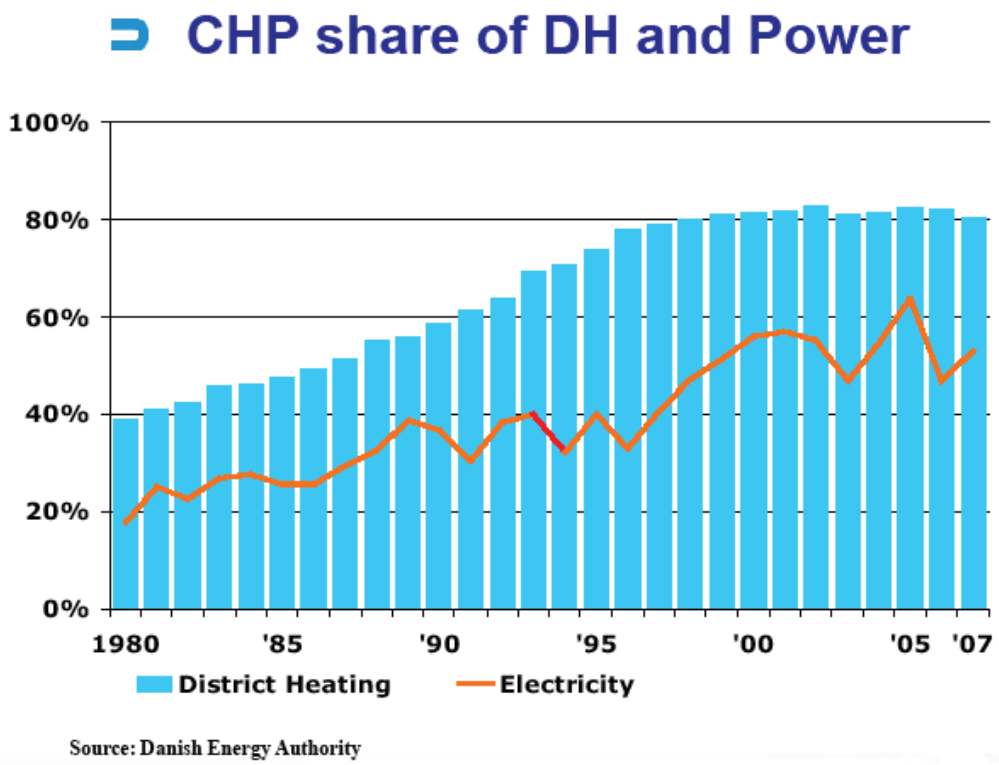


FIGURE 5.2: GROWTH IN DISTRICT HEATING AND ELECTRICITY PRODUCTION THROUGH CHP IN DENMARK

The lesson learned from the low population available around the Beznau CHP facility (250-500 persons/km2) would not be repeated in the population clusters in Connecticut. The population density in the urban areas of Hartford, Bridgeport, New Haven, and Stamford is typically greater than 2,000 persons/km2. In addition, while transportation is presently strongly tied to fossil fuels, Figure 5.3 shows the composition of fuels used by Denmark in its district heating program. This figure shows a dramatic drop in oil and coal use during this period. Even though the use of natural gas has risen, the use and growth of renewable energy has outstripped that of natural gas in Denmark.

aste Heat

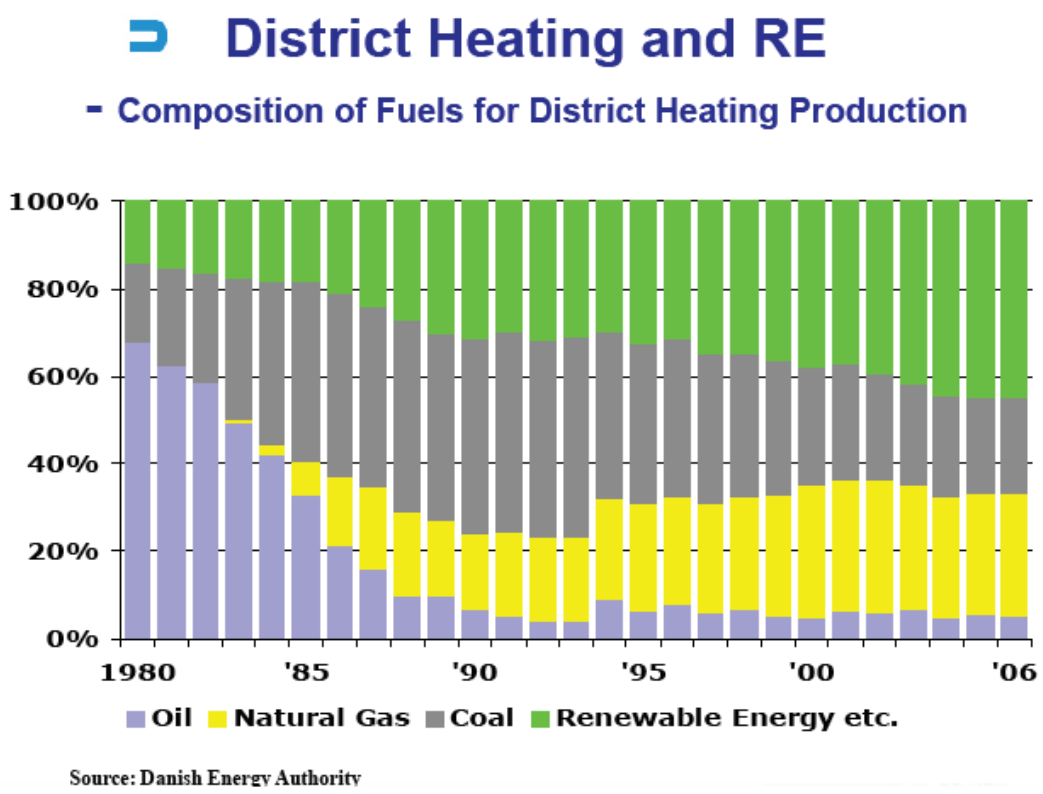


FIGURE 5.3: FUEL MIXTURE FOR DISTRICT HEATING IN DENMARK

5.3 INDUSTRIAL PROCESS HEAT APPLICATIONS

These applications involve locating uses for heat in close proximity to an electric generation power plant to minimize the issues of distribution of the heat.

5.3.1 Industrial Ecology Park

Industrial ecology parks are sustainable developments that are planned, designed and built so that it is easy for businesses to cooperate with each other and the local community to share resources and reduce waste. They typically consist of manufacturers and service businesses that are co-located not only to share energy through district energy systems but also to address multiple objectives such as shared logistics for shipping and receiving, parking, purchasing blocks, and local education and resource centers.

An example of an industrial ecology park that also combines residential needs is Kalundborg, Denmark. Waste heat from a 1,500 MW coal-fired power plant is used

to heat 3,500 local homes and a fish farm, and steam is sold to a pharmaceutical and enzyme manufacturer. In addition, the plant's sulfur dioxide scrubber contains gypsum, which is sold to a wallboard manufacturer; fly ash and clinker are used for road construction and cement production. Interestingly, this industrial ecology park was not a planned initiative but instead evolved gradually as environmental regulations became stricter and companies were motivated to reduce the cost of compliance by turning their byproducts into products (J. Ehrenfeld and N. Gertler (1997), "Industrial Ecology in Practice. The Evolution of Interdependence at Kalundborg," *Journal of Industrial Ecology*, 1:1, pp 67-79).

5.3.2 Greenhouses

Using the waste heat from power plants to support greenhouse operation would seem like a natural endeavor. Greenhouses need to maintain a warm growing environment year-round, and their temperature goals are close to the temperatures found in the effluent stream of once-through cooling condensers. While the idea of using waste heat for greenhouse operation is enticing, the application may be much more difficult.

Professor Richard McAvoy (University of Connecticut Department of Plant Science) provided a presentation on the present method of greenhouse operation in Connecticut. This presentation gave information on the types of plants and energy intensity of commercial greenhouses. Most wholesale greenhouse operations in Connecticut rely on ornamental plant production, which represents approximately 78% of their business. These greenhouses presently rely on oil-fired boilers to produce hot water to maintain growing temperatures throughout the year. A typical greenhouse may consume nearly 1 gallon of fuel oil per year for every square foot of growing floor space. The typical greenhouse in the Northeast uses heated flooring or other focused methods to bring the heat closest to the region of interest (root and plant matter). These heating systems frequently circulate hot water in the range of 120°F–140°F.

Assuming an electrical efficiency of about 33% for a simple cycle nuclear plant (e.g., Millstone), about 10 to 16 acres is required per MW of electricity generated (i.e., 2 MW heat rejected for each MW electricity generated). This land requirement would be reduced by 50% for a combined cycle plant (e.g., Lake Road) that has an electricity efficiency of 50% (i.e., 1 MW of heat rejected for each MW of electricity generated).

If designed for peak capacity of 4.6 million BTU/hr/acre (33 gallons heating oil/ hr/acre) for a 60°F temperature difference between the greenhouse and outside air temperature, 1.5 acres of land would be needed for each MW of electricity generated for a simple cycle power plant (e.g., Millstone) and about 0.75 acres for each MW of electricity generated for a combined cycle plant (e.g., Lake Road).

Since the peak heat load is reached only for a relatively short time, the design of a greenhouse to absorb power plant heat would be somewhere between the average and peak requirement conditions. Modifications to the cooling system to provide the best temperature conditions during cold weather may require equipment changes in the plant. Regardless of the design, absorbing heat from a large generating plant would require a significant amount of land, and the total greenhouse area would represent a

significant addition to Connecticut greenhouse capacity, which may not be supported by market demand. Further, the amount of heat needed in higher temperature portions of the year—when environmental effects of heat discharge to once-through cooling systems are most severe—would be low, and not much alleviation of the adverse effects would be achieved.

Professor McAvoy also discussed some other potential concerns from greenhouse operators, including the following:

- Cost of installing piping systems and the question of who pays for these capital outlays
- Availability of land around these large central electric generating stations: Southwestern Connecticut does not have large footprints available for greenhouse installation
- Quality of waste heat water since many of these once-through cooling systems use seawater that greenhouse owners may be reluctant to bring into their facilities
- Potential for unforeseen interruption (i.e., how routine are outages due to mechanical, electric grid or fuel issues)

5.3.3 Fish Farms

Fish farming offers an alternative to wild fisheries, which are being stressed due to overfishing. The most common fish that are raised for food are salmon, carp, tilapia, catfish, and cod.

There are two types of fish farms. They are

- Extensive aquaculture: depends on local photosynthetic production of food supply; and
- Intensive aquaculture: fish are fed with an external food supply.

The limiting growth factor in extensive aquaculture systems is the availability of a food supply such as zooplankton feeding on pelagic algae or benthic animals like crustaceans and mollusks. Fertilizing the water increases the photosynthetic production, which increases the yield of fish. However, most fish are carnivorous, so only about 1% of the primary photosynthetic production is converted into harvestable fish. One concern with adding fertilizers is the risk of algal blooms, which can lead to exhaustion of available nutrients and depletion of oxygen from decaying algal biomass. Thus, the selection of fish and input of nutrients is very important in maintaining a healthy and stable environment for growing the desired species of fish.

Intensive aquaculture systems have higher fish production per surface unit because they are not limited by the natural production of food. The success of these systems

depends on maintaining good water quality, so much effort and expense is expended in water purification systems that allow recycling of water. The drawback of intensive aquaculture systems is the higher cost per unit weight of fish because of the high cost of fish food, which must contain about 60% protein. This is somewhat offset by the high food conversion efficiency. For example, the food conversion efficiency is 1.1 kg feed per kg of salmon compared to 2.5 kg of feed per kg of chicken. Another disadvantage of intensive aquaculture systems is that the risk of infections increases with fish densities.

One very promising type of system combines an intensive aquaculture system with hydroponic horticulture in a greenhouse. In this type of system, the wastewater from the fish tanks is used as a fertilizer for growing hydroponic crops such as basil and parsley. The water discharged from the hydroponic crops is then recirculated back to the aquaculture system. While this type of system produces more edible protein per unit area and can be adapted to most climates because it is housed in a greenhouse, many well-capitalized systems have still failed because of the complications of managing the biology of the fish and hydroponic crops, and understanding the fish and crop market conditions.

Attempts have been made to use a power plant's waste to increase the fish yields of fish farms. For example, a pilot study was conducted in the 1970s by the Public Service Electric and Gas Company using waste heat from the 550 MW Mercer Generation Station (Hamilton Township, New Jersey). Interestingly, the goal of the study was to find a use for waste heat from power plants to reduce waste and thermal pollution of waterways. Researchers examined shrimp, striped bass, catfish, eels, and rainbow trout. Rainbow trout turned out to be the hardiest and most adaptable of the fish tested. The system consisted of discharging the power plant cooling water at 11°F warmer than the river's natural temperature through a raceway configuration before flowing it back into the river. Fish food and oxygen were added to the water to increase the growth rate of the trout. The system operated well in the winter time when the increase in temperature was beneficial to the growth rate of the rainbow trout, but the higher temperature in the summer killed the rainbow trout. As an alternative, catfish were farmed in the summer, but they were very susceptible to disease.

Fish farming techniques have improved since the 1970s, but environmental concerns with the operation of some facilities still remain, and the use of waste heat from power plants to increase the fish production rate during the winter in cold climates has still not been widely adopted as an efficient use of waste heat.

5.3.4 Algae Farms

The US Department of Energy's National Renewable Energy Laboratory's Aquatic Species Program investigated the use of algae for energy production from 1978 to 1996. Initially, the program focused on the production of hydrogen, but this was shifted to the production of transportation fuels such as biodiesel in 1982, with the emphasis on microalgae (i.e., phytoplankton, microphytes, or planktonic algae) as opposed to macroalgae (i.e., seaweed).

The major advantages of algae for biofuel productions are

- Algae are the fastest growing plants and can be grown year-round, unlike seasonal crops;
- Algae farming does not require agricultural land, so it does not compete with food crops;
- Entire biomass of algae can be used to produce end products;
- Algae contain up to 60% oil, which is greater than other crops;
- Algae can be grown in wastewater, fertilizer runoff, or brackish water (e.g., saltier water – saltwater algae contain more oil than freshwater algae); and
- Algae can capture carbon dioxide from power stations.

The yield of biocrops is quite variable because it is dependent on many factors. Even given this variability, the yield per unit area is considerably higher for algae than for corn and soybeans, as shown below.

Soybeans:	8 gallons of biodiesel/acre/year
Corn:	100 – 127 gallons of biodiesel/acre/year
Algae:	4,000 – 15,000 gallons of biodiesel/acre/year

(References: http://thefraserdomain.typepad.com/energy/2005/06/index.html and http://saferenvironment.wordpress.com/2008/10/03/algae-tremendous-potential-for-next-generation-green-energy-%e2%80%93-%e2%80%98algae-biodiesel%e2%80%99/)

If biodiesel were to replace the 140 billion gallons of fuel that is annually used for transportation in the United States, the following amount of land area would be required.

Soybeans:	About 3 billion acres
Corn (rapeseed):	About 1 to 1.4 billion acres
Algae:	9.5 to 35 million acres

As a point of comparison, there are currently 450 million acres used for crop farming and 500 million acres used for grazing land by farm animals. Thus, growing soybeans or corn as a source for biofuel production is at best only a partial alternative for replacing transportation petroleum requirements. However, algae farming, because of the high areal yield and because it does not require arable land, has the potential to be an important source of biofuel if the cost is competitive with petroleum.

One of the major technical challenges in making algae production cost effective is to identify the strains of algae that have the highest oil content (i.e., high lipid concentration) and growth rates. Optimum operating conditions that also need to be identified are sunlight, temperature, carbon dioxide, water, and nutrients. The importance of each of these factors is discussed below.

- Sunlight

  Photosynthesis is the process that plants use to convert the energy of the sun to produce new plant matter (i.e., biomass). Of the total available solar energy, 45%–50% is usable by plants. The conversion to biomass is further reduced by a factor of 4 due to the energy requirements of the photosynthetic reaction. Thus, the theoretical energy use is about 11% of the overall solar radiation. In actuality, the photosynthetic efficiency of algae grown in bioreactors has been measured to about 5.4% under natural light conditions. However, this is still significantly greater than the 1% efficiency of general crops.

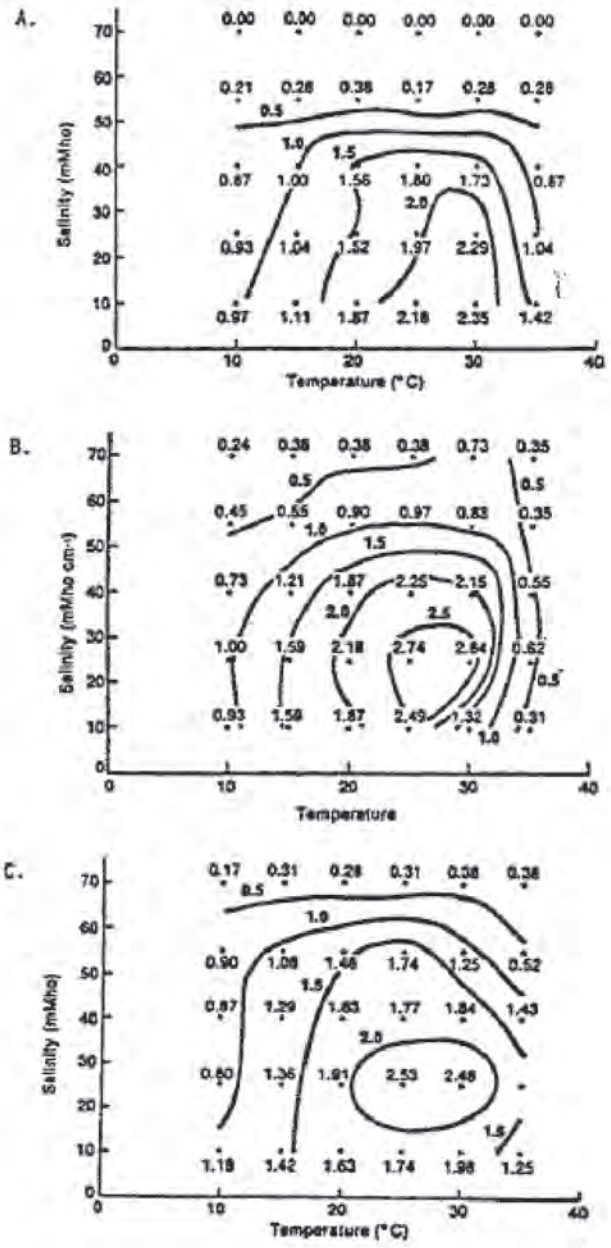
  Sunlight only penetrates about 3 or 4 inches into the water. Therefore, open pond systems with deeper depths must be agitated to circulate the algae throughout the water column. Also, too much direct sunlight can kill algae, while overcrowding of algae inhibits their growth because they have too little exposure to sunlight.

