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UNION CARBIDE

District Heating/Cogeneration Application Studies for the Minneapolis–St. Paul Area

Economic Comparison of New Coal-Fueled, Cogeneration Power Plants for District Heating and Electricity-Only and Heat-Only Power Plants

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DISTRICT HEATING/COGENERATION APPLICATION STUDIES FOR THE MINNEAPOLIS-ST. PAUL AREA

ECONOMIC COMPARISON OF NEW COAL-FUELED, COGENERATION POWER PLANTS FOR DISTRICT HEATING AND ELECTRICITY-ONLY AND HEAT-ONLY POWER PLANTS

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United Engineers & Constructors Inc.

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ORNL/TM-6830/P12. *Allocation Methods for the Separation of Electrical and Thermal Cogeneration Costs.* October 1980.

CONTENTS

Page

Page

FOREWORD

District heating is the distribution of thermal energy from a central source for residential and commercial space heating. The central source is usually a heat-only unit or a cogeneration, dual-purpose facility that produces both electricity and thermal energy. The most significant advantage of cogeneration power plants compared with conventional steam electricity generating stations is the improved fuel utilization efficiency. Figure F.1 shows graphically the comparative efficiencies of both types of plants. The overall conversion efficiency of an electricity-only plant is about 33%. The remaining two-thirds of the energy is rejected to the environment through once-through cooling systems or cooling towers at about 308 to 313 K (95 to 104°F). A cogeneration power plant, on the other hand, can operate at an overall efficiency as high as 85% with some sacrifice in electrical output. To supply thermal energy at a temperature level high enough for district heating (e.g., 212°F), steam must be extracted from the power plant's turbine before it has expanded to its full potential. Therefore, there is some reduction in the power output of the turbine which, in turn, reduces the quantity of electricity generated. However, for each unit of electrical energy sacrificed, 5 to 10 units of thermal energy are available for district heating.

District heating has been in existence for approximately 100 years. In 1877, a short underground steam pipe was installed in Lockport, New York, to transport thermal energy from a central source to heat a group of buildings.[1] However, it was not until the early part of the twentieth century that cogeneration/district heating systems came into existence. These systems utilized the exhaust steam from small, noncondensing steam electric power plants to heat buildings in nearby business districts. After a period of rapid growth, the expansion of steam district heating systems slowed in the late 1940s, when inexpensive oil and natural gas became available for heating purposes. At about the same time, utilities were introducing large condensing steam electric power plants remotely located from urban areas. Transporting steam over such long distances

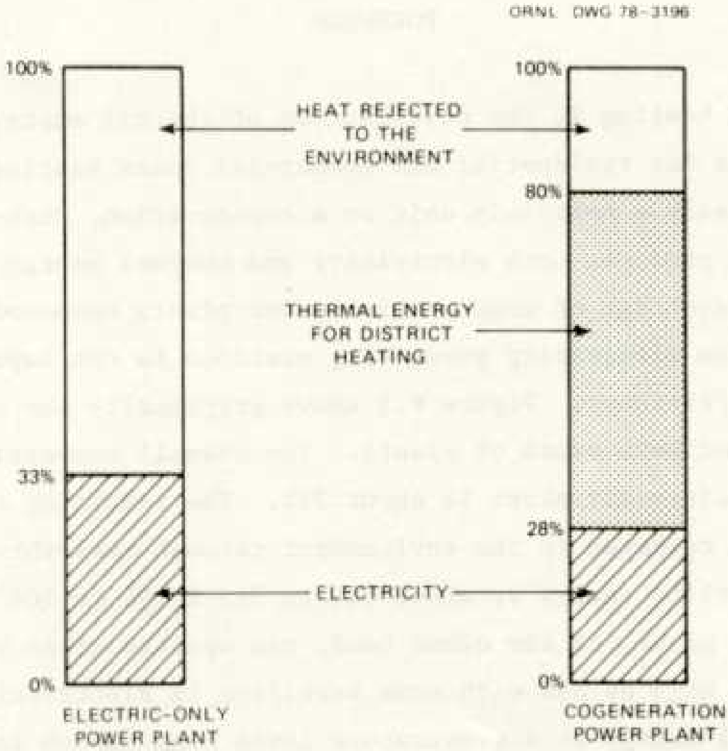

Fig. F.1. Comparison of fuel utilization of electricity-only and cogeneration power plants.

