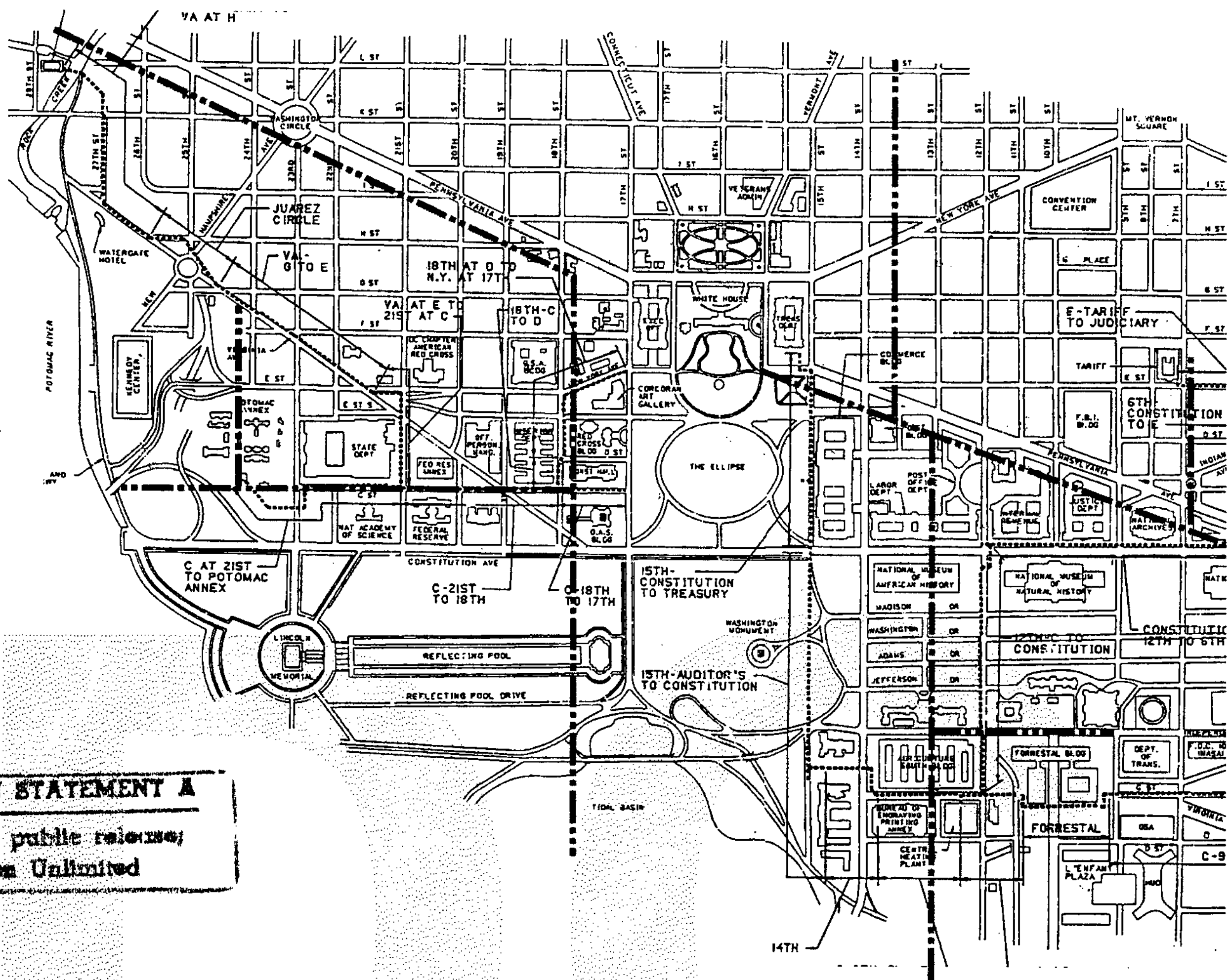
Evaluation of the

Heating Operation and Transmission District

Feasibility of Cogeneration GS301MR3



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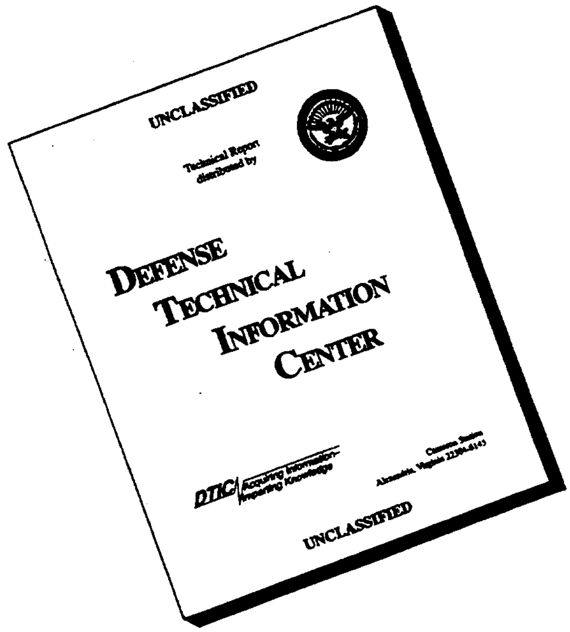

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November 1995

Evaluation of the Heating Operation and Transmission District

Feasibility of Cogeneration

GS301MR3

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Evaluation of the Heating Operation and Transmission District: Feasibility of Cogeneration

Executive Summary

The General Services Administration (GSA), through its National Capital Region, operates a district heating system – called the Heating Operation and Transmission District (HOTD) – that provides steam to approximately 100 Federal, quasi-Federal, and District of Columbia government buildings in Washington, D.C. The HOTD system comprises the Central Heating and Refrigeration Plant, the West Heating Plant, and a steam distribution network of nearly seven miles of steam tunnels and over five miles of buried pipe.

The HOTD is examining a host of options that will improve its ability to provide reliable, environmentally sound, and cost-effective service to its customers. One option is cogeneration, a technology that would enable HOTD to produce steam and electricity simultaneously. GSA tasked the Logistics Management Institute to evaluate the economic and environmental feasibility of incorporating cogeneration into the HOTD system.

By purchasing and installing cogeneration equipment, HOTD would save money over a 20-year period, as compared to current operations. How much it would save depends on the regulatory environment. Under current regulations prohibiting a non-utility power producer from transmitting, or "wheeling," that power to another user, HOTD would save about $14 million over a 20-year period. However, those savings are not sufficient to offset the capital costs of the equipment, as evidenced by the payback period of about 15 years. That length of time exceeds Federal return-on-investment guidelines that require a maximum of a 10-year payback period.

Cogeneration would be far more attractive financially if the regulatory environment changes to allow wheeling. In that case, HOTD would save anywhere from $38 million to $118 million, depending on the equipment used and the price that the Potomac Electric Power Company would charge to transmit HOTD's electricity to other GSA facilities. The investment would pay back in 7 to 10 years.

From an environmental standpoint, a system with cogeneration equipment has no significant advantage (or disadvantage) over the existing steam-only system. Assuming HOTD uses gas-fired cogeneration units, the ground-level concentrations of nitrogen oxides and sulfur dioxide would be about the same as they are with the existing system.

Not only are the economic and environmental advantages of cogeneration not strong enough at this time, a District of Columbia regulation prohibits the construction or operation of any cogeneration plant in the District until the D.C. Public Service Commission defines specific energy conservation and environmental protection standards for cogeneration facilities. The D.C. Council would have to pass favorable legislation before GSA could implement cogeneration at HOTD. Another potential option is for GSA to claim exemption from the D.C. regulation based on a clear presentation on the savings to the Federal taxpayer.

Because incorporating cogeneration into the HOTD system has no strong benefit, we recommend the following:

- For the short term, GSA should give no further consideration to cogeneration as an alternative for HOTD operations. Federal regulations prohibiting wheeling and local legislation prohibiting cogeneration in the District of Columbia preclude the implementation of cogeneration.

- In one or two years, GSA should reevaluate cogeneration. Federal regulations regarding wheeling are under review. Should wheeling be approved, cogeneration would be a much more attractive alternative from an economic standpoint.

- GSA should work with the D.C. Public Service Commission to develop appropriate standards for cogeneration facilities.

- Should HOTD decide to replace any of the existing boilers, a cogenerator should be one of the replacement options considered. While it is not compelling to replace the current boilers solely for the benefit of cogeneration, cogeneration may reduce the long-term cost should other factors necessitate replacing the existing boilers.

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Acknowledgment

This report is based in part on work provided by MPR Associates, Inc., a subcontractor to the Logistics Management Institute.

CHAPTER 1

Introduction

The General Services Administration (GSA), through its National Capital Region, manages a Heating Operation and Transmission District (HOTD) that provides steam and a limited amount of chilled water to approximately 100 Federal, quasi-Federal, and District of Columbia government buildings in the Washington, D.C., area. Among those buildings, which contain almost 50 million square feet of space, are offices, the Smithsonian Institution, and the White House.

The HOTD system began in 1934; today it delivers heat from two sources – the Central Heating and Refrigeration Plant and the West Heating Plant – through a steam distribution network of nearly seven miles of steam tunnels and five miles of buried pipes. Over the years, GSA has updated the equipment to ensure that it can maintain a reliable steam supply, maintain fuel and plant flexibility, reduce pollutants to comply with increasingly stringent environmental regulations, and operate the heating plants cost-effectively.

Recently, GSA initiated a series of studies to identify and assess operational alternatives that will ensure that HOTD continues to provide reliable, environmentally sound, and cost-effective service to its customers. In support of that effort, the Logistics Management Institute (LMI) evaluated the feasibility of incorporating cogeneration at the HOTD plants.

Cogeneration is the simultaneous production of heat and electricity. It is an attractive technology primarily because it uses fuel more efficiently than a steam-only system; it also typically produces fewer air pollutants and lower thermal discharges. The National Research Council states that a low-pressure process steam producer can add cogeneration equipment and produce electricity with about half the fuel required by a single-purpose utility plant.[1] Because HOTD must produce a large amount of steam, it follows that it should consider producing electricity at the same time with cogeneration equipment. Moreover, installing cogeneration equipment at a Federal facility offers the Federal government the potential to conserve energy and reduce its overall energy costs – a goal recently set in Executive Order 12902 and in previous congressional energy conservation legislation.

Whether cogeneration would be economical for HOTD depends on whether the fuel savings, combined with the value of the cogenerated electricity, justify the capital cost of cogeneration equipment. The value of the electricity depends in turn on whether HOTD sells the electricity to the local utility – Potomac Electric Power Company (Pepco) – or whether it can use the electricity to meet its

[1] National Academy of Sciences, *Energy in Transition 1985 – 2010,* W. H. Freeman and Company, 1979, p. 97.

own needs, transmitting, or "wheeling," any excess power to other GSA facilities. (Current District of Columbia regulations do not allow wheeling, but it is likely that wheeling may be allowed by the time HOTD could implement cogeneration because of the increasing interest by Federal regulators in wheeling as a means to deregulate the power industry.) The value of the electricity also depends on the rates Pepco would charge to purchase electricity from, or to transmit electricity for, a non-utility generator. Thus, in our assessment of the feasibility of cogeneration, we focused on determining if the savings would offset the capital cost of cogeneration equipment.

Whether cogeneration would have an adverse effect on the environment is another issue of concern to HOTD. In particular, HOTD must comply with the Environmental Protection Agency's National Ambient Air Quality Standards (NAAQS). Cogeneration would not be considered a desirable alternative for HOTD if it resulted in higher levels of air pollution. Thus, we assessed the environmental feasibility of cogeneration, focusing on changes in levels of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) that might result if HOTD were to add cogeneration equipment to its system.

As the basis for assessing the economic and environmental feasibility of cogeneration compared with the existing steam-only system, we established design parameters for the system with cogeneration equipment that would match the steam-generating capacity of the existing system as closely as possible – that is, the steam output will not change. The only difference between HOTD's existing system and one that incorporates cogeneration would be the equipment itself.

We present our conclusions and recommendations in Chapter 2. Chapter 3 describes cogeneration equipment options that would be reasonable candidates for use in the HOTD system; that chapter also discusses the design criteria that we established before selecting those options. We provide the results of our assessments of the economic and environmental feasibility of cogeneration in Chapter 4. In Chapter 5, we discuss local regulatory and political issues that must be resolved before HOTD could implement cogeneration. Details are provided in the appendices.

CHAPTER 2

Conclusions and Recommendations

Two cogeneration equipment options are reasonable candidates for use in the HOTD system:

- *Equipment Option 1.* Two 16.9-MW combustion turbine generators and two supplementary-fired heat recovery steam generators (HRSGs), each with a capacity of 220,000 pounds of steam per hour. The total steam generation capacity of Option 1 is 440,000 pounds per hour, and the total power generation capacity is 34 MW.

- *Equipment Option 2.* Four 3.5-MW combustion turbine generators and four supplementary-fired HRSGs, each with a capacity of 100,000 pounds of steam per hour. The total steam generation capacity of Option 2 is 400,000 pounds per hour, and the total power generation capacity is 14 MW.

We assumed that the cogeneration equipment would replace Boilers 5 and 6 at the Central Heating and Refrigeration Plant but the remaining nine boilers in HOTD's inventory would remain in operation. The total steam-generating capacity of the HOTD system would remain at about 2.4 million pounds per hour. We also assumed that, because of the time required for approval, acquisition, permitting, and construction, 2002 would be the earliest possible year that HOTD could begin cogenerating steam and electricity.

With either cogeneration equipment option, HOTD could produce enough steam to meet its average hourly demand of 330,000 pounds per hour. It could then use the existing boilers to meet its peak demand and redundancy requirements. Having selected equipment that would fulfill HOTD's main mission – to produce steam – we then assumed that the electricity produced would be a byproduct that would be sold to Pepco or, should wheeling be allowed, used by GSA at the HOTD plants and other GSA facilities.

Regardless of the equipment option chosen and the regulatory conditions specifying whether HOTD could sell or wheel its electricity, the annual credit that HOTD would receive from the sale of electricity would offset the cost of the cogeneration equipment and the annual incremental increase in the fuel cost. Of the two options, Equipment Option 1 is the more economically attractive. Assuming that Pepco purchases any power HOTD generates, the net present value (NPV) of a 20-year cash flow of Equipment Option 1 in 2002 would be $14.8 million. In contrast, the NPV of Equipment Option 2 over the same period would be only $4.75 million. It should be noted that these numbers are sensitive to the initial investment costs. For example, with Equipment Option 2, a 10 percent increase in projected equipment and construction costs would result in a negative NPV. However, for both options, the relative financial benefit to HOTD is small, as evidenced by the lengthy payback period of about 15 years.

If the regulatory environment changes to allow wheeling, the net present value of Equipment Option 1 would be at least \$75 million and could be as high as \$118 million. (The wide range is due to the uncertainty concerning electricity prices.) The NPV of Equipment Option 2 would be in the range of \$37 million to \$51 million if wheeling were allowed, and the payback period would decline to between 7 and 10 years for both options. Under these conditions, the use of cogeneration becomes more economically attractive.

From an environmental standpoint, a system with cogeneration equipment has no significant advantage (or disadvantage) over the existing steam-only system. By using gas-fired cogeneration units, HOTD would reduce its emissions of NO_x at the stack by about half, and, as with any gas-fired system, the emission of SO_2 would be negligible. However, at ground level, the concentrations of NO_x would decrease only slightly while SO_2 concentrations would not change substantially from current levels. The emission rates from oil-fired cogeneration equipment depend on the sulfur content of the fuel oil; general guidelines from the manufacturers of cogeneration equipment indicate that the NO_x and SO_2 emissions may be slightly higher for cogeneration than for steam-only systems. However, changes that HOTD makes to comply with NAAQS are likely to offset any marginal increases in emission rates if oil is the fuel used in the cogeneration equipment. In any case, we anticipate that natural gas will be the primary fuel for the foreseeable future.

Overall, neither the economic nor the environmental advantages of cogeneration are strong enough, given current regulations, to recommend that GSA incorporate it into HOTD operations. Moreover, a District of Columbia regulation prohibits the construction or operation of any cogeneration plant in the District until the D.C. Public Service Commission defines specific energy conservation and environmental protection standards for cogeneration facilities. The D.C. Council would have to pass favorable legislation before GSA could implement cogeneration at HOTD. Another potential option for GSA is to claim exemption from the D.C. regulation based on a clear presentation on the savings to the Federal taxpayer.

Because incorporating cogeneration into the HOTD system has no strong benefit, we recommend the following:

- For the short term, GSA should give no further consideration to cogeneration as an alternative for HOTD operations. Federal regulations prohibiting wheeling and local legislation prohibiting cogeneration in the District of Columbia preclude the implementation of cogeneration.

- In one or two years, GSA should reevaluate cogeneration. Federal regulations regarding wheeling are under review. Should wheeling be approved, cogeneration would be a much more attractive alternative from an economic standpoint.

- GSA should work with the D.C. Public Service Commission to develop appropriateness standards for cogeneration. It also should investigate whether its status as a U.S. government agency gives it practical options for implementing cogeneration.

- Should HOTD decide to replace any of the existing boilers, a cogenerator should be one of the replacement options considered. While it is not compelling to replace the current boilers solely for the benefit of cogeneration, other factors may necessitate replacing the existing boilers, and cogeneration would be one means to reduce long-term costs.

CHAPTER 3

Candidate Cogeneration Equipment

A number of cogeneration cycles are available. For the HOTD system, we selected a highly efficient and economical thermal cycle comprising a combustion turbine combined with an HRSG.[1] Combustion turbines are particularly well suited to generate electric power and high temperature exhaust gases simultaneously for cogeneration of steam in an efficient manner. The exhaust energy from the combustion turbine generally represents 60 percent to 70 percent of the inlet fuel energy. Large exhaust flow rates at high temperatures provide an ideal source of heat for generating steam in the HRSG. Moreover, steam output can be increased by supplemental firing at the inlet ducts to the HRSG; combustion fuels can be sustained because the exhaust gases contain a relatively high concentration of oxygen. HRSGs also can be fresh-air fired; that is, steam can be generated without operating the combustion turbines.

Figure 3-1 is a schematic of a typical combustion turbine - HRSG cogeneration cycle and its major components, including the deaerator, feed pump, condensate pump, and gas compressor. Figure 3-2 shows a combustion turbine - HRSG in a simplified arrangement, and Figure 3-3 shows the features of an HRSG.

The following sections discuss the design criteria that we used as the basis for selecting candidate combustion turbine - HRSG cycles and describe the specific equipment we selected for further analysis.

DESIGN CRITERIA

We envisioned a system in which the cogeneration units would produce enough steam to meet HOTD's average hourly demand (330,000 pounds per hour at 250 psig). Those units would replace two of the existing boilers at the Central Heating Plant. Since HOTD's actual hourly demand is above 330,000 pounds per hour for about 140 days per year, the remaining boilers at the Central and West plants would be used to supply steam needed to meet HOTD's peak demand and redundancy requirements. Since HOTD's primary focus is to produce steam, any electricity generated would be considered a byproduct.

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[1] We briefly considered two other types of cogeneration cycles: high backpressure, noncondensing steam turbines and diesel generator - hot windbox boilers. We eliminated the former from further consideration because their capital costs are about 70 percent higher than the capital costs of combustion turbines - HRSGs. We eliminated the latter because they do not produce steam as efficiently as combustion turbines - HRSGs, and steam production is the primary emphasis of the HOTD system.

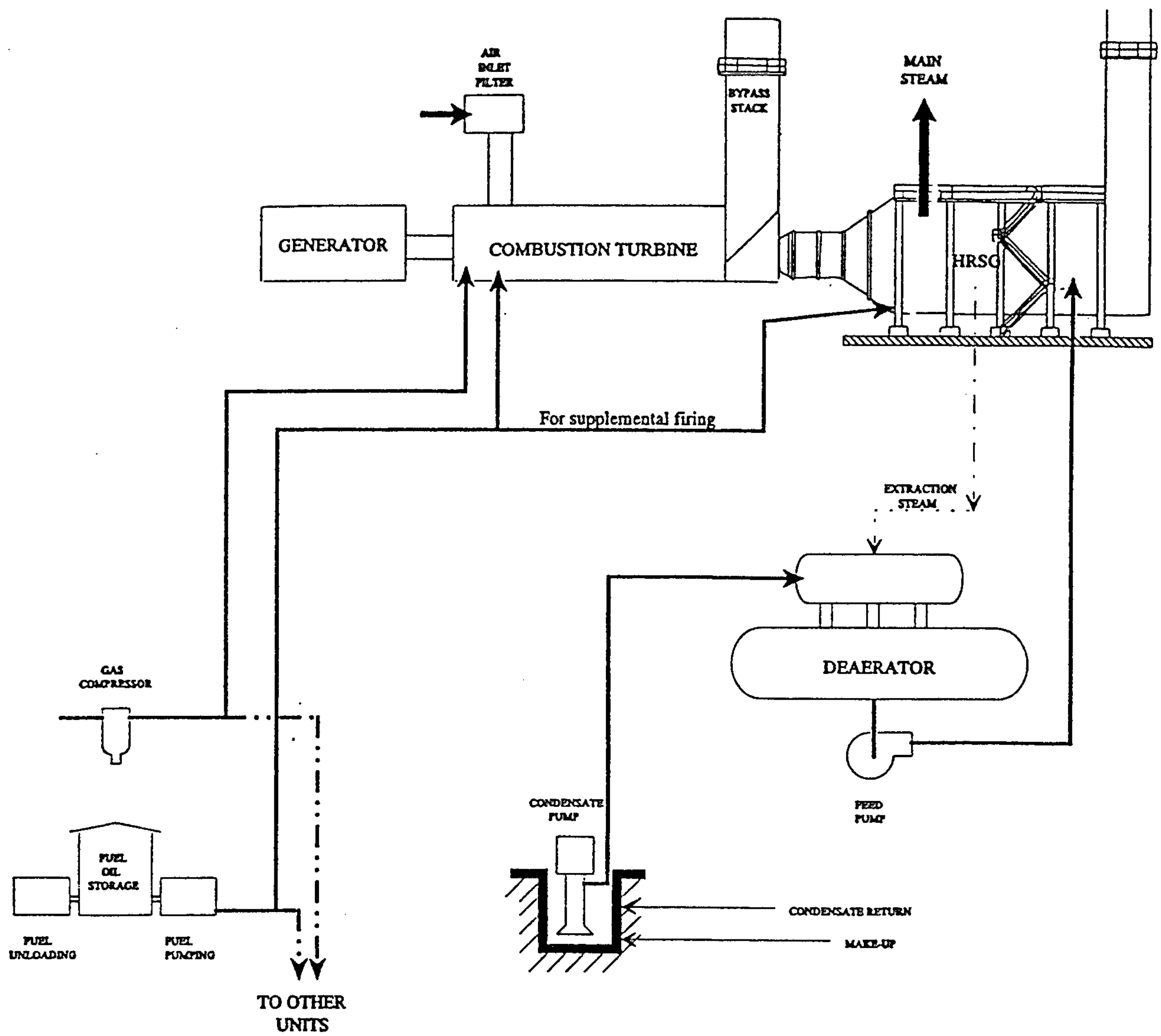

Figure 3-1.
Typical Combustion Turbine – Heat Recovery Steam Generator Cogeneration Cycle

In developing our specific design criteria, we made a number of assumptions:

- The total steam-generating capacity of the HOTD system will remain at 2.4 million pounds per hour. (That capacity is more than twice the capacity needed to meet the peak demand of 1.1 million pounds per hour, which occurs on cold winter days. HOTD maintains 100 percent redundancy in steam capability because of the critical nature of the buildings it serves.)

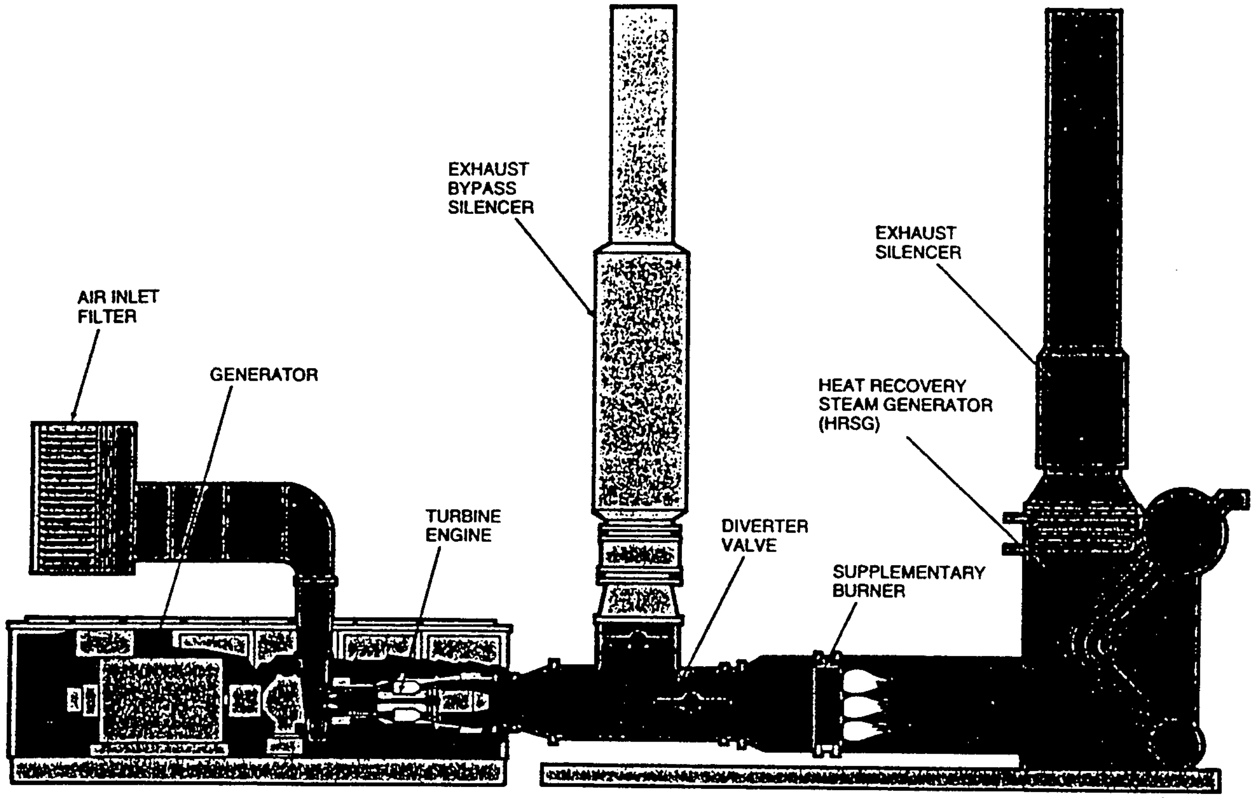

Figure 3-2.
Simplified Arrangement of the Combustion Turbine - Heat Recovery Steam Generator

- The cogeneration equipment will be placed in the Central Heating Plant. We selected the Central Heating Plant as the site for the cogeneration equipment because GSA intends to use that plant for its base load and the West Heating Plant for its peak load and redundancy requirements.

- Two boilers will be replaced. Replacing two units (versus one) allows phased installation and operation of cogeneration units and provides operational flexibility.