- Temperature

  The optimum temperature depends on the strain of algae and the water quality. For example, growth contour plots of Monoraphidium sp. is shown in Figure 5.4 as a function of temperature, salinity, and water quality. The growth rate is given as doublings per day. Figures A and B are data for inland saline water and Figure C is for seawater (see Figure title for a more detailed description of water quality characteristics). For this species, the optimum temperature is about 86°F with a significant decrease in growth rate if the water becomes too warm. Also, algae are adversely affected by changing temperature, so it is important to maintain a constant water temperature to maximize growth rate.

FIGURE 5.4: GROWTH CONTOUR PLOTS FOR MONORAPHIDIUM SP. IN DOUBLING RATES/ DAY (A: INLAND SALINE WATER WITH LOW MONOVALENT-TO-DIVALENT ION RATIO OF 0.4; B: INLAND SALINE WATER WITH HIGH MONOVALENT-TO-DIVALENT ION RATIO OF 9.4 AND IS CLASSIFIED AS A "SODIUM BICARBONATE WATER"; C: ARTIFICIAL SEAWATER USING A RILA MARINE MIX)

(FROM A LOOK BACK AT THE US DOE'S AQUATIC SPECIES PROGRAM: BIODIESEL FROM ALGAE, JULY 1998)



- Carbon Dioxide

  The carbon dioxide in the atmosphere is not concentrated enough for obtaining the growth rates needed to make a system economically viable. To obtain higher concentrations of CO_2, algae farming systems typically use exhaust from power plants, cement, and chemical plants as their feedstock. For example, stack exhaust from coal power plants contain about 13% carbon dioxide. Tests have indicated that a photo bioreactor algae system can convert about 40% of the emitted carbon dioxide to biomass.

- Water

  Freshwater is not needed to grow algae, so it does not compete with our drinking water supply and irrigation water. Wastewater and runoff from farm land may be beneficial because of the nutrients (e.g., nitrogen and phosphorous) in the water. Also, studies have found that saltwater algae have a higher oil concentration than freshwater algae.

- Nutrients

  Like all plants, algae need nutrients such as nitrogen, phosphorous, potassium, and trace metals in addition to sunlight, carbon dioxide, and water. By using power plant stack exhaust, the algae not only utilize the carbon dioxide but also can remove up to 86% of the nitrogen oxides. Algae farming can also be used as part of a water treatment process to remove nutrients from water before it is discharged into rivers or ocean. In Connecticut, this is especially important because of the hypoxia that occurs in Long Island Sound during the summer. This hypoxia is caused by excessive growth of algae resulting from too much nitrogen being discharged directly into the Sound and into the rivers that feed the Sound.

  Open systems (e.g., pond) and closed systems (e.g., greenhouse-enclosed pond and photobioreactor) have been used for growing algae. The Aquatic Species Program concentrated on the design of open systems by creating a 1,000 m2 pond in Roswell, NM. The pond system was a raceway configuration as shown in Figure 5.5. Paddlewheels circulated the algae, water and nutrients around the racetrack. The paddlewheels, along with the injection of stack gas emissions, kept the algae in suspension. Also, the ponds were kept shallow because of the need to keep the algae exposed to sunlight. Water and nutrients were constantly fed to the pond and algae-containing water was removed at the opposite end. The goal was to obtain yields of 50 g algae/m2/day. While this was achieved, it could not be obtained consistently because of occasional low temperatures.

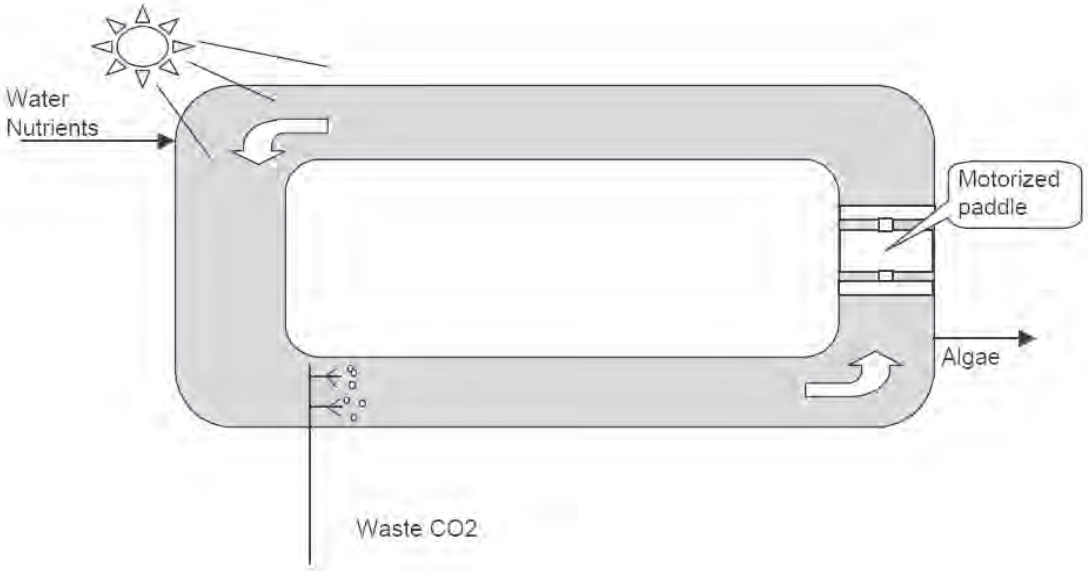


FIGURE 5.5: OPEN "RACEWAY" SYSTEM FOR ALGAE FARMING

More recently, there has been an increase in the development of closed photobioreactor systems. One of the major developers of these systems is Greenfuel Technologies Corporation (www.greenfuelonline.com) in Cambridge, MA. They have six pilot installations, including a system at the MIT cogeneration plant that has been operating since August 2004. This system consists of 8-foot tall bioreactors in a triangular shape (see Figure 5.6). The tubes are 4-8 inches in diameter and are clear polycarbonate. Water is continuously circulated, with the gas making one pass through the system; the algae are harvested daily. The microalgae are selected for the specific climatic conditions based on a number of factors including growth rate and composition (lipids, carbohydrates, and proteins), and are not genetically modified. According to Greenfuel, the optimal amount of light exposure is obtained by having the hypotenuse facing the sun and the horizontal and vertical legs in the shadow of the hypotenuse.

Greenfuel also conducted a pilot test at the 1,060 MW combined cycle APS Redhawk Power Plant in Arizona about 65 miles west of Phoenix. Using a proprietary light matrix system that reportedly increases areal production, algae productivity was between 62 and 174 g/m2/day with an average of 98 g/m2/day during the two-week test. The daily average culture temperature was between 24°C and 35°C and the flue gas carbon dioxide concentration was between 2% and 4%. The pilot scale field test and lab scale tests had similar average productivity, but the peak productivity of 174 g/m2/day of the pilot test exceeded the 130 g/m2/day of the lab scale unit.

There currently are not any commercial systems, but the plan is for the facilities to be designed in 100 hectares (247 acres) modular units. It is expected that these configurations will grow an average of 80 grams of algae/m2. For an average coal power plant of 655 MW, it would take 3,400 hectares to reduce the carbon dioxide emissions by 40%.

FIGURE 5.6. GREENFUEL'S PHOTOBIOREACTOR INSTALLATION AT MIT COGENERATION FACILITY

(FROM THE ENERGY BLOG – THE ENERGY REVOLUTION HAS BEGUN AND WILL CHANGE YOUR LIFESTYLE, JUNE 17, 2005, HTTP://THEFRASERDOMAIN.TYPEPAD.COM/ENERGY/2005/06/INDEX.HTML)

A summary of the advantages and disadvantages of open and closed systems is given in Table 5.1.

TABLE 5.1. ADVANTAGES AND DISADVANTAGES OF OPEN AND CLOSED ALGAE FARMING SYSTEMS

	Advantages	Disadvantages
Open Systems (Raceway Type Design)	• Less expensive to construct	• Lower yield • Vulnerable to contamination by other organisms • Subject to evaporation and rainfall that causes salinity and pH imbalances • Less control over temperature and lighting conditions
Closed Systems (Photobioreactors)	• Higher yield because they can operate in the log growth phase when excess nutrients are available • Maximum productivity when the "exchange rate" (time to exchange one volume of liquid) is equal to the doubling time of the algae	• More expensive to construct

The final steps in the biofuel production process are harvesting the algae and extracting the oil. Several techniques can be used to harvest the algae. They include microscreens, centriguation, flocculation, and froth flotation. The primary means for extracting the oil is mechanical crushing (expeller/press), hexane solvent extraction or supercritical fluid extraction.

5.3.5 LNG Vaporization

Large amounts of low-grade thermal energy are required for the vaporization of liquefied natural gas (LNG). The process typically consists of LNG being transported in large insulated tankers at about -260°F (110 K) and near ambient pressures. The LNG is transferred to either an onshore or floating offshore receiving station, where it is pressurized to between 3.3 and 10 MPa, vaporized, and superheated to ambient temperature so it can be added to the natural gas distribution pipeline.

Anson (2009) has described several possibilities for taking advantage of the temperature difference between cooling water discharge temperature or condenser operating temperature (i.e., heat source) and the LNG temperature (i.e., heat sink). The following sections summarize some approaches for retrofitting an existing facility utilizing a

Rankine cycle and integration of an LNG vaporization cycle into the design of a new electrical generating facility.

Retrofitting Existing Rankine Electrical Generating Facility

A LNG vaporization system using cooling water discharge and Rankine cycle is shown in Figure 5.7. In this configuration, ethane (shown in blue) is used as the working fluid where the cooling water discharge at between 60°F and 100°F (shown in red) is used to heat and evaporate the ethane at about 27°F and 2.2 MPa. The ethane is then expanded through a turbine and the LNG is used to condense the ethane back to a liquid at about -117°F and 0.13 MPa. Additional cooling water effluent is used to further heat the natural gas to ambient temperature.

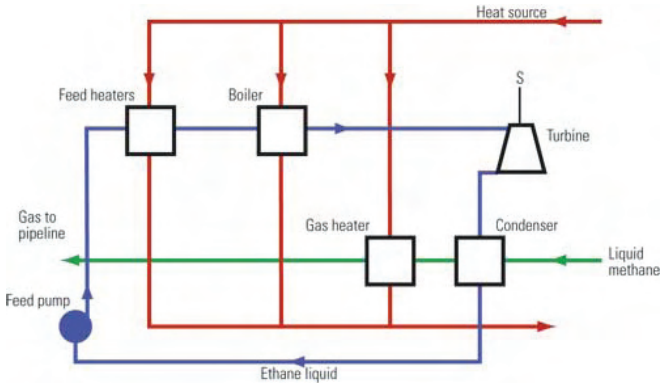


FIGURE 5.7: INTEGRATION OF LNG VAPORIZATION AND RANKINE CYCLE (FROM *POWER MAGAZINE*, 2009; SOURCE: BATTELLE)

Design of a New Rankine cycle Facility

Instead of investing in a cooling water system, it would be preferable to condense all of the steam with an independent closed circuit fluid system. One potential system is shown in Figure 5.8, with the fluid properties given in Table 5.2. This system uses an intermediate heat transport medium as opposed to directly using the ethane to condense the steam because of the possible difficulties in controlling steam pressure resulting from the large variations in temperature that could occur. For example, a plant evaporating 1,000 tons of methane per hour would produce about 160 MW of electrical power. Also, using a closed circuit fluid system would eliminate the need for 900 million kJ of fuel for vaporizing the natural gas.

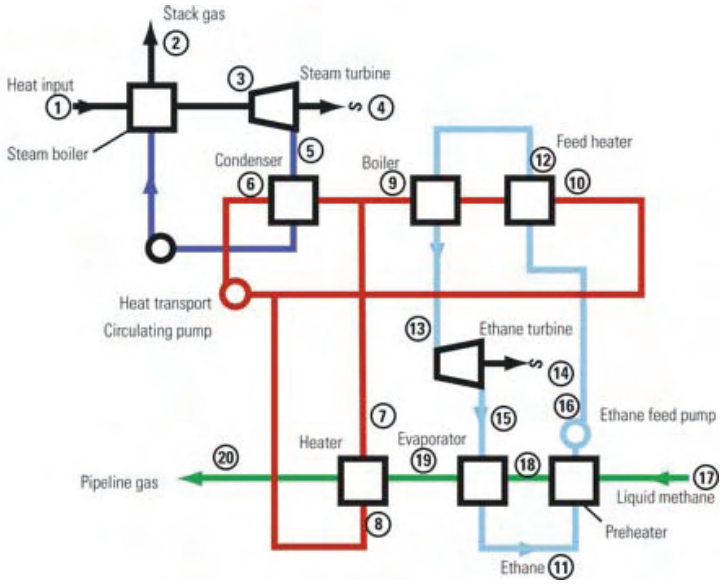


FIGURE 5.8: DUAL RANKINE CYCLE PLANT WITH CLOSED LOOP COOLING SYSTEM (FROM *POWER MAGAZINE*, 2009; SOURCE: BATTELLE)

TABLE 5.2: THERMODYNAMIC PROPERTIES FOR STATE POINTS IN FIGURE 5.8

Point	Process	Energy flux (kJ/kg steam)	Percentage of input energy
1	Fuel input	3,897	100
2	Stack and miscellaneous losses	585	15
3	Steam to turbine	3,312	85
4	Turbine output	1,192	30.6
5	Turbine exhaust	2,120	54.4
6	Condenser coolant inlet	0	0
7	Coolant to methane superheater	573	14.7
8	Coolant leaving methane superheater	0	0
9	Coolant to ethane circuit	1,547	39.7
10	Coolant leaving ethane circuit	0	0
11	Ethane liquid to preheater	0	0
12	Ethane leaving preheater	1,547	17.9
13	Ethane entering turbine	593	39.7
14	Ethane turbine output	308	7.9
15	Ethane vapor to methane circuit	1,239	31.8
16	Ethane condensate return	0	0
17	Methane liquid from storage	0	0
18	Methane liquid preheater outlet	561	14.4
19	Methane saturated vapor	1,239	31.8
20	Methane at 20C to pipeline	1,812	46.5

Brayton cycle Alternative

The integration of LNG vaporization and a Brayton cycle is shown in Figure 5.9 with the thermodynamic properties for the referenced state points listed in Table 5.3. In this case, the preferred working gas is an inert, dry gas (e.g., nitrogen). For this type of system, the heat utilization factor is very high because the heat supplied to the turbine is utilized either for power generation or LNG vaporization. For example, a plant evaporating 1,000 tons of methane per hour generates about 54 MW of electrical power.

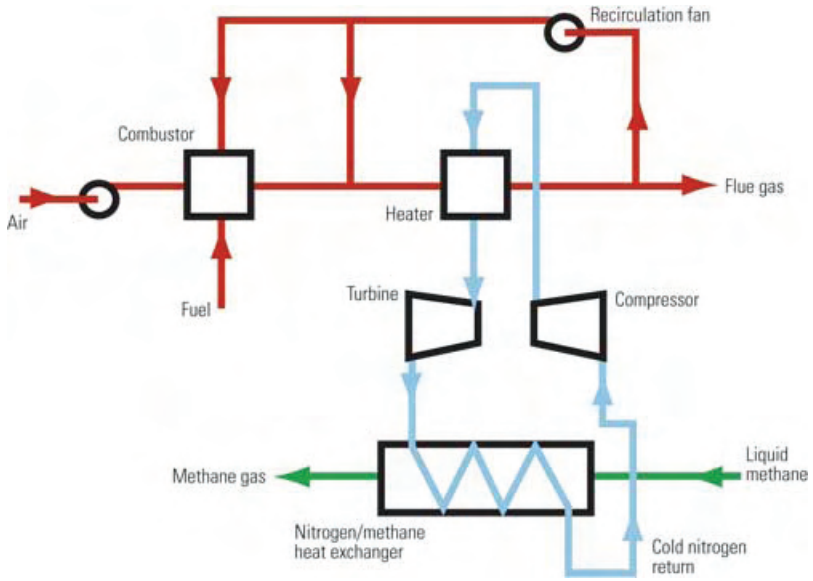


FIGURE 5.9: CLOSED BRAYTON CYCLE AND LNG VAPORIZATION (FROM *POWER MAGAZINE*, 2009; SOURCE: BATTELLE)

TABLE 5.3: THERMODYNAMIC PROPERTIES FOR CLOSED LOOP BRAYTON CYCLE

Process	State points	Pressure (MPa)	Temperature (K)	Enthalpy change (kJ/kg)
Energy input from source	s→s'	0.1	810–385	1,075
Nitrogen compression	1→2	0.3–1.5	200–343	358
Nitrogen heating	2→3	1.5–1.39	343–750	1,075
Nitrogen expansion	3→4	1.39–0.3	750–524	589
Nitrogen cooling	4→1	0.3	524–200	843
Methane re-evaporation	m→m'	10.3	111–293	843

5.3.6 Hydrogen Production

The Hydrogen Fuel Initiative (HFI) was established in 2004 to accelerate the research, development, and demonstration of hydrogen and fuel cell technologies. The

development of hydrogen production is divided into renewable-based hydrogen, hydrogen from coal, and nuclear hydrogen. Hydrogen from coal and nuclear hydrogen processes require high temperature and are not suitable for using low-quality waste heat from power plants. The emphasis on research in the area of renewable-based hydrogen is on the reforming of biofuels to produce hydrogen. For example, Ohio State University has demonstrated hydrogen yields greater than 90% from bio-ethanol using non-precious metal catalysts at temperatures below 500°C (FY 2008 DOE Hydrogen Program Annual Progress Report).

Two potential hydrogen production technologies that are still in the early stages of development that could utilize low-quality waste heat are fermentative hydrogen production and biological production. Fermentative hydrogen production converts organic substrates to hydrogen in a process similar to anaerobic digestion and can be done in either dark conditions where hydrogen production can be achieved continuously, or with bacteria that need light, called photofermentation. In 2004, DOE held a workshop on hydrogen production via direct fermentation to discuss yield and cost requirements to make the technology competitive with hydrogen production technologies, identify technical barriers that must be overcome to achieve cost-effective production, and explore ideas about breakthrough technologies. The workshop participants agreed that 8-12 moles hydrogen per mole of glucose, along with glucose at less than 5 cents per pound, were needed to make the process commercially viable. At the time of the workshop, yields of greater than 4 moles of hydrogen per mole of glucose had not been verified in a reproducible manner from any known organism. While efforts continue to overcome the technical and economic barriers, it is not expected that waste heat from Connecticut power plants could be utilized as part of a fermentative hydrogen production process in the near future.

Biological production of hydrogen can be produced in algae bioreactors. In 2000, it was found that C. reinhardtii algae will switch from the normal photosynthetic process of producing oxygen to the production of hydrogen when algae are deprived of sulfur. It is estimated that about 25,000 km2 (about the size of Vermont) would be needed to produce enough hydrogen to displace the gasoline used in the United States. To achieve the US DOE target of $2.60/kg that would make renewable hydrogen economically viable, the efficiency of light to hydrogen conversion must be increased from about 1% to 10%. As with fermentative hydrogen production, it is not expected that power plant waste heat could be integrated into a biological hydrogen production process in the near future.