was not economical. As the smaller, older cogeneration units were retired, sources for the steam district heating system were eliminated, and the cost of supplying steam escalated, making district heating even less attractive. District heating technology is now being reassessed because of rapidly escalating energy prices and the increasing dependence of the United States on imported oil. Large hot water district heating systems have the potential of providing consumers with space-heating energy at competitive prices while substituting more plentiful domestic fuels, such as coal and uranium, for heating needs currently supplied by oil and natural gas.

The history of district heating in Europe is somewhat different from that of the United States.[2] Most of the development of large district heating networks in Europe took place after World War II. This development has been due in large part to high energy prices and a scarcity of alternative heating options, such as natural gas. These factors, although new to the United States, have been strong motivation for the expansion of district heating technology in Scandinavian and other northern European countries. Their district heating technology uses hot water as the distribution medium. Hot water was chosen over steam for its flexibility and adaptability to long-distance transport. Over the past 20 years, technology and hardware have been developed that successfully provide large-scale hot water district heating.

Northern States Power Company (NSP), the Department of Energy (DOE), the Minnesota Energy Agency, the City of St. Paul, the Minnesota Gas Company, the Minneapolis Central Heating Company, the University of Minnesota, and other local governments and private organizations are cooperatively performing an in-depth application study to determine the feasibility of hot water district heating for a large U.S. metropolitan area — namely, Minneapolis-St. Paul, Minnesota. The program to assess district heating for the Twin Cities area consists of several coordinated studies focusing on technical, economic, environmental, and institutional issues. A list of the various studies is given in Table F.1. The stimulus for most of the Twin Cities work has been the overall feasibility study[3] done by Studsvik Energiteknik AB, Sweden.

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2. V. Scholten, *Survey about the Existing District Heating Systems*, presented at a topical meeting on low-temperature nuclear heating, Otaniemi, Finland, Aug. 21-24, 1977.

3. Peter Margen et al., *Overall Feasibility and Economic Viability for a District Heating/New Cogeneration System in Minneapolis-St. Paul*, ORNL/TM-6830/P3 (August 1979).

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PREFACE

The study of coal-fired cogeneration plants for district heating described in this report was jointly funded by the Northern States Power Company (NSP) and the U.S. Department of Energy. In developing the work scope for this program, NSP was delegated the overall management of the program and the responsibility for the development of a site selection program; United Engineers & Constructors Inc. was given the responsibility for the conceptual design, cost estimate, and economic comparison of the cogeneration plants at one existing metropolitan site and at the newly selected site.

This evaluation has been divided into three parts. Part 1 is devoted to the conceptual design, description, and capital costs for 200-MW(e)-350-MW(t) cogeneration plants at a reference site in Minnesota, at the High Bridge site adjacent to downtown St. Paul, Minnesota, and at a new site north of the city of Minneapolis, designated as the Coon Rapids site. Part 2 is devoted to the conceptual design, description, and capital costs for 400-MW(e)-700-MW(t) cogeneration plants at the same sites. Parts 1 and 2 are presented as appendixes on microfiche attached to the inside back cover of this report. Part 3, which constitutes the body of this report, examines the economics associated with the delivery of the products, steam and electricity, from the cogeneration facilities.

The 200-MW(e)-350-MW(t) plants have either a pulverized-coal boiler with dry flue gas desulfurization or an atmospheric fluidized-bed boiler with sulfur absorbed in the bed material. For 400-MW(e)-700-MW(t) plants, three concepts were considered: a pulverized-coal boiler with dry flue gas desulfurization, an atmospheric fluidized-bed boiler with sulfur absorbed in the bed material, and a closed-cycle air turbine with heat supplied in an atmospheric fluidized-bed combustor utilizing closed-cycle air heaters. All systems were designed to burn low-sulfur, western coal.