We selected Boilers 5 and 6 in the Central Heating Plant as the most reasonable candidates for replacement with cogeneration equipment. Boilers 1 and 2 are being rebuilt and will be returned to service in late 1995. Boilers 3 and 4 are compact and have a rated capacity of 400,000 pounds per hour each. Cogeneration equipment with comparable capacity would require twice as much space as is now occupied by Boilers 3 and 4. (Appendix A describes the existing facilities in more detail.) Not only do Boilers 5 and 6 have unstable operating characteristics in any case, but they also are good candidates for our analysis because, together, the two boilers have a capacity of about 440,000 pounds of saturated steam per hour and thus can meet HOTD's average hourly steam demand of 330,000 pounds per hour.

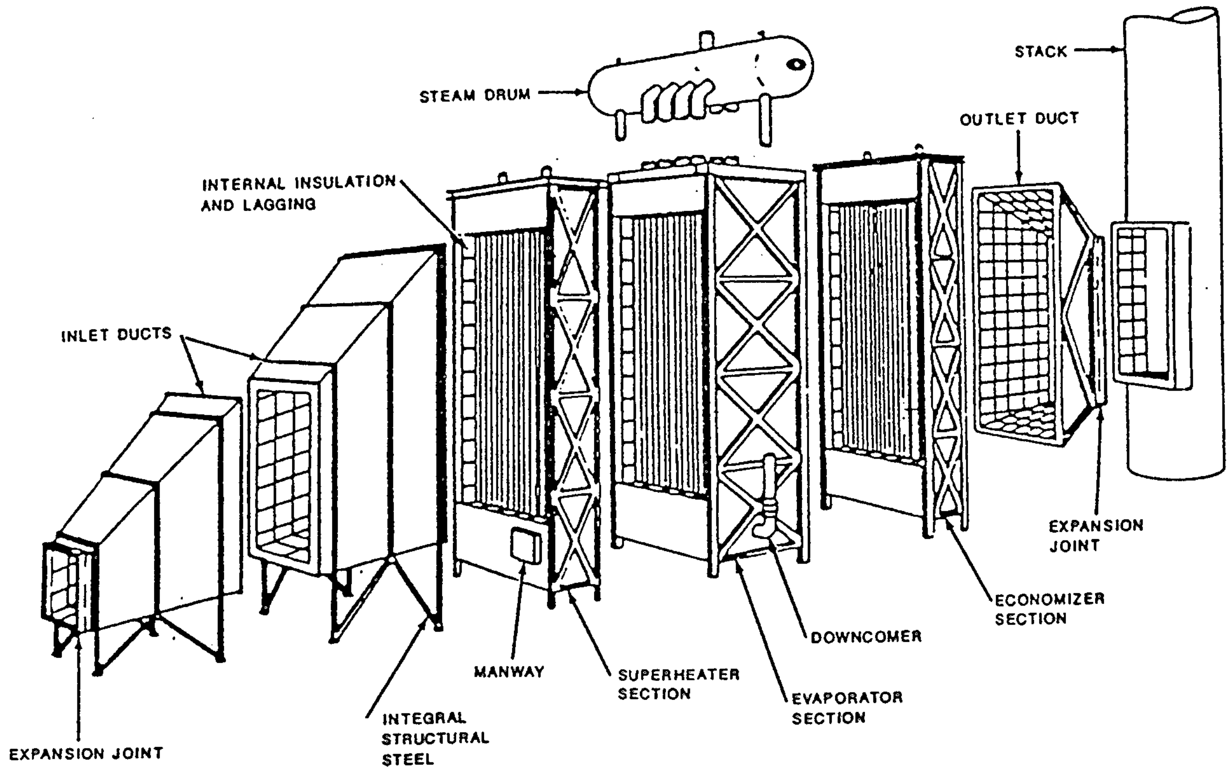

Figure 3-3.
Modular Construction of the Heat Recovery Steam Generator

To ensure a fair cost comparison of a system using cogeneration units with the existing steam-only system, the cogeneration units must match the capacity of Boilers 5 and 6 as closely as possible – that is, produce a total of about 440,000 pounds per hour of steam at 250 psig. In addition, the cogeneration system must meet the following criteria:

- The cogeneration equipment must fit in the existing space – that is, in the space occupied by the boilers being replaced. We also assumed that, if necessary, a portion of the coal yard can be used to locate some of the cogeneration equipment.

- Each unit must generate no more than 25 MW (the maximum circuit fault load), and the total load must not exceed 75 MW.[2] Those limits are imposed by Pepco's electrical infrastructure (circuit fault protection equipment, switchgear, and transmission lines) supporting the Central Heating Plant.

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[2]Combustion turbines - HRSGs could meet HOTD's peak steam demand of 1.1 million pounds per hour but would generate about 200 MW of electrical power, far more than can be supported by the existing Pepco electrical infrastructure.

Equipment Options

To identify cogeneration equipment that meets our criteria, we contacted various manufacturers of combustion turbines and HRSGs and found two equipment options:

- *Equipment Option 1.* Two 16.9-MW combustion turbine generators and two supplementary-fired HRSGs, each with a capacity of 220,000 pounds of steam per hour. The total steam generation capacity of Option 1 is 440,000 pounds per hour, and the total power generation capacity is 34 MW.

- *Equipment Option 2.* Four 3.5-MW combustion turbine generators and four supplementary-fired HRSGs, each with a capacity of 100,000 pounds of steam per hour heat. The HRSGs included in this option also can be fresh-air-fired. The total steam generation capacity of Option 2 is 400,000 pounds per hour, and the total power generation capacity is 14 MW.

In the following subsections, we briefly discuss those options. Appendix B contains more detailed data about the combustion turbines and steam generators for each option, as well as conceptual arrangement sketches. Appendix B also contains information about a cogeneration cycle comprising two 37.7-MW combustion turbine generators and two unfired HRSGs (i.e., steam is produced solely by the exhaust energy from the combustion turbine); each has a capacity of 200,000 pounds of steam per hour. We eliminated that cycle from further consideration because the amount of electricity generated by each combustion turbine exceeds Pepco's single fault load capacity by 12.7 MW. However, that option might be feasible, depending on the cost of modifying the service substation to upgrade the distribution switchgear to handle a circuit fault load larger than 25 MW.[3]

Equipment Option 1

Equipment Option 1 comprises two Asea Brown Boveri (ABB) combustion turbines each rated at 16.9 MW and each exhausting to a supplementary-fired HRSG rated at 220,000 pounds per hour of 250 psig saturated steam. Table 3-1 lists the major characteristics of the ABB combustion turbine and the summary data for the HRSG, made by Energy Recovery International (ERI). Appendix B shows possible arrangements of the ABB combustion turbines – HRSGs.

[3]To obtain an estimate of the cost of expanding the switchgear capability, GSA must submit a formal project request to Pepco.

Table 3-1.
Equipment Option 1: Combustion Turbine - Supplementary-Fired Heat Recovery Steam Generator Cycle

Design parameter	Specification
Combustion turbine	
Manufacturer	Asea Brown Boveri
Model	GT35
Number of units	2
Rating	16.9 MW
Overall dimensions	71' L × 10' W × 18.5' H (31' H over exhaust duct)
Heat rate	10,660 Btu/kWh
Exhaust gas flow rate at rated output	728,000 lb/hr
Exhaust gas outlet temperature	705°F
Fuel consumption	1.8×10^8 Btu/hr
Heat recovery steam generator	
Manufacturer	ERI
Number of units	2
Steam generation rate	220,000 lb/hr (supplemental firing) 62,000 lb/hr (unfired)
Fuel consumption	170 MMBtu/hr
Design steam pressure	350 psig
Steam outlet pressure	250 psig
Design steam temperature	700°F (tubes), 650°F (header)
Steam outlet temperature	407°F
Feedwater inlet temperature	180°F
Gas outlet temperature	330°F (supplemental firing) 353°F (unfired)

Equipment Option 2

The second equipment option we selected for analysis utilizes four HRSGs that can be supplementary fired utilizing exhaust gases from combustion turbines, fired separately with fresh air, or operated at a reduced load using only the exhaust from combustion turbines. This combination allows complete flexibility to generate steam with or without the combustion turbine in operation (fresh-air firing requires no operation of the combustion turbines) or to utilize the exhaust from the combustion turbines when electrical power is needed but steam demand is low and supplemental firing is not utilized.

This cycle is based on using four 3.5-MW Solar Centaur 40-T4700 combustion turbines, each exhausting to an HRSG made by ERI and rated at 100,000 pounds per hour of 250 psig saturated steam. ERI indicated that this HRSG is about the largest made for fresh-air firing. Table 3-2 lists the major characteristics of the Solar Centaur combustion turbine and summary data for the ERI HRSG for three cases: supplemental firing, no supplemental firing, and fresh-air firing. Appendix B shows a typical arrangement of this equipment option.

Table 3-2.
Equipment Option 2: Combustion Turbine – Supplementary-Fired or Fresh-Air-Fired Heat Recovery Steam Generator Cycle

Design parameter	Specification
Combustion turbine	
Manufacturer	Solar
Model	Centaur 40-T4700
Number of units	4
Rating	3.5 MW
Overall dimensions	28' L × 8' W × 10' H
Heat rate	12,883 Btu/kWh
Exhaust gas flow rate at rated output	147,274 lb/hr
Exhaust gas outlet temperature	829°F
Fuel consumption	45.51 MMBtu/hr
Heat recovery steam generator	
Manufacturer	ERI
Number of units	4
Steam generation rate	100,000 lb/hr (supplemental firing) 100,000 lb/hr (fresh-air firing) 18,000 lb/hr (unfired)
Fuel consumption	88 MMBtu/hr (supplemental firing) 116 MMBtu/hr (fresh-air firing)
Design steam pressure	350 psig
Steam outlet pressure	250 psig
Design steam temperature	700°F (tubes); 650°F (header)
Steam outlet temperature	407°F
Feedwater inlet temperature	108°F
Gas outlet temperature	301°F (supplemental firing) 294°F (fresh-air firing) 331°F (unfired)

CHAPTER 4

Economic and Environmental Feasibility of Cogeneration

To be an attractive operational alternative for HOTD, a system using cogeneration units must be more cost-effective than the existing steam-only system. In addition, the cogeneration system must comply with environmental guidelines. This chapter discusses our assessment of each of those criteria.

ASSESSMENT OF ECONOMIC FEASIBILITY

Approach

To assess the economic feasibility of cogeneration, we compared the costs that differ between the existing steam-only system and a system with cogeneration. Those costs are the capital costs of procuring and installing cogeneration equipment and the energy costs. For a system using cogeneration units, the energy costs include the fuel costs and the credits from the sale of electricity to Pepco; for the existing steam-only system, the energy costs are the fuel costs only. We assumed that all other costs — maintenance and personnel, for example — would be equal. As the base year for our calculations, we used 2002, which is the earliest year that cogeneration would be on line given the approval, permitting, and construction time requirements.

We used two financial analysis techniques — net present value and payback period — as the basis for identifying the more cost-effective operating scenario. For this analysis, the NPV is the initial capital investment cost plus the annual energy cost savings over a 20-year period. The energy cost savings is the energy cost of the steam-only system less the energy cost of the system with cogeneration. A positive NPV would indicate that HOTD would be better off using cogeneration.

Assuming the NPV is positive, the payback period can then be used as an indicator of how quickly HOTD will recover its initial capital investment. The longer it takes to recover the initial investment, the higher the risk of unforeseen factors impacting the anticipated savings. For this analysis, payback (in years) is the capital cost divided by the energy savings (in dollars per year).[1] Federal energy conservation guidelines indicate that, for a project to be feasible, the

[1] A simple payback period is used for evaluating these cogeneration options. The energy savings over the 20-year period are not discounted to account for the time value of money. The payback period will be somewhat higher if discounting is used.

payback period should be 10 years or fewer. In contrast, for-profit firms generally require a payback period of considerably less time.

In the following subsections, we present the capital and energy costs associated with cogeneration then discuss the economic feasibility of cogeneration relative to the existing steam-only system.

Capital Costs

The capital costs include the costs of purchasing the combustion turbines and the HRSGs; the costs of connecting to the Pepco grid; plant construction costs (demolition, general construction, auxiliaries, etc.); and the supplemental costs of engineering, construction management, and administration. Appendix C provides detailed information about our assumptions and our sources of cost data. Table 4-1 shows the total capital costs, in 1995 dollars, for the two equipment options. Given a 3 percent annual inflation rate, Option 1 would cost $57 million in 2002, and Option 2 would cost $37 million.

Table 4-1.
Estimate of Capital Procurement and Construction Costs (1995 dollars)

Item	Equipment Option 1[a]	Equipment Option 2[b]
Combustion turbine	16,280,000	7,040,000
HRSG	4,620,000	3,500,000
Electric tie-in	4,800,000	4,800,000
Demolition	2,250,000	2,250,000
General construction	1,125,000	1,125,000
Auxiliary equipment	4,004,000	3,003,000
Pipe, valves, and fittings	5,824,000	4,368,000
Stack	972,800	466,400
Supplemental costs	5,981,370	3,982,860
Total	45,857,170	30,535,260

[a] Two ABB GT35 combustion turbine – HRSG units, each rated at 16.9 MW with a capacity of 220,000 pounds of steam per hour. Each turbine costs an estimated $8,140,000, and each HRSG costs $2,310,000.

[b] Four Solar Centaur 40-T4700 combustion turbine – HRSG units, each rate at 3.5 MW with a capacity of 100,000 pounds of steam per hour. Each turbine costs an estimated $1,760,000, and each HRSG costs $875,000.

Energy Costs

In our analysis, the energy costs include both the fuel costs and the credits from the sale of electricity to Pepco. We based our calculation of the annual energy costs for the cogeneration and steam-only systems on the annual and daily steam production, the annual amount of electricity generated and its selling price, the efficiency of the boilers, and the price of boiler fuel.

The amount of steam that HOTD generates annually drives both the annual boiler fuel consumption as well as the annual amount of electricity produced. The annual steam production is the same for each cogeneration scenario as well as the steam-only option. Our design basis for steam production is 2.9×10^9 pounds per year, which assumes that demand will grow 10 percent over HOTD's 10-year historical average demand of 2.6×10^9 pounds of steam per year.[2,3,4]

The portion of the annual steam production supplied by the combustion turbines – HRSGs varies for each equipment option and is determined from HOTD's daily steam production records. We assumed that the cogeneration units will run at rated capacity and that the remaining boilers will supply the balance of the demand. Equipment Option 1 — two ABB GT35 combustion turbines and HRSGs — will produce 2.4×10^9 pounds of steam per year, while Equipment Option 2 — four Solar Centaur 40-T4700 combustion turbines and HRSGs — will produce 2.28×10^9 pounds of steam per year. The remaining boilers will supply the balance of the annual demand of 2.9×10^9 pounds per year. (Refer to Appendix D for the specific calculations.)

The amount of steam produced by the cogeneration equipment determines how much fuel is required and how much electricity the turbines will generate over the course of a year. Given those amounts, we can then calculate fuel costs and electricity credits for the cogeneration and existing steam-only systems. We then use those data to calculate the energy cost savings associated with the cogeneration systems relative to the existing system. The following subsections summarize key elements of those calculations.

Fuel Costs

For both operating scenarios — existing steam-only system and a system with cogeneration units — we assumed that HOTD would burn natural gas only. In 1994, natural gas cost \$3.60 per MMBtu. Using fuel escalation factors

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[2] HOTD's historical annual fuel consumption has averaged 3.27×10^{12} Btu. Given that the boilers are 80 percent efficient, $[(3.27 \times 10^{12}$ Btu) (80 percent)]/(1,000 Btu per pound) = 2.6×10^9 pounds of steam per year. We confirmed the steam load by examining the 10 a.m. readings taken during the severe winter of 1994; the cumulative demand profile for that period was found to be 2.9×10^9 pounds per hour.

[3] If HOTD's steam-generating capacity remains the same but the demand for steam increases 10 percent, HOTD would no longer be able to meet its desired 100 percent redundancy during some periods of peak demand. However, the maximum demand occurs for only short periods, on the order of hours; thus, the 100 percent redundancy would be in effect more than 95 percent of the time.

[4] Potential sources of increased demand include the Southeast Federal Center (SEFC), the Navy Yard, and the Capitol Heating Plant. (Appendix H contains data on the SEFC extension.) The demand for steam also would increase if HOTD switched from electrically driven chillers to steam absorption chillers.

developed by the National Institute of Standards and Technology, we estimate that natural gas will cost $4.07 per MMBtu in 2002.[5]

To calculate the fuel cost for the operation of the cogeneration units, we assumed that the combustion turbines – HRSGs would run at full capacity:

- Two ABB GT35 combustion turbines and HRSGs would operate for 5,438 equivalent full-power hours annually and generate 2.4×10^9 pounds of steam and 184 million kWh of electricity; that production rate requires 3.81 million MMBtu of fuel at a cost of $15.5 million in 2002 dollars.

- Four Solar Centaur 40-T4700 combustion turbines and HRSGs would operate for 5,700 equivalent full-power hours annually and generate 2.28×10^9 pounds of steam and 79.8 million kWh of electricity; that production rate requires 3.04 million MMBtu of fuel at a cost of $12.4 million in 2002 dollars.

For the existing steam-only system, we based the energy costs solely on the cost of the natural gas needed to produce the equivalent amount of steam that the cogeneration units would produce and assumed that the existing Boilers 5 and 6 would operate at 80 percent efficiency:

- To produce the annual equivalent amount of steam as Equipment Option 1 — 2.4×10^9 pounds per year — Boilers 5 and 6 would require 3×10^6 MMBtu of fuel at a cost of $12.2 million in 2002 dollars.

- To produce the annual equivalent amount of steam as Equipment Option 2 — 2.28×10^9 pounds per year — Boilers 5 and 6 would require 2.85×10^6 MMBtu of fuel at a cost of $11.6 million per year in 2002 dollars.

Electricity Credits

We calculated electricity credits for two cases:

- GSA sells all electricity generated by HOTD to Pepco in accordance with prevailing rates and rules in effect for non-utility generators.[6]

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[5] National Institute of Standards and Technology, *Energy Price Indices and Discount Factors for Life Cycle Cost Analysis,* Annual Supplement, Handbook 135, October 1994.

[6] HOTD could bypass the Pepco system only if it had its own primary and backup electrical supplies. Cogeneration would provide primary electrical service, but HOTD would still have to depend on Pepco for backup electrical service. Because it must rely on Pepco for backup electrical service, it would not make sense to invest in an internal electric distribution system for primary service. Pepco does not have a rate for backup service only.

- GSA uses a portion of the cogenerated electricity to meet the requirements at the HOTD plants and transmits — wheels — the excess cogenerated electricity to other GSA facilities over Pepco's lines. (Wheeling requires approval by the D.C. Public Service Commission.[7] Although the Public Service Commission has not yet approved wheeling, we evaluated the financial implications to HOTD if wheeling were allowed because Federal regulators are showing increased interest in wheeling as a means of deregulating the power industry.)

Federal regulations require utility companies to buy electricity generated by any qualified non-utility facility — that is, any facility not engaged primarily in the generation or sale of electric power. Rates that Pepco will pay for power generated by a non-utility are regulated by the D.C. Public Service Commission. We projected that Pepco's annualized rate for purchasing electricity from HOTD in 2002 will be \$0.0397 per kWh. (Appendix D provides a derivation of this purchase rate, and Appendix E contains Pepco's schedule for purchasing electricity.)

Utilities that allow wheeling charge a fee for transmitting the power. Because of the uncertainties associated with wheeling charges, we used a range for our calculations. We assumed a high wheeling cost of \$0.0214 per kWh, which is 110 percent of the transmission credit specified in the Pepco rate schedule for cogeneration, and a low wheeling cost of \$0.006 per kWh, which is the rate charged in Delaware for wholesale wheeling.

The electricity credit is the current price GSA pays for electricity less any wheeling charge. The electricity credits assuming GSA sells the electricity to Pepco are calculated as follows:

- Equipment Option 1 would generate 183.8×10^6 kWh of electricity that is sold at \$0.0397 per kWh to yield a credit of \$7.3 million a year.

- Equipment Option 2 would generate 79.8×10^6 kWh of electricity that is sold at \$0.0397 per kWh to yield a credit of \$3.17 million a year.

To calculate the electricity credits if wheeling is approved, we assumed, based on HOTD's past electricity consumption patterns, that 27.4×10^6 kWh of the cogenerated electricity would be used by the plants and that HOTD would not be assessed a wheeling charge for this power.[8] The credit for cogenerated electricity used in the Central Heating Plant equals \$2.1 million, the amount it

[7] Wheeling may be wholesale or retail. Wholesale wheeling refers to bulk power transmission from a generating facility to a distributor. Retail wheeling refers to power transmission from a generating plant to a customer. Retail wheeling is more appropriate for cogeneration by the HOTD facility.

[8] Pepco's bills to GSA show that the peak electricity demand in 1993 was 9,700 kW (8,500 kW at the Central Heating Plant and 1,200 kW at the West Heating Plant). An internal electricity consumption rate of 10,000 kW is a reasonable design base for our calculations because it allows for short-term surges. Table D-7 (Appendix D) contains 1993 data.

currently pays Pepco for electricity. We calculated the charges and resulting credits for wheeling the remaining electricity as follows:

- With Equipment Option 1, GSA would wheel 156.4×10^6 kWh to other GSA facilities. At the high wheeling charge, the resulting credit would be \$10.7 million; at the low wheeling charge, the credit would be \$13.1 million.
- With Equipment Option 2, GSA would wheel 79.8×10^6 kWh to other GSA facilities. At the high wheeling charge, the resulting credit would be \$5 million; at the low wheeling charge, the credit would be \$5.78 million.

Energy Cost Savings

Table 4-2 shows the energy costs for both cogeneration equipment options, the equivalent fuel cost for the existing steam-only system, and the energy cost savings that would result from cogenerating electricity rather than generating steam only. Depending on the regulatory environment and the equipment option selected, the energy costs could be reduced anywhere from \$2 million to nearly \$10 million per year.

Table 4-2.
Comparison of Energy Savings for Equipment Options 1 and 2 and for Wheeling versus No Wheeling (\$ millions, year 2002)

	Equipment Option 1		Equipment Option 2	
Cost category	Wheeling not allowed	Wheeling allowed	Wheeling not allowed	Wheeling allowed
Cost of fuel for operation of combustion turbines – HRSGs	15.5	15.5	12.40	12.40
Credit for sale of electricity to Pepco	7.3	10.7 – 13.1[a]	3.17	5.00 – 5.78[a]
Net fuel cost for operation of combustion turbines – HRSGs	8.2	2.4 – 4.8	9.23	6.62 – 7.40
Equivalent fuel cost for existing steam-only boilers	12.2	12.2	11.60	11.60
Annual energy cost savings	4.0	7.4 – 9.8	2.37	4.20 – 4.98

[a] Assumes an upper price of \$0.0214 per kWh and a lower price of \$0.006 per kWh.

The primary uncertainty associated with the calculation of the energy cost savings is the price that Pepco will pay for electricity and their charges for wheeling. The electricity values used in those calculations could change based on D.C. Public Service Commission hearings between now and 2002.

Economic Feasibility of Cogeneration

The net present value of the annual energy cost savings and the capital cost of the equipment required to achieve those savings determines if cogeneration is economically feasible. To calculate the NPV of each equipment option, we deducted the capital and installation costs of the cogeneration equipment from the present value of the fuel savings over the next 20 years.

Table 4-3 highlights the resulting NPVs, in 2002 dollars, for each equipment option and each scheme under which Pepco may purchase or allow the transmission of the electricity. In all cases, the NPV is positive, indicating that HOTD would save by replacing Boilers 5 and 6 with cogeneration units. Of the two cogeneration options, Equipment Option 1 is more attractive; its NPV is higher regardless of how the credit for the electricity is determined. If wheeling is not allowed, the NPV of Option 1 is about $10 million higher than that of Option 2; if wheeling is allowed, the NPV would be anywhere from $38 million to $67 million higher.

Table 4-3.
Summary of Cogeneration Financial Analysis
($ millions, year 2002)

Cost category	Equipment Option 1		Equipment Option 2	
	Wheeling not allowed	Wheeling allowed	Wheeling not allowed	Wheeling allowed
Annual energy savings	4.0	7.4 – 9.8[a]	2.37	4.20 – 4.98[a]
20-year present value of energy savings	71.3	132.0 – 175.0	42.25	75.0 – 88.8
Capital investment	56.5	56.5	37.5	37.5
NPV	14.8	75.42 – 118.20	4.75	37.4 – 51.3
Payback period (years)	14.0	7.6 – 9.8	16.0	7.5 – 9.0

[a] Assumes an upper price of $0.0214 per kWh and a lower price of $0.006 per kWh.

While HOTD would be better off financially by using cogeneration, the savings would be marginal under current regulations. The long payback period also reduces the attractiveness of cogeneration. As shown in Table 4-3, it would take HOTD 14 years to recover its investment in equipment for Option 1 through the resulting energy savings. That length of time exceeds Federal return on investment guidelines that require a 10-year payback period.

ASSESSMENT OF ENVIRONMENTAL FEASIBILITY

Another component to assessing the feasibility of cogeneration is the effect on the environment that such a change in operations would have. Environmental impacts encompass a variety of areas, including air, water, aesthetics, and noise. In general, the operational changes associated with cogeneration are likely to have minimal or no environmental impact. However, air pollution is of particular concern for the HOTD plants, so any change that might affect HOTD's plant emissions needs to be reviewed carefully.

Several government agencies have issued regulations applicable to the emission of pollutants.[9] The regulations most pertinent to HOTD are the limits specified in the U.S. Environmental Protection Agency's National Ambient Air Quality Standards. NAAQS establishes limits for ground-level concentrations of seven pollutants — nitrogen dioxide (NO_2), SO_2, carbon monoxide, hydrocarbons, oxidants, particulate matter, and lead. At the HOTD plants, the pollutants that pose the most difficulty for HOTD's compliance are NO_2 and SO_2. Recently completed modeling analyses show that the NO_x and SO_2 concentrations at ground level near both plants exceed NAAQS. Table 4-4 shows the various NAAQS limits for those two pollutants. HOTD is evaluating ways to bring both plants into compliance with NAAQS.

Table 4-4.
NAAQS Maximum Allowable Concentration Levels of Nitrogen Dioxide and Sulfur Dioxide (micrograms per cubic meter)

Maximum concentration	NO_2	SO_2
Annual	100	80
3 hours	Not specified[a]	1,300
24 hours	Not specified[a]	365

Source: General Services Administration, *Draft Environmental Impact Statement*, Bibb and Associates, June 1995.

[a] While no Federal 3- or 24-hour limits exist for NO_2, some states have adopted such limits, and similar standards might be incorporated into NAAQS in the future.

HOTD needs to consider any changes to its operations such as the addition of cogeneration that may affect its emissions rates. Modern design combustion turbines and supplemental-fired HRSGs offer reduced NO_x emission rates when firing natural gas, compared with the existing boilers in the HOTD plants. Table 4-5 compares the emission rates of the existing steam-only system with the emissions of the two cogeneration options when burning gas. When firing

[9] Other regulations include the Clean Air Act and the National Environmental Policy Act. The District of Columbia's Department of Consumer and Regulatory Affairs and the National Capital Planning Commission also have issued environmental regulations with which HOTD must comply.

natural gas, the combustion turbines – HRSGs emit about half the NO_x emitted from the existing boilers. At ground level, the concentration of NO_x from cogeneration would not be substantially different from the current levels. (Appendix F provides the calculations made to estimate the NO_x emissions.)