5.3.7 Desalination

Using the same type of process as previously described for an osmotic heat engine, Professor Menachem Elimelech, Chair of Chemical Engineering, Yale University, and co-researchers are developing a desalination process that uses low temperature waste heat. The forward osmotic process uses a “draw solution” to pass water through a semi-permeable membrane from salt water (or any contaminated water source) into the draw solution. The properties of the draw solution are selected so that it has a higher osmotic pressure than the saltwater solution. Therefore, electrical power is not required to “pump” pure water from the saltwater into the draw solution. In contrast, reverse

osmosis processes require electric power to pump the water "uphill" to overcome the osmotic pressure difference between the saltwater and the freshwater. The pumping pressure ranges from 400 to 1,100 psi in order to obtain the desired water fluxes across the membrane. A comparison between forward and reverse osmosis is shown in Figure 5.10.

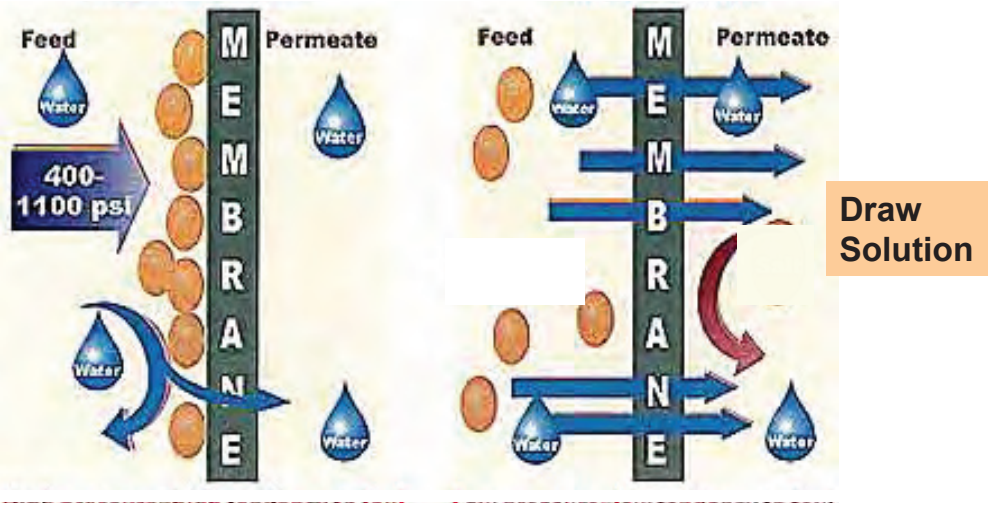


FIGURE 5.10: COMPARISON OF REVERSE AND DIRECT OSMOSIS
(COURTESY, MENACHEM ELIMELECH, PHD, YALE UNIVERSITY)

The challenge in developing a forward osmosis system is to separate the pure water from the draw solution. The ideal characteristics of a draw solution for desalination are

- Highly soluble solution to generate high osmotic pressure gradient;
- Recoverable and recyclable solution; and
- Soluble species that do not pass through the membrane

For the draw solution, Professor Elimelech has proposed using ammonium salts (ammonium bicarbonate, ammonium carbonate, and ammonium carbamate) that are formed by dissolving ammonia and carbon dioxide gas in water at room temperature. Thermal decomposition is then used to separate and recover the ammonia and carbon dioxide from the product water. At atmospheric pressure, the decomposition occurs at about 60°C but can be accomplished at lower temperatures by reducing the pressure. The complete ammonia-carbon dioxide forward osmosis desalination process is shown in Figure 5.11.

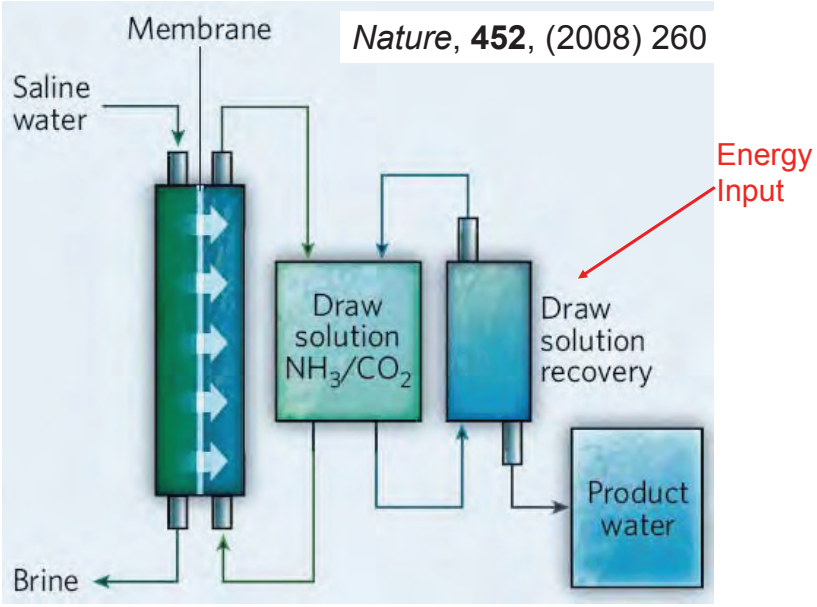


FIGURE 5.11: AMMONIA-CARBON DIOXIDE FORWARD OSMOSIS DESALINATION PROCESS (FROM *NATURE*, 452 (2008) 260 AND DESALINATION, 174 (2005) 1-11)

Temperature as low as 40°C (104°F) can be used to drive the desalination process, making it an attractive candidate for utilizing the low-quality waste heat available from power plants. While the process is more efficient at higher temperatures, as shown in Figure 5.12, for a 1 M draw solution concentration, the availability of large quantities of low-quality heat that is currently being "dumped" into the atmosphere makes this an attractive process for coastal locations that have limited supplies of freshwater.

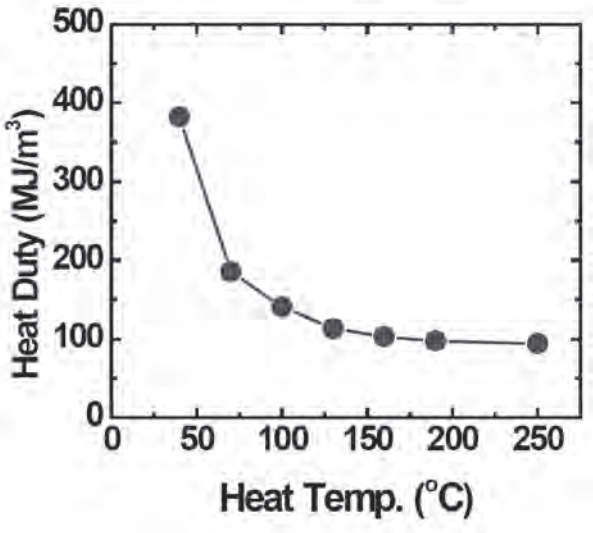


FIGURE 5.12. HEAT DUTY VERSUS TEMPERATURE FOR 1 M AMMONIA – CARBON DIOXIDE DRAW SOLUTION
(COURTESY, MENACHEM ELIMELECH, PHD, YALE UNIVERSITY)

The energy efficiency of low-temperature vacuum forward osmosis (FO-LT) compared to other desalination processes such as multi-stage flash distillation (MSF), low temperature multi-effect distillation (MED-LT), thermal vapor compression multi-effect distillation (MED-TVC), reverse osmosis (RO) is shown in Figure 5.13. Also shown is the fraction of energy required that is electrical power versus thermal energy. As can be seen in the figure, forward osmosis requires significantly less energy than the other technologies. Furthermore, most of the energy required is low-quality thermal energy currently being thrown away by power plants that could be purchased at minimal cost.

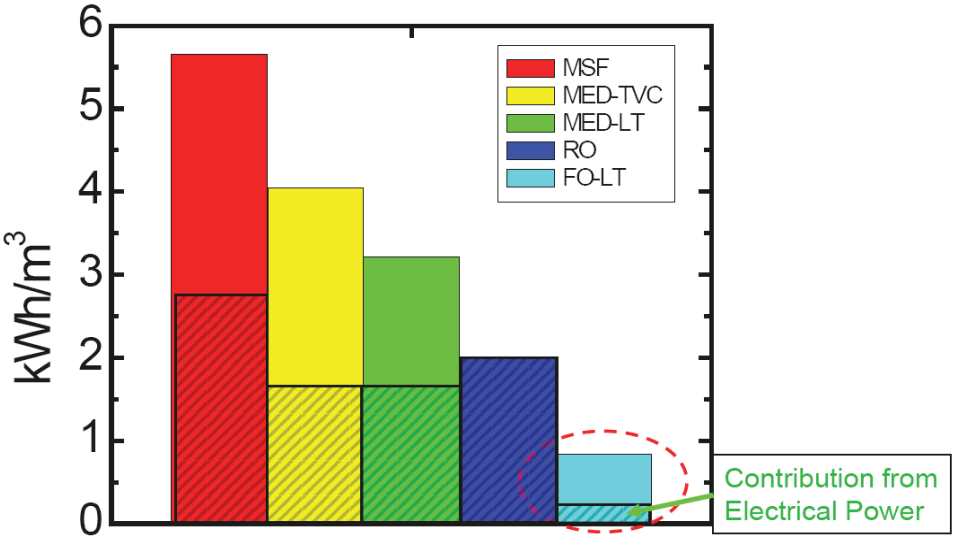


FIGURE 5.13: EQUIVALENT WORK COMPARISON FOR MULTI-STAGE FLASH DISTILLATION (MSF), THERMAL VAPOR COMPRESSION MULTI EFFECT DISTILLATION (MED-TVC), LOW TEMPERATURE MULTI EFFECT DISTILLATION (MED-LT), REVERSE OSMOSIS (RO), AND LOW TEMPERATURE FORWARD OSMOSIS (FO-LT) SEAWATER DESALINATION TECHNOLOGIES (FROM *DESALINATION*, 207 (2007) 370-382)

5.4 FEASIBILITY OF USING WASTE HEAT FROM UNDERGROUND TRANSMISSION CABLES

The study committee also investigated whether underground electric transmission lines might be a resource for scavenging waste heat. Electrical resistance losses are well known, but now that higher voltage lines are beginning to be encased in underground vaults, a process might be employed to harvest the resistance losses from transmitting electricity through these tunnels. The Study Committee analyzed data for the Middletown to Norwalk underground 345kV line. Based on the expected power transmission and current loading on these lines, Northeast Utilities expects an electric loss of 6W per foot of line. A pre-installation analysis has estimated that the cables could reach a maximum temperature of 60°C. The combination of low energy density (6W per foot will only reach ~ 32kW per mile) and the low maximum temperatures make energy recovery from underground electric cables impractical.

6.0 SUMMARY OF FINDINGS, RECOMMENDATIONS AND CONCLUDING REMARKS

BACKGROUND

Federal Clean Water Act regulations for protecting fisheries are requiring electricity generating facilities to evaluate best available technologies to minimize thermal releases and entrainment and impingement of fish eggs and larvae. The general trend in the United States has been for new facilities to install dry cooling towers or wet cooling towers to reduce impact on fisheries. Depending on the outcome of several court cases, there may be increased regulatory pressure for existing facilities to replace once-through cooling systems with wet or dry cooling towers. Wet and dry cooling towers will reduce the adverse impact of once-through cooling systems on fisheries, but wet systems still have environmental impacts such as water consumption and wastewater discharge, drift (small water droplets entrained in the air that are carried out of the tower), and visible plumes. They can also be visually obtrusive. In addition, wet cooling towers reduce the efficiency of the power plant, thus increasing fuel consumption and air emissions. Dry cooling towers do not impact fisheries, but they require about twice the land area. Also, dry towers further reduce the plant's efficiency compared to wet towers because of the higher turbine backpressure. This impact is greatest during the hottest periods of the year when demand for electricity is the greatest, resulting in a greater need for peaking units. As with wet towers, the reduced efficiency results in higher fuel consumption and correspondingly higher air emissions. Noise from air-cooled systems is comparable or greater than wet cooling towers unless low-noise fans are installed.

Whether using once-through cooling, wet cooling towers or dry cooling towers, the waste heat from the process must be transferred either to a water body or to the atmosphere. The Study Committee believes that the issue of the beneficial use of waste heat should be readdressed to determine how to best transform this waste product into a valuable commodity. Considering that the amount of energy that goes unutilized (i.e., wasted) by electricity generating facilities is about equivalent to the energy content of the $3.8 billion worth of fossil fuels consumed by the residential, commercial, and industrial sectors in Connecticut, there is an opportunity to significantly reduce the state's energy usage and air emissions. Beneficial use of waste heat could keep hundreds of millions of dollars from leaving the state, which would have long-term economic and national security benefits since much of this money goes to foreign countries, mainly Canada. This concept is not a novel idea or policy developed by the Study Committee, but one that has been the basis for energy planning in many locales around the world. This is especially the case in Scandinavia where, since the 1970s, waste heat has been used to minimize their dependence on imported fossil fuels. To further substantiate this concept, the Institution of Civil Engineers (ICE) recently recommended that the United Kingdom (UK) "look closely at introducing district heating networks in areas surrounding viable existing power stations in the UK and ensure we assess potential heat capture possibilities for any new facilities." This conclusion mirrors a portion of the Study Committee's suggestions that follow.

CURRENT USE OF ELECTRIC POWER PLANT HEAT IN CONNECTICUT

With minor exceptions, electric power used in Connecticut is produced in central station power plants optimized for high electrical efficiency with technology available at the time of construction. Designing for high electrical efficiency results in heat being available only at low temperatures, which are not well suited for thermal needs (e.g., about 100°F steam turbine outlet temperature).

The Public Utility Regulatory Policies Act (PURPA) was designed to encourage efficient use of fossil fuels by allowing non-utility generators (known as Qualifying Facilities or QFs) to enter the wholesale power market. PURPA designated two main categories of Qualifying Facilities: cogenerators, which used a single fuel source to produce electric energy as well as another form of energy, such as heat or steam; and independent power producers (IPPs).

Cogeneration has not been widely adopted in Connecticut central station power plants. Examples of where it has been successful in using a small portion of the rejected heat are:

- AES Thames:
  - 181 MW Summer Rating
  - 100,000 lbs/hr steam to Smurfit-Stone Container Corporation for recycling 155,000 tons/yr corrugated cardboard
- Algonquin Power:
  - 54 MW Summer Rating
    - 38.5 MW sold to CL&P and the remainder used by Ahlstrom Fiber Components Mill
  - 100,000 lb/hr steam to Ahlstrom Fiber Components Mill

Cogeneration systems providing space heat and cooling have been more frequently used on university campuses. Because of common ownership between power plant and buildings, universities are able to retain 100% of energy savings; they typically have a long investment horizon and own the electrical distribution system (therefore avoiding issues associated with a utility franchise). Examples in Connecticut include the University of Connecticut and Yale University. Urban heating and cooling systems have not been used extensively in Connecticut, with Hartford Steam being the only large-scale heating and cooling system. This system serves the capital area, downtown, and south end (Hartford Hospital). In addition, there is minimal application of combined heat and power units that provide power and heat to individual buildings, with some of these units being fuel cell power plants funded by the Connecticut Clean Energy Fund.

Although intended to be an environmental statute, a primary effect of PURPA was to introduce competition into the generation sector of the electricity marketplace. In 1992 Congress passed President George H.W. Bush's Energy Policy Act (EPACT), which opened access to transmission networks to non-utility generators. EPACT further facilitated the development of a competitive market by creating another category of qualifying facilities known as Exempt Wholesale Generators (EWGs), which were exempted from regulations faced by the traditional utilities. To assist in the implementation of PURPA and EPACT, FERC issued Order No. 888 and Order No. 889 in April 1996. The two orders provided guidelines on how to open electricity transmission networks on a nondiscriminatory basis in interstate commerce.

As a result, the electric power industry is changing from a structure of regulated, locally or regionally vertically integrated monopolies, to one where separate companies focus on a different aspect of a core commodity supply. For example: Dominion Resources Inc. and NRG are in the electricity generating business, Connecticut Light and Power and United Illuminating are in the electrical transmission and distribution business and Connecticut Natural Gas, Southern Connecticut Gas and Yankee Gas are in the natural gas distribution business. This structure is not conducive to energy districts, where the challenge is to increase the integration of thermal and electricity generation, transmission, and distribution. In addition, the companies involved with electricity generation have a simple, limited customer structure and utilizing the power plant heat would introduce additional customers (and many customers in the case of district heating system) which is inconsistent with the project financing business models now used in this industry.

Use of distributed generation at individual buildings introduces economic penalties associated with the economies of scale for the smaller plant ratings, but overcomes many of the business, regulation and infrastructure cost problems of district heating and cooling systems. CHP with distributed generation systems should be considered as an alternative to central station CHP plants, particularly in areas with low building density or where creating the distribution infrastructure presents significant problems.

The challenge for Connecticut is to develop the infrastructure and policies that enable rejected heat to be cost-effectively utilized near the generation plant or transported to end-users where it can be beneficially used to reduce the state's dependence on fossil fuels. To accomplish this, what is required is a paradigm shift in which the state's electricity and thermal requirements are considered as a whole instead separately.

Beneficial Uses of Power Plant Waste Heat

The committee considered technical viability, efficiency impact, economics, national security, environmental impact, regulatory impact, and utilization implications when examining potential use of waste heat. The findings for the waste heat applications reviewed in Chapter 5 that have potential application in Connecticut versus the above criteria are summarized in Table 6.1. The findings for the applications that are still in the development phase or would likely not be well suited for Connecticut (osmotic heat engine, fish farms, hydrogen production, and desalination) are summarized in Appendix D.

For all of the applications listed in Table 6.1, it is not expected that all waste heat can be utilized 24/7 and 365 days a year. In contrast, many applications have diurnal and seasonal peak heating loads and, thus, a heat rejection system must still be in place for proper operation of the electricity generating facility. Furthermore, given that the savings are quite significant, a long-term approach should be taken. However, many power plants in Europe and, to a more limited extent in the United States, do find economic uses for the heat. The high population density and reasonable concentration of businesses/industries in Connecticut are important factors for achieving favorable economics for the use of power plant heat.