The designs for all of the plants considered are based on 300-MW(e) and 500-MW(e) standard, low-sulfur-coal-fired plants previously designed by United Engineers & Constructors Inc. Minispecifications were prepared and issued to manufacturers of major components of each plant. Brief evaluations of the responses were performed, and offers from specific vendors were selected for the design. Other data were developed from the standard plant designs. Costs were developed based on vendor quotations for major equipment and takeoff quantities and unit prices from the standard plant designs.

NOMENCLATURE

A = annual cost, \$/year

A^{e} = annual cost for electricity generation, \$/year

A^{t} = annual cost for heat generation, \$/year

A_{A} = annual fixed costs, \$/year

A_{F} = annual fuel costs, \$/year

$A_{O\&M}$ = annual operating and maintenance cost, \$/year

A_{cg} = total annual cost of combined generation (cogeneration plant and associated peaking hot water generators) plants, \$/year

A_{cg}^{e} = annual cost share of electricity generation for combined generation, \$/year

A_{cg}^{t} = annual cost share of heat generation for combined generation (including hot water generation), \$/year

A_{sep} = total annual cost of separate generation (electricity and heat) plants, \$/year

A_{sep}^{e} = annual cost of electricity-only plant, \$/year

A_{sep}^{t} = annual cost of heating plants, \$/year

A_{HPP} = annual cost of cogeneration (heat and power) plant, \$/year

A_{HPP}^{e} = annual cost share of electric generation in the cogeneration plant, \$/year

A_{HPP}^{t} = annual cost share of heat generation in the cogeneration plant (excluding hot water generation), \$/year

A_{PP} = annual cost of the electricity-only (power) plant, \$/year

A_{HP} = annual cost of the heating plants, \$/year

A_{HP}^{base} = annual cost of the base-loaded heating plant, \$/year

A_{HWG} = annual cost of the peaking hot water generators, \$/year

A_{tl} = annual cost of the heat transmission line, \$/year

A_{ds} = annual cost of the distribution system, \$/year

B = annual fuel consumption, Btu/year

B_{HPP} = annual fuel consumption of the cogeneration plant, Btu/year

B^e_{HPP} = annual fuel consumption share of electricity generation in the cogeneration plant, Btu/year

B^t_{HPP} = annual fuel consumption share of heat generation (excluding hot water generators) in the cogeneration plant, Btu/year

B_{PP} = annual fuel consumption of electricity-only plants, Btu/year

B_{HP} = annual fuel consumption of heating plants, Btu/year

B^{base}_{HP} = annual fuel consumption of base-loaded heating plants, Btu/year

B_{HWG} = annual fuel consumption of peaking hot water generators, Btu/year

B_{cg} = total annual fuel consumption of combined generation (cogeneration plant and associated hot water generators) plants, Btu/year

B_{sep} = total annual fuel consumption of separate generation (electricity-only and heating) plants, Btu/year

b = heat rate of electricity generation, Btu/kW(e)h

$b^{net}_{turbine}$ = net turbine heat rate, Btu/kW(e)h

b^{gross}_{plant} = gross plant heat rate, Btu/kW(e)h

b^{net}_{plant} = net plant heat rate, Btu/kW(e)h

c_e or c^e = unit cost of electricity, mills/kW(e)h

c_t or c^t = unit cost of heat, $\$/10^6$ Btu

c^{cg}_e = bus bar electricity cost of cogeneration plant, mills/kW(e)h

c^{sep}_e = bus bar electricity cost of electricity-only plant, mills/kW(e)h

c^*_e = bus bar electricity cost of cogeneration plant if all cogeneration costs are allocated to electricity generation, mills/kW(e)h

c^{cg}_t = plant gate heat cost of combined generation (cogeneration plant and peaking hot water generators) plants, $\$/10^6$ Btu

c_t^{sep} = plant gate heat cost of heating plants, \$/10^6 Btu

c_t^* = plant gate heat cost of cogeneration plant if all cogeneration costs are allocated to heat generation, \$/10^6 Btu

c_{pg}^t = plant gate heat cost, \$/10^6 Btu

c_{trans}^t = cost of heat at end of transmission line, \$/10^6 Btu

c_{del}^t = delivered heat cost, \$/10^6 Btu

D = cogeneration discount (the equal discount rate), %

ΔA = cogeneration savings, \$/year

E = annual electricity generation, kW(e)h/year

E_{HPP} = annual gross electricity generation of cogeneration plant, kW(e)h/year

E_{HPP}^{aux} = annual auxiliary power requirement of cogeneration plant, kW(e)h/year