Table 4-5.
Emission Rates When Burning Natural Gas (pounds per MMBtu)

Equipment	NO_x	SO_2
Existing steam-only system (Boilers 5 and 6)	0.20	Negligible
Cogeneration Option 1 (average)	0.13	Negligible
Cogeneration Option 2 (average)	0.10 – 0.12	Negligible

Note: The rates shown were assumed to occur at the exit of the smokestack in the modeling studies and were then used to model the ground-level concentration of pollutants in micrograms per cubic meter, which is the basis for NAAQS compliance.

When burning fuel oil, the emission rates of the combustion turbines – HRSGs would be higher than those of the existing boilers, as shown on Table 4-6. Unlike NO_x emissions, the SO_2 emissions are proportional to the sulfur content of the fuel oil. The figures shown for the two cogeneration options are general parameters; HOTD would need to compare the sulfur content of the fuel oil it burns with the manufacturers' guidelines to obtain a more definitive sulfur emission rate when burning oil.

Table 4-6.
Emission Rates When Burning Fuel Oil (pounds per MMBtu)

Equipment	NO_x	SO_2
Existing steam-only system (Boilers 5 and 6)	0.16	0.25
Cogeneration Option 1 (average)	Not applicable	Not applicable
Cogeneration Option 2 (average)	0.18	0.37[a]

Note: The rates shown were assumed to occur at the exit of the smokestack in the modeling studies and were then used to model the ground-level concentration of pollutants in micrograms per cubic meter, which is the basis for NAAQS compliance.

[a] Reflects emission rate when firing the turbine only.

To bring both plants into NAAQS compliance, HOTD will have to implement a change at the plants in order to burn fuel oil even if cogeneration units are not installed. Among other options for bringing the plants into compliance, HOTD could add pollution control equipment, use reduced-sulfur fuel oil, increase the height of the exhaust stacks, reduce the amount of fuel oil it burns, or implement some combination of those options. The decrease in emissions from implementing these pollution reduction options may be enough to offset any marginal increases in emission rates from oil-fired cogeneration equipment.

CHAPTER 5

Regulatory and Political Issues

A District of Columbia regulation prohibits the construction or operation of any cogeneration plant in the District until the D.C. Public Service Commission defines, and the D.C. Council approves, specific standards for cogeneration facilities. We provide a copy of that regulation — *Cogeneration Facilities Appropriateness Standards Act of 1993* — in Appendix G.

The *Appropriateness Standards Act* was the result of local citizen opposition to a cogeneration plant proposed by Georgetown University in 1988. The university planned to add a combustion turbine – HRSG to its existing on-campus power plant to meet its energy needs over the next 25 years. At the same time, the university planned to shut down an inefficient coal-fired fluidized-bed boiler and reduce its use of two older oil-fired boilers. The university proposed a cogeneration facility because it believed cogeneration would provide energy more cleanly, more dependably, and less expensively than any other option. (See Appendix H for more detailed information about the Georgetown University project.)

Georgetown University first included the cogeneration project in its campus plan in 1988. At that time, it began holding meetings with the community to explain and discuss the project, and it began negotiating with Pepco regarding terms of the power purchase agreement. The university also began the process of obtaining required reviews and approvals from various D.C. government agencies, including the Public Service Commission, Board of Zoning Adjustment, Department of Consumer and Regulatory Affairs, Fire Department, Police Department, Department of Public Works, Commission on Fine Arts, Office of Planning, and Historic Preservation Review Board; from the Old Georgetown Board; and from the Federal Energy Regulatory Commission and the Federal Aviation Administration.

As of July 1993, after several years of design and analysis effort and numerous successful permit applications, the university had obtained all required permits except for the building permit. The university expected to obtain the building permit by October 1993.

While the university was successfully obtaining the necessary permits, a citizens coalition fought against the project on a variety of grounds. For instance, it objected to having a high-pressure gas pipeline under 35th and Prospect streets, a tank farm on the campus for storing fuel oil, and new high-voltage power lines. However, it focused on concerns about electromagnetic field (EMF) radiation that would emanate from the 69 kV transmission lines connecting the cogeneration facility to the Pepco grid. The coalition cited studies suggesting a correlation between exposure to EMF emissions and increased risk of cancer.

Coalition objections were overruled. For example, in March 1991, the Federal Energy Regulatory Commission denied a coalition request for a rehearing, noting that the community misinterpreted information. In January 1993, the D.C. Court of Appeals rejected all appeals by the citizens coalition and affirmed the Board of Zoning Adjustment's approval of the facility. Nevertheless, the local opposition was successful in convincing the D.C. Council to reject the proposed cogeneration plant, primarily on the basis of concerns about EMF radiation. The D.C. Council rejected the project on those grounds even though 69 kV lines are not uncommon in the District of Columbia and no quantitative limits on EMF have been imposed by local or Federal regulations. The D.C. Council passed the *Appropriateness Standards Act* in late 1993.

The D.C. Public Service Commission has not yet prepared the energy conservation and environmental protection standards for the location, size, ownership, and power consumption of cogeneration facilities, as required by the *Appropriateness Standards Act,* nor does it have any plans to do so at this time.[1] Moreover, the act set no deadline for completion of the standards. Whenever they are developed, the appropriateness standards are likely to result in siting and environmental hurdles that will increase the cost of any cogeneration plant project within the District of Columbia.

It is unclear whether GSA's status as a U.S. government agency provides practical options with respect to the D.C. law prohibiting cogeneration. The Federal government may be in a position to negotiate a cogeneration project on two grounds:

- Cogeneration at the Central Heating Plant will cause no negative environmental effects as cited in Section 2(c) of the *Appropriateness Standards Act.* The size of the plant will remain the same, the plant is not located near a residential community or fragile ecosystems, and the fuel used to power the cogeneration units would be the same as that used now to power the steam boilers.

- The transmission lines connecting the Central plant to the Pepco grid are 35 kV rather than 69 kV. Thus, the concern about EMF radiation as specified in Section 2(d) of the *Appropriateness Standards Act* is not an issue at the Central Heating Plant.

[1] Telephone conversation with staff member of the D.C. Public Service Commission, April 24, 1995.

APPENDIX A

Existing Facilities

Existing Facilities

The Heating Operation and Transmission District operated by the General Services Administration (GSA) has two plants — the Central Heating and Refrigeration Plant and the West Heating Plant — and a steam distribution system consisting of approximately seven miles of underground tunnels and five miles of buried pipe. The Central and West plants supply steam at 250 psig to approximately 100 buildings. In addition, the Central plant supplies chilled water to the Agriculture and Forrestal buildings.

The district heating system is considered critical to the functioning of the Federal government in that it provides steam for space heating, hot water, cafeteria use, and humidity control to such important buildings as the White House, Old Executive Office Building, the State Department, and the buildings of the Smithsonian Institution. The proper functioning of the system is essential since the individual buildings have no backup systems.

Central Heating and Refrigeration Plant

The Central Heating and Refrigeration Plant, located at 13th and C Streets, SW, was completed in 1933 and went into service in January 1934. The Central plant originally contained six coal-fired, underfeed, multiple-retort stoker boilers. In 1972, GSA awarded a contract for the removal of four of the six original boilers and installation of three new oil-fired boilers. During the contract period, the oil shortage developed, so only Boilers 3 and 4 were replaced. The portion of the contract covering the removal of the last two boilers and installation of the third boiler was terminated. In the late 1970s, GSA replaced the original Boilers 5 and 6 with new pulverized-coal boilers and new electrostatic precipitators. More recently, GSA modified Boilers 3 and 4 so they could fire both natural gas and oil, and it modified Boilers 5 and 6 so they could burn both oil and coal. In 1994, the controls on Boilers 3 and 4 were changed from the original analog to digital. Table A-1 provides data on the existing boiler equipment, and Table A-2 provides data on the chiller equipment.

Boilers 1 and 2 were shut down in 1980 following a memorandum of understanding between GSA and the District of Columbia government stating that Boilers 1 and 2 cannot operate until GSA installs adequate particulate control equipment. In 1985, GSA initiated reconstruction of those boilers; the boilers will be capable of firing coal and natural gas. Completion is scheduled for 1995. When Boilers 1 and 2 are returned to service, the fuel firing capability of the Central Heating Plant boilers will be coal/gas on 1 and 2, oil/gas on 3 and 4, and coal/oil on 5 and 6. The capacity of the Central Heating Plant will be 1,510,000 pounds per hour at 250 psig.

Table A-1.
Central Heating and Refrigeration Plant Boilers

Boiler	Year installed	Fuel	Steam press./temp. (psig/°F)	Design heat input (MMBtu/hr)	Steam flow capacity (pounds per hour)	Particulate control equipment
1[a]	1933	Coal Natural gas	250/sat.	250	175,000 (coal) 180,000 (natural gas)	Baghouse
2[a]	1933	Coal Natural gas	250/sat.	250	175,000 (coal) 180,000 (natural gas)	Baghouse
3	1973	Natural gas Fuel oil	250/sat.	500	400,000	Electro-static pre-cipitator
4	1973	Natural gas Fuel oil	250/sat.	500	400,000	Electro-static pre-cipitator
5	1977	Coal Fuel oil	250/sat.	250	180,000 (coal) 220,000 (fuel oil)	Electro-static pre-cipitator
6	1977	Coal Fuel oil	250/sat.	250	180,000 (coal) 220,000 (fuel oil)	Electro-static pre-cipitator

[a] Being rebuilt; will be returned to service in late 1995.

Table A-2.
Central Heating and Refrigeration Plant Chillers

Chiller	Year installed	Nominal capacity (tons)	Compressor motor drive (horsepower)
1	1957	3,030	3,000
2	1957	2,770	3,000
3	1965	2,350	2,500
4	1965	2,350	2,500
5	1974	1,000	250

On September 8, 1994, the D.C. Department of Consumer and Regulatory Affairs issued GSA a permit restricting fuel use at the Central Heating Plant to only natural gas, except when service is interrupted by the supplier; then only No. 2 "on-road diesel" with a maximum sulfur content of 0.05 percent (K-1 oil) is allowed. In its current configuration, Boilers 5 and 6 at the Central Heating Plant can be operated only during periods of natural gas interruptions. GSA plans to install gas burners on Boilers 5 and 6 in 1995 and 1996. Also, GSA is in the process of finalizing an Environmental Impact Study that indicates compliance with Environmental Protection Agency requirements for all combinations of fuels if the flue gas stack is extended in height. Considering the regulatory reviews and permitting steps, it may be several years before this modification is approved.

The rated steam capacity of the operating boilers at the Central Heating Plant — Boilers 3, 4, 5, and 6 — is 1,240,000 pounds per hour. However, Boilers 3 and 4 appear to be susceptible to low recirculation flows during periods of high steam demands, particularly if subjected to sudden pressure transients such as occur if another boiler trips off line; the problem appears to result because the design operating pressure is 400 psig but the boilers are operated at 250 psig, which affects the density head for recirculation. In addition, Boilers 5 and 6 are undersized and cannot be fired by coal without cofiring with oil; even when burning oil, combustion control is marginal because of high air in-leakage at the stokers. At the present time, with Boilers 1 and 2 in a construction status, and considering the limitations on the remaining boilers, the actual stable steaming capacity of the Central Heating Plant is about 700,000 pounds per hour if natural gas and oil can be fired; if only natural gas can be fired, the steaming capacity is about 500,000 pounds per hour.

West Heating Plant

The West Heating Plant, located at 1051 29th Street, NW, in the Georgetown area of the District of Columbia, was built in 1948. Initially, the West plant was provided with two coal-fired, underfeed stoker boilers. In 1958, GSA added a third boiler, currently designated Boiler 4; it is similar in design to Boilers 1 and 2. In 1966, GSA added two traveling-grate spreader stoker boilers, designated Boilers 3 and 5, rated at the same steam capacity and pressure as Boilers 1, 2, and 4. In 1972, GSA awarded a construction contract to convert all five boilers from coal to oil. However, in 1973, portions of the contract were terminated in response to changes in national policy to utilize coal; Boilers 3 and 5 were converted to fuel oil with coal burning ability eliminated. In the mid-1970s, gas burners were added to Boilers 3 and 5. In 1980, in conformance with the memorandum of understanding with the D.C. government, GSA shut down Boiler 4 to add particulate removal equipment; Boiler 4 is not currently operational. In 1989, GSA replaced the coal stokers and installed gas burners on Boilers 1, 2, and 4. At the present time, the fuel firing capability is coal/gas on Boilers 1, 2, and 4, and oil/gas on Boilers 3 and 5. The rated steam capacity of the West Heating Plant is 885,000 pounds per hour at 250 psig. Table A-3 provides data on the boiler equipment for the West Heating Plant.

The West Heating Plant is subject to the same restrictions as the Central Heating Plant — namely, that only natural gas may be burned except in times of gas interruption, when K-1 fuel may be burned.

Table A-3.
West Heating Plant Boilers

Boiler	Year installed	Fuel	Steam press./temp. (psig/F)	Design heat input (MMBtu/hr)	Steam flow capacity (pounds per hour)	Particulate control equipment
1	1948	Coal Natural gas	250/sat.	250	175,000 (coal) 180,000 (natural gas)	Baghouse
2	1948	Coal Natural gas	250/sat.	250	175,000 (coal) 180,000 (natural gas)	Baghouse
3	1966	Fuel oil Natural gas	250/sat.	250	180,000 (fuel oil) 220,000 (natural gas)	Electro-static pre-cipitator
4[a]	1958	Coal Natural gas	250/sat.	250	175,000 (coal) 180,000 (natural gas)	Electro-static pre-cipitator
5	1966	Fuel oil Natural gas	250/sat.	250	180,000 (fuel oil) 220,000 (natural gas)	Electro-static pre-cipitator

[a] Not currently operating.

APPENDIX B

Tabular Data and Arrangement Drawings of Combustion Turbines and Heat Recovery Steam Generators

Tabular Data and Arrangement Drawings of Combustion Turbines and Heat Recovery Steam Generators

This appendix provides tabular data and arrangement drawings of combustion turbines and heat recovery steam generators (HRSGs) considered as options for the Heating Operation and Transmission District, as follows:

- Tables and figures labeled B-1 provide information on a cogeneration cycle comprising two combustion turbine generators and two unfired HRSGs. This cycle is feasible only if the Potomac Electric Power Company upgrades its distribution switchgear to accept a circuit fault load larger than 25 MW.
- Tables and figures labeled B-2 provide information on a cogeneration cycle comprising two combustion turbine generators and two supplementary-fired HRSGs. This cycle corresponds to Option 1 in Chapter 3.
- Tables and figures labeled B-3 provide information on a cogeneration cycle comprising four combustion turbine generators and four supplementary- or fresh-air-fired HRSGs. This cycle corresponds to Option 2 in Chapter 3.

Table B-1A.
Two Combustion Turbines - Unfired Heat Recovery Steam Generator Cycle Combustion Turbine Data
(Page 1 of 1)

Design parameter	Manufacturer: General Electric
Type	MS 6001B
Model	PG 6541B
Number of units	2
Rating	37.7 MW
Overall dimensions	85' L × 12' W × 13' H (25' over inlet duct)
Heat rate	11,034 Btu/kWh
Exhaust gas flow rate at rated output	1.08×10^6 lb/hr
Exhaust gas outlet temperature	1,006°F
Fuel consumption	4.16×10^8 Btu/hr

Table B-1B.
Combustion Turbine – Unfired Heat Recovery Steam Generator Cycle
Steam Generator Data
(Page 1 of 2)

Component	Measure	Outlet	Evaporator	Economizer
Gas turbine exhaust side: GE PG6541B				
Fluid			Flue gas	Flue gas
Fouling resistance	hr-sq. ft-F/Btu		0.001	0.001
Flow rate	lb/hr		1,080,000	1,080,000
Design pressure	in. H_20		20	20
Inlet pressure	in. H_20		10	4.8
Outlet pressure	in. H_20		4.8	0.8
Pressure drop	in. H_20		5.2	4.0
Design temperature (liner)	°F		1050	650
Inlet temperature	°F		1006	429
Outlet temperature	°F		429	263
Temperature drop	°F		577	166
Average heat capacity	Btu/lb-°F		0.268	0.256
Heat released	MMBtu/hr		167.02	45.78
Fuel flow (0 Btu/lb LHV)	lb/hr			
Efficiency	%		99.0	99.0
Cooling side:				
Fluid		Sat. steam	Sat. steam	Water
Fouling resistance	hr-sq. ft-F/Btu		0.001	0.001
Flow rate	lb/hr	199,000	199,600	201,600
Design pressure	psig		350	350
Outlet pressure	psig	250	261	266
Inlet pressure	psig	258		283
Pressure drop	psi	8		17
Design temperature (tubes/hdrs)	°F		700/650	700/650
Outlet temperature	°F	407	410	399
Inlet temperature	°F	409	399	180
Temperature rise	°F	-2	11	219
Heat absorbed	MMBtu/hr		165.39	45.34
Blowdown	5		1	

Table B-1B.
Combustion Turbine – Unfired Heat Recovery Steam Generator Cycle
Steam Generator Data
(Page 2 of 2)

Component	Measure	Outlet	Evaporator	Economizer
Tube bundle data:				
Heating surface	sq. ft		122,700	129,900
Tube diameter/minimum thickness/length	in./in./ft		2/0.105/32	2/0.105/32
Tube material			SA-178 A	SA-178 A
Tube rows			17	18
Tubes per row/circuits			32/All	32/16
Longitudinal tube spacing	in.		4	5
Transverse tube spacing	in.		4	4
Fin density/height	(fins/in.)/in.		6/0.75	6/0.75
Fin thickness/serr. width	in./in.		0.06/10.172	0.06/10.172
Fin material			CS	CS
Headers			2	36
Header diameter/length	in./ft		30/12	6/11
Header material			SA-515 Gr70	SA-106B
Steam drum diameter/length	in./ft		6620	
Steam drum material			SA-515 Gr70	

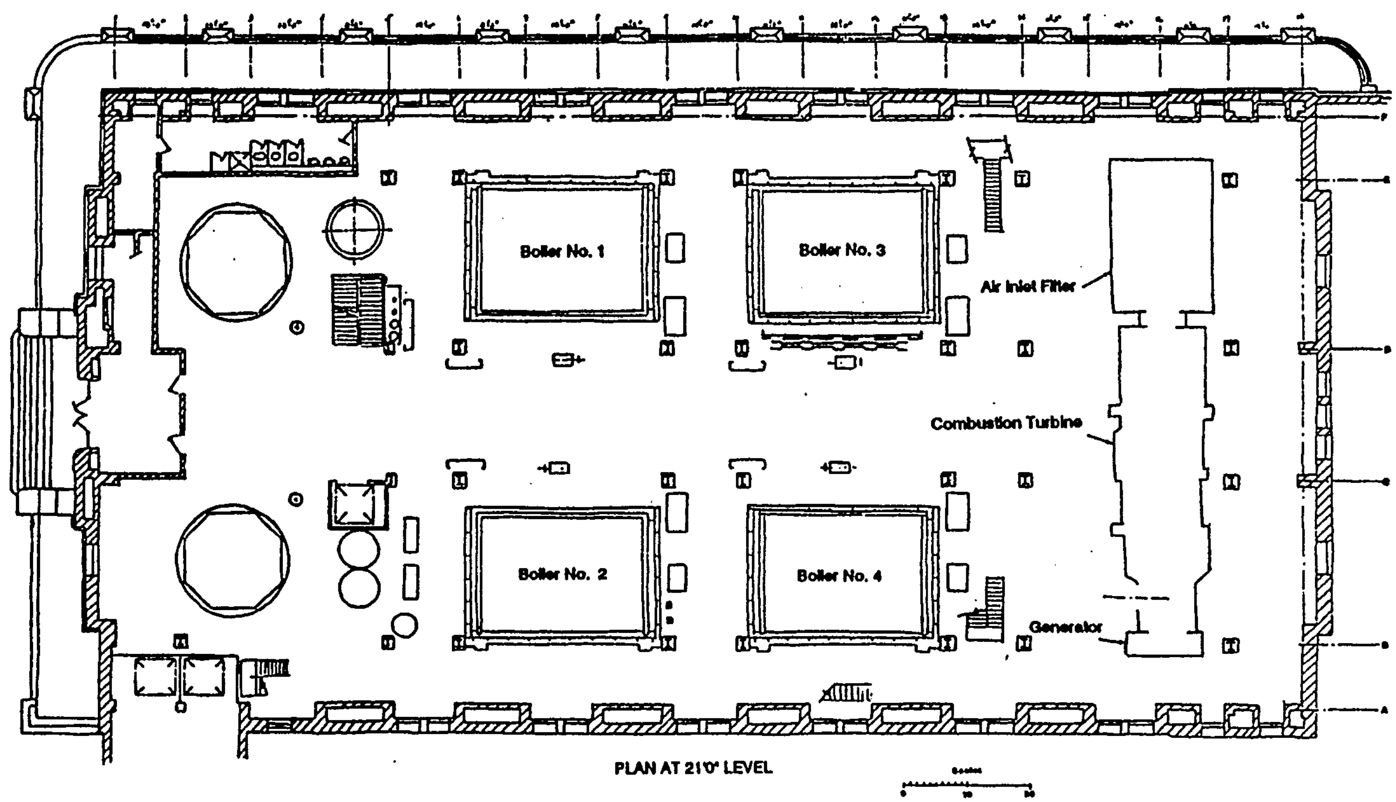

Figure B-1A.
General Electric 37.7 MW Combustion Turbine and Vogt 200,000 lb/hr Unfired HRSG Arrangement in Central Heating Plant Building Plan at Elevation 21 Feet

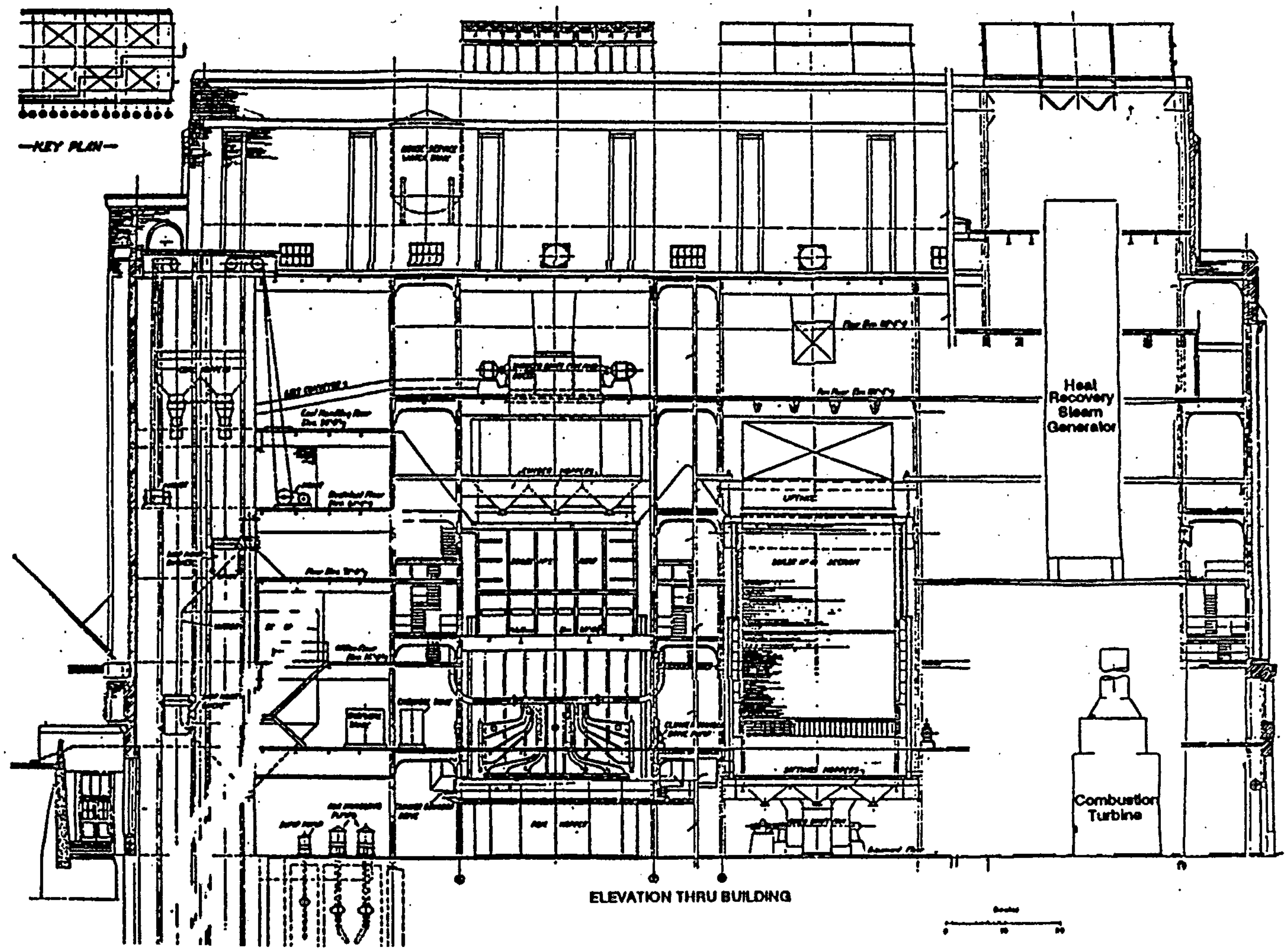

Figure B-1B.
General Electric 37.7 MW Combustion Turbine and Vogt 200,000 lb/hr Unfired HRSG Arrangement in Central Heating Plant Building Sectional Elevation

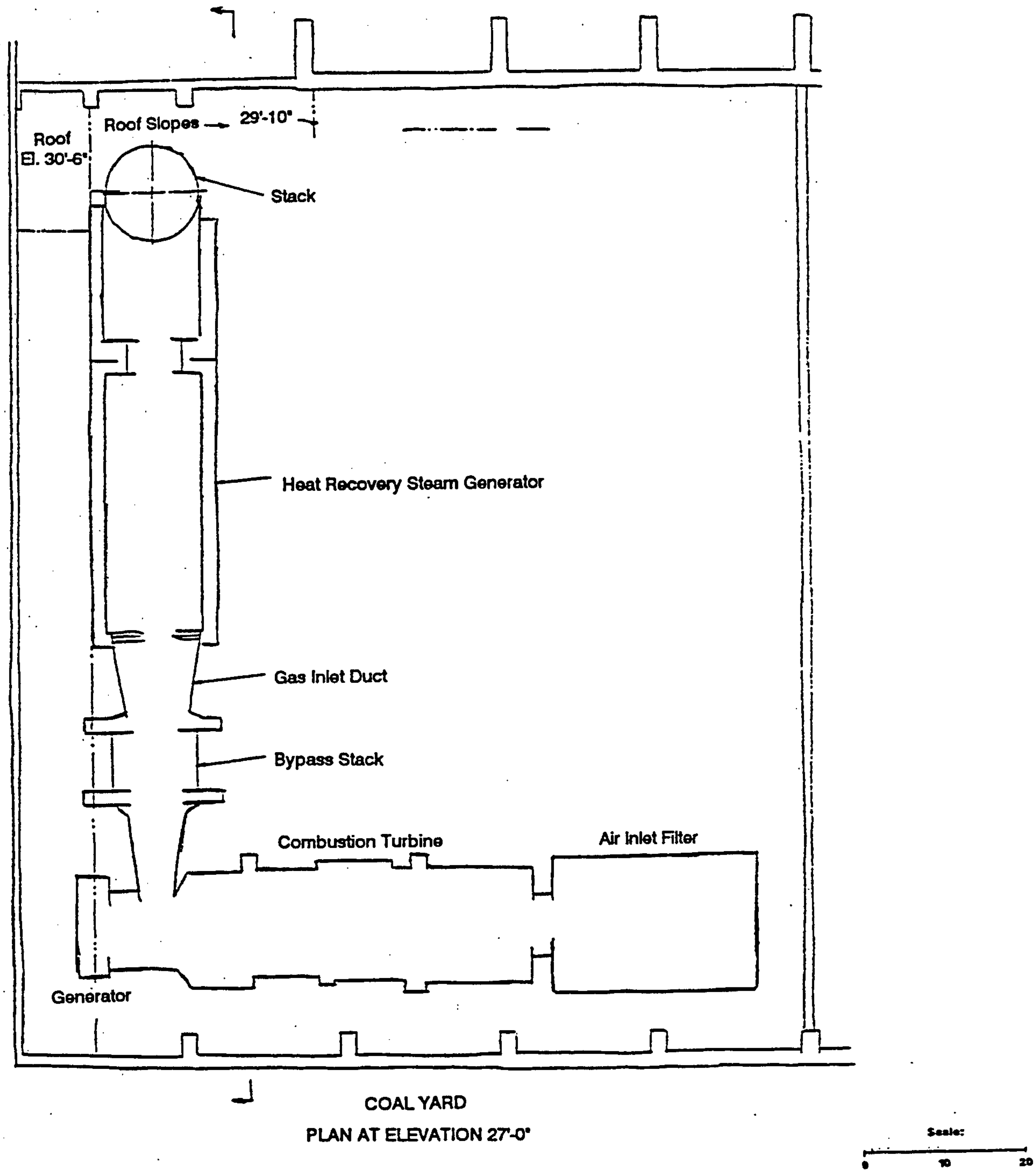

Figure B-1C.
General Electric 37.7 MW Combustion Turbine and Vogt 200,000 lb/hr Unfired HRSG in Coal Yard Plan at Elevation 27 Feet