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
Increasing Electricity Efficiency - Kalina, Organic Rankine, and Cheng cycle applied to gas turbine peaking plants	Established and Proven Technology Kalina - Small scale ; Organic Rankine - Many applications; and Cheng - Limited applications	All cycles – No increase in efficiency for steam or combined cycle plants Increased quality of waste heat and increased electrical efficiency when added to a gas turbine plant as follows: Kalina: ~5 to 25%; Organic Rankine: ~8-20%; Cheng: ~20%-40%	Potentially less expensive than equivalent combined cycles	Efficiency Increase provides potential for reducing imports of energy	Kalina -Potential problem with ammonia vapor; Cheng – Large consumption of water with visible steam plume	Cheng – Water consumption and steam plume	Likely only cost effective if these gas turbine plants were needed for base load operation

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS (CONTIONUED - PAGE 2)

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
Combined Heat & Power (Cogeneration) – Power, District Heating and Cooling Facilities	Established and proven technology	Increased overall efficiency (~80% max.) Reduced electrical efficiency to provide hot water / steam at required operating temperature	Retrofit of power plant required to take steam off at required temperature Infrastructure needed for hot water and cooling loops	Significant increase in efficiency that replaces fossil fuels currently used for space heating applications	Reduced emissions including green house gases	Policy changes required to provide infrastructure for hot water and cooling loops in high population areas. Operating decisions must be modified to include waste heat use.	Infrastructure required to transport heat to users; Policy and business model that includes long-term electricity contracts and development of organizations to purchase power plant heat and distribute it to multiple customers; Education to enable power plants to be built in high population areas

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS (CONTINUED - PAGE 3)

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
Industrial Ecology Park	Established and proven technology	Increased overall efficiency (~80% max.) Reduced electrical efficiency to provide hot water / steam at required operating temperature for industrial application	Good symbiotic relationship between electric generating facility and industry and service providers should reduce costs Reduce need for regulatory compliance should reduce overhead costs	Significant increase in efficiency that partially replaces fossil fuels currently used for steam generation and hot water	Reduced emissions including green house gases	Policy changes required to provide incentives for development of industrial ecology parks. Operating decisions must be modified to include waste heat use.	Infrastructure required to transport heat to users; Opportunity for long-term electricity contracts: Policy and business model for many thermal customers

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS (CONTINUED - PAGE 4)

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
Greenhouses	Established Technology	Increased efficiency during winter time when waste heat is required. Retrofit not required if greenhouse located adjacent to power plant Improved greenhouse economics if power plant can provide low cost electricity for artificial light	Greenhouse heating is about 10-20% of operating expenses, depending on the type of crops produced. Low-cost waste heat can reduce greenhouse heating expenses to some extent depending on temperature of waste heat provided. Access to inexpensive electricity for artificial light increases the type and value of crops that can be grown during the winter months	Increases production of locally grown food and stimulates local economy	Locally grown foods reduces the fuel needed to transport vegetables long distances during the winter months Reduction in greenhouse gas emissions for reduced transportation requirements	No regulatory changes required	Land area required to absorb significant amounts of heat; Market for greenhouse products

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS (CONTINUED - PAGE 5)

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
Algae Farms	Significant research effort to make algae farms a viable source for producing biofuels	Algae farms utilize the carbon dioxide and waste heat from stack emissions. Additional waste heat may be required to maintain photo-biorectors at about 30 °C in the winter and at night time	Provides local production of biofuel and related jobs to grow and process the algae	Potential to significantly reduce importation of fossil fuels	Recycling of carbon dioxide reduces greenhouse gas emission	Closed systems likely to have less regulatory issues than open systems. Use of natural strains of algae also will reduce regulatory issues	Further proof oftechnology; Business model for algae farm industry; No significant reduction in cooling water requirements for nuclear plants unless atmospheric CO_2 is a viable alternative Significant land requirements

TABLE 6-1. SUMMARY OF WASTE HEAT APPLICATIONS (CONTINUED - PAGE 6)

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation	Utilization Implications
LNG Vaporization	Proven Technology Need to co-locate power plant and LNG receiving station	Up to 20%+ increase in electrical efficiency through use of Organic Rankine cycle Eliminates need for burning of natural gas to vaporize LNG	Economics need careful assessment	Possible increased security risks as Mideast gas replaces gas from Canada	Other LNG vaporization plants have met environmental requirements	Same regulation requirements as for siting LNG vaporization station	Siting of LNG terminal and vaporization station New gas supplies associated with fracturing shale reduces incentive to import LNG

The applications were then analyzed to see if they could be integrated into an existing power plant without changes (i.e., use water between 60°F and 100°F) or whether modifications would be needed to provide higher temperature hot water and/or steam.

1. No changes to retrofit existing power plants

- **Algae Farms**

  Algae farms for producing biofuel are a very promising technology for utilizing waste gases and heat from stack gas. Fuel production per acre is much higher than for other biofuel sources and does not require land suited for agriculture. Currently, there are no commercial algae farms, but pilot testing of closed system photobioreactors that utilize the carbon dioxide, nitrogen oxides, and waste heat from fossil fuel power plant stack gases have produced encouraging results. Because the biofuels would be produced using carbon dioxide from fossil plant stack gas, overall production of greenhouse gas would be reduced and Connecticut would have an indigenous supply of transportation fuels, improving energy security, increasing jobs and keeping some of its energy expenditures within the state. Data from limited pilot testing where 40% of the carbon dioxide from a fossil power plant's stack gas is converted to algae biomass indicate that the total production of biofuels from Connecticut's baseload power plants (i.e., 875 MW from Bridgeport Harbor #3, AES Thames, Milford Power #2, and South Meadows #5 and #6) would be 30 million gallons per year, which is 15% of our annual transportation fuel consumption. This would require about 7,000 acres of land assuming an algae growth rate of 100 g/m2/day. This would also reduce greenhouse gases by over 1.8 million tons per year.

  The concentration of carbon dioxide found in the atmosphere is too low for the algae yields required to make a system economically feasible. Therefore, it is not practical to use heat from Millstone nuclear power plant unless a cost-effective carbon dioxide concentration process can be used to increase the concentration of atmospheric carbon dioxide from about 0.04% to between 2 and 14% carbon dioxide.

  The laboratory and pilot studies that were reviewed do not utilize waste heat from the steam condenser, but it may be beneficial for additional heat to be supplied during cold weather months and at night in order to maintain a temperature of about 85°F to 90°F. Although it is unlikely that algae production would reduce concerns associated with once-through cooling systems, an indigenous fuel supply for transportation, and reduction of greenhouse gases both represent significant benefits.

  The potential benefits of this application warrant consideration of a demonstration project to be conducted in Connecticut to better determine the application's economic viability.

- **LNG Vaporization**

  Excellent potential for increasing electricity generation and plant efficiency because the heat is rejected at the low temperatures consistent with gasifying liquefied natural gas. However, a liquefied natural gas terminal for Long Island Sound was just rejected after considerable opposition from Connecticut and New York, and it is unlikely any plant would be considered in the foreseeable future.

- **Heating Greenhouses**

  Floor heating for greenhouses is typically designed for 120°F - 140°F hot water, but could be designed to use 100°F water. On average, greenhouses use about 0.6 to 1.0 gallons of heating oil per square foot per year. Assuming an electrical efficiency of about 33% for a simple cycle nuclear plant (e.g., Millstone), about 10 to 16 acres is required per MW of electricity generated (i.e., 2 MW heat rejected for each WM electricity generated). The land area required would be reduced by 50% for a combined cycle plant (e.g., Lake Road) that has an electricity efficiency of 50% (i.e., 1 MW of heat rejected for each MW of electricity generated).

  If designed for peak capacity of 4.6 million BTU/hr/acre (33 gallons heating oil/hr/acre) for a 60°F temperature difference between the greenhouse and outside air temperature, 1.5 acres of land would be needed for each MW of electricity generated for a simple cycle (e.g., Millstone) and about 0.75 acres for each MW of electricity generated for a combined cycle power plant (e.g., Lake Road).

  Since the peak heat load is reached only for a relatively short time, the design of a greenhouse to absorb power plant heat would be somewhere between the average and peak requirement conditions. Modifications to the cooling system to provide the best temperature conditions during cold weather may require equipment changes in the plant. Regardless of the design, absorbing heat from a large generating plant would require significant amount of land and the total greenhouse area would represent a significant addition to Connecticut greenhouse capacity which may not be supported by market demand. For example, Millstone would require 5,000 to 10,000 acres compared to the approximately 200 acres of greenhouses currently in Connecticut. Furthermore, the amount of heat needed in higher temperature portions of the year, when environmental effects of heat discharge to once-through cooling systems are most severe, would be low and not much alleviation of the adverse effects would be achieved. However, should use of power plant heat and other factors make greenhouse food production attractive, this application may make a significant contribution to reducing the environmental effects of power plant cooling.

- **Kalina, Organic Rankine and Cheng Cycle**

  These cycles can be added to gas turbine plants with little modification but implementation of these cycles would require significant modifications to the existing steam power plants and would not increase efficiency for either steam plants or combined cycle plants.

- **District Heating and Cooling**

  Heat is available at temperatures around 100°F while domestic hot water requires temperatures around 120°F -140°F and space heating using hydronic systems requires heat at temperatures around 160°F - 200°F. Therefore, district heat and cooling requires modification of existing plants

- **Industrial Ecology Parks**

  Industrial or commercial process water can be preheated to 90°F or 95°F to reduce boiler fuel requirements. The industrial facility would need to be located close to the power plant and analysis would need to be conducted to determine if it were economical to construct the infrastructure needed to transport the waste heat.

2. Modifications to existing plants to provide higher temperature heat

When considering each of the following applications, the power plant efficiency will be reduced, resulting in lower MW rating due to selling of steam that otherwise would have been used to generate electricity. This capacity loss must be replaced by existing facilities operating at a higher capacity factor or by the construction of new facilities. The benefit to this modification is higher overall thermal efficiency (i.e., more of fuel's energy is utilized). Another important benefit would be that any steam extracted for the power plant for use in steam adsorption chillers would reduce the peak electricity demand during the summer. This factor could favorably impact the planning for future electricity peaking units.

- **Industrial Ecology Parks**

  Co-located industrial facilities could be used to absorb the heat. Several Connecticut generating facilities have available land. A search for industrial customers for "over the fence" heat could be conducted to determine whether the capital expense, heat cost and land availability are consistent with sale to industrial customers. The benefit of this approach is that a significant amount of thermal energy can be utilized with minimal amount of infrastructure cost needed for piping since the application will be near the electricity generating facility.

  This type of cogeneration system has not been widely adopted in Connecticut, but examples of facilities where it has been successful with a small portion of the plant heat are AES Thames and Algonquin Power. These facilities provide steam to one dedicated customer, in addition to generating electricity.

  This application requires that an economic development effort be integrated with plant siting and approval plans and recognition of heat use in decisions regarding plant operation.

- **District Heating and Cooling**

  District heating and cooling systems are not new technology. The largest district energy systems in the United States, as reported in the 2009 Member Survey of the International District Energy Association, include:

1. Con Edison Steam Operations, New York City serving 6,546,229 square feet of buildings;
2. NRG Energy Center, Minneapolis serving 5,898,886 square feet of buildings; and
3. Detroit Thermal, Detroit serving 5,724,932 square feet of buildings.

In Europe, many countries have a high penetration of district heating and cooling, with Denmark being a prime example. There, localized waste-to-energy power plants are incorporated into district heating and cooling. District heating requires comprehensive planning to ensure the proper density, distribution corridors and coordinated government action.

For heating, temperatures of 160°F - 200°F were necessary to maintain temperature in a poorly insulated building and to allow for losses during transport. However, lower temperatures are now possible in tighter, more efficient buildings. Typically, hot water can be piped about 12 miles from the centralized generating facility.

Steam absorption chillers can provide water at between 40°F - 60°F. For example, a singe-stage absorption chiller operating at 12 psig steam or 270°F hot water has a coefficient of performance of 0.71, while a two-stage absorption chiller operating at 115 psig steam or 370°F has a coefficient of performance of 1.21 (Trane Horizon Absorption Series Chillers). Because of the lower temperature difference between the desired indoor air temperature and the chilled water, the typical distance that chilled water can be piped is about 4 miles.

- **Kalina, Organic Rankine, and Cheng Cycle**

  The application of Kalina cycle equipment to an existing steam plant requires extracting steam from the steam turbine to heat the Kalina ammonia-water working fluid. This steam extraction reduces the turbine output and efficiency. Because of the properties of this fluid, condensing temperature can be changed, perhaps providing somewhat higher temperature waste heat with little or no penalty on electrical efficiency.

  The Organic Rankine cycle (ORC) and Cheng cycles are more suitable for using the waste heat from gas turbine power plants. Similar to the Kalina cycle, however, the ORC could use extraction steam for heating the working fluid and then condense at a higher temperature. The overall electrical efficiency would be lower than with the Kalina cycle.

  Similarly, in a Cheng cycle, extraction steam could be sent to the gas turbine. But this would be more of a peaking system and would defeat much of the advantage of this cycle in that the gas turbine waste heat is not used regeneratively in the cycle. This waste heat could be used to raise process steam or hot water for heating, but the viability of this scheme would have to be established as there are other, more effective methods to attain this end.

RECOMMENDATIONS

To meet this challenge, the following first steps are suggested to begin the paradigm shift to integrating electricity and thermal requirements.

1. Request for proposals for new electricity generating capacity should require that electricity and thermal generation be integrated into the design and operation of the new facility.

   This policy would likely require that new electricity facilities be located near high population centers and industrial parks. Typically, power plants are sited near high voltage transmission lines and have easy access to fuel supply (e.g., natural gas pipeline, port or railroad). The new policy constraints would likely encourage "smart growth" development. For example, new electricity generating facilities would be located on "old" or underutilized power plant sites, or possibly brownfield sites, that are in high population centers.

2. The best opportunity that the Study Committee identified to demonstrate the benefits of combining electricity generation and district heating and cooling is to connect the CRRA South Meadow waste-to-energy units to export steam to the Hartford heating and cooling loop. The expected economic and societal benefits include:

   - Increase in energy utilization of CRRA South Meadow waste-to-energy units from about 25% to over 50%
   - Simple payback of about 5 years
   - Reduce impact on fisheries
   - Reduce fossil fuel usage
   - Reduce air pollution and carbon dioxide emissions

   One approach to obtaining these benefits is to reconfigure the CRRA power plant to provide 150 psig steam via new transmission piping that connects CRRA to the existing Hartford Steam Company (HSC) Downtown District. This would largely replace the costs and air emissions from the natural gas and oil currently fueling HSC's Columbus Avenue plant. The Metropolitan District Commission (MDC) is about to start a major sewer piping replacement project which will require major excavation of Hartford streets. Constructing the heat transmission piping in parallel offers great potential cost savings, and thus merits investigation. The CRRA steam export transmission run would have to be brought to the HSC Columbus Avenue plant, as it is the hub of the Downtown District and where the major steam turbine chillers are located. A likely route would be to parallel the I-91 right-of-way, possibly running some above ground or suspended beneath elevated highway segments. An alternative might be to cross Colt Park and route to intercept the South End District at Hartford Hospital, connecting new customers, and extending along Maple Avenue / Main Street, and then interconnecting to the Downtown District—ideal if HSC steam distribution is large enough to backfeed to the Columbus Avenue central plant.

An additional synergy of the MDC project and a CRRA steam service to HSC is that it affords a major opportunity for recapitalization of the aged HSC steam infrastructure. The Downtown District currently distributes steam with no return of condensate, yet the majority of customer buildings now have hydronic heating and can accept hot water. Energy and water conservation could be achieved through conversion to hot water. There is also potential for HSC to increase the number of connected buildings by appropriately selected new street routings in concert with the MDC project evolution.

Supplying HSC's Capitol District from CRRA steam would be dependent upon whether the Downtown District gets converted to hot water; otherwise, steam would have to the extended to the CDECA plant, such that it would provide the energy for the existing hot water system and minimal steam chiller capacity.

3. Initiate an algae farm demonstration project at the University of Connecticut cogeneration power plant. The project should evaluate the cost and yield of growing algae using the stack gases from a natural gas combined cycle power plant in comparison to an algae farm using nuclear power plant condenser reject heat: (1) with carbon dioxide concentrated from the atmosphere via an air extraction process; and (2) from another non-fossil fuel CO_2 source such as waste water treatment plants. The results could then be used for determining the viability of using this type of process at a nuclear power plant such as Millstone.

4. Provide that facilities that convert to a CHP mode of operation or new CHP plants and utilities be allowed to pursue long-term purchase contracts for selling electricity to the grid or to each other. Not only would this encourage facilities to consider cogeneration as opposed to business as usual, but it will allow them to better manage their facilities. With long-term contracts, CHP facilities would not have to bid their electricity generation each day and would manage load based mainly on the varying demand of their thermal customers. Without long-term contracts, the daily bidding significantly increases the complexity of operation for these types of facilities. This issue came to the Study Committee's attention when discussing the Algonquin Power's CHP facility. Currently, they have a long-term contract that expires at the end of 2009. Without the long-term contract, they are uncertain if the "open electricity market" is a viable alternative or if they will decrease their electrical output by only generating the electricity and thermal needs of their one dedicated customer, Ahlstrom Mill.

5. To further promote the conversion from electricity only to cogeneration facilities, there is a need to develop a framework for establishing thermal distribution utilities. The business model for electricity generators is based on having only one or very few customers (e.g., CL&P or UI) and not having many individual customers as would be the case if the generator were selling its thermal output directly to each customer connected to an energy district. Therefore, a public or private organization is needed that would buy heat from the electricity generator and sell hot water and/or cooling to the customers connected to the heating and cooling loop.

6. Provide Class I or Class II renewable energy credits for use of rejected heat from electricity generating facilities that otherwise would have been disposed of to the atmosphere or a water body. This would incentivize energy districts for urban areas with high population densities by helping to offset the initial costs of retrofitting the electricity generating facility. Also, this would help increase the use of combined heat

and power plants for individual buildings where centralized energy districts with district heating and cooling are not feasible.

As part of this initiative, develop Waste Heat Enterprise zones around existing and new generation facilities to promote local development that utilizes power plant waste heat as part of a smart growth policy. The boundaries of these zones would be defined by utility master plans. Incentives should be provided to encourage users to connect to the system, especially after their individual mechanical and cooling equipment is reaching its end-of-life. For example, there could be a demand reduction payment given to users that connect to a chilled water supply as opposed to using electricity driven air conditioning and/or the state should consider using rejected heat as an incentive to industrialize areas near/adjacent to generation plants.

Developers would likely be attracted to the Waste Heat Enterprise Zones. Instead of having to invest in mechanical heating and cooling equipment, developers would only need to make a piping connection to the district heating and cooling loop. The advantages are

- Upfront capital savings on purchase of boilers and chillers;
- Elimination of property taxes associated with new boilers and chillers;
- Reduction in insurance premiums;
- Reduction in ongoing boiler and chiller operation, maintenance and labor costs; and
- Additional space available for income generating purposes that was previously occupied by the mechanical equipment.

Additionally, as required by the 2007 US Energy Independence and Security Act (EISA), EPA is in the process of establishing a Registry of Recoverable Waste Energy Sources, as well as a survey to collect data for the registry. When implemented, this will provide valuable information regarding existing and potential waste heat energy recovery opportunities, and will provide companies with access to this information for industrial/business development purposes. It will also serve as a basis for potential waste heat energy recovery projects to qualify for financial and regulatory incentives as provided for in the Energy Policy and Conservation Act (EPCA – Sections 373 and 374), and additional incentives provided for in EISA.

7. Major urban population areas should be encouraged to develop master utility plans so that utility upgrades (i.e., water, gas, electricity, cable, and phone) can be coordinated with installation of district heating and/or cooling loops. If the waste heat cannot be transported to the potential users, it is not possible to even consider using the waste heat. These master plans are intended to set up heating and cooling loops that will allow not only the option of district heating and cooling, but in time a complete sharing of all utilities, including water and communication, in common accessible areaways or utility corridors. Successful implementation would require cooperation between the varying utility companies, policy makers, and public interests.