E_{HPP}^{net} = annual net electricity generation of cogeneration plant, kW(e)h/year

E_{HPP}^{cg} = annual fraction of electricity generation (by pure cogeneration) of cogeneration plant, kW(e)h/year

E_{HPP}^{cd} = annual fraction of electricity generation (by pure cogeneration) of cogeneration plant, kW(e)h/year

E_{PP}^{net} = annual net electricity generation of electricity-only plant, kW(e)h/year

η_{SG} = steam generator efficiency

P = electric powers, kW(e)

P_{HPP} = gross electric capacity of cogeneration plant, kW(e)

P_{HPP}^{aux} = auxiliary power requirement of cogeneration plant, kW(e)

P_{HPP}^{net} = net electric capacity of cogeneration plant, kW(e)

P_{PP}^{net} = net electric capacity of electricity-only plant, kW(e)

Q = annual heat generation, 10^6 Btu/year

Q_{HPP} = annual heat generation of cogeneration plant, 10^6 Btu/year

Q_{HWG} = annual heat generation of hot water generators, 10^6 Btu/year

Q_{del} = annual amount of heat delivered to heat users, 10^6 Btu/year

Q_{trans} = annual amount of heat transmitted to the distribution system, 10^6 Btu/year

q = plant heat capacity (thermal power), kW(t)

q_{HPP}^{cg} = cogeneration plant heat capacity (at minimum condensing steam flowrate), kW(t)

q_{cg}^{peak} = peaking capacity for heat production of combined generation (cogeneration plant and hot water generators), kW(t)

q_{HP}^{base} = base-loaded heating plant heat capacity, kW(t)

q_{HWG} = hot water generators heat capacity, kW(t)

ABSTRACT

The study analyzes the economics of coal-fired, cogeneration plants for district heating. A comparison is made among several equipment configurations and two alternative sites. Total project costs are estimated by totaling direct and indirect plant costs, escalation, and allowance for funds during construction. Costs of bus bar electricity and heat delivered to the distribution system are determined by the equal discount method of cogeneration cost allocation. Bus bar electricity costs are used as the measure of economic performance of cogeneration compared with separate conventional electric and heat generation plants.

Cogeneration/district heating plants equipped with condensing-tail turbines and full-sized heat rejection systems cost approximately 3% more than comparable sized electric-only plants. Bus bar electricity costs of cogeneration plants are comparable with those of an 800-MW(e) electric-only plant. The cost of bus bar electricity is practically independent of the two sites evaluated, but the heat delivered to the load center from the Coon Rapids site is 30-50% more costly than the heat delivered from the High Bridge site because of the greater transmission distance from the Coon Rapids site. The cogeneration plant operating at its assigned capacity factor will provide heat and electricity at the plant boundary at significantly less cost than will separately sized heat-only and electricity-only plants because of (1) better fuel utilization, (2) common use of facilities, and (3) the sale of two products — heat and electricity.

1. EXECUTIVE SUMMARY

In the development of the heat sources for a cogeneration-based district heating system, the most readily available sources will be existing steam plants that can be modified to cogeneration. For the Minneapolis-St. Paul metropolitan area, the High Bridge station of Northern States Power (NSP) was identified as the most likely candidate, and a detailed evaluation of the potential conversion of the four operating units at High Bridge was completed.[1] These units can provide up to 440 MW(t) through cogeneration.

The next stage in the planning of the heat sources envisions the design and construction of new coal-fired, cogeneration plants.