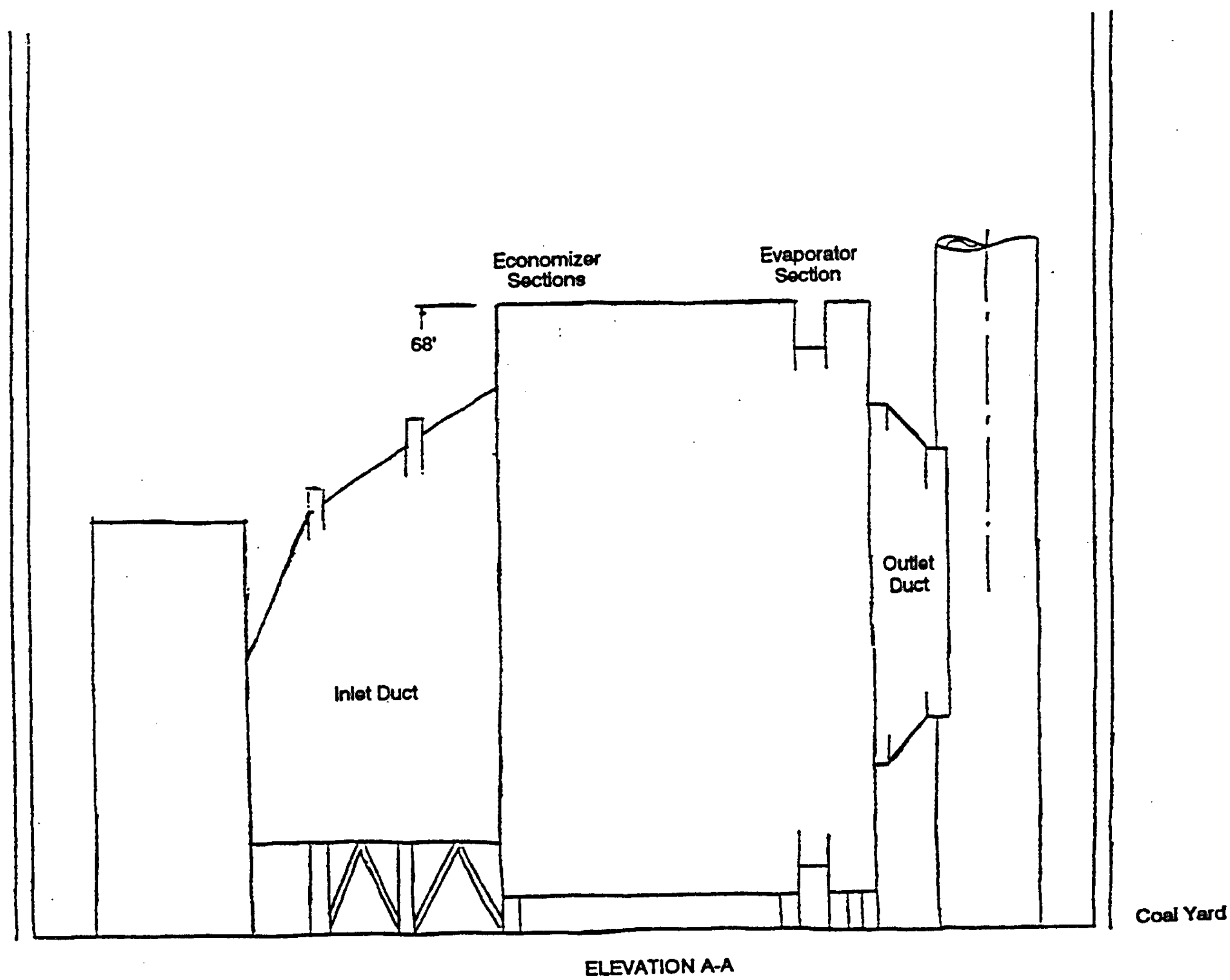

Figure B-1D.
General Electric 37.7 MW Combustion Turbine and Vogt 200,000 lb/hr Unfired HRSG in Coal Yard Sectional Elevation

Table B-2A.
Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Combustion Turbine Data
(Page 1 of 1)

Design parameter	Manufacturer: Asea Brown Boveri (ABB)
Model	GT35
Number of units	2
Rating	16.9 MW
Heat rate	10,660 Btu/kWh
Overall dimensions	81' L × 10' W × 18.5' H (31' H over exhaust duct) (71 excluding MCC compartment)
Exhaust gas flow rate	728,000 lb/hr
Exhaust gas outlet temperature	705°F
Fuel consumption	1.8×10^8 Btu/hr

Table B-2B.
Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data
(Page 1 of 6)

With Supplemental Firing						
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Gas turbine exhaust side: ABB GT35						
Fluid		Flue gas	Flue gas	Flue gas	Flue gas	Flue gas
Fouling resistance (hr-sq. ft-°F/Btu)			0.001	0.001	0.001	0.001
Flow rate (lb/hr)		728,000	736,292	1	736,292	736,292
Design pressure (in. H_20)			20	20	20	20
Inlet pressure (in. H_20)		10	8.8	8.6	7.8	2.5
Outlet pressure (in. H_20)		8.8	8.6	7.8	2.5	0.8
Pressure drop (in. H_20)		1.0	0.2	0.8	5.2	1.7
Design temperature (liner) (°F)			1,550	1,550	1,550	650
Inlet temperature (°F)		705	1,470	1,409	1,147	489
Outlet temperature (°F)		1,470	1,409	1,147	489	330
Temperature drop (°F)		765	61	262	658	159
Average heat capacity (Btu/lb-°F)			0.297	0.292	0.278	0.264
Heat released (MMBtu/hr)		170	13.39	56.47	134.63	30.80
Fuel flow (20,122 (Btu/lb LHV) (lb/hr)		8,292				
Efficiency (%)		99.0	99.0	99.0	99.0	99.0

Table B-2B.

Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data (Page 2 of 6)

With Supplemental Firing						
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Cooling side:						
Fluid	Sat. steam		Water	Sat. steam	Sat. steam	Water
Fouling resistance (hr-sq. ft-°F/Btu)			0.001	0.001	0.001	0.001
Flow rate (lb/hr)	220,000		14,400	60,900	145,200	222,700
Design pressure (psig)			350	350	350	350
Outlet pressure (psig)	250		282	282	282	288
Inlet pressure (psig)	272		283			295
Pressure drop (psi)	22		17			7
Design temperature (tubes/hdrs) (°F)			700/650	700/650	700/650	700/650
Outlet temperature (°F)	408		416	416	416	315
Inlet temperature (°F)	414		315	315	315	180
Temperature rise (°F)	6		101	101	101	135
Heat absorbed (MMBtu/hr)			13.22	55.92	133.33	30.49
Blowdown (%)			1	1	1	

Table B-2B.
Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data
(Page 3 of 6)

With Supplemental Firing						
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Tube bundle data:						
Heating surface (sq. ft)			600	5,800	56,400	26,000
Tube diameter/ minimum/thickness/ length (in./in./ft)			2/0.105/22	2/0.105/22	2/0.105/22	2/0.105/22
Tube material			SA-178 A	SA-178 A	SA-178 A	SA-178 A
Tube rows			2	2	13	6
Tubes per row/circuits			28 All	28 All	28 All	28/14
Longitudinal tube spacing (in)			4	4	4	4
Transverse tube spacing (in.)			4	4	4	4
Fin density/height [(fins/in.)/in.]				6/0.5	6/0.5	6/0.5
Fin thick/serr. width (in./in.)				0.06/0.172	0.06/0.172	0.06/0.172
Fin material			Bar tube	CS	CS	CS
Headers					2	12
Header diameter/length (in./ft)					30/11	6/10
Header material					SA-515 GR70	SA-106 B
Steam drum diameter/length (in./ft)					66/20	
Steam drum material					SA-515 GR70	

Table B-2B.
Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data
(Page 4 of 6)

Unfired						
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Gas turbine exhaust side: ABB GT35						
Fluid		Flue gas	Flue gas	Flue gas	Flue gas	Flue gas
Fouling resistance (hr-sq. ft-°F/Btu)			0.001	0.001	0.001	0.001
Flow rate (lb/hr)		728,000	728,000	1	728,000	728,000
Design pressure (in. H_20)			20	20	20	20
Inlet pressure (in. H_20)		9.0	7.4	7.2	6.7	2.6
Outlet pressure (in. H_20)		7.4	7.2	6.7	2.6	0.8
Pressure drop (in. H_20)		1.0	0.2	0.5	4.1	1.8
Design temp (liner) (°F)			1,550	1,550	1,550	650
Inlet temperature (°F)		705	705	689	618	429
Outlet tempera-ture (°F)		705	689	618	429	353
Temperature drop (°F)		0	16	71	189	76
Average heat capacity (Btu/lb-°F)			0.268	0.266	0.262	0.257
Heat released (MMBtu/hr)		0.0	3.13	13.70	36.03	14.22
Fuel flow (0 Btu/lb LHV) (lb/hr)		0				
Efficiency (%)		99.0	99.0	99.0	99.0	99.0

Table B-2B.
Two Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data
(Page 5 of 6)

Unfired						
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Cooling side:						
Fluid	Sat. steam		Sat. steam	Sat. steam	Sat. steam	Water
Fouling resistance (hr-sq. ft-°F/Btu)			0.001	0.001	0.001	0.001
Flow rate (lb/hr)	62,000		3,700	16,300	42,900	63,500
Design pressure (psig)			350	350	350	350
Outlet pressure (psig)	250		253	253	253	254
Inlet pressure (psig)	252					255
Pressure drop (psi)	2					1
Design temperature (tubes/hdrs) (°F)			700/650	700/650	700/650	700/650
Outlet temperature (°F)	406		407	407	407	495
Inlet temperature (°F)	407		395	395	395	180
Temperature rise (°F)	1		12	12	12	215
Heat absorbed (MMBtu/hr)			3.08	13.56	35.683	14.08
Blowdown (%)			1	1	1	

Table B-2B.

Two Combustion Turbines - Supplementary-Fired Heat Recovery Steam Generator Cycle Steam Generator Data (Page 6 of 6)

	Unfired					
Component	Outlet	Supp. Fire	Evap. 3	Evap. 2	Evap. 1	Economizer
Tube bundle data:						
Heating surface (sq. ft)			600	5,800	56,400	26,000
Tube diameter/ minimum/ thickness/length (in./in./ft)			2/0.105/22	2/0.105/22	2/0.105/22	2/0.105/22
Tube material			SA-178 A	SA-178 A	SA-178 A	SA-178 A
Tube rows			2	2	13	6
Tubes per row/circuits			28/All	28/All	28/All	28/14
Longitudinal tube spacing (in.)			4	4	4	5
Transverse tube spacing (in.)			4	4	4	4
Fin density/height [(fins/in.)/in.]				6/0.5	6/0.75	6/0.75
Fin thick/serr. width (in./in.)				0.06/10.172	0.06/10.172	0.06/10.172
Fin material			Bar tube	CS	CS	CS
Headers					2	12
Header diameter/ length (in./ft)					30/11	6/10
Header material					SA-515 GR70	SA-106 B
Steam drum diameter/length (in./ft)					66/20	
Steam drum material					SA-515 GR70	

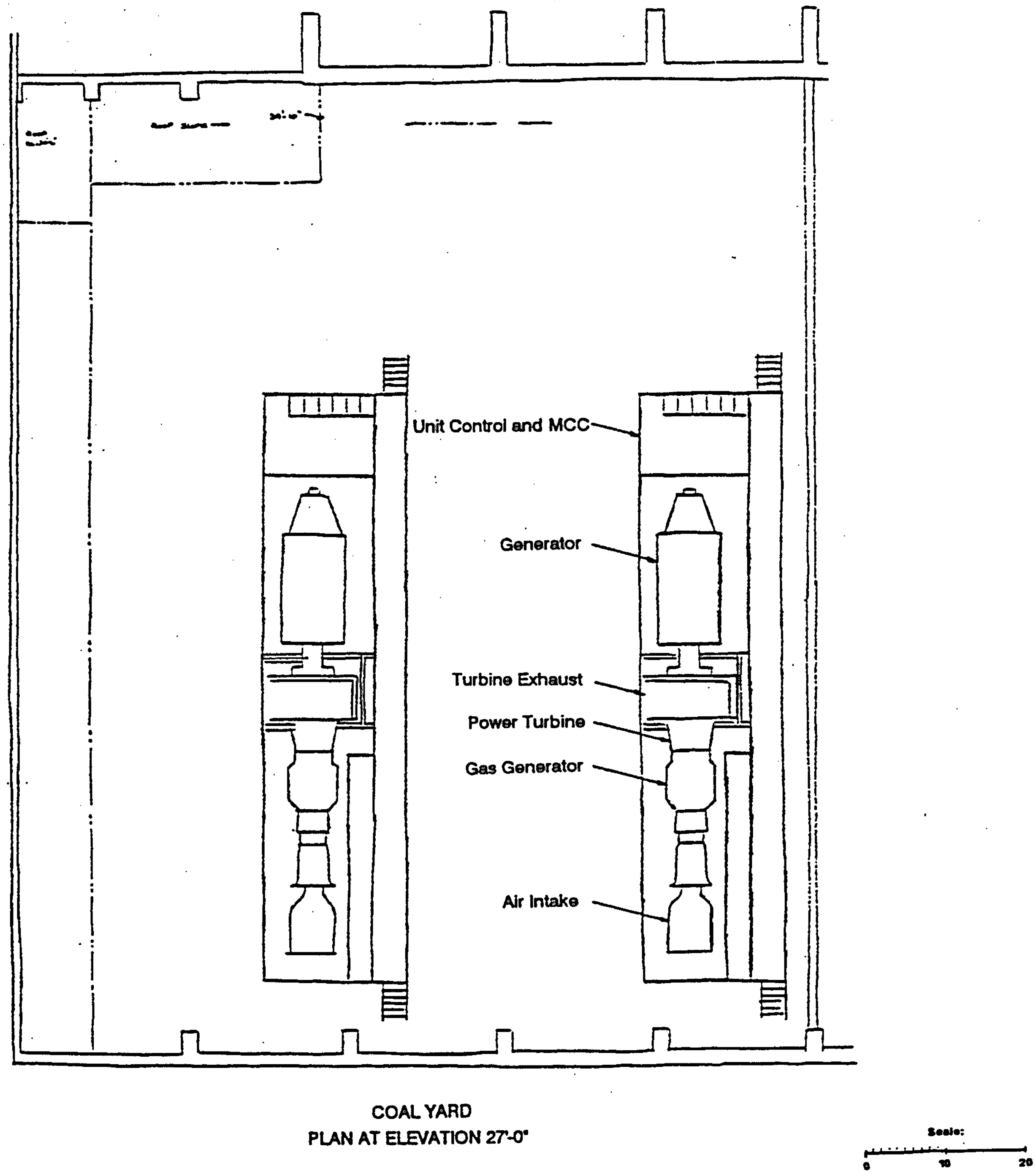

Figure B-2A.
Two ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangements in Central Heating Plant Coal Yard Plan at Elevation 27 Feet

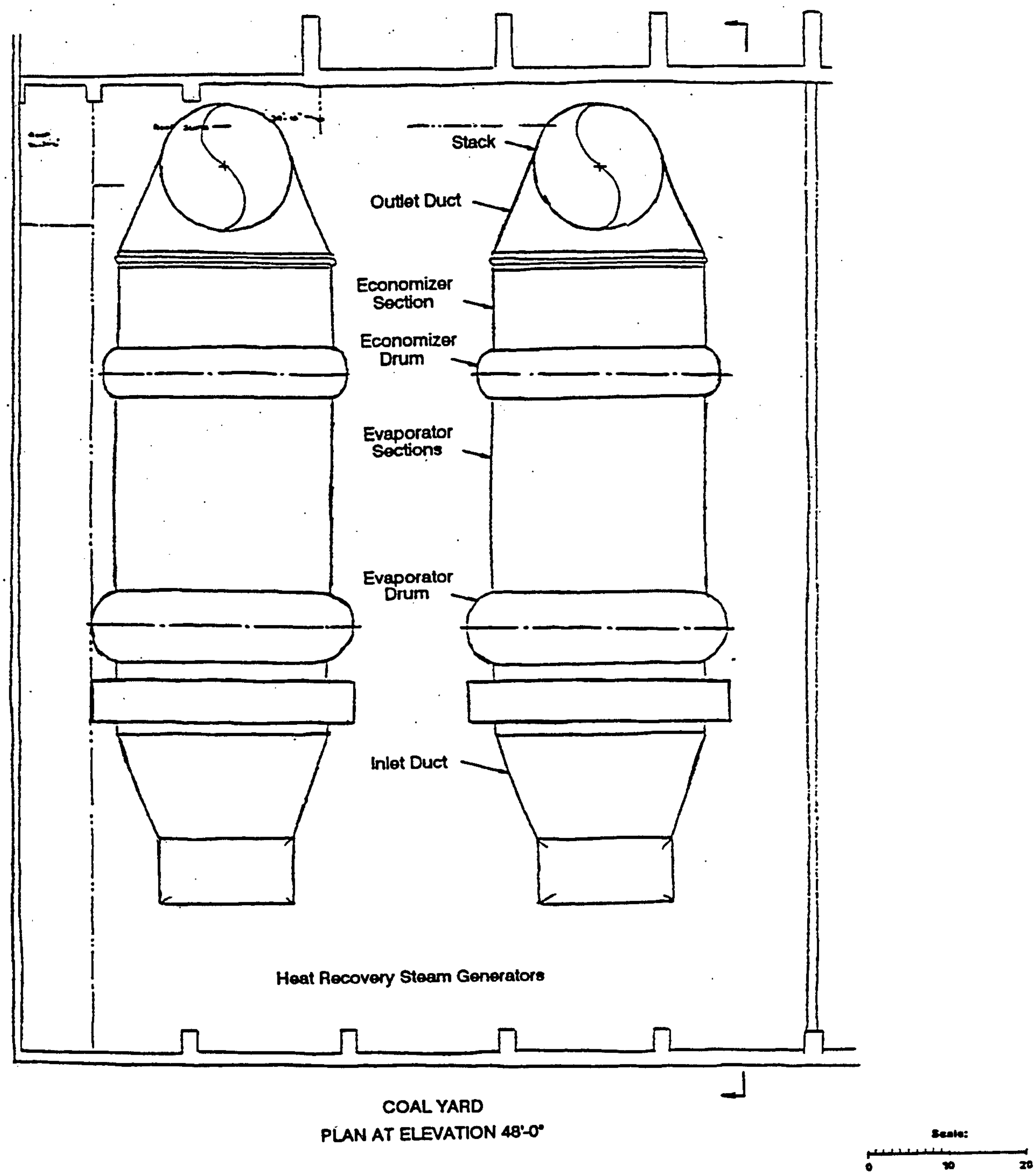

Figure B-2B.
Two ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangement in Central Heating Plant Coal Yard Plan at Elevation 48 Feet

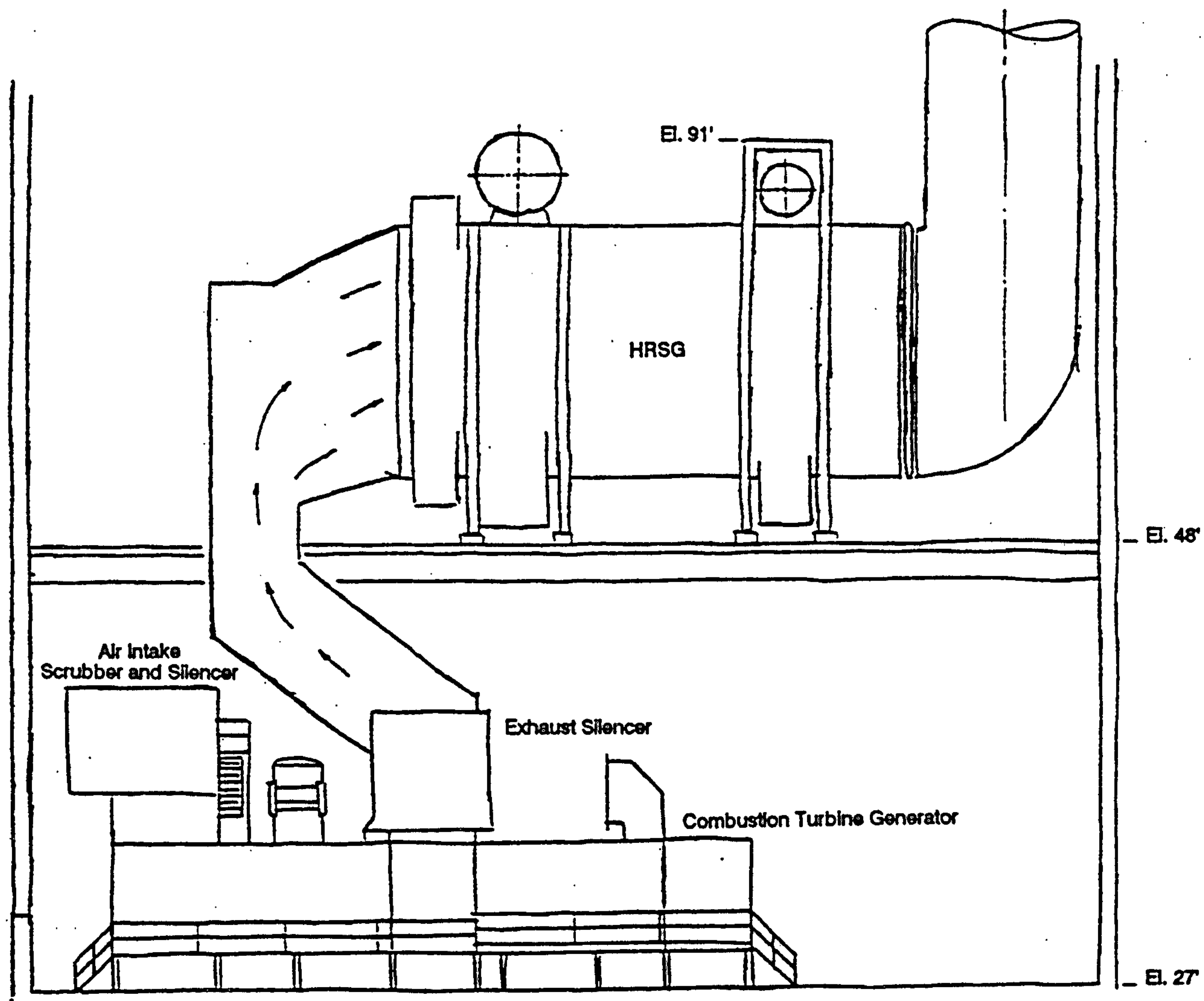

Figure B-2C.
Two ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangement in Central Heating Plant Coal Yard Sectional Elevation

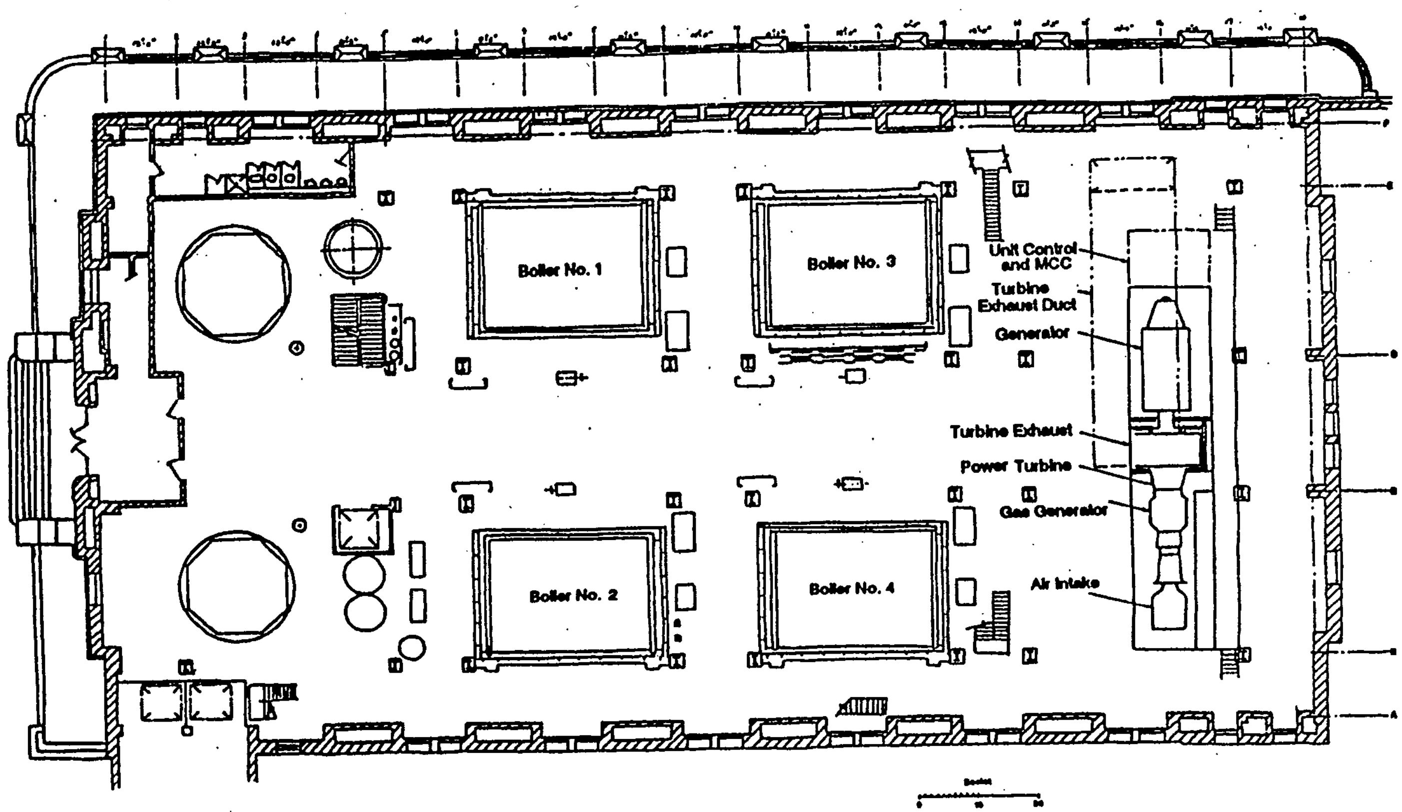

Figure B-2D.
ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangement in Central Heating Plant Building Plan at Elevation 21 Feet