An example of where a coordinated utility master plan and the above cogeneration policy would have benefited the state is the Kleen Energy Systems facility under construction south of Middletown. As a baseload facility with a 20- year contract with the DPUC, Kleen Energy Systems looked into the possibility of using the waste heat for known Middletown facilities that could directly benefit from the resource. In the course of due diligence, they examined what would be necessary to transport and distribute the waste heat to Middlesex Memorial Hospital, Wesleyan University and others. They studied the most direct route to the possible end-users and determined that the cost of digging and piping the resource was too much to bear by the developers alone. The final economic decision was made to discharge the potential resource as waste heat to the atmosphere in a broad array of cooling towers. In short, the cost, maintenance and energy use of the cooling towers was deemed appropriate. However, it is arguable that the same investment in heat dumping apparatus might have equally well provided the heat transmission and distribution system. Certainly, if a heating and cooling loop were in place, the decision to distribute the waste heat might have been different or the facility would have been sited in a location where the waste heat would have been economically distributed. In either case, the utilization gains would be significant.

8. For those existing facilities located away from population centers, there should also be incentives for promoting cogeneration applications. Development of programs to support specialized uses of waste heat that help the state meet a variety of environmental goals should be considered. While the concept of Waste Heat Enterprise Zones focuses on population centers, in certain cases they should also be a tool for economic development around power plants located in other areas of the state. Two possible examples of this include:

    - The area adjacent to Millstone would be a good location for new industry that could benefit from hot water as well as process water. These essentially free waste products of the Millstone facility could provide a far greater incentive for industrial development than the traditional use of state tax incentives.

    - There may be an opportunity for a large-scale greenhouse to be co-located at the Lake Road power plant. In addition to utilizing the plant's waste heat, the types of vegetables that can be grown are limited by the amount of sunlight in the winter unless artificial light is provided. Under current regulations, Lake Road can sell electricity for artificial lighting directly to the greenhouse only if they are on abutting property. If they don't abut, the greenhouse would need to pay the associated transmission and distribution costs, which in most cases makes using artificial light not a viable option.

9. By their very nature, the Kalina, ORC, and Cheng cycles used with gas turbines lend themselves to meeting variable electric and heat loads. By a combination of varying fluid properties and temperature of heat input in the Kalina cycle, varying heat input into the ORC, and trading steam injection for process steam in the Cheng cycle, these cycles allow rapid variation of electricity and thermal loads with minimum sacrifice of overall energy utilization.

The benefits to integrating electricity generation and thermal needs are the following:

- Reduced energy use, since waste heat from all electricity generating facilities is about equivalent to the fossil fuels utilized by Connecticut's industrial, commercial, and residential sectors.
- Utilizing the waste heat will reduce the approximately $3.8 billion that is spent each year in Connecticut by the residential, commercial, and industrial sectors on fossil fuels imported from out of state and often out of the country.

Utility corridors that bundle all services in a common right of way could provide sound infrastructure to serve Connecticut for many years providing an incentive for in-state business development job creation, and promoting smart growth strategies.

- Reduced air emissions, including carbon dioxide and nitrogen oxides, by burning less fossil fuels.
- Increased national security by reducing dependence on imported fossil fuels.
- Chilled water loops could reduce peak electricity demand, thus reducing the need to make investments in peaking units that run less than 50 hours a year.

CONCLUDING REMARKS

The challenges for implementing the Study Committee's recommendations are not technical, but would require a paradigm shift in Connecticut's energy policy and planning—to consider all energy forms/sectors along with their impacts on the environment and economic development holistically. The potential for beneficial use of power plant rejected heat is significant. The benefits have been demonstrated in several metropolitan areas in the United States and much of northern Europe, particularly Scandinavia, and can also be achieved in Connecticut. However, policy changes are needed to integrate electricity and thermal requirements, and more detailed analysis is suggested to determine the portion of rejected heat that can be practically utilized from Connecticut's power generation plants. The question can no longer be how do we best dispose of the waste heat, but how the facilities can be best designed (new or retrofitted) to beneficially use the rejected heat.

ACKNOWLEDGEMENTS

This study benefited from the cooperation, support and input of the following individuals and the organizations they represent. Their interest and effort in this study are greatly appreciated by the Connecticut Academy of Science and Engineering.

William J. Corvo, JD
President
Wm. Corvo Consultants, Inc.
(for Kleen Energy Systems, LLC)

Menachem Elimelech, PhD
Roberto C. Goizueta Professor of Chemical and Environmental Engineering
Yale University

James L. Fuda, PE
Principal and Senior Vice President
BSC Group, Inc.

Scott Jellison, PE
Chief Operating Officer
Metropolitan District Commission

Richard J. McAvoy, PhD
Professor and Extension Specialist
Greenhouse Crops
University of Connecticut

Michael O'Connor
Manager – Systems and Component Engineering
Millstone Power Station
Dominion Nuclear Connecticut, Inc.

Henry A. Reis
Production Manager
Lake Road Generating Company

Joseph J. Sangiovanni, PhD
Senior Research Fellow, Thermal and Chemical Sciences
United Technologies Research Center

Robert Thornton
President
International District Energy Association

Michael Tracey, PE
Director of Operations
CT Resources Recovery Authority (CRRA)

James A. White
Plant Manager
Algonquin Power Windsor Locks, LLC

Other Participating Companies:

AES Thames, Inc.

Bridgeport Energy, LLC

Lake Road Generating Company, LP

Milford Power

APPENDIX A
THERMODYNAMICS OF POWER CYCLES

Before starting the discussion of the thermodynamics of power cycles, it would be useful to have a summary of the laws of thermodynamics:

"There ain't no such thing as a free lunch."

That pretty much sums up all the laws of nature—whatever one does, some place in the overall scheme of the process, one pays. The basic tenet of good engineering is to minimize the cost in terms of energy, environment and pocketbook.

A thermodynamic cycle occurs when a system working fluid is taken through a series of different states, and finally returned to its initial state. In the process of going through this cycle, the system may perform work on its surroundings, thereby acting as a heat engine. A heat engine acts by transferring energy from a warm region to a cool region of space and, in the process, converting some of that energy to mechanical work such as driving a generator, which then converts the mechanical work to electricity. The usual index used to gauge the "goodness" of a cycle is its efficiency in converting the input heat to output work. Before describing the various power cycles discussed in Sections 2 and 5, there is a basic precept of thermodynamics that applies to all heat engine power cycles, delineating the limits for the maximum efficiency that can be obtained, the amount of work that can be done, and the amount of heat that will be rejected. Note that the fuel cell, while an energy conversion system, is not a heat engine and is limited in efficiency by a different natural law (the Gibbs Free Energy).

In 1824, Nicolas Léonard Sadi Carnot (1796 – 1832) a French physicist and military engineer, proposed his Carnot cycle heat engine. This engine "operates" only with ideal conditions, which cannot be found in actual practice. Nonetheless, the Carnot cycle defines the most efficient heat engine cycle allowed by the second law of thermodynamics. This law states that not all the supplied heat in a heat engine can be used to do work; some must be rejected to the environment.

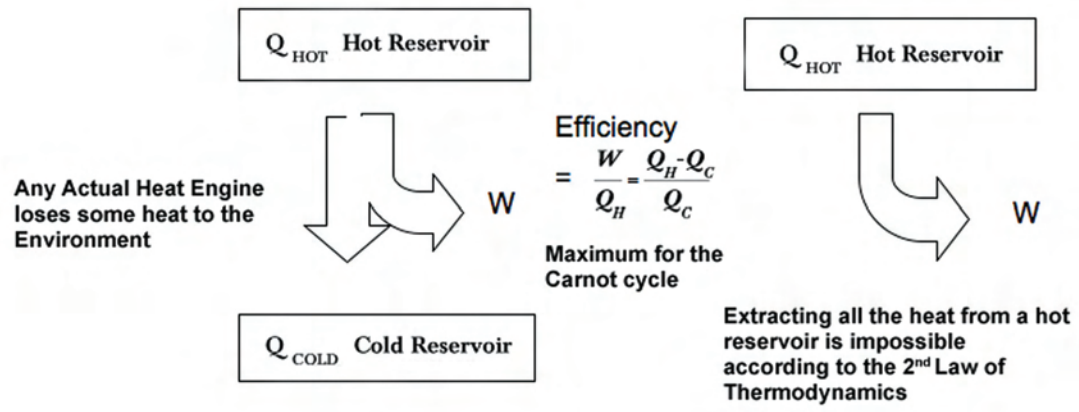


FIGURE A.1: CARNOT CYCLE AND THE SECOND LAW OF THERMODYNAMICS
(W = WORK, Q_H = HEAT EXTRACTED FROM HOT RESERVOIR,
Q_C = HEAT REJECTED TO COLD RESERVOIR)

The Carnot efficiency sets the limiting value on the fraction of the heat which can be so used. This heat fraction can also be represented by the temperatures of the heat source and the heat sink. The conceptual value of the Carnot cycle is that it establishes the maximum possible efficiency for an engine cycle operating between the highest temperature in the system (T_H) and the lowest temperature (T_C). This relationship is shown in Equation A.1.

$$\text{Maximum Cycle Efficiency} = (T_H - T_C)/\ T_H \quad \text{(A.1)}$$

This can also be written as

$$\text{Maximum Efficiency} = 1 - T_C/T_H \quad \text{(A.2)}$$

The temperatures must be "absolute" meaning that absolute zero (0) is the starting point of the temperature scale rather than the more common "0's" used in daily life. On the Fahrenheit scale, absolute zero is -460°F. The Rankine scale begins at zero at absolute zero, so 0°F is equal to 460° Rankine. As an example, applying this equation to the Millstone unit 2 case, steam is generated at about 520°F (980°R or Rankine) and the condenser operates with a steam temperature of 100°F (560°R), which will predict a maximum overall efficiency of

$$1 - 560/980 = 41\%$$

Faced with operating in real world, non-ideal conditions, Millstone 2 and 3 are actually about 33% efficient. However, the maximum achievable efficiency is represented by this temperature difference ratio.

RANKINE CYCLE

The Rankine cycle (Figure A.2) is a thermodynamic heat engine cycle that converts heat into shaft work. The high temperature heat is supplied externally (Q_H) to a closed loop, which usually uses water as the working fluid. The heat supplied, less the fraction converted to shaft work (W_{net}), is rejected at a low temperature (Q_L) to an external heat sink (Note that W_{net} is denoted as W and Q_L is denoted as Q_C in Figure A.1). While what might be considered as the first steam "turbine" was described by Hero of Alexandria in the 1st century, the invention of the modern turbine is credited to Sir Charles Parsons, who in 1884 constructed a 7.5 kW engine. Improvements throughout the years have resulted in present-day machines of over 1,000 MW. Rankine cycle turbines now generate about 80% of all electric power used throughout the world including virtually all fossil fuel, nuclear, biomass and solar thermal power plant.

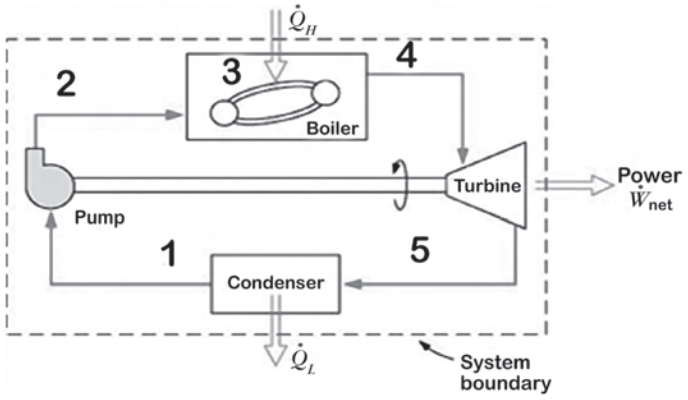


FIGURE A.2: SIMPLE RANKINE CYCLE

In the Rankine cycle, water at a low pressure and low temperature, usually a vacuum around 1 to 1.5 psia at 100°F or so, (Point 1), is sent to a feedwater pump where it is raised to a high pressure that can be as much as 4,500 psi but in older technology turbines is typically around 2,400 psi or lower (Point 2). This high pressure water is generally preheated by the exhaust gases from the boiler (not shown in Figure A.1) before going to the boiler where it is first vaporized (Point 3) and then the vapor—steam—is further heated to a higher temperature, generally around 1,000°F but as high as 1,200°F, (Point 4) using the input heat Q_H. The high temperature, high pressure steam is sent to the turbine where it is expanded (Point 5), both reducing pressure and cooling the vapor while providing work to turn the turbine shaft. The condenser extracts heat from the vapor, changing it back to water and rejecting the heat (Q_L) to an external heat sink.

While Figure A.2 indicates where actions occur in a Rankine cycle, to understand why there is so much heat rejected (so called waste heat) from the cycle, it is necessary to look at a diagram of the way an energy engineer would see the Rankine cycle, Figure A.3. Here, the same points as shown in Figure A.2 are shown on a Temperature – Entropy, or T-S, diagram. Entropy is a governing property of thermodynamics, but for our discussion it does not have to be considered. The diagram shows the Rankine cycle for a power plant operating with maximum steam conditions of 2,500 psi and 1,000°F, typical of older steam plants. An actual T-S diagram for an operating plant would be much more complex, as additional heating takes place in many locations in the cycle using a variety of input sources. For clarity, the pumping of the condensed water (1-2) is exaggerated in this diagram, as the temperature increase would not be as great as indicated. The high pressure water is first preheated, then evaporated (boiled) (2-3), and finally superheated, which in this case means it is heated well beyond its boiling temperature, which at 2,500 psi is 669°F, to 1,000°F (3-4). The superheated steam is expanded from 2,500 psi to a vacuum around 1.5 psia, providing energy to turn a turbine. It is then condensed and sent to the feedwater pump.

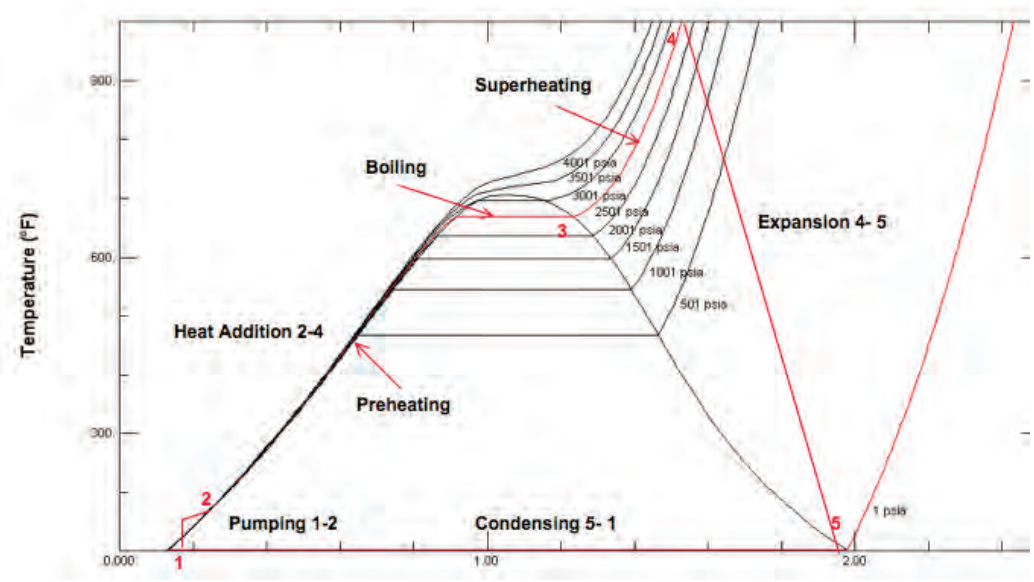


FIGURE A.3: T-S DIAGRAM FOR RANKINE CYCLE POWER PLANT

It takes 1,366 BTU per pound of water to heat the water and convert it to steam at 1,000°F and 2,500 psi. The low-pressure condensation process rejects 1,023 BTU/lb, leaving 342 BTU/lb to do work. Simplistically, the cycle efficiency would be

$$\text{Efficiency} = W/Q_{in} = \text{Work Out/Heat In}) \quad \text{(A.3)}$$

Which for the example would be = 342/1,366 = 25%.

In reality, the cycle is more complex, with heat added from the boiler exhaust gases and regenerative heating using steam extracted from various places in the cycle. Typically, the cycle efficiency at these conditions is over 35%.

The T-S diagram allows us to see that because of the properties of steam, it is necessary to reject heat at a low temperature and in the example at this low temperature, more than 2/3 of the input heat is rejected. If the heat is rejected at a higher temperature, more energy needs to be rejected and less energy is available for expansion in the turbine, which will significantly reduce cycle efficiency. This occurs when the condenser operates at a higher temperature, such as when a cooling tower rather than once-through cooling is used.

As shown in Figure A.3, if the pressure and temperature are high enough, over 3,206 psia and 705°F, the so-called critical point at which water and steam are indistinguishable, there is not a constant temperature boiling but rather the steam temperature simply increases as heat is added. The steam is said to be supercritical. Almost all of the new fossil-fired steam plants being built now operate in the supercritical or ultra-critical (above 1,100°F) range. For example, the newest steam plant being built by American Electric Power for operation in 2012 has steam conditions of 3,515 psia/1,110°F at the turbine inlet. The steam is partially expanded and reheated to 1,125°F. This ultra-critical plant has an estimated efficiency approaching 44%.

BRAYTON CYCLE

The Brayton cycle, Figure A.4, differs significantly from the Rankine cycle in that it is an open-loop system with the heat directly added to the working fluid, air, and exhausted from the cycle without having the fluid recirculated as in a closed-loop system. The first gas turbine used to generate electricity was produced by Brown Boveri (now part of Alstom) in 1939. It produced approximately 4 MW at 18% efficiency. The firing temperature was approximately 1,000°F with an exhaust temperature of about 590°F. Currently the largest gas turbine is the Mitsubishi Heavy Industries M701G2 with an output of 334 MW at an *efficiency* over 39%. The firing temperature is over 2,730°F with an exhaust temperature of roughly 1,090°F.

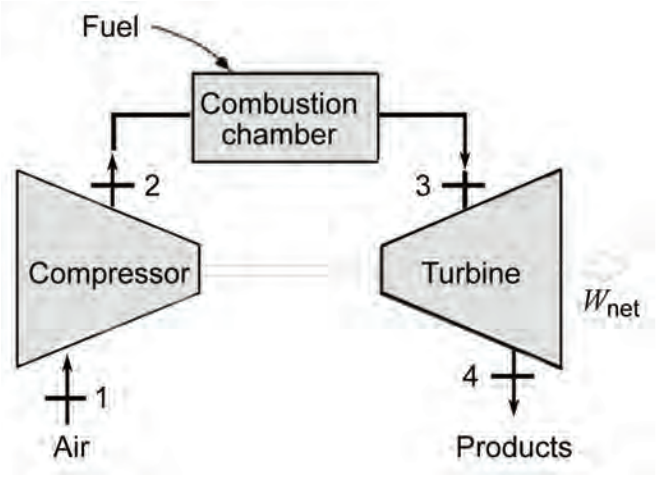


FIGURE A.4: SIMPLE BRAYTON CYCLE

Air at ambient conditions enters the compressor section of the gas turbine Point 1. It is compressed to values from 15-30 times more than ambient, roughly 225 to 450 psi (Point 2). The high pressure air is mixed with fuel, usually natural gas or distillate oil, and combusted to temperatures ranging from 1,850°F to 2,700°F+ (Point 3), the value being regulated by the ratio of fuel to air. The hot, high pressure combustion products are expanded in a turbine doing work and then exhausted to the ambient at pressures near 15 psia and temperatures from 700°F to over 1,000°F (Point 4).