1.1 Objectives

The major objectives of this study are (1) to develop several conceptual designs of new coal-fired, cogeneration/district heating plants to be located at a reference site and at the High Bridge and Coon Rapids sites in the Minneapolis-St. Paul area, (2) to develop capital costs of the cogeneration plants and heat transmission lines, (3) to develop unit costs of heat and electricity produced in cogeneration plants, and (4) to perform a comparison of bus bar electricity costs for 200 and 400 MW(e) cogeneration plants and comparably sized electricity-only plants, as well as for an 800-MW(e) electricity-only plant.

1.2 Scope

Appendix A documents the 200-MW(e)–350-MW(t) steam turbine cogeneration plant designs developed for a reference site, the High Bridge site, and the Coon Rapids site and the capital cost estimates in January 1980 dollars. Two heat sources were considered: (1) a conventional utility pulverized-coal (PC) boiler with dry flue gas desulfurization and a baghouse for particulate removal and (2) an atmospheric fluidized-bed (AFB) boiler with flue gas desulfurization in the bed and both cyclones and a baghouse for particulate removal. Both boiler designs use a condensing-tail turbine with two-stage steam extraction for hot water district heating.

Appendix B documents the 400-MW(e)-700-MW(t) cogeneration plant designs and capital cost estimates using both steam turbines and a closed-cycle gas turbine (CCGT). The steam cogeneration units were considered at all sites; the CCGT unit was considered at the reference and Coon Rapids sites only. Three heat sources were considered: (1) a conventional utility PC boiler with dry flue desulfurization and a baghouse for particulate removal, (2) an AFB boiler with flue gas desulfurization in the bed and both cyclones and a baghouse for particulate removal, and (3) an AFB combustor for air heating with both cyclones and a baghouse for particulate removal. The first two heat sources use a condensing-tail turbine with two-stage steam extraction for hot water district heating. The AFB combustor uses a CCGT unit with hot water heating in the air precooler.

The body of this report documents the economic assessment of the cogeneration plants, which includes development and determination of operating characteristics for a district heating system, cogeneration plant heat rate diagrams, annual generations of heat and electricity, annual fuel consumptions, annual plant costs, and heat transmission costs. Costs of bus bar electricity and heat delivered to the distribution system are determined by the equal discount method of cogeneration cost allocation. Bus bar electricity costs are used as the measure of economic performance of cogeneration plants compared with conventional steam-condensing plants.

1.3 Conceptual Design Summary

Northern States Power selected a low-sulfur, subbituminous western coal as a basis for the cogeneration plant conceptual designs. For the steam cogeneration plants, condensing-tail and back-pressure turbines were considered. A condensing-tail turbine with two controlled extractions was selected because the maximum electrical capacity of the turbine is available in summer to satisfy the peak electricity demand and the peak thermal load can be supplied in winter, when the electrical demand is below the annual peak demand. Turbine specifications were prepared and issued to the major vendors to obtain heat balance, size, and cost information. Responses were obtained from the General Electric Company and Maschinenfabrik Augsburg-Neurnberg (M.A.N.); the M.A.N. design was selected. The heat balance information was used to develop equipment specifications and to estimate the sizes and costs of other major components for plant designs using a PC and an AFB boiler. Key plant parameters for the 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) reference plants are shown in Table 1.1.

For the CCGT plant, performance specifications were prepared for the combustor unit, turbine-compressor-generator sets, air preheaters, regenerators, cycle air piping, and other major pieces of equipment. Design reports were obtained from Rocketdyne and AiResearch; both companies made technical presentations on their designs to United Engineers & Constructors Inc. (UE&C). Information was extracted from the reports and used as the basis for the 400-MW(e)-700-MW(t) CCGT reference design and cost estimate. Oak Ridge National Laboratory had overall responsibility for the selection of the key plant parameters of the CCGT cycle (Table 1.2).

The reference plant designs were modified to suit the specific characteristics of the High Bridge and Coon Rapids sites. Except for piling, the reference plant designs required little modification to fit the Coon Rapids site; for the High Bridge site, however, the reference plant design required considerable modification to utilize some of the existing facilities and to accommodate the new units. The existing site is sufficient to accommodate one 200-MW(e)-350-MW(t) unit; a 400-MW(e)-700-MW(t) unit would require additional land.