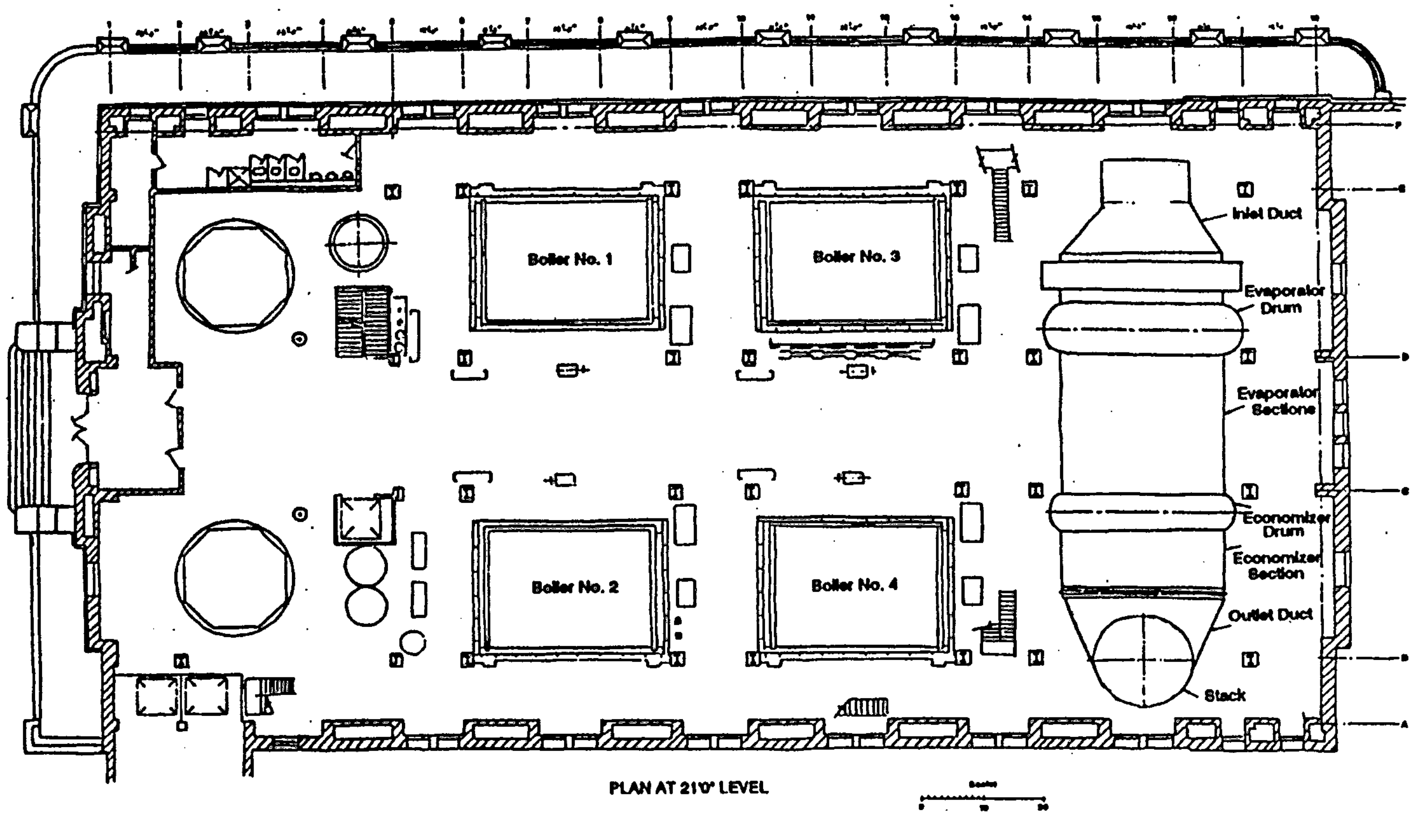

Figure B-2E.
ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangement in Central Heating Plant Building Plan at Elevation 70 Feet

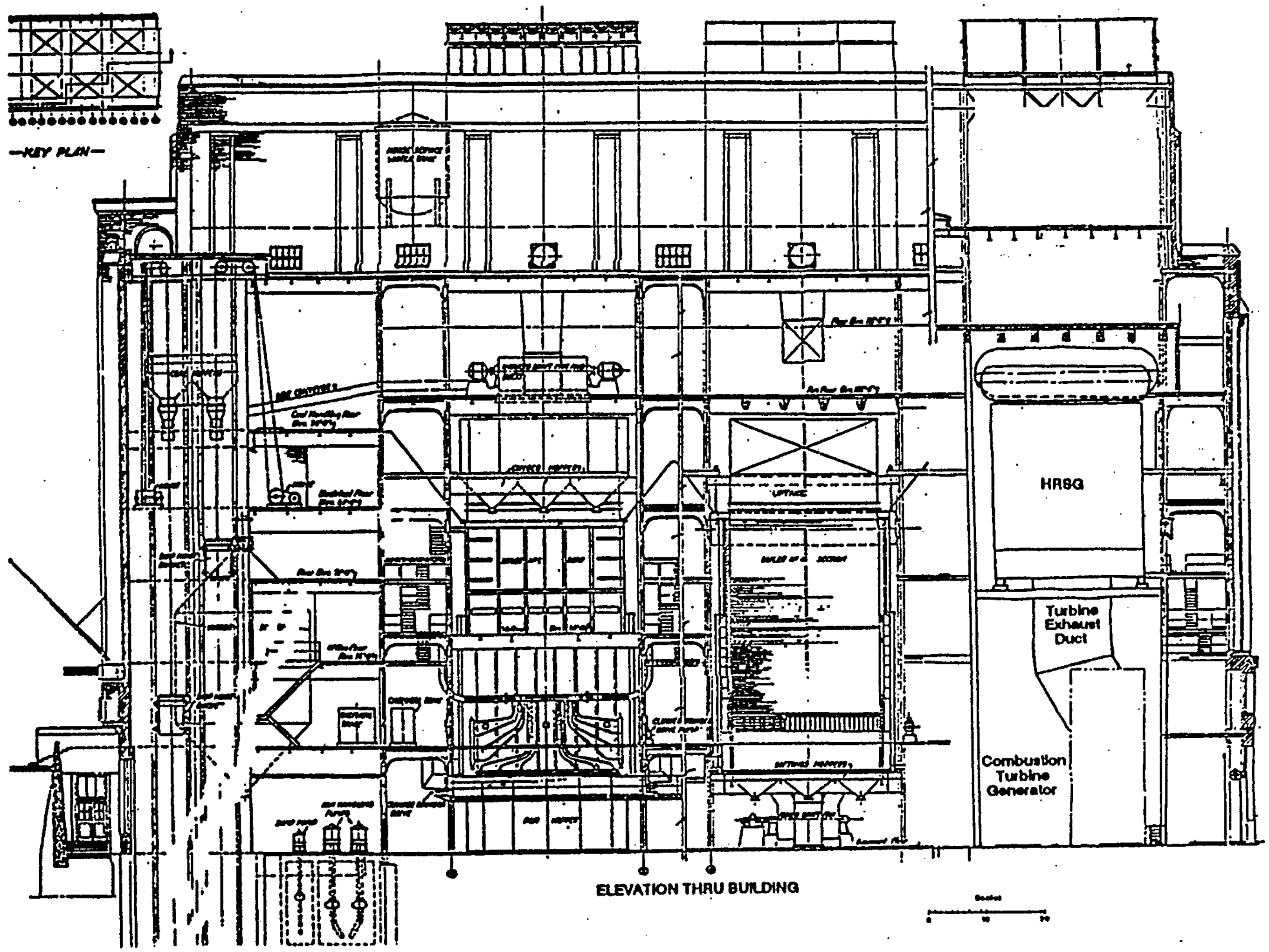

Figure B-2F.
ABB 17.7 MW Combustion Turbine and ERI 200,000 lb/hr Fired HRSG Arrangement in Central Heating Plant Building Sectional Elevation

Table B-3A.
Four Combustion Turbines – Supplemental or Fresh-Air-Fired Heat Recovery Steam Generators Combustion Turbine Data

Design parameter	Manufacturer: Solar
Model	Centaur 40-T4700
Number of units	4
Rating	3.5 MW
Overall dimensions	28' L × 8' W × 10' H
Heat rate	12,883 Btu/kWhr
Exhaust gas flow rate at rated output	147,274 lb/hr
Exhaust gas outlet temperature	829°F
Fuel consumption	45.51 MMBtu/hr

Table B-3B.
Four Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generators Data
(Page 1 of 3)

With Supplemental Firing				
Component	Measure	Outlet	Evaporator	Economizer
Gas turbine exhaust side: Solar Centaur 40-T4700				
Fluid		Flue gas	Flue gas	Flue gas
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flow rate	lb/hr	147,274	151,680	151,680
Design pressure	in. H_2O	12	12	10
Pressure drop	in. H_2O	4	0.99	0.54
Inlet temperature	°F	829	2,580	513
Outlet temperature	°F	2,580	513	301
Average heat capacity	Btu/lb-°F		0.3138	0.2774
Heat released	MMBtu/hr	88	98.37	8.92
Fuel flow (20,122 Btu/lb LHV)	lb/hr	4,406		
Cooling side:				
Fluid			Sat. steam	Water
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flow rate	lb/hr		100,000	102,041
Design pressure	psig		300	350
Outlet pressure	psig		250+	250+
Pressure drop	psi			9.9
Outlet temperature	°F		Sat.	265
Inlet temperature	°F		265	180
Steam quality	% moisture		0.5	
Blowdown	%		2	
Heat exchanger data:				
Total heating surface	sq.ft		17,866	9034

Table B-3B.

Four Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generators Data
(Page 2 of 3)

Fresh Air Fired				
Component	Measure	Outlet	Evaporator	Economizer
Gas turbine exhaust side: Solar Centaur 40-T4700				
Fluid		Flue gas	Flue gas	Flue gas
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flow rate	lb/hr	140,000	145,864	145,864
Design pressure	in. H_2O	12	12	10
Pressure drop	in. H_2O	1	0.99	0.05
Inlet temperature	°F	60	2706	506
Outlet temperature	°F	2,924	506	294
Average heat capacity	Btu/lb-$_o$F		0.3077	0.2716
Heat released	MMBtu/hr	116	98.73	8.4
Fuel flow (20,122 Btu/lb LHV)	lb/hr	5,864		
Cooling side:				
Fluid			Sat. steam	Water
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flowrate	lb/hr		100,000	102,041
Design pressure	psig		300	350
Outlet pressure	psig		250+	250+
Pressure drop	psi			9.9
Outlet temperature	°F		Sat.	253
Inlet temperature	°F		253	180
Steam quality	% moisture		0.5	
Blowdown	%		2	
Heat exchanger data:				
Total heating surface	sq.ft		17,866	9034

Table B-3B.
Four Combustion Turbines – Supplementary-Fired Heat Recovery Steam Generators Data
(Page 3 of 3)

No Supplemental Firing				
Component	Measure	Outlet	Evaporator	Economizer
Gas turbine exhaust side: Solar Centaur 40-T4700				
Fluid		Flue gas	Flue gas	Flue gas
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flowrate	lb/hr	147,274	147,274	147,274
Design pressure	in. H_2O	12	12	10
Pressure drop	in. H_2O	4	0.57	0.51
Inlet temperature	°F	829	829	432
Outlet temperature	°F	829	432	331
Average heat capacity	Btu/lb-F		0.2680	0.2608
Heat released	MMBtu/hr		15.67	3.88
Fuel flow (20,122 Btu/lb LHV)	lb/hr	4406		
Cooling side:				
Fluid			Sat. steam	Water
Fouling resistance	hr-sq.ft-°F/Btu		0.001	0.001
Fluid flowrate	lbs/hr		18,000	18,387
Design pressure	psig		300	350
Outlet pressure	psig		250+	250+
Pressure drop	psi			0.4
Outlet temperature	°F		Sat.	382
Inlet temperature	°F		382	180
Steam quality	% moisture		0.5	
Blowdown	%		2	
Heat exchanger data:				
Total heating surface	sq.ft		17,888	9,034

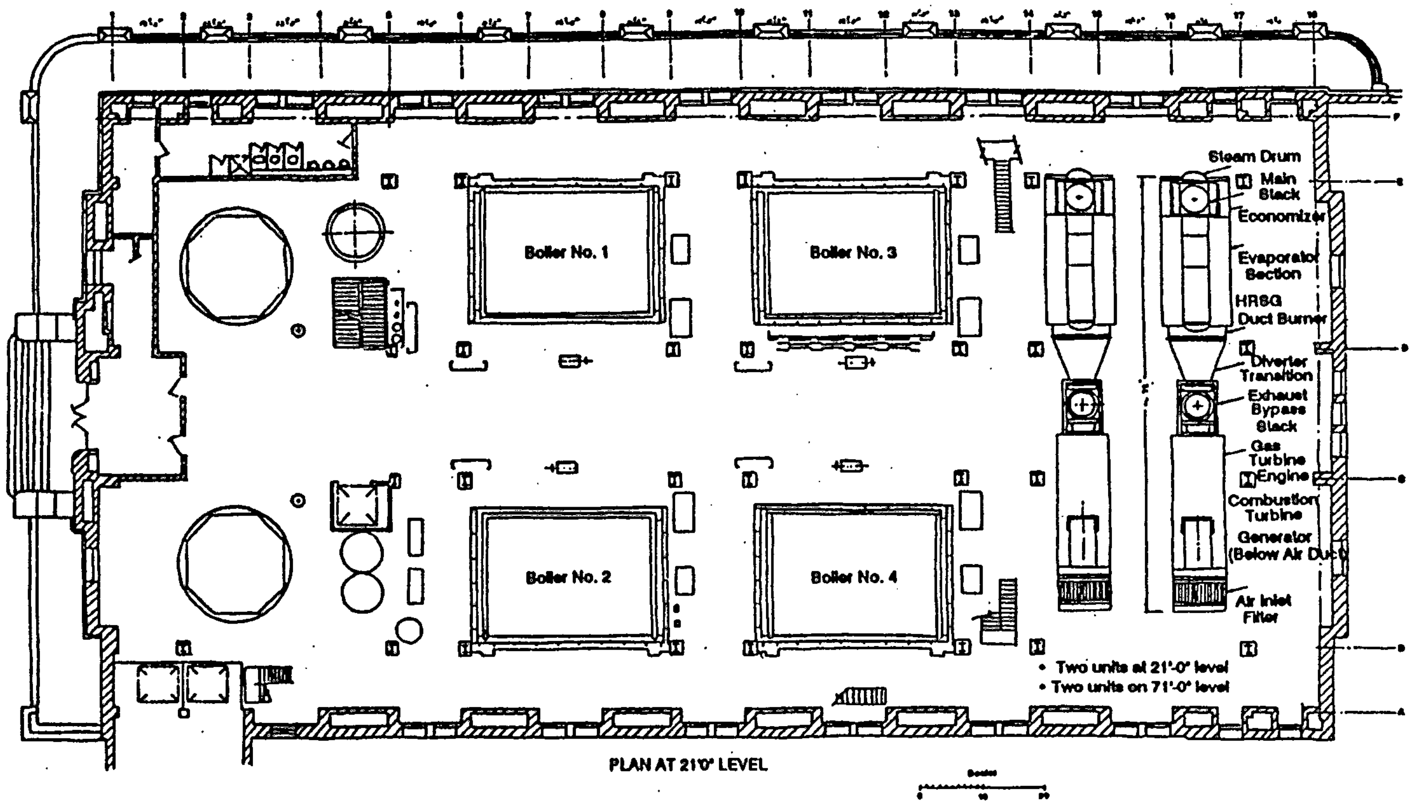

Figure B-3A.
Four Solar 3.5 MW Combustion Turbine 100,000 lb/hr HRSG Arrangement in Central Heating Plant Building Plan at Elevation 21 Feet

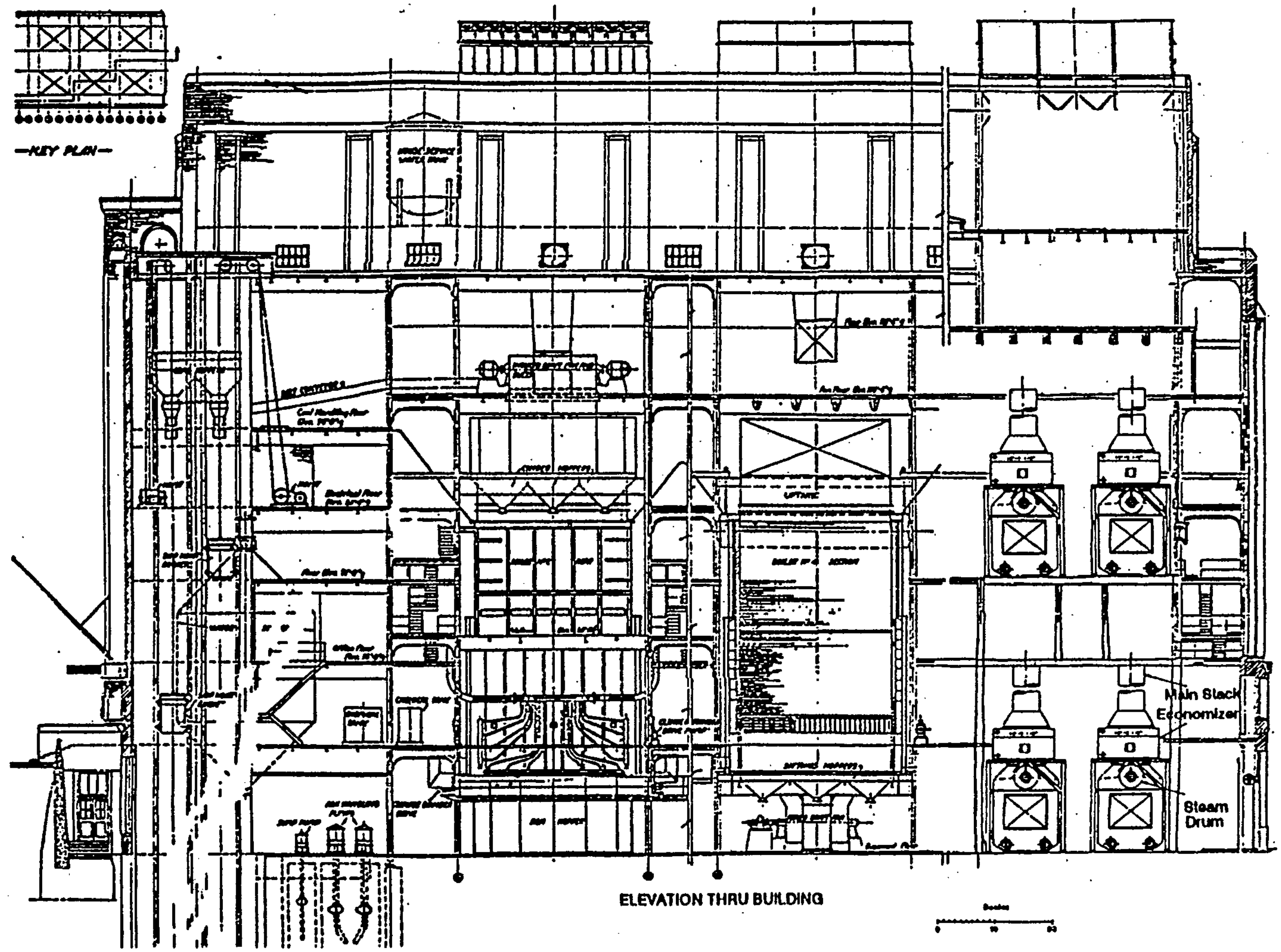

Figure B-3B.
Four Solar 3.5 MW Combustion Turbine 100,000 lb/hr HRSG Arrangement in Central Heating Plant Building Sectional Elevation at HRSGs

Appendix C

Calculation of Capital Costs of Candidate Cogeneration Cycles

Calculation of Capital Costs of Candidate Cogeneration Cycles

This appendix provides an estimate of the costs of procuring and installing cogeneration equipment that would replace Boilers 5 and 6 at the Central Heating and Refrigeration Plant operated by the General Services Administration's Heating Operation and Transmission District (HOTD). We develop estimates for two types of cogeneration cycles:

- Two Asea Brown Boveri (ABB) GT35 combustion turbines and two heat recovery steam generators (HRSGs) for replacement of Boilers 5 and 6 at HOTD's Central Heating Plant
- Four Solar Centaur 40-T4700 combustion turbines and four HRSGs for replacement of Boilers 5 and 6 at HOTD's Central Heating Plant.

Assumptions

- *Major equipment.* Budgetary estimates of the combustion turbines and HRSGs provided by the manufacturers. To cover increases beyond those given in preliminary specifications to the manufacturer for this study, we increased those estimated by 10 percent.
- *Electric tie-in.* Costs provided by the Potomac Electric Power Company (Pepco) for substation work, metering, communications, conduit cable, splices, and terminations for a 35-kV electrical tie-in. We assumed same costs would apply to both cogeneration cases.
- *Plant construction.* Costs derived from data in an earlier report as follows:[1]
    - Demolition:
        - Site survey and asbestos assessment: $51,400
        - Asbestos removal and disposal: $935,000
        - Demolition of equipment: $4,907,000
        - Lead-based paint abatement: $953,000
        - Total: $6,846,400

[1] LMI Report GS301MR1, *Evaluation of the Heating Operation and Transmission District, District Heating vs. Local Boiler Plants,* May 1995.

- Plant floor area: 145,000 square feet

- Cost per square foot: \$47.22 or \$50.00

► *General construction.* The area for general construction is the same as the area for demolition. The work includes doors and hardware, partitions, ceilings, mechanical systems, electrical services and lighting, plumbing, fire protection and finishes. Cost per square foot: \$25.00.

► *Auxiliaries.* The plant auxiliaries include the condensate tanks, transfer pumps, deaerator, feed water pumps, chemical feed and treatment, water softeners, motor control center and electrical distribution, blowdown equipment, and other accessories required for an operational system. Cost per equivalent steam capacity (in pounds per hour):[2] \$5.50.

► *Pipe, valves, and fittings.* The price includes costs for the steam header piping, condensate piping, boiler discharge piping and nonreturn valves, boiler isolation valves, header valves, feed water piping and valves, fuel piping and valves, blowdown piping, raw and process water piping, insulation, hangers, piping auxiliaries, and painting. Cost per equivalent steam capacity (in pounds per hour): \$8.00.

► *Stack.* Since the units will be fired on natural gas, stack costs are based on using Type 304 stainless steel factory-fabricated, UL-listed, triple-wall stack. Stack diameters for the various cases will be based on keeping about the same flue gas exit velocity as Central Heating Plant Boilers 5 and 6. Stack sizes and costs are approximately as shown in Table C-1.

◆ *Supplemental costs (engineering, construction management, and administration).* 15 percent of total construction and equipment costs.

Table C-1.
Stack Unit Costs

Cogeneration cycle	Diameter (inches)	Number of stacks	Cost per foot of height per stack
ABB – HRSG	108	2	\$3,800
Solar – HRSG	72	4	\$1,100

[2] Equivalent steam capacity is the steam capacity of the HRSGs (in pounds per hour) plus the heat rate equivalent of electrical capacity (kW converted to pounds per hour).

RESULTS

Table C-2 shows the cost elements for each concept. Total costs are as follows:

- Two ABB GT35 combustion turbines – HRSGs: $46 million
- Four Solar Centaur 40-T4700 combustion turbines – HRSGs: $30 million.

Table C-2.
Estimate of Capital Procurement and Construction Costs (1995 dollars)

Item	ABB combustion turbine – HRSG[a]	Solar combustion turbine – HRSG[b]
Combustion turbine	16,280,000	7,040,000
HRSG	4,620,000	3,500,000
Electric tie-in	4,800,000	4,800,000
Demolition[c]	2,250,000	2,250,000
General construction[c]	1,125,000	1,125,000
Auxiliary equipment	4,004,000	3,003,000
Pipe, valves, and fittings	5,824,000	4,368,000
Stack	972,800[d]	466,400[e]
Supplemental costs	5,981,370	3,982,860
Total	45,857,170	30,535,260

[a] Two units, each rated at 16.9 MW with a capacity of 220,000 pounds of steam per hour. Each turbine costs an estimated $8,140,000, and each HRSG costs $2,310,000. The equivalent steam capacity is 728,000 pounds per hour.

[b] Four units, each rate at 3.5 MW with a capacity of 100,000 pounds of steam per hour. Each turbine costs an estimated $1,760,000, and each HRSG costs $875,000. The equivalent steam capacity is 546,000 pounds per hour.

[c] Assumes a floor area of 45,000 square feet.

[d] Assumes a stack of 128 feet.

[e] Assumes a stack of 106 feet.

APPENDIX D

Calculation of Cogeneration Energy Exchange Costs and Credits

Calculation of Cogeneration Energy Exchange Costs and Credits

This appendix compares the economics of the generation of steam only with the cogeneration of electricity and steam at the Heating Operation and Transmission District (HOTD) operated by the General Services Administration (GSA). The economic viability of operating under a cogeneration scenario is evaluated using two financial analyses — net present value (NPV) and payback period.

Net present value calculates the difference in cost associated with operating under the steam-only scenario and that associated with the cogeneration scenario. A positive difference (costs of operating steam only are greater than costs of operating with cogeneration equipment) or NPV indicates that costs are lower under the cogeneration operating scenario as compared with the steam-only scenario.[1] A negative NPV indicates that HOTD is worse off financially by adding cogeneration equipment in the plant. The greater the NPV, the greater the financial benefit to adopting cogeneration.

A positive NPV analysis indicates that HOTD is better off adopting cogeneration technology (i.e., a positive NPV); the payback period indicates how long it takes to recoup the initial capital investment in the cogeneration equipment through the resulting cost savings in future years. Federal energy conservation guidelines indicate that, for a project to be feasible, the payback period should be 10 years or fewer. (For-profit firms usually require a payback period of about 5 years.)

Determination of the cost-effectiveness of cogeneration — NPV and payback period — requires a variety of information such as the annual steam production, the portion of the steam provided by the cogeneration equipment, the price HOTD currently pays for electricity, the price that the Potomac Electric Power Company (Pepco) will pay for the cogenerated electricity, the cost of boiler fuel, and the capital cost of purchasing and installing the cogeneration equipment.