As was the case with the Rankine cycle, we can use the T-S diagram to understand how the various actions affect the "waste heat." In Figure A.5, the T-S diagram shows the ideal Brayton cycle (Points 1-4) and also the more realistic cycle (1-4′), which accounts for losses in the actual machine. The compression of the air (1-2′) results in a relatively large increase in temperature, some several hundred degrees, because it takes more work to compress a gas than to pump a liquid as in the Rankine cycle. The heat addition (2′-3′) is at essentially constant pressure less losses in the combustor but is over a much larger temperature range (say from 300°F to 2,200°F – 2,700°F+) than in the Rankine cycle (roughly 120°F to 1,000°F+). The heat rejection (turbine exhaust 4′) is not at a constant temperature set by condensation as in the Rankine cycle, but at a temperature that is dependent on the pressure and temperature at 3′ (turbine inlet). This temperature ranges from 600°F to as much as 1,000°F higher than ambient, meaning there is a significant amount of "waste heat" that could be recovered for another use.

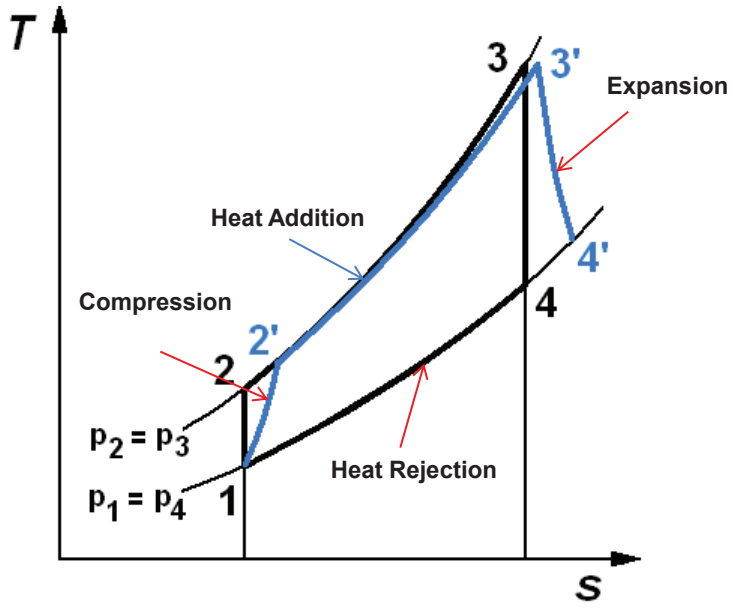


FIGURE A.5: T-S DIAGRAM FOR SIMPLE BRAYTON CYCLE

Gas turbines for power production range in size from 10's of kW to the 324 MW MHI machine previously mentioned. The smaller turbines have efficiencies in the low-to-mid 20% range while turbines larger than 10 MW or so can have efficiencies from the upper 20's to well over 40%.

COMBINED CYCLES

As the name implies, the combined cycle consists of two cycles, the Brayton and the Rankine. In a combined cycle power plant, the hot exhaust gas of a gas or oil fired gas turbine is utilized to generate steam in a separate water/steam cycle. The hot steam is expanded in a steam turbine, providing power to drive a generator (Figure A.6.) The combination of gas and steam turbine cycles allows electric power generation with highest efficiency (Figure A.7).

The efficiency of the combined Brayton cycle gas turbine and Rankine cycle steam turbine can be found using the laws of thermodynamics and the definition of *efficiency* (Equation A.3). In engineering shorthand, efficiency is abbreviated η for convenience so that one arrives at the thermal efficiency of the combined cycle (CC)

$$\eta_{cc} = \eta_{GT} + \eta_{ST} - (\eta_{GT})(\eta_{ST}) \quad \text{(A.4)}$$

where the thermal efficiencies of the Brayton cycle gas turbine and the Rankine cycle steam turbine are η_{GT} and η_{ST} respectively.

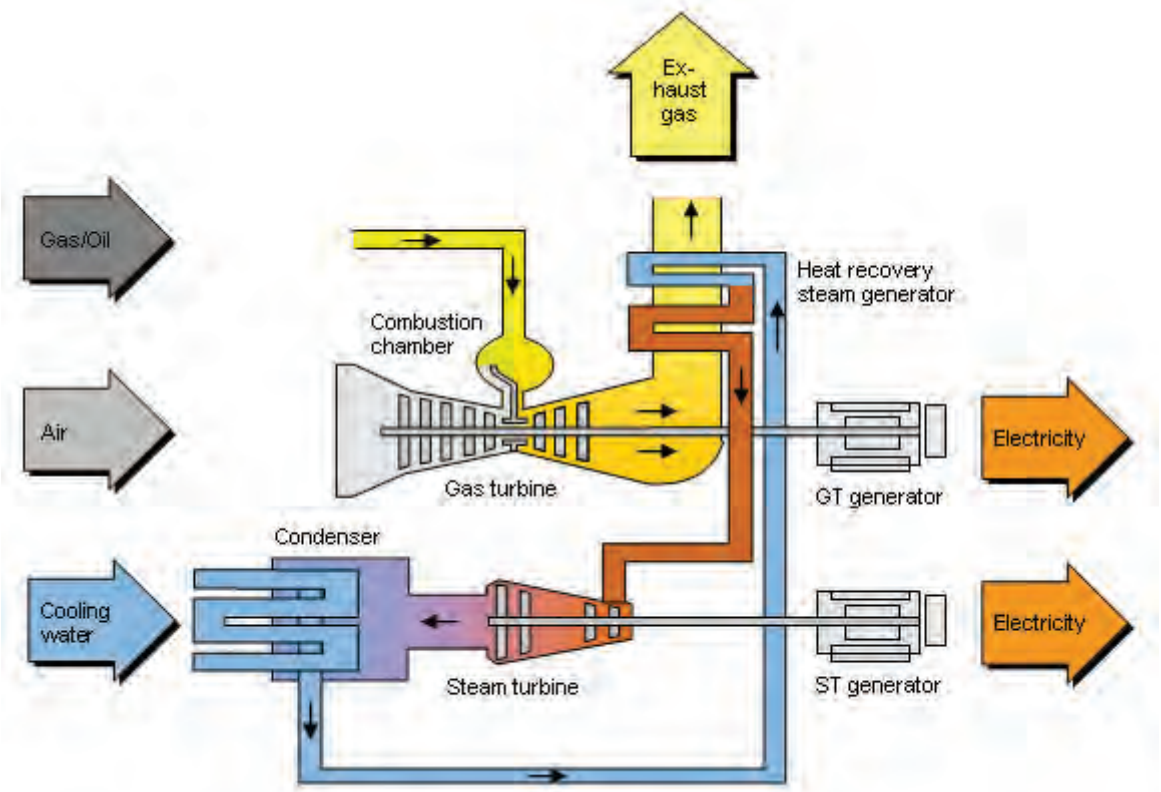


FIGURE A.6: A COMBINED CYCLE SYSTEM
(COURTESY SIEMENS ENERGY)

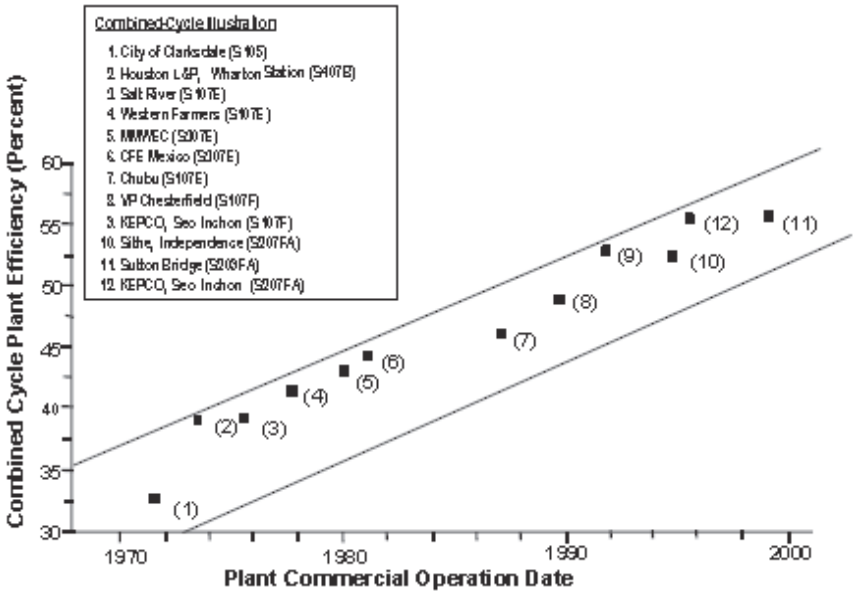


FIGURE A.7: COMBINED CYCLE EFFICIENCIES OVER TIME

(FROM GENERAL ELECTRIC BROCHURE)

The efficiency advantage of the combined cycle can be demonstrated using some typical values for gas and steam turbine efficiencies in Equation A.4. For ease of calculation, round the efficiency value (η_{GT}) for the MHI 701G2 to 40%. A fair value for a Rankine cycle operating at typical combined cycle conditions would be 30%. Thus, A.4 becomes

$$\eta_{cc} = 0.40 + 0.30 - (0.40)(0.30) = 58\ \%$$

In actuality, the efficiency of the combined cycle using the MHI 701G2 is over 59%, larger by far than either of the two cycles working separately.

As efficient as it is, even a combined cycle has waste heat, as illustrated in Figure A.8. Here, using the exhaust from the MHI 701G2 as an example, steam is raised for the Rankine cycle portion of the combined cycle.

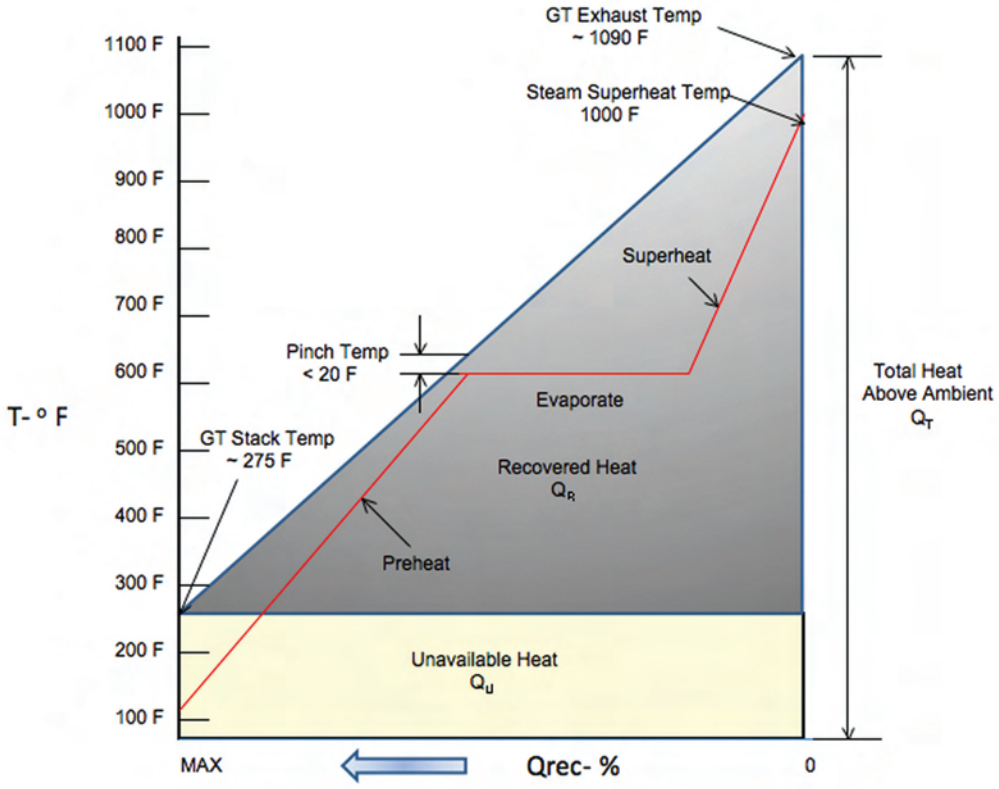


FIGURE A.8: TEMPERATURE VS. HEAT RECOVERED

The exhaust temperature of 1,090°F is high enough to produce 1,000°F steam. However, concerns about the way that the Heat Recovery Steam generator (HRSG) must operate limit the amount of steam that can be produced. The details of HRSG operation are not within the scope of this discussion, but a design factor called the pinch point temperature difference does not allow the exhaust (stack) temperature in the combined cycle to be reduced to an arbitrary lower limit, usually set by corrosion concerns in the metal stack at around 230°-240°F (i.e., identified as unavailable heat in Figure A.6). Nonetheless, in the simple example above, approximately 87%

of the available heat (in the gas turbine exhaust) above ambient is recovered by the steam cycle and converted to electricity at the steam cycle efficiency (>30%).

The three cycles discussed above—Rankine, Brayton, and combined—are the backbone of power generation. However, other methods of converting waste heat to electricity are well known and have been demonstrated at scales large enough to be of interest in the power industry. Three of the more promising are discussed in the following sections.

KALINA CYCLE

The Kalina cycle is a variation on the Rankine that uses a binary fluid, in this case variable mixture of ammonia and water, as a working fluid. The Kalina cycle takes advantage of the properties of the binary to better match the heat available from lower temperature waste heat sources, say less than 700°F. To gain this advantage, however, the resulting power cycle is more complex than the usual Rankine cycle, Figure A.9. In addition, this cycle relies on a much more hazardous fluid (ammonia-water mix) versus the water-steam of the traditional Rankine cycle.

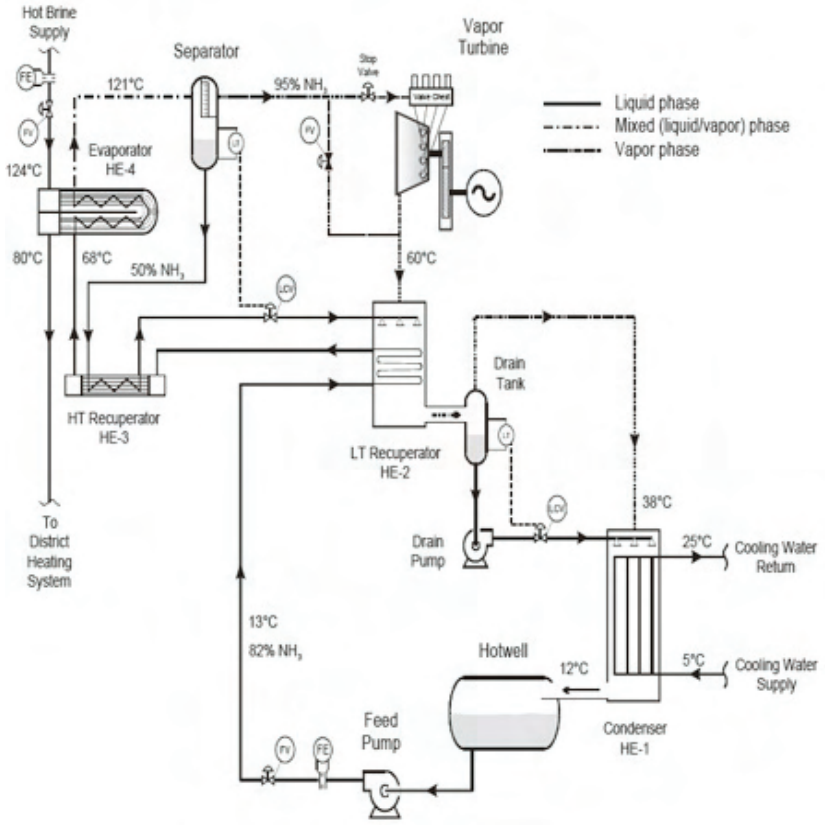


FIGURE A.9: SCHEMATIC OF A KALINA CYCLE
(COURTESY RECURRENT ENGINEERING, KENNETT SQUARE, PA)

The system shown in Figure A.9 takes heat from a low-temperature source, in this example brine at 255°F (124°C), to evaporate the ammonia-water mixture. The cycle includes several separators and heaters that allow the ammonia-water mixture to change the concentration ratio between the two, allowing a change in the temperature at which the mixture boils and condenses to best match the heating and cooling sources. This maximizes the power that could

be generated given the range of heat captured from the brine. The fluid that is boiled and condensed has 82% ammonia/18% water while the vapor that is expanded in the turbine is 95% ammonia/5% water (as steam). In this example, the low temperature of the heat source means that the water fraction would be low, as steam at these conditions has very little energy that could be extracted during expansion in the vapor turbine.

The ability of the mixture to capture more heat from a given low-temperature source than from a pure steam working fluid is shown in Figure A.8. While the scale in Figure A.10 is somewhat exaggerated to demonstrate the point, it can be seen that at similar temperature and pressure, the Kalina cycle captures considerably more heat from the 550°F heat source. Note that at these higher temperatures, the ammonia concentration drops.

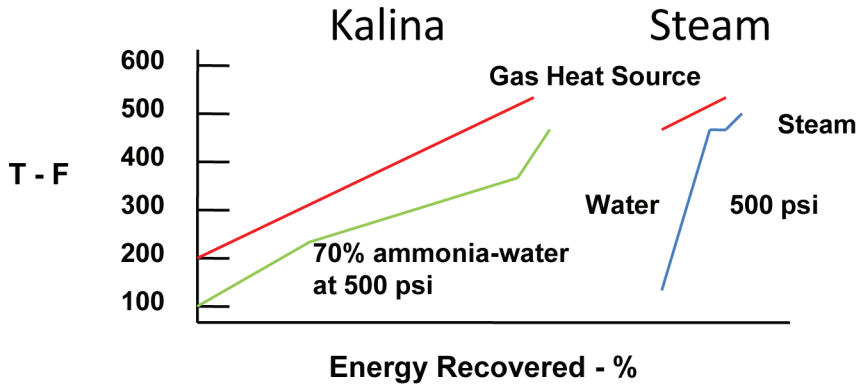


FIGURE A.10: ENERGY RECOVERY BINARY VS. STEAM – LOW TEMPERATURE

As the heat source temperature increases, however, the properties of steam at the higher allowable temperature bring it closer to the binary fluid's ability to capture heat, Fig. A.11.