The annual amount of steam that HOTD generates drives both boiler fuel consumption as well as the amount of electricity produced. The annual steam production is the same for each cogeneration scenario as well as the steam-only option. The portion of the annual steam production supplied by the combustion turbines – heat recovery steam generators (HRSGs) is determined from HOTD's daily steam production records and determines how much electricity the turbines generate over the course of a year. Knowing the amount of electricity generated, the terms for selling it, and the selling price yields the electricity credit. In addition, knowing the amount of steam and electricity produced by the combustion turbines – HRSGs allows for the calculation of the boiler fuel required and its cost. To determine the energy savings resulting from cogeneration, data

[1] Since only costs are being compared, lower cost results in a higher NPV.

on the amount and cost of fuel used by the existing steam-only Boilers 5 and 6 to produce the same amount of steam as the combustion turbines – HRSGs are also needed.

Scenario Description

Cogeneration Scenario Options

We assessed two cogeneration scenarios:

- All cogenerated electricity is sold to Pepco in accordance with prevailing rates and rules currently in effect for non-utility generators. HOTD's overall energy costs are reduced by the dollar amount GSA receives from Pepco in exchange for the electricity.

- Part of the cogenerated electricity is used to satisfy all of the in-plant electricity requirement, and the remainder is transmitted over Pepco's lines to other GSA facilities to satisfy some of their electricity needs. In this case, GSA's energy costs are reduced by the amount it currently pays Pepco for that electricity. However, this savings is not a direct offset because Pepco charges for transmitting the cogenerated electricity across its lines.

Equipment Options

We assume that steam-only generation is provided by the existing boilers at HOTD's Central Heating and Refrigeration Plant and that cogeneration is provided by one of two cycles:

- *Equipment Option 1.* Two Asea Brown Boveri (ABB) GT35 combustion turbines each rated at 16.9 MW and two HRSGs each rated at 220,000 pounds per hour of steam.

- *Equipment Option 2.* Four Solar Centaur 40-T4700 combustion turbines each rated at 3.5 MW and four HRSGs each rated at 100,000 pounds per hour.

Assumptions

General

Our general assumptions included the following:

- Steam generation for the steam-only case is provided by existing steam generators.

- Maintenance, water, personnel, and capital costs are the same for both the cogeneration cycle and the steam-only case. (The assumption regarding capital improvements remaining the same is conservative since, with new equipment, capital costs under the cogeneration option are likely to decline over time.)

Derivation of Credits for the Sale of Electricity

The average value for the sale of electricity to Pepco is based on estimates of the time that electricity is generated over a one-year period. This derivation allows use of a single annual equivalent rate in terms of dollars per kWh. The price Pepco will pay for electricity is given in terms of an energy rate and a capacity rate.

Energy Rate

Table D-1 shows Pepco's energy rates by time of day and season.

Table D-1.
Energy Rates
(dollars per kWh)

Time of day	Summer (June – October)	Winter (November – May)
Peak (noon to 8:00 p.m.)	0.04	0.03
Intermediate peak (8:00 a.m. to noon and 8:00 p.m. to midnight)	0.03	0.03
Off peak (midnight to 8:00 a.m.)	0.02007	0.02
Average $/kWh	0.03	0.03

Source: Potomac Electric Power Company, "Cogeneration and Small Power Producer Service Purchase of Power" Schedule DC-CG-SPP, June 30, 1994.

The energy rate is multiplied by a voltage adjustment factor. Discussions with Pepco indicate tie-in could be at 138 kV at high power levels (about 70 MW) or at 69 or 34 kV at lower power levels. For 34 kV transmission, the voltage adjustment factor is 0.9622. Thus, the energy rates are as follows:

- Summer = $0.9622 \times 0.0279 = \$0.0268/kWh$
- Winter = $0.9622 \times 0.0285 = \$0.0274/kWh$.

Capacity Rate

The capacity rate has two components: production and transmission. Table D-2 projects Pepco's capacity rates through 2008.

Table D-2.
Capacity Rates
(dollars per kWh)

Year	Production component	Transmission component
1994 – 2001	0	0.01
2002	0.08	0.01
2003 – 2008	0.07752 – 0.12739	0.01

The capacity payment is calculated by multiplying the capacity rate by the kWh of electricity delivered during summer peak periods and by the voltage adjustment factor. At 34 kV, the voltage adjustment factor is 0.9466.

If we assume that the capacity credits apply only one-third of the time (during the peak hours of the day, from noon to 8:00 p.m.) during a summer period, the credit for 2002 (the earliest year that cogeneration could be implemented at HOTD) would be calculated as follows:

- Total credit
  - Winter $= 0.0274 + 0 = \$0.0274/kWh$
  - Summer $= 0.0268 + (0.01202 + 0.08366) \times 0.9466 \times \frac{1}{3} = \$.057/kWh$
- Annual average credit
  - Winter rates = 7 months/year
  - Summer rates = 5 months/year
  - Annual rate $= \left[\frac{7}{12}(0.0274) + \frac{5}{12}(0.057)\right]\frac{\$}{kWh} = \$0.0397/kWh.$

The production capacity and transmission capacity components are stated in 1994 dollars. Assuming a 3 percent annual inflation rate, the average annual credit of $0.0397/kWh computed above would be about 8 percent higher. However, for our economic comparison, we assume that this increase will be offset by the amount Pepco charges non-utility generators for its "stranded investment." In the case of the Central Heating Plant, the stranded investment is the cost of equipment such as circuit breakers, metering relays, terminals, etc., that Pepco originally installed to supply electricity to the Central Heating Plant. Currently, Pepco is assessing a monthly stranded investment charge of 2 percent.

Derivation of the Cost of Electricity Used by the Central Heating Plant

This subsection estimates the average cost of electricity based on Pepco's bills for electricity to the Central Heating Plant in 1993 and 1994.

Purchase Costs

The cost for purchasing electricity for HOTD has two components: energy rate and demand rate. Tables D-3 and D-4 show the average monthly energy rates for summer and winter, respectively. The rates include a discount, fuel rate adjustment, and D.C. gross receipts adjustment, but they exclude demand charges. In summer, the rate averaged \$0.0416 per kWh, and in winter, it averaged \$0.0372 per kWh.

Table D-3.
Monthly Average Summer Energy Rates

Dates	Dollars	kWh
May 24 – June 23, 1993	111,535	2,855,601
Aug. 23 – Sept. 22, 1993	140,850	3,259,979
May 17 – June 14, 1994	102,920	2,424,100

Table D-4.
Monthly Average Winter Energy Rates

Dates	Dollars	kWh
April 23 – May 24, 1993	52,632	1,430,295
Dec. 15, 1993 – Jan. 19, 1994	43,159	1,310,100
April 15 – May 17, 1994	55,901	1,340,100

Tables D-5 and D-6 show the average monthly demand rates for summer and winter, respectively. The total demand (distribution, production, and transmission) averaged \$17.03 per kW in summer and \$6.56 per kW in winter.

Table D-5.
Summer Demand Charges

Dates	Distribution		Production and transmission	
	Billed ($)	Demand (kW)	Billed ($)	Peak (kW)
May 24 – June 23, 1993	54,285	8,351	86,856	8,351
Aug. 23 – Sept. 22, 1993	56,832	8,743	90,931	8,743
May 17 – June 14, 1994	57,045	8,559	90,557	8,531

Table D-6.
Winter Demand Charges

Dates	Distribution		Production and transmission	
	Billed ($)	Demand (kW)	Billed ($)	Peak (kW)
April 23 – May 24, 1993	49,190	7,568	0	0
Dec. 15 – Jan. 19, 1994	13,819	2,126	0	0
May 17 – June 14, 1994	39,242	5,901	0	0

Electricity Usage

Table D-7 lists the electricity usage for both the Central Heating Plant and the West Heating Plant for 1993. Most entries were obtained from Pepco invoices; those that were estimated are noted.

Estimated Annual Costs for Electricity

Table D-8 provides the calculation of costs of electricity based on the energy and demand rates and electric usage for 1993, which totaled 27.4 million kWh. Although the electricity usage includes the Central Heating Plant and West Heating Plant, it is assumed that this amount of electricity will be required at the Central plant because it will be the main plant and the West Heating Plant will be a peaking plant. Costs total $2.1 million and average $0.0763 per kWh. Although these costs are based on 1993 – 1994 data, we assumed that they will prevail in 2002, the earliest year that cogeneration units could begin operation.

Estimate of Wheeling Costs

Wheeling of electricity — in this case, transmitting of power generated at the Central Heating Plant directly to other GSA facilities — is not permitted by Pepco. However, because we believe that Pepco eventually will permit wheel-

Table D-7.
Electricity Usage Summary by Plant, 1993

Month	Energy usage (kWh)			Peak demand (kW)		
	Central	West	Total	Central	West	Total
January	759,343	**293,000**	1,052,343	1,464	**670**	2,134
February	**760,000**	**293,000**	**1,053,000**	**1,700**	**700**	**2,400**
March	**760,000**	**293,000**	**1,053,000**	**2,000**	**750**	**2,750**
April	726,047	279,818	1,005,865	3,649	864	4,512
May	1,430,295	312,360	1,742,655	7,568	823	8,391
June	2,855,601	404,018	3,259,619	8,352	792	9,144
July	4,317,382	506,529	4,823,911	8,514	1,065	9,579
August	3,325,851	410,598	3,736,449	8,176	1,170	9,346
September	3,259,979	363,472	3,623,451	8,743	1,081	9,824
October	**2,200,000**	122,545	**2,322,545**	**7,500**	316	**7,816**
November	**1,500,000**	236,339	**1,736,339**	**7,000**	679	**7,679**
December	**1,400,000**	631,952	**2,031,952**	**4,000**	1,167	**5,167**
Totals	23,294,498	4,146,631	27,441,129	68,665	10,076	78,741

Note: Boldface entries are estimated.

Table D-8.
Costs for the Purchase of Electricity, 1993

Month	Energy usage (kWh)	Peak demand (kW)	Energy rate ($/kWh)	Demand rate ($/kW)	Total costs ($)
January	1,052,343	2,134	0.0372	6.56	53,146
February	1,053,000	2,400	0.0372	6.56	54,916
March	1,053,000	2,750	0.0372	6.56	57,212
April	1,005,865	4,512	0.0372	6.56	67,019
May	1,742,655	8,391	0.0372	6.56	119,870
June	3,259,619	9,144	0.0416	17.03	291,314
July	4,823,911	9,579	0.0416	17.03	363,798
August	3,736,449	9,346	0.0416	17.03	314,597
September	3,623,451	9,824	0.0416	17.03	318,040
October	2,322,545	7,816	0.0416	17.03	229,719
November	1,736,339	7,679	0.0372	6.56	114,968
December	2,031,952	5,167	0.0372	6.56	109,485
Total	27,441,129	78,741	—	—	2,094,083

Note: Annual average = $0.0763/kWh.

ing, we attempted to account for it in our economic estimates by establishing two bounds:

- For the upper bound, we assumed that the cost basis of the transmission component credit specified in the Pepco rate schedule for cogeneration applies and added 10 percent. Pepco rate schedule DC-CG-SPP indicates that the transmission component = \$0.01944 per kWh for voltage below 69 kV (transmission voltage is expected to be 35 kV). Wheeling costs = \$0.01944 × 1.1 = \$0.0214 per kWh.

- For the lower bound, we assumed that the current costs for wheeling in Delaware would apply in the District of Columbia. Wheeling costs = \$0.006 per kWh.

To estimate the net benefit of transmitting power to other GSA facilities, we subtracted the costs for wheeling from the normal cost of electricity, assuming that the normal cost of electricity to the GSA facilities is the same as that estimated above for Central Heating Plant.

Fuel Costs

For the cogeneration cycles, we calculated the fuel costs for the maximum amount of steam that the HRSGs can supply to the HOTD system, taking into consideration the representative daily steam demand over a year. Supplemental firing of the HRSGs to provide the steam demand is included. We translated the steam supplied by the HRSGs into an equivalent number of full power hours that the combustion turbines can operate and determined the amount of electricity generated for this time. To determine the net fuel costs for the combustion turbine – HRSG cycle, we subtracted the credit for the sale of electricity from the fuel costs.

For the Central Heating Plant boilers, we determined the fuel costs based on the generation of the same quantity of steam determined for the HRSGs.

For those days when steam demand exceeds the capacity of the HRSGs, we assumed that steam would be provided by the four remaining Central Heating Plant boilers (and that backup units at the West Heating Plant would be used for 100 percent system redundancy). Fuel for the generation of this steam would be equal to the case where all steam is supplied by the Central Heating Plant boilers and hence, is not included in the comparative fuel costs.

The steam demand load profile in pounds per hour versus number of days is shown in Table D-9.

Table D-9.
HOTD Cumulative Steam Demand Load Profile

Number of days demand exceeded	Demand (thousands of pounds)	Cumulative Demand (thousands of pounds)
1	950	22,800
2	900	45,000
3	850	66,000
10	800	204,600
19	750	372,000
32	700	598,200
40	660	728,760
48	650	857,400
62	600	1,067,400
75	550	1,246,800
93	500	1,473,600
94	495	1,485,540
112	440	1,687,500
121	400	1,778,220
131	350	1,868,220
147	300	1,993,020
162	250	2,092,020
195	200	2,270,220
300	150	2,711,220
363	100	2,900,220
365	50	2,903,820

Notes: Based on 10:00 a.m. steam flow readings at Central and West plants, 9/15/93 through 9/14/94. Annual total steam load = 2.9×10^9 lb/yr. Equivalent heat load = 2.9×10^9 lb/yr $\times$ 1,000 Btu/lb/0.8 efficiency = 3.63×10^{12} Btu/yr.

We assumed the efficiency of the Central Heating Plant boilers to be 80 percent.

We extrapolated the cost of natural gas in 1994 — \$3.60 per MMBtu — to 2002 (the assumed year of startup of combustion turbine - HRSG operation) based on fuel escalation factors given in the 1995 supplement to NIST Handbook 135.[2] The extrapolation factor is 1.13, resulting in a fuel cost of (\$3.60 × 1.13) = \$4.07 per MMBtu.

To determine present worth values of the annual fuel savings, we used the uniform present value discount factor for a 20-year period, assuming commercial rates for natural gas. Those values are given in the NIST Handbook 135

[2]National Institute of Standards and Technology, *Energy Price Indices and Discount Factors for Life Cycle Cost Analysis,* Annual Supplement, Handbook 135, October 1994.

supplement. We compared the present worth values of the 20-year fuel savings to the capital costs of the combustion turbine – HRSG cycles.

CALCULATIONS

For both cogeneration cycles, we calculated costs for two cases: GSA sells all electricity generated by HOTD to Pepco and, assuming wheeling is permitted, GSA wheels electricity not used by HOTD to other GSA facilities.

Case 1 — GSA Sells All Electricity Generated by HOTD to Pepco

For Case 1, we assumed that Pepco would purchase all electricity at a price of \$0.0397 per kWh — the prevailing Pepco rate schedule.

TWO ABB GT35 COMBUSTION TURBINES AND TWO HRSGS

Cost of Fuel for Operation of Cogeneration Units

- Total steam demand for the year = 2.9×10^9 lb.
- Annual steam requirements that exceed steam provided by HRSGs and supplied by the remaining steam-only boilers in the Central Heating Plant.
  - Number of days that the steam demand exceeds 440,000 lb/hr (steam supplied by two HRSGs, each rated at 220,000 lb/hr) is an average of 112 days/year.
  - Total cumulative steam demand for these 112 *days* = 1.69×10^9 *lb*

$$= 1.69 \times 10^9\, lb - \left(440,000\frac{lb}{hr} \times 24\frac{hr}{day} \times 112\ days\right)$$

$$= 5.07 \times 10^8\ lb\ per\ year.$$

- Annual steam supplied by HRSGs

$$= (2.9 \times 10^9 - 5.07 \times 10^8) = 2.4 \times 10^9 \frac{lb}{year}.$$

- Number of equivalent full power hours of combustion turbines – HRSGs use (each unit)

$$= \frac{2.4 \times 10^9\ lb/year}{4.4 \times 10^5\ lb/hr} = 5,438\frac{hr}{year}\ .$$

- Total fuel consumed by combustion turbines (CT) – HRSGs

$$= \left[1.7 \times 10^8 \frac{Btu}{hr} (\textit{for one CT}) + 1.8 \times 10^8 \frac{Btu}{hr} (\textit{for one HRSG})\right]$$

$$\times 2 \times 5,438 \frac{hr}{year} = 3.81 \times 10^{12} \frac{Btu}{year}.$$

- Annual fuel cost for combustion turbines – HRSGs

$$= 3.81 \times 10^{12} \frac{Btu}{year} \times \frac{\$4.07}{10^6\ Btu} = \$15.5 \times 10^6.$$

- Credit for sale of electricity

$$= 2 \times 16,900\, kW \times 5,438 \frac{hr}{year} \times \frac{\$0.0397}{kWh} = \$7.3 \times 10^6.$$

- Net cost of fuel for combustion turbines – HRSGs

$= \$15.5 \times 10^6 - \$7.3 \times 10^6$

$= \$8.2 \times 10^6$ per year.

Cost of Fuel for Steam-Only Operation

- Cost of fuel for existing Central Heating Plant boilers to provide the same amount of steam as ABB combustion turbines – HRSGs

$$= 2.4 \times 10^9 \frac{lb}{year} \times 1,000 \frac{Btu}{lb} \times \frac{1}{0.8\ \textit{efficiency}} \times \frac{\$4.07}{10^6\ Btu}$$

$= \$12.2 \times 10^6$ per year.

Net Present Value Calculation

- Annual fuel savings (annual benefit) when using ABB combustion turbines – HRSGs as compared to steam-only operation

$= \$12.2 \times 10^6 - \$8.2 \times 10^6$

$= \$4 \times 10^6$ per year.

- Uniform present value discount factor for a 20-year period and commercial rates for natural gas = 17.83.

- Present value of 20 years of annual benefit = $17.83 \times \$4 \times 10^6 = \$71.32 \times 10^6$.

- Capital cost of ABB combustion turbines – HRSGs = $\$45.9 \times 10^6$ (1995 dollars).

- Assuming a 3 percent annual inflation rate, the capital cost in 2002 = $\$45.9 \times 10^6 \times (1.03)^7 = \$56.5 \times 10^6$.
- Net present value = $\$71.32 \times 10^6 - \$56.5 \times 10^6 = \$14.8 \times 10^6$.

Payback Period Calculation

- Annual fuel savings = $\$4 \times 10^6$ per year.
- Capital cost = $\$56.5 \times 10^6$.
- Payback period = $\$56.5 \times 10^6/\$4 \times 10^6$ = 14 years.

FOUR SOLAR CENTAUR 40-T4700 COMBUSTION TURBINES AND FOUR HRSGS

Cost of Fuel for Operation of Cogeneration Units

- Total steam demand for the year = 2.9×10^9 lb.
- Annual steam requirements that exceed steam provided by HRSGs and supplied by the remaining steam-only boilers in the Central Heating Plant.
  - Number of days that the steam demand exceeds 400,000 lb/hr (steam supplied by HRSGs, each rated at 100,000 lb/hr) is an average of 121 days/year.
  - Total cumulative steam demand for these 121 *days* = 1.78×10^9 *lb*.

$$= 1.78 \times 10^9\, lb - \left(400{,}000\,\frac{lb}{hr} \times 24\,\frac{hr}{day} \times 121\; days\right) = 6.18 \times 10^8\, lb.$$

- Annual steam supplied by four HRSGs

$$= (2.9 \times 10^9 - 6.18 \times 10^8) = 2.28 \times 10^9\,\frac{lb}{year}.$$

- Number of equivalent full power hours of combustion turbines – HRSGs use (each unit)

$$= \frac{2.28 \times 10^9\, lb/year}{4.0 \times 10^5\, lb/hr} = 5{,}700\,\frac{hr}{year}.$$

- Total fuel consumed by combustion turbines – HRSGs

$$= \left[0.4551 \times 10^8\,\frac{Btu}{hr}\,(for\ one\ CT) + 0.88 \times 10^8\,\frac{Btu}{hr}\,(for\ one\ HRSG)\right]$$

$$\times 4 \times 5{,}700 \frac{hr}{year} = 3.04 \times 10^{12} \frac{Btu}{year}.$$

- Annual fuel costs of combustion turbines – HRSGs

$$= 3.04 \times 10^{12} \frac{Btu}{year} \times \frac{\$4.07}{10^6\ Btu} \$12.4 \times 10^6.$$

- Credit for sale of electricity

$$= 4 \times 3{,}500\, kW \times 5{,}700 \frac{hr}{year} \times \frac{\$0.0397}{kWh} = \$3.17 \times 10^6.$$

- Net cost of fuel for combustion turbines – HRSGs

$$= \$12.4 \times 10^6 - \$3.17 \times 10^6$$

$$= \$9.23 \times 10^6 \text{ per year.}$$

Cost of Fuel for Steam-Only Operation

- Cost of fuel for existing Central Heating Plant boilers to provide same amount of steam as Solar Centaur combustion turbines – HRSGs

$$= 2.28 \times 10^9 \frac{lb}{year} \times 1{,}000 \frac{Btu}{lb} \times \frac{1}{0.8\ efficiency}$$

$$\times \frac{\$4.07}{10^6\ Btu} = \$11.6 \times 10^6\ per\ year.$$

Net Present Value Calculation

- Annual fuel savings (annual benefit) when using Solar Centaur combustion turbines – HRSGs as compared with the steam-only operation

$$= \$11.6 \times 10^6 - \$9.23 \times 10^6$$

$$= \$2.37 \times 10^6 \text{ per year.}$$

- Uniform present value discount factor for a 20-year period and commercial rates for natural gas = 17.83.
- Present value of 20 years of annual benefit = $17.83 \times \$2.37 \times 10^6 = \$42.25 \times 10^6$.
- Capital cost of Solar Centaur combustion turbines – HRSGs = $\$30.5 \times 10^6$ (1995 dollars).

- Assuming a 3 percent annual inflation rate, the capital cost in 2002 = $\$30.5 \times 10^6 \times (1.03)^7 = \$37.5 \times 10^6$.

- Net present value = $\$42.25 \times 10^6 - \$37.5 \times 10^6 = \$4.75 \times 10^6$.

Payback Period Calculation

- Annual fuel savings = $\$2.37 \times 10^6$ per year.

- Capital cost to receive benefit = $\$37.5 \times 10^6$.

- Payback period = $\$37.5 \times 10^6 / \$2.37 \times 10^6$ = 16 years.

Case 2 — GSA Wheels Electricity to Other GSA Facilities

The estimate for wheeling electricity to other GSA facilities assumes that the in-plant electrical needs are provided directly by the cogenerator without having to pay the costs of wheeling to Pepco. The electricity not used within the Central Heating Plant will be transmitted to the other GSA facilities at the assumed cost of wheeling; the benefit is the difference between what the facility would normally pay for electricity minus the cost of wheeling.

In-Plant Electricity Costs

The cost of cogenerated electricity used in the Central Heating Plant (27.4×10^6 kWh) equals $2.1 million, credited to HOTD.

Estimate of Wheeling Costs

Wheeling of electricity — in this case, transmitting of power generated at the Central Heating Plant directly to other GSA facilities — is not permitted by Pepco. However, because we believe that wheeling may eventually be permitted, we attempted to account for it in our economic estimates by establishing two bounds:

- For the upper bound, we assumed that the cost basis of the transmission component credit specified in the Pepco rate schedule for cogeneration applies and added 10 percent. Pepco rate schedule DC-CG-SPP indicates that the transmission component = $0.01944 per kWh for voltage below 69 kV (transmission voltage is expected to be 35 kV). Wheeling costs = $\$0.01944 \times 1.1 = \$0.0214$ per kWh.

- For the lower bound, we assumed that the current costs for wheeling in Delaware would apply in the District of Columbia. Wheeling costs = $0.006 per kWh.

Two ABB GT35 Combustion Turbines and two HRSGs (High Wheeling Cost)

Cost of Fuel for Operation of Cogeneration Units

- Annual fuel cost for combustion turbines – HRSGs

  = $\$15.5 \times 10^6$ (from earlier calculation).

- Net credit from electricity savings

  - Plant electricity cost = \$2.1 million for 27.4×10^6 kWh

  - Wheeling costs = $\frac{\$0.0214}{KWh}$; potential electric savings = $\frac{\$0.0549}{KWh}$

  - Electricity savings from the remaining electricity wheeled to other GSA facilities

$$= \left(2 \times 16{,}900\, kW \times 5{,}438 \frac{hr}{year} - 27.4 \times 10^6\, kWh \text{ used in plant}\right)$$

$$\times \frac{\$0.0549}{KWh} = \$8.59 \times 10^6 \text{ per year.}$$

  - Total savings = $27.4 \times 10^6 kWh$

$$= \frac{\$0.0549}{kWh} + \$2.1 \times 10^6 \textit{ credit for in-plant electricity} = \$10.7 \times 10^6.$$

- Net cost of fuel for combustion turbines – HRSGs

  = $\$155 \times 10^6 - \$10.7 \times 10^6 = \$4.8 \times 10^6$.

Cost of Fuel for Steam-Only Operation

- Cost of fuel for existing Central Heating Plant boilers to provide the same amount of steam as ABB combustion turbines – HRSGs

  = $\$12.2 \times 10^6$ per year.

Net Present Value Calculation

- Net annual fuel savings of ABB combustion turbines – HRSGs = $\$12.2 \times 10^6 - \$4.8 \times 10^6 = \$7.4 \times 10^6$.

- Uniform present value discount factor for a 20-year period and commercial rates for natural gas = 17.83.

- Present value of 20 years of annual benefit = $17.83 \times \$7.4 \times 10^6 = \$131.9 \times 10^6$.
- Capital cost of ABB combustion turbines – HRSGs = $\$45.9 \times 10^6$ (1995 dollars).
- Assuming a 3 percent annual inflation rate, the capital cost in 2002 = $\$45.9 \times 10^6 \times (1.03)^7 = \$56.5 \times 10^6$.
- Net present value = $\$131.9 \times 10^6 - \$56.5 \times 10^6 = \$75.42 \times 10^6$.

Payback Period Calculation

- Annual fuel savings = $\$7.4 \times 10^6$.
- Capital cost to receive benefit = $\$56.5 \times 10^6$.
- Payback period = $\$56.5 \times 10^6 / \$7.4 \times 10^6 = 7.6$ years.

TWO ABB GT35 COMBUSTION TURBINES AND TWO HRSGS (LOW WHEELING COST)

- Following the same steps as above.
  - Wheeling costs = $\frac{\$0.006}{KWh}$
  - Net annual fuel savings = $\$9.80 \times 10^6$ per year
  - Net present value = $\$118.2 \times 10^6$
  - Payback period = 5.8 years.

FOUR SOLAR CENTAUR 40-T4700 COMBUSTION TURBINES AND FOUR HRSGS (HIGH WHEELING COST)

Cost of Fuel for Operation of Cogeneration Units

- Annual fuel cost for combustion turbines – HRSGs

  = $\$12.4 \times 10^6$ (from earlier calculation).
- Net credit from electricity savings
  - Plant electricity cost = \$2.1 million for 27.4×10^6 kWh

- Additional electricity savings given wheeling cost of $\frac{\$0.0214}{KWh} = \frac{\$0.0549}{KWh}$

$$= \left(4 \times 3{,}500\,kW \times 5{,}700\,\frac{hr}{year} - 27.4 \times 10^6\,kWh\ used\ in\ plant\right)$$

$$\times \frac{\$0.0549}{kWh} + \$2.88 \times 10^6 \text{ per year}$$

- Total annual savings = $\$2.1 \times 10^6 + \$2.88 \times 10^6 = \$5.0 \times 10^6$.

- Net cost of fuel for combustion turbines – HRSGs

  = $\$12.4 \times 10^6 - \$5 \times 10^6 = \$7.4 \times 10^6$ per year.

Cost of Fuel for Steam-Only Production

- Cost of fuel for existing Central Heating Plant boilers to provide the same amount of steam as Solar Centaur combustion turbines – HRSGs

  = $\$11.6 \times 10^6$ (from earlier calculation).

Net Present Value Calculation

- Net annual fuel savings using Solar Centaur combustion turbines – HRSGs = $\$11.6 \times 10^6 - \$7.4 \times 10^6 = \$4.2 \times 10^6$.
- Uniform present value discount factor for 20-year period and commercial rates for natural gas = 17.83.
- Present value of 20 years of annual benefit = $17.83 \times \$4.2 \times 10^6 = \$74.9 \times 10^6$.
- Capital cost of Solar Centaur combustion turbines – HRSGs = $\$30.5 \times 10^6$ (1995 dollars).
- Assuming a 3 percent annual inflation rate, the capital cost in 2002 = $\$30.5 \times 10^6 \times (1.03)^7 = \$37.5 \times 10^6$.
- Net present value = $\$74.9 \times 10^6 - \$37.5 \times 10^6 = \$37.4 \times 10^6$.

Payback Period Calculation

- Annual fuel savings = $\$4.2 \times 10^6$.
- Capital cost to receive benefit = $\$37.5 \times 10^6$.
- Payback period = $\$37.5 \times 10^6 / \$4.2 \times 10^6 = 9$ years.

FOUR SOLAR CENTAUR 40-T4700 COMBUSTION TURBINES AND FOUR HRSGS (LOW WHEELING COST)

- Following same steps as above
  - Wheeling costs = $0.006/kWh
  - Net annual fuel savings = $\$4.98 \times 10^6$
  - Net present value = $\$51.3 \times 10^6$
  - Payback period = 7.5 years.

APPENDIX E

Excerpts from the Potomac Electric Power Company's Qualifying Facility and Non-Utility Generation Information

July 1994

POTOMAC ELECTRIC POWER COMPANY

Qualifying Facility (QF) and Non-Utility Generator (NUG) Information

Need for Capacity: The Company foresees no need for additional capacity resources until about the year 2002.

Existing Commitments: The Company has power purchase agreements in effect for five projects. Three small QFs are currently in operation. Two larger projects are in development. These are:

Project	Size	Expected In-Service
Northeast Maryland Waste Disposal Authority/ Montgomery County Resource Recovery Facility	36 MW	1995
Panda-Brandywine, LP	230 MW	1996

Availability of Avoided Costs: Avoided costs are available for QFs in operation and directly connected to the Pepco electric system in accordance with either Schedule "MD-CG-SPP" or Schedule "DC-CG-SPP" depending on whether the project is located in Maryland or the District of Columbia. The currently effective Schedule "MD-CG-SPP" is included in this booklet. The Company has recently filed a revised Schedule "DC-CG-SPP", including updated avoided costs, with the District of Columbia Public Service Commission. Although not yet effective, this filed schedule is included here since it provides the Company's latest estimate of avoided costs.

At this time, Pepco will not make multi-year commitments for new capacity. The availability of avoided costs is more fully discussed in the Schedules "MD-CG-SPP" and "DC-CG-SPP".

Pepco will purchase QF energy made available to it at any time.

Availability of Standby Service: Standby service is available for customers with generating equipment in accordance with tariff Schedules "S". Schedules "S" for both Maryland and the District of Columbia are included in this booklet.

Interconnection with the Pepco Electric System: The potential for additional capacity purchases from outside the Company's system is currently limited by the availability of firm transmission capability. Pepco's transmission interconnections are fully subscribed by existing external capacity resources and emergency import requirements. At this time, no "wheeled-in" power will be accepted for capacity credit. The Company will continue to monitor technical developments and, when in the future it identifies a need to obtain new capacity resources, will reassess the availability of transmission for delivery of new capacity. The Company would be willing to purchase short-term energy from QFs and NUGs which are not directly connected to its electric system, when such purchases are determined to be economic compared to other off-system options.

Pepco's major transmission and subtransmission facilities are identified on the "General Map" included in this booklet. Engineering and operational requirements for interconnection are described in the "Guidelines and Performance Standards for Parallel Operation of Customer Generation Equipment with the Pepco System" which are also included in this booklet.

Specific interconnection location and voltage will be determined by the Company on a case-by-case basis.

Following up with Pepco: At present, Pepco does not have a need for additional capacity. While additional capacity is not required now, Pepco plans to competitively procure any future capacity from QFs, EWGs, other NUGs either within or outside its system, or from other utilities. Pepco will contract for capacity resources that are economic, reliable and meet an identified future need. The next anticipated need does not occur until about the year 2002.

Developers are encouraged to discuss their projects with Pepco early in the development process and to stay in touch regularly in order that their planning may be based on the most up-to-date information.

Please contact:

Peter E. Schaub
Manager, Supply Side Resources
Potomac Electric Power Company
1900 Pennsylvania Avenue, NW
Washington, DC 20068

Telephone: 202-872-3044

DC - CG - SPP

COGENERATION AND SMALL POWER PRODUCER SERVICE
PURCHASE OF POWER
SCHEDULE "CG-SPP"

AVAILABILITY - This schedule is available for the receipt and purchase of electric power from a District of Columbia qualifying cogeneration facility or qualifying small power production facility (a QF) as defined pursuant to the Federal Power Act and Section 210 of the Public Utility Regulatory Policies Act of 1978.

As modified by Rider "CG-SPP-1", this schedule applies to small QFs (1,000 kilowatts or less).

As modified by Rider "CG-SPP-2", this schedule provides for dispatchable and/or non-standard rates.

CHARACTER OF SERVICE - The service supplied under this schedule is interconnected operation with the QF and the purchase of electric energy or capacity, or both, by the Company from the QF. As used in this schedule, "QF" means either the QF facility or the QF operator (referred to elsewhere in the Company's District of Columbia Electric Tariff as the "Customer") as appropriate.

CONTRACTUAL ARRANGEMENTS - The Company will interconnect with the QF, and will purchase all power generated by the QF, pursuant to a detailed agreement negotiated between the Company and the QF. The detailed agreement must be filed with and accepted by the Commission except for an agreement entered into under Rider "CG-SPP-1". This schedule (including the General Terms and Conditions of the Company's Tariff) may be incorporated into the detailed agreement by reference. Unless otherwise expressly stated in this schedule or the detailed agreement, such reference shall mean this schedule as revised and made effective from time to time.

The detailed agreement between the Company and the QF will specify the rates for purchases of electric energy and capacity from the QF. An applicant either may accept the standard offering rates set forth in this rate schedule or, pursuant to Rider "CG-SPP-2", may negotiate dispatchable and/or non-standard rates. The applicant may be required to provide legally enforceable financial assurances satisfactory to the Company that the QF will be placed in service

CONTRACTUAL ARRANGEMENTS - (continued)

on schedule and will be able thereafter to fulfill its obligation to provide the contracted-for capacity for the entire contractual period at the contracted-for availability. Dispatchable projects will be required to conform to the Company's requirements for coordinated economic dispatch.

Applicants for service under this schedule should apply to the Company for further information about application and interconnection requirements.

METHOD OF PURCHASE - The Company normally will meter and purchase all power generated by the QF on a simultaneous sale and buy-back basis. However, at the initial election of the QF, the Company will purchase only such generated power as is determined by the QF to be excess and metered as such for purchase by the Company. QFs selling power under the standard rates set forth below may change this initial election upon at least two (2) years notice to the Company, provided that this election is changed no more frequently thereafter than once in three (3) years and the costs to the Company of changing the interconnection and metering are borne by the QF. QFs selling power pursuant to rates negotiated under Rider "CG-SPP-2" shall be governed by the negotiated agreement.

Under the simultaneous sale and buy-back option, all electricity used by the QF (consisting of the electrical station consumption of the QF and the electrical consumption of the QF operator for other purposes at the same service location) will be considered purchased from the Company at the applicable retail rate, while all electricity produced by the QF will be considered purchased by the Company pursuant to this schedule. Under the excess generation option, the Company will purchase the power generated in excess of the electricity used by the QF, and any purchases from the Company will be supplied as standby or auxiliary service under Schedule "S".

As a condition of interconnection, the QF must cease interconnected operations immediately upon notification by the Company that the QF's operation is degrading the quality and reliability of service being provided to the Company's other customers. The Company is not responsible for monitoring the QF's operation and is not liable for any loss, cost, damage or other expense to any party resulting from

METHOD OF PURCHASE - (continued)

the use or presence of electric current or potential which originates from the QF's generation facilities. The QF shall indemnify and hold the Company, its officers, directors, affiliates, agents, employees, contractors and subcontractors, harmless from and against any and all claims, demands, actions, losses, liabilities, expenses (including reasonable attorneys' fees), suits and proceedings of any nature whatsoever for personal injury, death, or property damage to third parties, except workers compensation claims, caused by any act or omission of the QF's own officers, directors, affiliates, agents, employees, contractors or subcontractors that arise out of or are in any manner connected with the QF's performance under this schedule or under any agreement between the QF and the Company, or both, except to the extent such injury or damage is attributable to the negligence or willful misconduct of the Company.

INTERCONNECTION FACILITIES - The point of interconnection and nominal interconnection voltage level will be specified by the Company on the basis of its available facilities and the magnitude of the generation and load to be served.

In general, extension or modification of the Company's electric system to accommodate interconnected operation with, or the purchase of electricity from, the QF shall be performed by or at the expense of the QF, and protective, operational metering (including kilovolt-ampere-reactive meters if required) and communications equipment shall be installed and maintained by or at the expense of the QF, in accordance with the specifications for interconnection and parallel operation furnished by the Company. Such protective equipment must be operational and inspected by and tested to the satisfaction of the Company prior to any interconnected operation of the QF. The Company normally shall install, own and maintain at the expense of the QF the metering equipment to measure the kilowatts and kilowatt-hours of electricity purchased from or sold to the QF by the Company. The installed cost to the Company of all such facilities which it provides will be payable to the Company as contributions in aid of construction. Except as provided in Rider "CG-SPP-1", payments will be due as invoiced and not later than the time of interconnection of the QF's equipment with the Company's system.

DC - CG - SPP

STANDARD RATES FOR PURCHASES FROM QFS - The following standard offering rates will apply for non-dispatchable QFs while this schedule is effective. Rates for dispatchable QFs and non-standard rates will be negotiated by the Company on a case-by-case basis pursuant to Rider "CG-SPP-2". The standard offering rates set forth in this schedule will be revised approximately annually, or more frequently in appropriate circumstances.

1. RATING PERIODS - The following rating periods apply:

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays
Off-Peak Period — All Hours

Holidays
For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

2. BILLING CHARGE - The monthly billing charge payable to the Company by QFs delivering power at approximately 600 volts or below (secondary voltage) shall be $18 per month. For QFs delivering power at voltages of approximately 4 kV (primary voltage) or higher the monthly billing charge shall be $112 per month. For QFs delivering power at transmission voltage (nominally 230 kV) the monthly billing charge shall be $308 per month.

3. ENERGY RATE - The standard offering Energy Rate is as follows:

	Summer Billing Months of June-October	Winter Billing Months of November-May
On-Peak Period	3.508¢ per kwh	3.198¢ per kwh
Intermediate Period	2.863¢ per kwh	3.019¢ per kwh
Off-Peak Period	2.007¢ per kwh	2.324¢ per kwh
Avg =	2.79	2.847

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1900 Pennsylvania Avenue, N.W.
Washington, D.C. 20068

STANDARD RATES FOR PURCHASES FROM QFS - (continued)

Energy payments shall be made on a monthly basis. The total energy payment for any given month shall be the sum of the amounts calculated by multiplying the number of kilowatt-hours of energy delivered in each rating period times the applicable Energy Rate for each such period times the Voltage Adjustment Factor if applicable.

4. CAPACITY RATE - The Company presently projects no avoidable production capacity cost until the year 2002, as indicated by the schedule of avoided capacity costs contained below. Revisions of the Company's projection of avoided costs will be reflected in future updates of this schedule.

In the absence of a negotiated multi-year capacity rate commitment, the standard Capacity Rate for the current year shall apply. The Company is not accepting multi-year commitments for New Capacity at this time. The Company will indicate its willingness to accept multi-year commitments by an update to this schedule which, in the Company's opinion, is sufficiently in advance to allow QF developers a reasonable lead time for the development of projects appropriate to meet the Company's projected need. Avoided costs provided in such updates will be calculated after including projects already in operation or substantially completed. For the purposes of this schedule, "New Capacity" means any QF capacity other than QF capacity which is subject to a currently-effective multi-year commitment previously accepted by the Company.

The standard offering Capacity Rate is the sum of the production component and appropriate transmission component, if any, as follows, for purchases which qualify based on the detailed agreement with the Company with respect to the QF generating facility, unit or increment thereof:

STANDARD RATES FOR PURCHASES FROM QFS - (continued)

Year Applied	Production Component*	plus	Transmission Component 69 kV**	or	Below 69 kV
1994	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
1995	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
1996	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
1997	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
1998	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
1999	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2000	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2001	0.000 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2002	8.366 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2003	7.752 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2004	11.770 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2005	10.835 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2006	12.739 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2007	11.456 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh
2008	9.262 ¢/kwh		1.202 ¢/kwh		1.944 ¢/kwh

* Only the current year value is applicable in the absence of a multi-year capacity commitment, which is not available for New Capacity at the current time. Projections of avoided cost rates for future years are provided solely for planning purposes.

** High voltage level (nominally 69 kV).

This standard Capacity Rate is payable on a monthly basis in each summer billing month. Payment is calculated by multiplying the applicable per-kilowatthour Capacity Rate by the kilowatt-hours of electricity delivered to the Company from the QF facility during summer month on-peak periods times the Voltage Adjustment Factor if applicable. Other capacity payment arrangements may be negotiated pursuant to Rider "CG-SPP-2".

A purchase qualifies for this Capacity Rate only to the extent that it qualifies as installed capacity pursuant to the installed capacity criteria of the Pennsylvania-New Jersey-Maryland Interconnection (the PJM power pool, of which the Company is a member), as implemented by the Company, for evaluating PJM member purchases of non-utility-generation (NUG) capacity, including QF capacity.

STANDARD RATES FOR PURCHASES FROM QFS - (continued)

A purchase qualifies for the transmission capacity component for deliveries at the 69 kV level, and the higher transmission capacity component for deliveries at a level below 69 kV, only if the QF's deliveries allow the Company to avoid transmission or subtransmission plant expenditure, as determined by the Company, consistent with the determination of delivery voltage for purposes of the Voltage Adjustment Factor, below. There is no transmission capacity component for deliveries to the Company at a nominal voltage level higher than 69 kV.

The foregoing standard production capacity and transmission capacity components are stated in 1994 dollars and shall be adjusted in each year by a general inflation adjustment factor, calculated by dividing the sum of the CPI-U's for October, November and December of the calendar year preceding the year the rate is to be in effect by the sum of the CPI-U's for October, November, and December of the calendar year preceding the Base Year (where: "CPI-U" means the Consumer's Price Index for All Urban Consumers, U.S. City Average, published monthly by the Bureau of Labor Statistics, Department of Labor, or a suitable successor index; and "Base Year" means the calendar year containing the first summer season in which this update of Schedule "CG-SPP" is designed to be effective).

5. VOLTAGE ADJUSTMENT FACTOR - The following adjustment factors apply to the Energy and Capacity Rates payable for QF deliveries at nominal delivery voltage levels of 4 kV or higher. For this purpose the delivery voltage shall be deemed the maximum voltage employed in the lowest voltage path linking the QF's point of interconnection to customers of the Company having a combined retail load as large as the QF's output, which path is capable of delivering the QF's output to those customers, as determined by the Company.

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STANDARD RATES FOR PURCHASES FROM QFS - (continued)

Voltage Adjustment Factor for:

Delivery Voltage	Energy Rates	Capacity Rates
Primary Voltage (4 kV & 13.2 kV)	.9765	.9654
High Voltage (69 kV)	.9622	.9466
Transmission Voltage (above 69 kV)	.9487	.9271

RIDER "CG-SPP-1" - SMALL QF SERVICE - This rider is applied to and becomes a part of Schedule "CG-SPP" when the total electric generating capability of the QF is 1,000 kW or less. Under this rider, the production component of the standard capacity rate will be increased by 16 percent to reflect an installed reserve credit. An agreement under this schedule and rider becomes effective when entered into by the QF and the Company and does not require approval by the Public Service Commission, unless Rider "CG-SPP-2" also applies. Bills will be rendered monthly based on meter readings taken in accordance with the appropriate billing rendition group for the QF and the method of purchase (simultaneous sale and buy back or excess generation) selected by the QF. Upon request, the Company will aid the QF in determining the most beneficial method of purchase.

In general, extensions or modifications of the Company's electric system within the Company's service territory to accommodate interconnected operation with, or the purchase of electricity from, the QF shall be performed by the Company at the expense of the QF, and operational metering (including kVAR metering if required) and protective equipment shall be installed and maintained at the expense of the QF, in accordance with specifications for interconnection and parallel operation furnished by the Company. Such protective equipment will be required prior to any interconnected operation with the QF. Also, the Company will install, own and maintain at the expense of the QF the metering equipment to measure the kilowatts and kilowatt-hours of electricity purchased from or sold to the QF by the Company. The installed cost to the Company of such facilities will be payable to the Company as one or more contributions in aid of construction, due prior to the time of interconnection, except that at the option of the QF and

RIDER "CG-SPP-1" - SMALL QF SERVICE - (continued)

upon providing a legally enforceable assurance of full payment satisfactory to the Company the total amount due for interconnection facilities may be paid in equal monthly installments, including interest at the current interest rate paid by the Company on customer deposits, spread over a period not to exceed three (3) years.

RIDER "CG-SPP-2" - DISPATCHABLE AND/OR NON-STANDARD RATES - This rider applies to and becomes a part of Schedule "CG-SPP" when the QF and the Company negotiate an agreement which incorporates dispatchable and/or non-standard project specific rates. Such an agreement will require the approval of the Commission. Non-standard rates under this rider are available only to a QF which, at any time during the negotiation, at its option could obtain a multi-year capacity commitment under the standard Capacity Rate as set forth in this Schedule "CG-SPP". Multi-year capacity commitments are not currently available.

Non-standard rates will be based on avoided costs determined by comparing a least cost plan (LCP) which includes the QF to a LCP which does not include the QF. The analysis will be conducted using the forecast and planning assumptions available at the time the Commission considers the Agreement. This differential revenue requirements method will be used to evaluate specific QF proposals. Developers will be required to provide sufficient project-specific information, including fixed and variable cost components, to enable the Company to calculate system incremental revenue requirements including the QF. The cumulative present worth of incremental revenue requirements including the QF must be less than or equal to the cumulative present worth of incremental revenue requirements based on the least cost plan without the QF. The developer may be required to provide cash equivalent security to protect against the risk incurred by the Company where annual revenue requirements including the QF exceed annual revenue requirements based on the least cost plan without the QF during the early years of the contract.

For projects with delivery voltages at or below 69 kV, the following avoided transmission costs will be multiplied by the QF capacity rating and credited to the differential revenue requirements between the least cost plan without the QF and the plan including the QF. In addition, the differential revenue requirements associated with the capacity and energy components will be adjusted for the delivery voltage.

RIDER "CG-SPP-2" - DISPATCHABLE AND/OR NON-STANDARD RATES - (continued)

Avoided Transmission Costs

Year Applied	Transmission Component 69 kV*	or Below 69 kV
1994	$9.30/kw	$15.04/kw
1995	$9.30/kw	$15.04/kw
1996	$9.30/kw	$15.04/kw
1997	$9.30/kw	$15.04/kw
1998	$9.30/kw	$15.04/kw
1999	$9.30/kw	$15.04/kw
2000	$9.30/kw	$15.04/kw
2001	$9.30/kw	$15.04/kw
2002	$9.30/kw	$15.04/kw
2003	$9.30/kw	$15.04/kw
2004	$9.30/kw	$15.04/kw
2005	$9.30/kw	$15.04/kw
2006	$9.30/kw	$15.04/kw
2007	$9.30/kw	$15.04/kw
2008	$9.30/kw	$15.04/kw

* High voltage level (nominally 69 kV).

The foregoing transmission capacity components are stated in 1994 dollars and shall be adjusted in each year by a general inflation adjustment factor, calculated by dividing the sum of the CPI-U's for October, November and December of the calendar year preceding the year the rate is to be in effect by the sum of the CPI-U's for October, November, and December of the calendar year preceding the Base Year (where: "CPI-U" means the Consumer's Price Index for All Urban Consumers, U.S. City Average, published monthly by the Bureau of Labor Statistics, Department of Labor, or a suitable successor index; and "Base Year" means the calendar year containing the first summer season in which this update of Schedule "CG-SPP" is designed to be effective).

GENERAL TERMS AND CONDITIONS - This schedule is subject in all respects, except as modified herein, to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

TABULAR DATA AND ARRANGEMENT DRAWINGS
COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS

Two Combustion Turbine-Unfired Heat Recovery Steam Generator Cycle

Two Combustion Turbine-Supplementary Fired Heat Recovery Steam Generator Cycle

Four Combustion Turbine-Supplementary or Fresh Air Fired Heat Recovery Steam Generator Cycle

APPENDIX F

Calculation of Nitrogen Oxide Emissions from Candidate Cogeneration Cycles

Calculation of Nitrogen Oxide Emissions from Candidate Cogeneration Cycles

This appendix provides the calculations made to estimate the nitrogen oxide (NO_x) emissions from candidate combustion turbine concepts, extrapolated from results of studies performed for the existing boilers at the Central Heating and Refrigeration Plant managed by the Heating Operation and Transmission District (HOTD).

Methodology

To evaluate the potential benefits of the low NO_x emission characteristics of the combustion turbines and heat recovery steam generators (HRSGs) when firing only natural gas, we developed an operational scenario based on steam demand and assuming that the combustion turbines are base loaded and that existing Boilers 3 and 4 serve for peak steam demand periods. We evaluated both the Asea Brown Boveri (ABB) and the Solar combustion turbines - HRSGs. The assumed scenario over a one-year period includes 110 to 120 days of peak steam demand (greater than 400,000 to 440,000 pounds per hour). Results of the environmental impact modeling studies for HOTD's Central Heating Plant were extrapolated to estimate ground-level concentrations of NO_x, based on release rate characteristics of the existing boilers and of the selected combustion turbine - HRSG combinations.

Assumptions

- Assume combustion turbines - HRSGs replace the Central Heating Plant Boilers 5 and 6, in either of the following arrangements:
  - Two ABB GT35 combustion turbines with two supplemental-fired HRSGs
    - Combustion turbine heat input at 16.9 MW = 180 MMBtu/hr
    - Combustion turbine emission rate = 0.14 lb NO_x/MMBtu
    - HRSG steam rate = 220,000 lb/hr
    - HRSG heat input = 170 MMBtu/hr

- HRSG emission rate = 0.1 lb NO_x/MMBtu

- Four Solar Centaur 40-T4700 combustion turbines with four supplemental-fired HRSGs

  - Combustion turbine heat input = 45.5 MMBtu/hr
  - Combustion turbine emission rate = 0.17 lb NO_x/MMBtu
  - HRSG steam rate = 100,000 lb/hr
  - HRSG heat input = 88 MMBtu/hr
  - HRSG emission rate = 0.1 lb/MMBtu.

- Assume results of environmental modeling studies[1] of existing Central Heating Plant boilers and stack height can be linearly extrapolated to the combustion turbine - HRSG systems by the ratio of NO_x emission rates and heat input:

  - Emission rate = 0.2 lb NO_x/MMBtu
  - Total annual heat consumption = 3.2×10^6 MMBtu (systemwide firing rate representing historical load from both the Central Heating Plant and the West Heating Plant)
  - Maximum annual average modeled ground-level concentration of NO_x from the Central Heating Plant boilers = 43.1 $\mu g/m^3$
  - Background concentration = 59 $\mu g/m^3$
  - Total NO_x concentration = 102.1 $\mu g/m^3$.

- Assume combustion turbines - HRSGs are operated to meet base steam demand and the existing boilers (the Central Heating Plant Boilers 3 and 4) are operated only when steam demand exceeds the capacity of the HRSGs. The average steam demands for the ABB HRSG case are 631,000 lb/hr for 112 days and 200,000 lb/hr for 253 days; the corresponding steam demands for the Solar HRSG case are 600,000 for 121 days and 192,000 lb/hr for 244 days.

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[1] General Services Administration, *Draft Environmental Impact Statement, Air Quality Improvements for the District Heating System Central and West Heating Plants,* Washington, D.C., Bibb and Associates, Inc., June 27, 1994.

CALCULATIONS

- Estimate of NO_x annual ground-level concentrations, ABB GT35 - HRSG

  - Total ground-level concentration equals contribution from existing steam generators during peak period (112 days) plus contribution from combustion turbine - HRSG during peak period (112 days) plus contribution from combustion turbine - HRSG during remainder of year (253 days).

  - Contribution will be estimated based on the heat consumed by each contributor divided by the total heat for the Central Heating Plant boilers of 3.2×10^6 MMBtu multiplied by the ground-level concentration of 43.1 $\mu g/m^3$ for the Central Heating Plant boilers, corrected by the difference in emission rates of the source compared with the Central Heating Plant boilers.

  - Contribution from the Central Heating Plant boiler during peak demand

$$= \left[112\ days \times 24 \frac{hr}{day} \times (631{,}000 - 400{,}000)\ \frac{lb\ steam}{hr} \times 1{,}000 \frac{Btu}{lb\ steam} \times \frac{1}{0.8}\ efficiency\right]$$

$$\times \left[43.1\ \mu g \frac{NO_x}{m^3}\right] \div 3.2 \times 10^{12}\ Btu\ = \frac{8.7\ \mu g}{m^3}\ NO_x .$$

  - Contribution from ABB combustion turbines - HRSGs during peak demand, assuming both combustion turbines - HRSGs operating at full capacity

$$= 112\ days \times 24 \frac{hr}{day} \times 2\left[1.8 \times 10^8\ \frac{Btu}{hr} \times \left(\frac{0.14}{0.2}\right) NO_x + 1.7 \times 10^8\ \frac{Btu}{hr} \times \left(\frac{0.1}{0.2}\right) NO_x\right]$$

$$\times \left[43.1\ \frac{\mu g}{m^3}\ NO_x\right] \div 3.2 \times 10^{12}\ Btu\ = 15.3\ \frac{\mu g}{m^3}\ NO_x\ .$$

  - Contribution from ABB combustion turbine — HRSG during off-peak period, assuming one combustion turbine — HRSG operating at reduced load to match steam demand

$$= 253\ days \times 24 \frac{hr}{day} \times \left[1.8 \times 10^8\ \frac{Btu}{hr} \times \left(\frac{0.14}{0.2}\right) NO_x + 1.7 \times 10^8 \times \left(\frac{0.1}{0.2}\right) NO_x\right]$$

$$\times \left(\frac{201{,}000}{220{,}000}\right) reduced\ load \times 43.1 \frac{\mu g}{m^3}\ NO_x \div 3.2 \times 10^{12}\ Btu\ = 15.7\ \frac{\mu g}{m^3} .$$

$$Total\ = 8.7 + 15.3 + 15.7 = 39.7 \frac{\mu g}{m^3} .$$

- Estimate of NO_x annual ground-level concentrations, Solar Centaur 40-T4700 – HRSG

  - Follow same procedure as for ABB GT35 – HRSG.