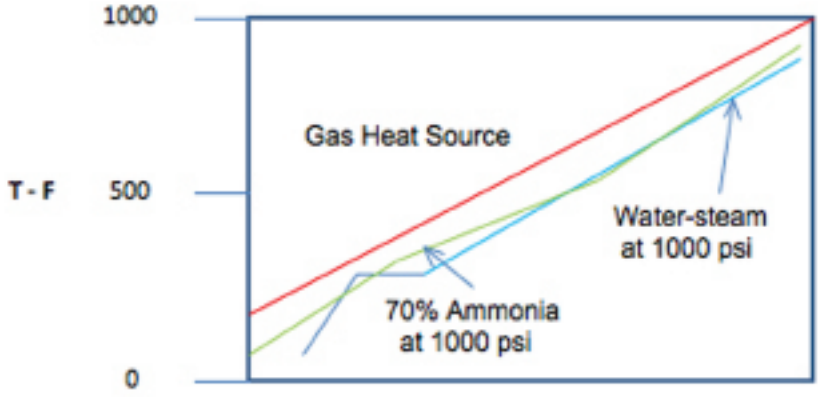


FIGURE A.11: ENERGY RECOVERY BINARY VS. STEAM- HIGH TEMPERATURE

At higher recovery temperatures, the steam recovers nearly as much heat as the binary fluid in a system that should be much less complex and thus, potentially less costly.

ORGANIC RANKINE CYCLE

Another variation on the Rankine cycle is the Organic Rankine cycle or ORC. This system, which is shown in Figure A.12, looks much like the system using water/steam shown in Figure A.2. The system in A.12, however, can use a number of different organic fluids ranging from refrigerants, similar to those used in air conditioners, to hydrocarbons such as butane, pentane and propane as the working fluid. For example, the Pratt & Whitney Power Systems PureCycle® produces approximately 250kW using the refrigerant R245fa, while larger ORC units from Ormat and WOW produce many 100's of kW to over 20 MW using the various hydrocarbons. The choice of fluids is based on the temperature of the waste heat available but has in common properties that allow an Organic Rankine cycle to be effectively operated at temperatures and pressures that in a water/steam system, would result in lower performance and larger physical size for equivalent power. One property of the hydrocarbon fluids that makes them especially attractive is shown in the T-S diagram (for butane) in Figure A.13.

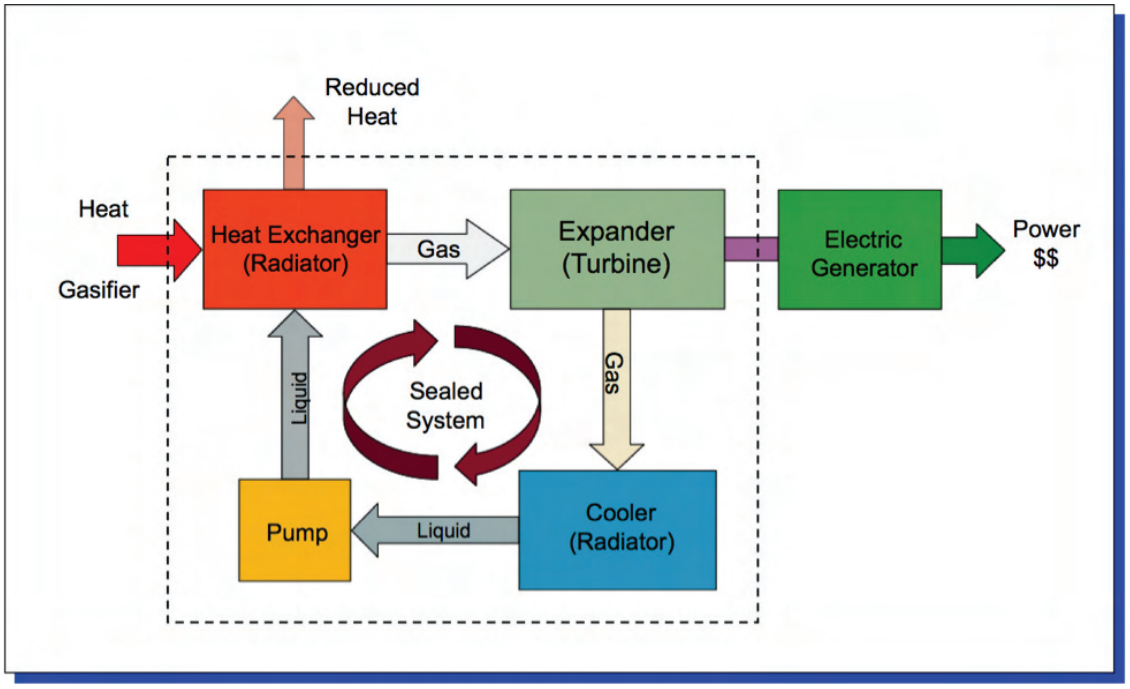


FIGURE A.12: SCHEMATIC OF A SIMPLE ORGANIC RANKINE CYCLE
(COURTESY WOW ENERGIES INC., HOUSTON, TX)

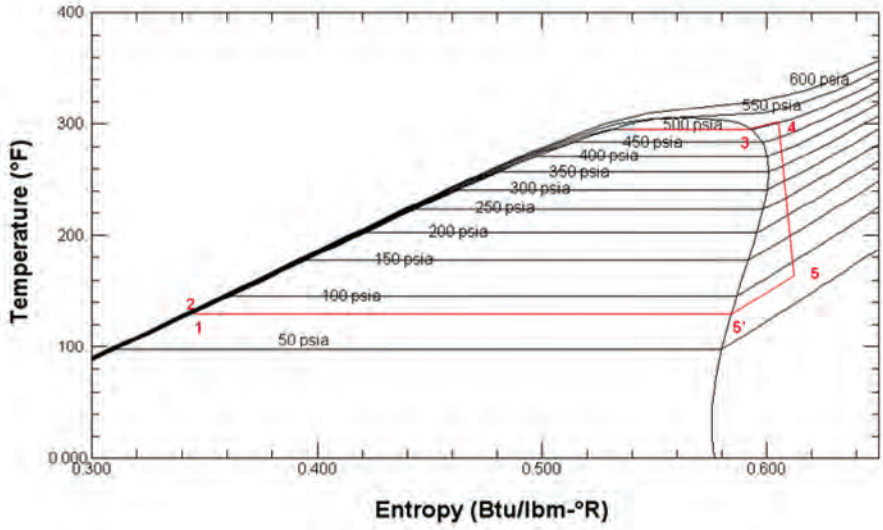


FIGURE A.13: T-S DIAGRAM FOR BUTANE

As with water/steam in Figure A.3, liquid butane at Point 1 in Figure A.13 is pumped to a higher pressure, in this case 500 psi, heated to the boiling temperature and evaporated (Point 3) and then superheated to only 10°F or so above the evaporation temperature, unlike steam, which must be superheated perhaps several 100's°F. This is because, unlike steam, the saturated vapor line actually "bends back" (note left leaning curve) allowing expansion from a low superheat temperature to avoid a creating a "wet" mixture in the turbine exhaust vapor state—the expansion line does not enter the dome (Points 4-5). Thus, the turbine in an ORC system can be much simpler, needing no special design for the last stages that would have been required to operate in a mixed (liquid-vapor) fluid. Note that the condensing temperature is approximately 120°F, 10-20°F higher than the desired steam condensing temperature, which allows an air-cooled condenser to be used. Also required is a cooler to bring the temperature from Point 5 to Point 5', the condensing temperature.

While a Kalina cycle and an ORC could operate between the same temperatures, it is obvious that the ORC is much simpler (Figure A.12 vs. Figure A.7) and has the capability of converting the recovered heat at about the same efficiency. An additional advantage of the ORC is that its operating conditions do not require an operating engineer, unlike steam, and many ORCs run unattended for long periods.

CHENG CYCLE

The Cheng cycle is a variation of the combined cycle in that steam is generated in a HRSG in the gas turbine exhaust. There is no Rankine cycle however; instead, the steam is injected into the gas turbine or used as process steam, or both. (Figure A.14)

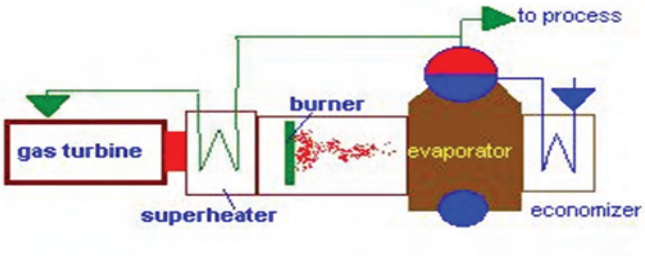


FIGURE A.14: CHENG CYCLE SCHEMATIC
(COURTESY VIS GANAPATHY, CONSULTANT, CHENNAI, INDIA)

The Cheng cycle consists of a gas turbine capable of being injected with a large amount of superheated steam (from 10% to 15% by mass of the exhaust flow) and a HRSG that can generate both saturated and superheated steam with additional firing. The ratio between amounts of superheated and saturated steam is variable depending on use of the steam. Injection of high temperature, superheated steam increases the electrical power output as more fluid (steam and air) is processed within the gas turbine (because of both the increased mass flow and higher specific heat). When process steam is desired, the amount of superheated steam being generated is decreased. This allows a wide range of electrical and process steam demands to be met using this concept. It is also simpler, with fewer components compared to a combined cycle.

In practice, the additional mass flow and higher specific heat of the steam/air mixture increases power and efficiency. The thermal efficiency increases by over 20% and the power increases by as much 70%, depending on turbine operating conditions. Steam conditions can be matched to gas turbine loads, keeping the efficiency nearly constant over a wide range of operation. Performance of the Cheng cycle indicates that the power output and efficiency remain essentially constant regardless of a high ambient temperature. The emissions of nitrous oxides are reduced to within most regulation requirements without the use of a scrubber.

OSMOTIC HEAT ENGINE

Professor Menachem Elimelech and co-researchers at Yale University have conceptually developed an osmotic heat engine to convert low-quality waste heat to electricity as shown in Figure A.15. A concentrated ammonia-carbon dioxide draw solution is used to create a high osmotic pressure. With nearly deionized water (< 1 ppm NH_3 and CO_2) on the other side of the semi-permeable membrane, a water flux can be generated against a hydraulic pressure gradient. The water flux expands the volume of the draw solution, which induces flow through the turbine to produce electrical power. The water flux also decreases the concentration of the draw solution. To complete the cycle, waste heat is used to vaporize the carbon dioxide and ammonia to form a concentrated draw solution, and the nearly deionized water working fluid is fed to the low osmotic pressure side of the membrane. In addition, the pressure of the new re-concentrated draw solution is increased through a pressure exchanger, with the draw solution leaving the membrane.

The temperature of the waste heat that drives the engine can be as low as 40°C (104°F) with ambient temperature of 68°F (20°C). The maximum efficiency of the osmotic heat engine is predicted to be 16% of Carnot efficiency (i.e., maximum theoretical engine efficiency) with

practical efficiencies most likely in the range of 5% to 10%. Depending on the concentration of the draw solution and the hydraulic pressure, the membrane power density can approach 250 W/m^2 as shown in Figure A.16.

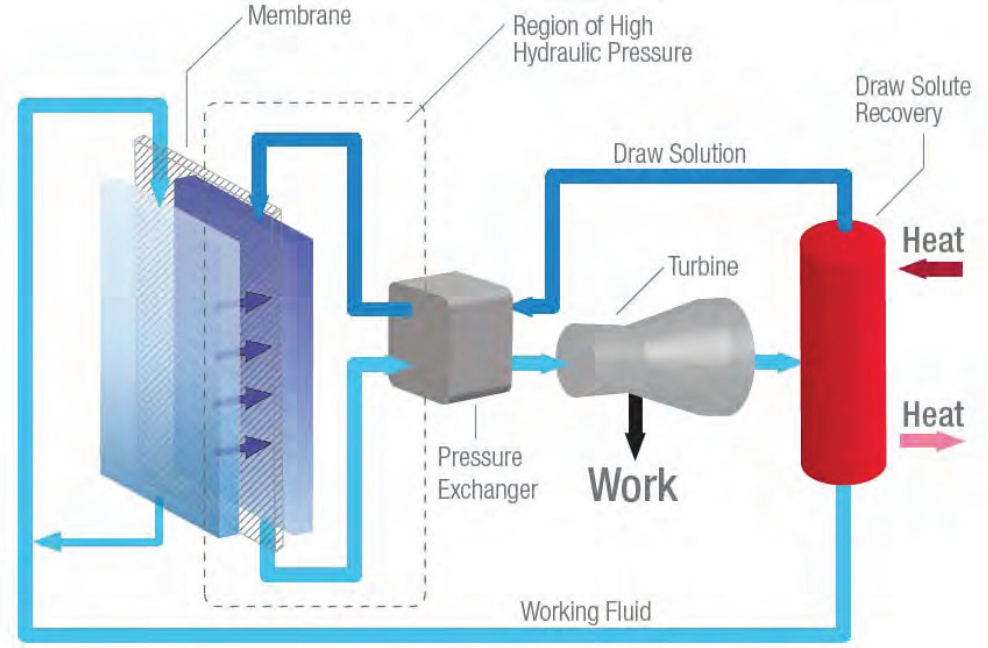


FIGURE A.15: SCHEMATIC OF AMMONIA-CARBON DIOXIDE OSMOTIC HEAT ENGINE FOR POWER GENERATION (FROM JOURNAL OF MEMBRANE SCIENCE, 305 (2007) 13-19)

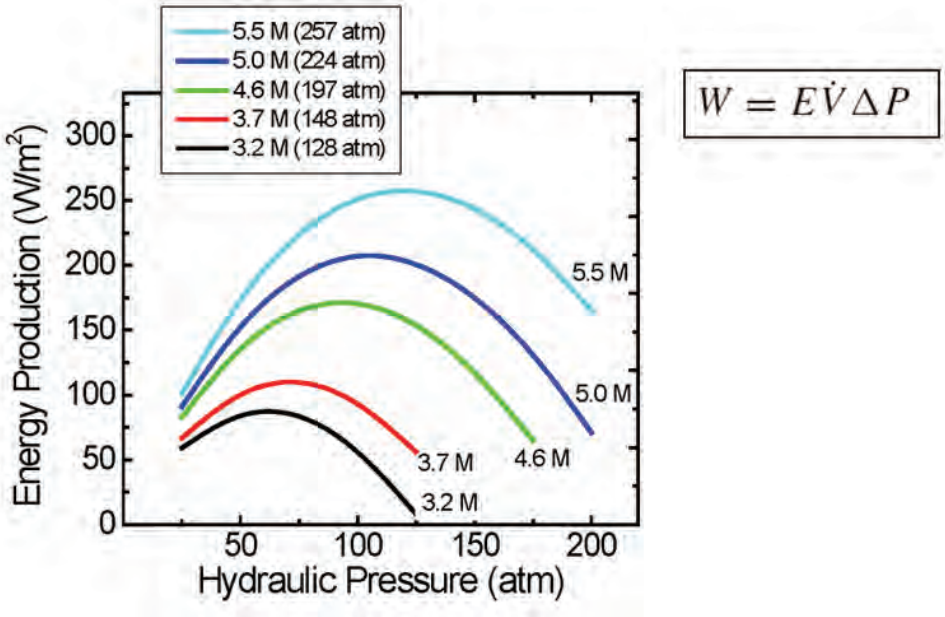


FIGURE A.16: MEMBRANE POWER DENSITY RELATIVE TO HYDRAULIC AND OSMOTIC PRESSURES IN THE OSMOTIC HEAT ENGINE (FROM JOURNAL OF MEMBRANE SCIENCE, 305 (2007) 13-19)

APPENDIX B

ELECTRICITY GENERATING FACILITIES SURVEY AND SUMMARY OF RESPONSES

SURVEY OF ELECTRICITY GENERATING FACILITIES IN THE STATE OF CONNECTICUT

Overview Questions

1. Do you currently use (or plan to use) the waste heat from your processes for a beneficial purpose? If so, what is this purpose?
2. If the answer to (1) is no, have you otherwise considered using the waste heat for a beneficial purpose(s)? If so, which ones?
3. Have you performed any previous studies of the feasibility of using waste heat? If so, what were the results of the studies and can you provide copies for review?
4. Have you performed any environmental impact studies relating to stack or fluid discharge relating to heat? If so, what were the results of the studies and can you provide copies for review?
5. Have you considered selling the waste heat for profit? If so, for what purposes?
6. Are there any barriers to using your waste heat for a beneficial purpose? If so, what are they?
7. If a buyer for your waste heat approached you, seeking 15 psig or 150 psig steam, are there barriers to modifying your steam cycle to change to non-condensing operation? If so, what are they?
8. How much total acreage do you own at this site? What is the percentage of unused land?
9. How much unused land contiguous to this site is owned by other parties?

Facility Operation

1. This question deals with the details of your facility's operation. That is, days of operation, hours per day, daily load variations and the like. Also, could you please indicate any seasonal variation in these details.
2. How many days per week do you operate? If less than 7, please indicate the days of operation (e.g., Mon – Fri)?

a. How many hours per day?
b. Do you operate at other than full-load?
c. What has been your typical operating history (i.e., percent load, unplanned shutdowns)?

3. What cycle do you operate (Rankine, Brayton, combined cycle, other)?
4. What is the nominal heat rate of your facility? How does the heat rate change with operating load? With ambient temperature?
5. Are any capital improvements planned over the next 24 months? If they relate to the availability of waste heat, what are they?

Operation Questions

1. What is the primary fuel used in your unit(s)? If a backup fuel is used, please specify the fuel and its typical usage.

The following four questions are for those electrical generating plants that use a liquid coolant. If that is not the case, please indicate the type of cooling system employed at your facility.

2. What is the source of your condenser coolant?
3. What is the coolant flow rate and inlet/outlet temperatures (please specify winter, spring, summer, and fall conditions)?
4. Do you inject biocide into the coolant (rate, material)?
5. Do you filter the coolant? If so, how are the filters cleaned and what is done with the by-products?
6. What is the stack exhaust flow rate and temperature? How do these change with operating load? With ambient temperature?
7. What are the maximum and minimum cycle working fluid operating temperatures?