  - Contribution from the Central Heating Plant boiler during peak demand

$$= \left[112\ days \times 24 \frac{hr}{day} \times (631,000 - 460,000) \frac{lb\ steam}{hr} \times 1,000 \frac{Btu}{lb\ steam} \times \frac{1}{0.8}\ efficiency \right]$$

$$\times \left[43.1 \frac{\mu g}{m^3} \right] \div 3.2 \times 10^{12}\ Btu = 9.8 \frac{\mu g}{m^3}.$$

  - Contribution from Solar combustion turbine – HRSG during peak demand, assuming four combustion turbines – HRSGs operating at full capacity

$$= 112\ days \times 24 \frac{hr}{day} \times 4 \left[45.5 \times 10^6 \frac{Btu}{hr} \times \left(\frac{0.17}{0.2} \right) NO_x + 88 \times 10^6 \frac{Btu}{hr} \times \left(\frac{0.1}{0.2} \right) NO_x \right]$$

$$\times 43.1 \frac{\mu g}{m^3} NO_x \div 3.2 \times 10^{12}\ Btu = 12.9 \frac{\mu g}{m^3} NO_x.$$

  - Contribution from Solar combustion turbines – HRSGs during off-peak period, assuming two combustion turbines – HRSGs operating at reduced load to match steam load demand

$$= 243\ days \times 24 \frac{hr}{day} \times 2 \left[45.5 \times 10^6 \frac{Btu}{hr} \times \left(\frac{0.17}{0.2} \right) NO_x + 88 \times 10^6 \frac{Btu}{hr} \times \left(\frac{0.1}{0.2} \right) NO_x \right]$$

$$\times \frac{192,000}{200,000}\ lb\ steam \times 43.1 \frac{\mu g}{m^3} NO_x \div 3.2 \times 10^{12}\ Btu = 12.5 \frac{\mu g}{m_3} NO_x.$$

$$Total = 9.8 + 12.9 + 12.5 + 35.2 \frac{\mu g}{m^3}.$$

Results

Given the uncertainty in the extrapolation from the base case studies, the only reasonable conclusion to draw is that cogeneration offers little improvement in emissions under the assumed scenario. Table F-1 shows the projected NO_x ambient air concentrations if cogeneration is adopted at the Central Heating Plant and natural gas is burned. For comparison, the table also shows current emission levels from the Central plant boilers.

Table F-1.
Summary of NO_x Emissions (micrograms/cubic meter)

Source	Contribution	Background	Total	Allowable
Central plant boilers	43.1	59	102.1	100
ABB GT35 and HRSG	39.7	59	100.2	100
Solar Centaur 40-T4700 and HRSG	35.2	59	95.8	100

APPENDIX G

The District of Columbia *Cogeneration Facilities Appropriateness Standards Act of 1993*

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OFFICE OF THE SECRETARY
DIST. OF COLUMBIA COUN.

Councilmember John Ray

Councilmember Jack Evans

Councilmember Jim Nathanson

A BILL

IN THE COUNCIL OF THE DISTRICT OF COLUMBIA

Councilmembers John Ray, Jack Evans and Jim Nathanson introduced the following bill which was referred to the Committee on ____________________

To prohibit the issuing of any permits allowing construction or operation of any cogeneration facility within the District of Columbia until the Public Service Commission of the District of Columbia has proposed and the Council of the District of Columbia has approved energy conservation and environmental protection appropriateness standards for the location, size, ownership and power consumption of cogeneration facilities.

BE IT ENACTED BY THE COUNCIL OF THE DISTRICT OF COLUMBIA, That this act may be cited as the "Cogeneration Facilities Appropriateness Standards Act of 1993".

Sec. 2. Findings.

The Council of the District of Columbia finds that:

(a) The District of Columbia lacks an overall policy on emerging technologies in the areas of energy and environmental protection and the impact those technologies may have on the quality of life in the District of Columbia, and is currently dependent on requirements in District of Columbia law to protect its citizens from potentially adverse effects of those technologies.

(b) Cogeneration can be an energy saving and cost efficient alternative to the building of additional electric utility plants.

(c) Cogeneration plants may cause negative environmental effects occasioned by the size of the plant, its proximity to residential areas and/or fragile eco-systems, the kind of fuel used to power the cogeneration plant and the technology and logistics of supplying that fuel, and any transfer of the power generated by the cogenerator to a receiver at a site other than that on which the cogenerator is housed.

(d) Cogenerators may be sources of electromagnetic field (EMF) radiation, and studies undertaken within the past decade indicate a strong potential for a substantive correlation between high amounts of electromagnetic field radiation and an increased risk of cancer in persons, particularly children, who are exposed to EMF emissions.

(e) The Public Service Commission has identified 21 sites in the city, in addition to the Georgetown University site, where there is an immediate potential for a cogenerator; these sites are:

Ward 1 Howard University

Ward 2	George Washington University
	GSA Central Heating Plant
	GSA West Heating Plant
Ward 3	University of the District of Columbia
	American University
	Sibley Memorial Hospital
Ward 4	Washington Hospital Center
	Walter Reed Army Medical Center
	U.S. Soldiers' and Airmen's Home
Ward 5	Gallaudet University
	Catholic University of America
	U.S. Postal Service (Brentwood Road)
Ward 6	D.C. General Hospital
	U.S. Capitol Power Plant
	Washington Navy Yard
Ward 7	None
Ward 8	Saint Elizabeth's Hospital
	Naval Research Laboratory
	Anacostia Naval Annex
	Bolling Air Force Base
	D.C. Village

(f) Cogenerators may be proposed as sources of power for an on-site receiver and/or an off-site receiver; and cogenerators may be proposed to be constructed with a capacity to produce power excess to the needs of an on-site host facility.

(g) The technology exists to transform and transfer electrical power produced by a cogeneration plant directly into an on-site receiving facility without first transmitting that electricity into an off-site power grid.

(h) There exists no impediment in current D.C. law to the ownership by foreign utility companies of cogenerators located in the District of Columbia.

(i) Pursuant to District of Columbia law, no gas corporation or electrical corporation shall begin the construction of a gas plant or electric ant without first having obtained the permission and approval of the Public Service Commission of the District of Columbia.

(j) D.C. Law mandates that if a public utility proposes an action, it shall prepare and submit a detailed environmental impact statement to the Public Service Commission, and that such a statement be must be prepared and filed before application is made to the Department of Consumer and Regulatory Affairs for a permit.

(k) The Office of Peoples' Counsel is statutorily established, empowered and required to be a party in any investigation, valuation, revaluation, or proceeding of any nature by the Public Service Commission of or concerning any public utility operating in the District of Columbia.

(l) The Public Service Commission and the Office of Peoples' Counsel have the experience and staff capability to establish and monitor the appropriateness of any proposed cogeneration facility in the District of Columbia.

Sec. 3. Prohibition on the issuing of permits.

(a) No agency of the District of Columbia government shall issue any permit for the construction, expansion, or operation of any cogeneration facility in the District of Columbia until the Public Service Commission of the District of Columbia shall establish appropriateness standards for cogenerators within the District of Columbia, and the appropriateness standards shall include consideration of:

(1) The location of the site of a cogeneration plant in relation to residential areas of varying density, to recreational areas, and to areas of fragile eco-systems.

(2) The size of the lot on which the cogenerator is to be located.

(3) The level of noise, electromagnetic radiation, and other types of emissions and environmental pollutants expected to be occasioned by the cogenerator in relation to the communities in and adjacent to the site of that cogeneration facility.

(4) The impact of the cogenerator on the property values of the owners of properties adjacent and surrounding the cogenerator site.

(5) The placement and environmental impact of equipment and auxiliary facilities such as fuel storage tanks or containers, pipelines, or switchyards, in relation to communities and property adjacent to and surrounding the cogenerator site.

(6) The circumstances under which foreign utility companies will be allowed to own and/or operate cogeneration plants in the District of Columbia.

(7) The circumstances under which an entity or entities other than the owners of the host property may own and/or operate a cogeneration plant in the District of Columbia.

(8) Any other criteria which will serve to ensure the protection of residential neighborhoods and the health and safety of the citizens of the District of Columbia.

(b) Notwithstanding the criteria outlined in section 3(a), no permit shall be issued for any cogeneration plant unless the host facility will use directly no less than 70% of the total output (such as heat and electrical energy) produced by the cogenerator at the time it becomes operable and at all times thereafter.

(c) In addition to the establishment of appropriateness standards for cogeneration plants in the District of Columbia, and prior to any agency of the District of Columbia government issuing any permits for the nstruction, expansion or operation of any cogeneration facility in the District of Columbia, the Public Service Commission shall also establish the procedure through which entities proposing to construct, expand or operate a cogeneration facility in the District of Columbia shall come before the Public Service Commission and demonstrate to the approval of the Commission that the proposed cogeneration plant is a facility which meets the appropriateness standards established by the Commission.

Sec. 4. Enactment by the Council of the District of Columbia.

The appropriateness standards and the procedures for approval required to be established by the Public Service Commission in section 3 of this act shall be submitted to the Council of the District of Columbia for its approval by Act, and no agency of District government may issue any permit for the construction, expansion, or operation of any cogeneration facility until the Council acts pursuant to this act.

Sec. 5. Effective date.

This act shall take effect after a 30-day period of Congressional review following approval by the Mayor (or in the event of veto by the Mayor, action by the Council of the District of Columbia to override the veto) as provided in section 602(c)(1) of the District of Columbia Self-Government and Governmental Reorganization Act, approved December 24, 1973 (87 Stat. 813; D.C. Code § 1-233(c)(1), and publication in either the District of Columbia Register, the District of Columbia Statutes-at-Large, or the District of Columbia Municipal Regulations.

Appendix H

Related Studies

Related Studies

Four studies are related to our analysis of cogeneration at the Heating Operation and Transmission District (HOTD) operated by the General Services Administration (GSA):

- General Services Administration, *Phase II Electric Steam Cogeneration Feasibility Study,* GSA Contract GS-11B-19019, Hennings, Dunham & Richardson, June 1985. This study evaluated various cogeneration options for HOTD.
- General Services Administration, *Heating System Study, Southeast Federal Center,* Contract ZDC-96095, Summer Consultants, Inc., February 1990. This study evaluated heating concepts for the proposed Southeast Federal Center (SEFC).
- General Services Administration, *Study of the Feasibility of Installing Steam Lines from Existing Tunnel Complex to the Navy Yard Annex,* Contract GS-11P-90EGD-0136, Summer Consultants, Inc., June 1994. This study evaluated steam tunnel routing concepts that would enable GSA to supply the SEFC with steam from the HOTD Central Heating and Refrigeration Plant.
- Radian Corporation, *Georgetown Cogeneration Facility Air Permit Application,* February 1991. This study was a proposal for a cogeneration facility at Georgetown University.

This appendix summarizes pertinent information from each of those studies.

Hennings, Durham & Richardson Report

Hennings, Durham & Richardson (HDR) performed a three-phase study for GSA comparing coal-fired boilers with and without cogeneration. At the time of the study (1983 – 1985), GSA's plants included the Pentagon Utilities Plant (referred to then as the Virginia plant), control of which has since been transferred to the Department of Defense. In addition, fuel use was about 75 percent No. 6 oil and 25 percent coal, with plans to change to 100 percent coal in the next five years. (Recent environmental restrictions now require that essentially all fuel be natural gas, which significantly affects financial considerations.)

The objectives of the HDR study were to determine the minimum energy strategy, the minimum cost strategy, and the maximum abundant fuel-use strategy. Initially, HDR prepared a list of 14 options, following criteria based on the physical characteristics of the plants and of the system, considerations of steam supply by and the sale of electricity to the Potomac Electric Power Company (Pepco), and pertinent government regulatory and financial factors.

Of the 14 options, 9 were selected for further study. For each of the 9 options, HDR determined capital costs, operations and maintenance (O&M) costs, manpower requirements, fuel uses, and electric and steam-generation potential. Three of the nine options — designated as Options 2A, 2B, and 6 — were evaluated in further detail:

- *Option 2A* — removal of Boilers 1 and 2 at the Central Heating Plant and installation of a coal-fired 250,000 pound-per-hour, 850 psig, 900°F boiler, with a dry scrubber and baghouse, and a 7,500-kW noncondensing turbine that would exhaust 250 psig steam to the heating system. All generated electricity would be sold to Pepco. Design optimization by HDR resulted in a boiler rated at 250,000 pounds per hour steam at 1,300 psig and 755°F, and a 9,540 kW turbine exhausting at 175 psig (summer) or 250 psig (winter). (The dual exhaust pressure takes advantage of the fact that a lower steam distribution pressure is possible in summer because the system steam loads are lower.)

- *Option 2B* — same as Option 2A, except generated electricity would be used internally; any excess would be sold to Pepco.

- *Option 6* — installation at the Virginia plant of a new coal-fired boiler rated at 125,000 pounds per hour, 850 psig, 900°F, and a 5,000-kW noncondensing turbine that would exhaust at 125 psig to the Pentagon steam system. Subsequently, this option was expanded into 6A and 6B, similar to Options 2A and 2B, in which electricity would be sold to Pepco.

The HDR study also included an evaluation of "wheeling" — transmitting excess electricity to other GSA facilities.

Adding chilled water generation as a steam load in summer was considered early in the project but was eliminated from detailed evaluation because the capacity of the new plant design was close to the GSA district heating load and the addition of refrigeration load was not considered justified.

HDR estimated that 13 additional people would be required to operate the proposed cogeneration facilities at the Central Heating Plant (Options 2A and 2B): two electronic instrument technicians, four general maintenance people, three coal-handling operators, and four turbine operators (one per shift).

The overall economic analysis was based on the life-cycle costing methodology outlined by the Department of Energy (DOE). As key indicators, HDR used the net present value and the savings-to-investment ratio. The economic evaluation was performed for three cases: all electricity sold to Pepco, electricity used for in-house HOTD needs with the remainder sold to Pepco, and electricity used internally with the excess wheeled to other government facilities. During the study, HDR determined that Boilers 1 and 2 at the Central plant would be replaced with comparably sized equipment in the near future.[1] Consequently,

[1] Subsequently, GSA decided to rebuild Boilers 1 and 2; the rebuild is scheduled to be completed in 1995.

HDR prepared cost estimates for the installation of one 220,000 pound-per-hour, low-pressure (250 psig), coal-fired boiler; those estimates became the basis of comparison for the cogeneration options at the Central plant.

The initial cost of the cogeneration facility was estimated to be $22.5 million. The initial cost of the low-pressure steam-only facility was estimated to be $12.2 million. However, the life-cycle economic analysis of the Central plant slightly favored cogeneration over replacement with steam only by approximately $2.5 million over a 25-year projected life assumed by the study. These results were found to be highly sensitive to the billing rates for power sold to Pepco, and the economics improved in favor of cogeneration if reduced charges/increased revenues could be negotiated with Pepco.

A number of assumptions contained in the HDR study regarding steam and electrical loads and plant costs can provide a base for comparison with current data. Table H-1 shows the pertinent assumptions made by HDR and the current cost and load data.

Table H-1.
Comparison of Cost and Load Assumptions in the 1985 HDR Study with 1994 Costs and Loads

Characteristic	1985 assumptions	1994 actual
Fuel costs		
Coal	$69.92/ton $2.64/MMBtu	$64.00/ton $2.37/MMBtu
Oil	$0.78/gallon (No. 6) $5.30/MMBtu	$0.59 gallon (No. 2) $4.15/MMBtu
Gas	$5.30/MMBtu	$3.60/MMBtu
Total Btu/year	3.4×10^{12}	3.32×10^{12}
Nonfuel O&M costs		
Labor	$6.66 million	$8.8 million
Material and maintenance	$8.03 million	$8.4 million
Steam		
Average generation rate	340,000 pounds per hour	330,000 pounds per hour
Peak demand	1.3 million pounds per hour	1.1 million pounds per hour
Electricity		
Annual usage	12 million kWh	25.8 million kWh
Peak demand	7,380 kW	10,000 kW
Average usage costs (energy and demand)	$0.081/kWh	$0.073/kWh

Significant points of the comparison include the following:

- Current fuel costs are lower than those used in the HDR study. The HDR study used costs of $2.64 per MMBtu ($69.92 per ton) for coal and $5.30 per MMBtu ($0.78 per gallon) for No. 6 oil. During the course of the HDR study, the Washington Gas Light Company reportedly offered to supply natural gas to HOTD at the same cost as No. 6 oil ($5.30 per MMBtu). In 1994, coal cost $63.93 per ton, No. 2 (light distillate) oil cost $0.59 per gallon, and natural gas cost $3.60/MMBtu. The world price of oil at the time of the HDR study was about $29 per barrel; the current price is $18 to $20 per barrel.

- Nonfuel O&M expenses have not escalated as much as the cost-of-living index over the intervening years. Comparative figures are $6.7 million (HDR) versus $8.8 million (1994) for labor and $8.0 million (HDR) versus $8.4 million (1994) for materials and maintenance. The increases are equivalent to an annual escalation factor of 1.3 percent, much less than the actual cost-of-living escalation rate for the 12-year period.

- HDR reported the annual consumption of electricity in the Central and West plants as 10.1 million kWh on weekdays and 1.91 million kWh on weekends and holidays, for a total of about 12 million kWh per year. (That total may include only electricity for the Central Heating Plant. Pepco billing data for 1993 and 1994 indicate a total of about 25.8 million kWh annual consumption for both the Central and West plants; electricity consumption at the West Heating Plant is between 10 and 25 percent of that at the Central Heating Plant. Allowing for this possible correction in the HDR data, there still remains a difference of about 35 percent. The reason for this difference is not apparent.)

- Pepco's 1994 energy rates for electricity are lower than those used in the HDR report (see Table H-2).

- The production and transmission (June – September) charge, based on the peak kilowatt usage in a month, used in the HDR report was $9.80 per kW, and the monthly distribution charge was $6.00 per kW. In 1994, the production and transmission (June – September) charge was $10.63 per kW, and the monthly distribution charge was $6.68 per kW.

- The total annual cost for electricity in the HDR report was $962,160 for 12.1 million kWh, equivalent to $0.08 per kWh. The corresponding data for both the Central and the West plants in 1994 are $1,900,000 for 25.8 million kWh at an average cost of $0.073 per kWh; unit costs in 1994 ranged from $0.043 per kWh (January) to $0.103 per kWh (June).

The HDR study did not cover the applicability of the Office of Management and Budget Circular A 76, which addresses the sale of commercial commodities such as electricity from Federal facilities to private industry. Circular A 76 pertains specifically to commercial versus government-provided commodities and

Table H-2.
Comparison of Pepco Energy Rates in 1985 HDR Study with 1994 Rates (cents per kWh)

Time of day	Summer		Winter	
	1985	1994	1985	1994
Peak	6.22	5.78	5.21	4.79
Intermediate	4.60	4.18	4.60	4.09
Off peak	2.94	2.91	2.94	3.11

defines electricity, as well as steam, as commercial sector items. The background statement in the circular states "the Government should not compete with its citizens." It goes on to prescribe the guidelines under which the government may perform a commercial activity. Two guidelines are applicable to HOTD: if no satisfactory commercial source is available and if the government is or can operate the activity at a lower cost than a commercial source. The supply of steam would be covered by these guidelines, particularly since the only viable source of steam from a commercial facility, the Buzzards Point Station owned by Pepco, has been retired. Generation of electricity also would be covered by these guidelines if it could be shown that, by cogeneration of steam, the generation of electricity for use by GSA were cost-effective. Thus, although the HDR study did not discuss Circular A 76, it appears that a case could be made justifying the assumptions on which the study was based.

In summary, although the results of the HDR study are not applicable to current and foreseeable operations of the HOTD plants, the assumptions contained in their report provide a reference for this study.

Summer Consultants 1990 Report

The GSA plans to construct the SEFC, consisting of office, retail, and utility space, next to the Navy Yard. The SEFC will consist of a series of buildings, proposed to be built in phases and ultimately to include up to 8.4 million square feet of space (HOTD currently serves about 50 million square feet of space). Summer Consultants, Inc., evaluated the use of five heating methods for the new SEFC at the Navy Yard:

- Electric resistance heating
- Electric-driven heat pumps
- Purchase of steam from the Navy boilers at the adjacent Navy Yard

- Individual oil- or gas-fired heating plants

- New GSA-owned heating plant, located at the SEFC or Navy Yard site.

The options are listed in the order of their life-cycle costs — that is, the electric resistance heat option was calculated to be the least expensive ($8.3 million) and the GSA Central Heating Plant was the most expensive ($21.4 million). (Since the study was completed, two new Navy boilers have been constructed and are in operation, which may affect the relative costs of the Navy steam option.) For each of the heating systems studied, Summer considered initial costs, annual heating costs, annually recurring O&M costs, nonrecurring repair costs, and O&M costs that do not recur annually. The economic model used DOE's life-cycle costing methodology; the key indicators were net present value and savings-to-investment ratio. Summer recommended electric resistance heating for the SEFC because of its low cost and low environmental impact.

The Summer Consultants study points out that the modern buildings that would be built at the SEFC have much lower heating needs and greater cooling needs than the older buildings for which the GSA's Central Heating System was designed. Compared with older buildings, modern buildings have

- block rather than "finger" design,

- tighter construction (lower heat infiltration),

- higher internal lighting loads,

- higher internal heating loads, and

- better insulation (lower heat transmission).

Consequently, the heating system is mostly for heating outside ventilation air and for space heating at night and on weekends in the cold seasons.

A key factor in the economics is the additional staffing costs associated with the various options. Local systems such as electric heat and local oil and gas furnaces are assumed to be manned by the normal staff of the SEFC and thus are not penalized for staffing cost. GSA Central plant operation requires 24-hour per day coverage by a licensed operator. The GSA Central and Navy steam plants require the most maintenance, highest level of skill for operation, and highest cost for recurring major repairs.

The study also raised the issue of reliability given the potential for flooding at the Navy Yard. A flood could make the Navy and GSA steam plants subject to failure. Electric resistance and heat pump systems would not be affected by the flood (assuming Pepco's ability to supply electricity was not affected).

Summer Consultants 1994 Report

The Summer Consultants report prepared in 1994 evaluated routing of piping to supply steam to the SEFC from HOTD's Central Heating Plant, assuming all heating and cooling were provided by steam (steam heaters in the winter and steam absorption chillers in the summer). Steam demand was estimated based on supplying not only the SEFC, but also the office facilities at the Navy Yard, District of Columbia public housing along the route between the Central Heating Plant and the SEFC, and the Architect of the Capitol's heating plant. The total design load was 500,000 pounds per hour, much higher than the winter peak load of about 300,000 pounds per hour for the Navy Yard and the SEFC. The report concluded that two 18-inch-diameter steam pipes, a 10-inch condensate return pipe, and a 3-inch-diameter high-pressure return pipe would be required. The recommended envelope for the piping is a 7-foot × 7-foot walk-in tunnel. The estimated cost was $18.7 million. This option is less expensive than building a new GSA-owned heating plant but more expensive than resistance heating.

Radian Corporation Report

The Radian Corporation study was a proposal for a cogeneration facility to be built on the campus of Georgetown University. The university operates two boilers fueled by natural gas, with No. 6 fuel oil as a backup, and one coal-fired atmospheric fluidized-bed combustion boiler; the three boilers each produce a nominal 100,000 pounds per hour of steam. The cogeneration facility was planned as the primary source of heating, cooling, and other energy needs of the campus. The coal-fired plant was to be shut down once the proposed cogeneration facility was operational, and the natural gas/oil-fired boilers were to be converted to burn No. 2 fuel oil as the backup fuel and used when the cogeneration plant was not available or cofired with the cogeneration facility, if needed. In addition to providing steam for the university, the cogeneration system would feed steam to existing turbine-driven chillers and to new 3,000-ton steam absorption chillers.

The proposed cogeneration plant included the following equipment and features:

- A dual fuel-fired (gas or oil) combustion turbine, operating in a combined-cycle mode with a heat recovery steam generator (HRSG) equipped with a duct burner, which provides direct supplemental heat input to the turbine exhaust gases before they enter the HRSG; steam would be produced in the HRSG, while electricity would be produced by separate generators driven by the combustion turbine and the steam turbine. The exhaust gas temperature from the combustion turbine would be about 1,000°F.

- A combined-cycle system capable of generating between 30 and 60 MW net electric power while producing a peak steam load of 225,000 pounds per hour; the best-available technology would be used to control emissions, including low NO_x burners and selective catalytic reduction emission controls.

- A 200 MMBtu per hour duct burner, located upstream of the HRSG, to provide heat for peak steam demand; the duct burner would be fueled by natural gas with No. 2 oil as backup.

Table H-3 summarizes the turbine design and performance data for both natural gas and No. 2 oil, and Table H-4 summarizes the design data for the duct burner.

By installing a cogeneration system, the university would be able to

- eliminate the use of coal and thus reduce air emissions;

- increase the overall energy efficiency by more than 20 percent over the existing system: one year's worth of steam and electricity for the university from the existing boilers and the Pepco system requires 4.35 million MMBtu; while the same amount of power can be produced using their proposed cogeneration technology using 3.16 million MMBtu, or a reduction of 27 percent in energy;

- provide a reliable source of energy to the campus and to Pepco, replacing the aging equipment that is approaching the end of its useful commercial life.

In late 1993, the District of Columbia government rejected Georgetown University's proposal to build and operate a cogeneration facility.

Table H-3.
Combustion Turbine Design Data for Georgetown University's Cogeneration Project

Design parameter	Specification
Manufacturer	General Electric Frame 6 Model MS6001
System type	Combined cycle
Fuel Natural gas Distillate oil (No. 2)	 20,469 Btu/lb LHV 18,550 Btu/lb LHV
Maximum heat input Natural gas Distillate oil	 479.2 $\times 10^6$ Btu/hr LHV 476.4 $\times 10^6$ Btu/hr LHV
Net energy output Natural gas Distillate oil	 39.9 MW 39.5 MW

Note: LHV = low heat value.

Table H-4.
Duct Burner Design Data for Georgetown University's Cogeneration Project

Design parameter	Specification
Manufacturer	Henry Vogt Co., Inc.
Heat input Natural gas Distillate oil	 200 MMBtu/hr LHV 200 MMBtu/hr LHV
Emissions Natural gas Distillate fuel	 0.15 lb/MMBtu NO_x 0.227 lb/MMBtu NO_x 0.324 lb/MMBtu SO_2

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13. ABSTRACT *(Maximum 200 words)*

The General Services Administration, through its National Capital Region, operates a district heating system — called the Heating Operation and Transmission District — that provides steam to approximately 100 government buildings in Washington, D.C. HOTD is examining a host of options that will improve its ability to provide reliable, environmentally sound, and cost-effective service to its customers. This report evaluates one of those options — cogeneration, a technology that would enable HOTD to produce steam and electricity simultaneously. The study concluded that, under current regulations, cogeneration is not attractive economically because the payback period (15 years) exceeds Federal return-on-investment guidelines. However, if the regulatory environment changes to allow wheeling (transmission of power by a non-utility power producer to another user), cogeneration would be attractive; HOTD would save anywhere from $38 million to $118 million and the investment would pay back in 7 to 10 years. Although incorporating cogeneration into the HOTD system has no strong benefit at this time, the report recommends that GSA reevaluate cogeneration in one or two years because Federal regulations regarding wheeling are under review. It also recommends that GSA work with the District of Columbia government to develop standards for cogeneration.

14. SUBJECT TERMS

District Heating, Cogeneration Steam, Electricity, GSA/NCR

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