Electrical Generating Survey
Overview

Facility	Beneficial uses of waste heat	Considered beneficial uses?	Previous Studies	Environmental Impact Studies of Waste Heat	Considered Selling Waste Heat?	Barriers	Barriers to modifying steam cycle	Unused land at site?	Unused contiguous land?
AES Thames	100,000 lbs/hr steam to Smurfit-Stone Container Corporation (SSCC) for recycling 155,000 tons/yr corrugated cardboard	NA	No	Performed and reviewed by CT Siting Council when facility was permitted for construction in 1986 (CSC Docket No. 61)	No	Temperature, pressure, and flow – thorough evaluation of existing heat balance would need to be conducted	No – with assumption that it is saturated steam. Biggest barrier would be quantity of steam required	Leases 100% of land from SSCC	Land owned by SSCC
Bridgeport Energy	No – very low grade heat and it has not been part of the core objectives for the facility	Very desirable to minimize waste heat. Design optimized accordingly	No	No Answer	Waste heat has always been considered of such low grade as to be infeasible for sale or even for reuse internally	Waste heat is of such low quality and that it not continuous as the facility does not operate all hours of the day	Value of doing so would have to be offset by both the value of keeping the steam in the cycle and cost of infrastructure to transport it to that other use	7.5 acres total with 1.5 acres open space that is often used for laydown space	None

Facility	Beneficial uses of waste heat	Considered beneficial uses?	Previous Studies	Environmental Impact Studies of Waste Heat	Considered Selling Waste Heat?	Barriers	Barriers to modifying steam cycle	Unused land at site?	Unused contiguous land?
Lake Road	Yes – combined cycle for maximizing electrical production. The low quality steam has little usable potential	NA	Facility was designed for maximum thermal efficiency for the production of waste heat	Performed intense siting and environmental permitting process with CSC and CT DEP	Heat is used to generate electricity in the most efficient manner	Yes, to the extent steam produced from waste heat was extracted from the combined cycle generation operation, the efficient but/kwh heat rate of the facility would be compromised, and so the megawatt hours bid into the regional energy market would by necessity be higher cost, and therefore more costly to regional electricity payers	Yes, only low quality steam available; facility was not designed as a non-condensing facility and this modification is not practical. Additionally very many expensive modifications would be required to retrofit the facility	Owns 57 contiguous acres with about 26 acres used for the existing facility	17 acre parcel owned by Town of Killingly as part on the Killingly Industrial Park that is currently undeveloped
Milford Power	No	No	No	No	No	Waste heat is at relatively low temperature (cooling tower) and environmental concerns with stack emissions	Economics	Site is situated on 28 acres. Only a very small area of unused land exists	There are a number of undeveloped industrial sites around the site.

Facility	Beneficial uses of waste heat	Considered beneficial uses?	Previous Studies	Environmental Impact Studies of Waste Heat	Considered Selling Waste Heat?	Barriers	Barriers to modifying steam cycle	Unused land at site?	Unused contiguous land?
South Meadows	No	Have not considered	No	Have not performed any studies	No	Flue gas exit temperature between end of pollution control equipment and stack entrance is ~230°F. Waste to energy units ductwork corrosion is high	Barriers would be cost and amount of processed downtime for tie-ins. MSW (fuel) would have to be diverted away from facility during changeover. Would rather look at adding a new MSW combustor	57 acres total with about 30 acres used (55%). Large portion of the unused land is the containment area for large jet fuel tank (5 mil gals) which would have to be relocated	CL&P has a small area (3 acres)
Millstone	No	Have not considered	No	Effluent studies were performed	No	Unknown	Steam cycle efficiency is highly dependent on operating with the lowest possible condenser backpressure (0.5 to 2 psia)	Unknown	Unknown

Electrical Generating Survey
Facility Operation

Facility	Days per Week Hours per Day	2008 Hours of Operation (from USEPA Clean Markets Air Data – not from survey)	Operate at other than full load?	Operating History	Cycle do you Operate?	Nominal Heat Rate? How does the heat rate change with operating load? With Ambient Temperature	Planned Capital Improvements
AES Thames	7 days per week 24 hours per day	Unit A – 6,291 hrs Unit B – 6,334 hrs	No, except during planning and unplanned outages where we typically operate at 45% load	Confidential Information	Rankine cycle with regenerative feedwater heating. This is done by extracting steam at various stages in the turbine to heat the feedwater as it is pumped from the hot well to the boiler economizer	Confidential Information	No
Bridgeport Energy	7 days per week Typ. 16 hrs / day	Unit 1 – 4,634 hrs Unit 2 – 5,372 hrs	Yes	Annual capacity factors between 50 and 65%. Unplanned shutdowns do occur, but are dwarfed by the nightly shutdowns for economic reasons	Combined cycle	7,000 BTU/kW-hr Combined cycle plants typically can only turn down to roughly 60%–75% of capability. At reduced load, heat rate will be elevated by 2%–3%. It changes little with changes in ambient temperature	None are planned related to waste heat
Lake Road	Facility is staffed and prepared to operate 7 days per week, 365 days per year	Unit 1 – 3,321 hrs Unit 2 – 4,262 hrs Unit 3 – 3,904 hrs	Yes	Load can vary between low operating levels, and high operating levels depending on current ISO-NE conditions, and dispatch. This can sometimes change by the minute (regulation)	Combined cycle	Heat rate at full load ranges between 7,100 and 7,200 BTU/kW-hr and at minimum load between 7,600 and 7,800 BTU/kW-hr depending on the time of year and ambient temperature.	No capital improvements are planned over the next 24 months that relate to waste heat or low quality steam

Facility	Days per Week Hours per Day	2008 Hours of Operation (from USEPA Clean Markets Air Data – not from survey)	Operate at other than full load?	Operating History	Cycle do you Operate?	Nominal Heat Rate? How does the heat rate change with operating load? With Ambient Temperature	Planned Capital Improvements
Milford Power – both operated about 6,000 hours – combined cycle	7 days per week 16-24 hours per day depending on market conditions	Unit 1 – 5,870 hrs Unit 2 – 6,318 hrs	Yes – down to approximately 60% load	Cycling to baseload operations with capacity factor of 65%–75%. Unplanned outages can vary significantly and have been up to 8% on one of the units	Combined cycle	Heat rate is 6,900 BTU/kW-hr and is minimally affected by operating load and temperature	No
South Meadows	7 days per week 24 hours per day	MSW units not listed in USEPA Table	Load is dictated by how well the MSW burns and if combustors are operating with tube leaks	Annual average of 84% availability at 90% capacity	Rankine cycle	Winter – 9.35 Kpph*/MW and Summer – 10.25 Kpph/MW Difference due to change in river water temperature *thousand pounds per hour	No Projects Planned
Millstone -	Millstone operates as a baseload station operating at 100% power, 24/7 for a period of 18 moths. Some minor power reductions or shutdowns may occur during the 18 month period	Capacity factor of greater than 98%	Baseload station operating at full load approximately 99% of the time. Some minor and short term power reductions can occur periodically.	Units typically operate with a capacity factor of greater than 98%	Rankine cycle	Millstone 2 gross heat rate of approximately 10,062 BTU per kW-hr Millstone 3 has a heat rate of approximately 9,948 BTU per kW-hr Units are baseload 100% power operation. Ambient (intake water) temperature increases heat rate.	No

Electrical Generating Survey
Operation Questions

Facility	Primary and Backup Fuel	Source of Condenser Coolant	Coolant Flow Rate and Inlet/Outlet Temperatures	Do you Inject a Biocide into the Coolant?	Do you Filter the Coolant?	What is the Stack Exhaust Flow Rate and Temperature? How does it Change with Operating Load and Ambient Temperature	Maximum and Minimum Cycle Working Fluid Operating Temperatures
AES Thames	Bituminous Coal	Thames River	1.25 million gallons per day (MGD) with inlet/outlet ΔT averaging 20°F Maximum Outlet Temp: Dec 1 – April 30 = 80°F May 1 – June 30 = 90°F July 1 – Sept 30 = 95°F Oct 1 – Nov 30 = 90°F	12.5% sodium hypochlorite solution, measured as residual oxidant, which shall not be discharged for a period of more than two hours per day with an instantaneous limit of 0.20 mg/L	No	307,850 actual cubic foot per minute (acfm) @ 270°F for 1 boiler operation 615,700 acfm @ 270°F for 2 boiler operation	Feedwater max/min = 475/100°F Steam max/min = 1,000/400°F
Bridgeport Energy	Pipeline natural gas (including some pipeline – quality landfill gas)	Bridgeport Harbor	Approximately 166 MGD. The intake water temperature generally follows a sinusoidal pattern, topping out at about 80°F in the summer and 30°F in the winter. The discharge temperature reflects an approximately 20°F rise when the facility is in operation	15% sodium hypochlorite – The rate is variable and dosing takes place less than two hours per day	Filtration consists of roughly 3/8 in. mesh traveling screens ahead of the circulating water pumps. These units are self cleaning, but semiannual system cleanings are required to deal with growth that takes place within the system. The material is landfilled.	3.5 million lbs/hr at 200 - 220°F, flat with load	The combustion turbine firing temperature is approximately 2,200°F and exhaust temperature (boiler inlet temp) is about 1,100°F. The steam turbine admission temp is nominally 1,000°F. Steam turbine exhaust temp is about 100°F, depending on the backpressure.

Facility	Primary and Backup Fuel	Source of Condenser Coolant	Coolant Flow Rate and Inlet/Outlet Temperatures	Do you Inject a Biocide into the Coolant?	Do you Filter the Coolant?	What is the Stack Exhaust Flow Rate and Temperature? How does it Change with Operating Load and Ambient Temperature	Maximum and Minimum Cycle Working Fluid Operating Temperatures
Lake Road	Natural gas is the primary fuel, with ultra-low sulfur distillate as the back-up source. The facility is permitted to operate about 30 days of distillate each year for each unit as a maximum amount. Due to the differential in fuel prices since the unit entered commercial operation in 2002, the facility has burned primarily natural gas with very little back-up fuel	Air Cooled Condenser	NA	NA	NA	Exhaust stack temperature can range from 220°–260°F depending on the time of year, ambient temperature, and gas turbine load	The facility does not use fluid for primary cooling.
Milford Power – both operated about 6,000 hours – combined cycle	Natural gas with low sulfur diesel as back-up (very limited usage)	Housatonic River	Dependent on load, but usually 132,000 gallons per minute (gpm) Winter: 77°–90°F Spring: 68°–86°F Summer: 85°–100°F Fall: 70°–88°F	Yes – Sodium hypochlorite (dependent on water conditions, but approximately 1-2 ppm	No	3.5 million lbs/hr at 220°F at base load. Flow and temperature decrease with load. Temperature can drop to 200°F.	High Pressure - 2,330 psi @ 1,045°F Reheat Pressure – 537 psi @ 1,045°F Low Pressure – 98 psi @ 607°F

Facility	Primary and Backup Fuel	Source of Condenser Coolant	Coolant Flow Rate and Inlet/Outlet Temperatures	Do you Inject a Biocide into the Coolant?	Do you Filter the Coolant?	What is the Stack Exhaust Flow Rate and Temperature? How does it Change with Operating Load and Ambient Temperature	Maximum and Minimum Cycle Working Fluid Operating Temperatures
South Meadows	MSW converted to Refuse Derived Fuel (RDF)	Connecticut River	Winter: 66.6 MGD Spring: 86.38 MGD Summer: 96.93 MGD Fall 87.96 MGD	No	Traveling screens are manually cleaned of larger debris 2 times per day (average). In addition, the screens are rinsed by a spray wash system to further dislodge any impinged debris/organisms from the screens. The debris/organisms removed by the spray wash system are discharged into a trough, which sluices its contents back to the CT River	1.4 million lbs/hr @ 213°F. Lower ambient temperature will drive down existing temperature due to fugitive air leakage	Need more information.
Millstone -	Enriched Uranium (U-235).	Long Island Sound seawater	Millstone 2 flow rate is 540,000 gpm with a temperature rise of 25°F Millstone 3 flow rate is 918,000 gpm with a temperature rise of 19°F Long Island Sound temperature varies from 34°F (winter) to 75°F (summer)	Yes! Hypochlorite. Rates vary. Service water gets continuous hypochlorite. Circulating water gets 20 minute shock treatments 2 or 3 days per week	Trash racks and traveling screens are used to remove debris (marine life, eel grass, etc) from entering pump suction.	Stack effluent and temperature is extremely minimal or non-existent.	Condensate temperature range from 85°F–120°F Intake coolant temperatures range from 34°F–75°F

APPENDIX C
LETTER FROM DONALD W. DOWNES, CHAIRMAN, DPUC

STATE OF CONNECTICUT
DEPARTMENT OF PUBLIC UTILITY CONTROL

DONALD W. DOWNES
CHAIRPERSON

October 28, 2008

I wanted to let you know about a study which is about to get underway and ask for your cooperation and help in making it successful.

As you know, we are seeing a convergence of two general policies – on the one hand, the need to control and reduce adverse thermal effects from electric generation, and on the other hand, the continuing encouragement and development of Combined Heat and Power (CHP) strategies.

Up to this point, CHP strategies have been largely limited to circumstances in which a single entity uses waste heat for industrial, space heating or generation purposes. CHP has not thus far been applied in Connecticut on a central site basis, where waste heat can be employed by more than one user.

Meanwhile, environmental regulators are searching for ways to reduce thermal impacts on the environment. So far, they are essentially considering new strategies to more effectively dissipate waste heat (like the installation of cooling towers or arrays).

The Connecticut Energy Advisory Board (CEAB) sees the potential of bringing these two policy trends into a symbiotic mode, where investments can be made to reuse the waste heat instead of being made in ways that would effectively waste that energy.

Therefore, the Connecticut Academy of Science and Engineering (CASE) has been awarded a contract by the CEAB to consider the feasibility of reusing waste heat from central site generation units.

To that end, CASE will be reaching out to the various thermal electric generators in Connecticut to collect various data and consult with generation operators in an effort to determine whether reuse strategies can be effective and potential strategies for implementation.

10 Franklin Square, New Britain, Connecticut 06051
An Equal Opportunity Employer

The Department of Public Utility Control (DPUC) is pleased to join with CASE in trying to make this effort as successful and meaningful as possible. As a member of CEAB, we believe that state policy should be designed to produce results that serve the interests of the public and the industry alike.

If you would like more information, please contact Rick Strauss, CASE Executive Director at 860-527-2161 or rstrauss@ctcase.org, or contact us at the DPUC through William Palomba at 860-827-2802 or william.palomba@po.state.ct.us. Additionally, the CASE project study management team, Professor David Pines and Professor Tom Filburn of the University of Hartford will be contacting you regarding your plant's technical operations.

Thank you in advance for your cooperation and assistance in this matter.

Sincerely,

Donald W. Downes
Chairman

This communication was made possible through the technical assistance of Chairman Caruso of the Connecticut Siting Council and his able staff, to whom we express our appreciation.

APPENDIX D

The following applications listed in Table D-1 are either in the development phase or could not be easily adopted in Connecticut.

TABLE D-1: SUMMARY OF WASTE HEAT APPLICATIONS THAT DO NOT MEET THE NEAR-TERM NEEDS OF CONNECTICUT

Waste Heat Application	Technical Viability	Efficiency Impact	Economics	National Security	Environmental	Regulation
Increasing Electricity Efficiency - Osmotic Heat Engine	Conceptual Stage	TBD with no retrofit of power plant required	TBD	Good – Conversion of waste heat to electricity	No apparent environmental issues	No apparent regulatory issues
Fish Farms	System improvements would be helpful producing healthy fish and using wastewater for growing hydroponics crops	Waste heat can be used during winter but likely not required during the summer. Retrofit not required if fish farm is located adjacent to power plant	Waste heat increases yield in the winter	May reduce stress on fishing of natural waters and provide high protein food source	Environmental issues related to fish disease and discharge of wastewater	Regulatory requirements for ensuring safe food supply and proper discharge of wastewater
Hydrogen Production	Low-temperature fermentation and biological hydrogen production systems are in research phase	Biological growth rates generally increase up to about 30°C and tend to like stable operating conditions	TBD	Provide domestic source of hydrogen production not dependent on fossil fuels	Reduced emissions and greenhouse gases through production of hydrogen	Regulatory issues concerning the safe transport, storage, and use of hydrogen
Desalination	Research phase of forward osmotic process using low-temperature waste heat for water desalination. Widespread use of heat from fossil and nuclear plants in the Mideast	Effective use of waste heat where freshwater supply is insufficient to meet demand	Decreased operating cost of desalination compared to reverse osmosis process	Important national security issue for locations that have abundant saltwater but insufficient freshwater supply	Low energy desalination process using readily available waste heat	Reduces stress on limited freshwater supply

MAJOR STUDIES OF THE ACADEMY

2009

- Independent Monitor Report: Implementation of the UCHC Study Recommendations

2008

- Preparing for Connecticut's Energy Future
- Applying Transportation Asset Management in Connecticut
- A Study of Weigh and Inspection Station Technologies
- A Needs-Based Analysis of the University of Connecticut Health Center Facilities Plan

2007

- A Study of the Feasibility of Utilizing Fuel Cells to Generate Power for the New Haven Rail Line
- Guidelines for Developing a Strategic Plan for Connecticut's Stem Cell Research Program

2006

- Energy Alternatives and Conservation
- Evaluating the Impact of Supplementary Science, Technology, Engineering and Mathematics Educational Programs
- Advanced Communications Technologies
- Preparing for the Hydrogen Economy: Transportation
- Improving Winter Highway Maintenance: Case Studies for Connecticut's Consideration
- Information Technology Systems for Use in Incident Management and Work Zones
- An Evaluation of the Geotechnical Engineering and Limited Environmental Assessment of the Beverly Hills Development, New Haven, Connecticut

2005

- Assessment of a Connecticut Technology Seed Capital Fund/Program
- Demonstration and Evaluation of Hybrid Diesel-Electric Transit Buses
- An Evaluation of Asbestos Exposures in Occupied Spaces

2004

- Long Island Sound Symposium: A Study of Benthic Habitats
- A Study of Railcar Lavatories and Waste Management Systems

2003

- An Analysis of Energy Available from Agricultural Byproducts, Phase II: Assessing the Energy Production Processes
- Study Update: Bus Propulsion Technologies Available in Connecticut

2002

- A Study of Fuel Cell Systems
- Transportation Investment Evaluation Methods and Tools
- An Analysis of Energy Available from Agricultural Byproducts, Phase 1: Defining the Latent Energy Available

2001

- A Study of Bus Propulsion Technologies in Connecticut

2000

- Efficacy of the Connecticut Motor Vehicle Emissions Testing Program
- Indoor Air Quality in Connecticut Schools
- Study of Radiation Exposure from the Connecticut Yankee Nuclear Power Plant

Connecticut Academy of Science and Engineering
179 Allyn Street, Suite 512, Hartford, CT 06103
Phone or Fax: 860-527-2161
e-mail: acad@ctcase.org
web: www.ctcase.org

Connecticut Academy of Science and Engineering

The Connecticut Academy is a non-profit institution patterned after the National Academy of Sciences to identify and study issues and technological advancements that are or should be of concern to the state of Connecticut. It was founded in 1976 by Special Act of the Connecticut General Assembly.

Vision

The Connecticut Academy will foster an environment in Connecticut where scientific and technological creativity can thrive and contribute to Connecticut becoming a leading place in the country to live, work and produce for all its citizens, who will continue to enjoy economic well- being and a high quality of life.

Mission Statement

The Connecticut Academy will provide expert guidance on science and technology to the people and to the State of Connecticut, and promote its application to human welfare and economic well being.

Goals

- Provide information and advice on science and technology to the government, industry and people of Connecticut.
- Initiate activities that foster science and engineering education of the highest quality, and promote interest in science and engineering on the part of the public, especially young people.
- Provide opportunities for both specialized and interdisciplinary discourse among its own members, members of the broader technical community, and the community at large.

Connecticut Academy of Science and Engineering
179 Allyn Street, Suite 512, Hartford, CT 06103
Phone or Fax: 860-527-2161
e-mail: acad@ctcase.org
web: www.ctcase.org