Hot water transmission lines were conceptually designed at 30-in. and 42-in. diameters for the 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) units, respectively. The transmission lines from High Bridge to a load center in St. Paul were 1.5 km (4900 ft) long; the transmission lines from Coon Rapids to a load center in Minneapolis were 18.6 km (61,000 ft) long. Intermediate pumping stations were provided only for the Coon Rapids lines.

Table 1.1. Key plant parameters of coal-fired, cogeneration plants with steam turbines

Parameter	200 MW(e)-350 MW(t)	400 MW(e)-700 MW(t)
Turbine configuration	Tandem-compound, two-flow, with 28-in. last-stage blades	Tandem-compound, four-flow, with 28-in. last-stage blades
Steam flow at high-pressure turbine inlet, (guaranteed), 10^6 lb/h	1.72	3.44
Steam pressure at high-pressure turbine inlet (guaranteed), psia	2,414.2	2,414.2
Steam temperature at high-pressure turbine inlet (guaranteed), °F	1,000	1,000
Turbine back pressure, in. Hg[a]	3	3
Turbine output, MW(e)		
Power-only mode	257[a]	514[a]
Cogeneration mode	200[b]	400[c]
Auxiliary power (power-only mode), MW(e)	22[d]	44[d]
Station output (power-only mode), MW(e)	235	470
Number of feedwater heating stages	6	6
Generator rating, MVA	285	570
Stages of district heating	2	2
District heating supply/return temperatures, °F/°F	270/150	270/150
Design district heating system flow, lb/h	9,698,000	19,396,000
Station heat rate,[e] Btu/kWh		
Power-only mode	10,175	10,175
Cogeneration mode	6,873	6,873
Station thermal efficiency (power-only mode),[e] %	33.5	33.5

Table 1.1 (continued)

Parameter	200 MW(e)–350 MW(t)	400 MW(e)–700 MW(t)
Steam generator	Subcritical pressure, single reheat with a balanced-draft furnace	Subcritical pressure, single reheat with a balanced-draft furnace
Steam flow, maximum continuous rating, 10^6 lb/h	1.9	3.8
Steam pressure at superheater outlet, psig	2,640	2,640
Steam temperature, °F		
Superheater outlet	1,010	1,010
Reheater outlet	1,005	1,005
Final feedwater temperature, °F	475.8	475.8
Fuel type	Western, subbituminous coal	Western, subbituminous coal

[a] Includes boiler feed pump.

[b] At 342 MW(t).

[c] At 684 MW(t).

[d] Assumed to be 8.6%.

[e] Based upon same auxiliary power requirements for pulverized-coal and atmospheric fluidized-bed and a boiler efficiency of 86%.

Table 1.2. Key plant parameters of cycle air heating system, 400-MW(e)-700-MW(t) closed-cycle gas turbine coal plant

Cycle air heaters	Atmospheric fluidized-bed with balanced-draft combustor
Cycle air flow rate at turbine inlet and 100% load, 10^6 lb/h	
Power-only mode	34.1
Cogeneration mode	25.1
Cycle air pressure, psia	
Power-only mode	
Fluidized-bed outlet	456
Economizer inlet	486
Turbine inlet	456
Cogeneration mode	
Fluidized-bed outlet	344
Economizer inlet	374
Turbine inlet	344
Cycle air temperature, °F	
Power-only mode	
Fluidized bed	1,500
Economizer inlet	1,022
Economizer outlet	1,134
Turbine inlet	1,500
Cogeneration mode	
Fluidized bed	1,500
Economizer inlet	851
Economizer outlet	1,005
Turbine inlet	1,500
Fuel type	Western, subbituminous coal
Fuel firing rate, tons/h	300
Limestone feeding rate, tons/h	35
Forced-draft fans	
Number of sets	2
Combined capacity, scfm	590,000
Fraction of total capacity, %	50
Induced-draft fans	
Number	2
Combined capacity, scfm	650,000
Fraction of total capacity, %	50
Baghouses	
Number	2
Collection efficiency, %	98.6

Table 1.2 (continued)

Turbines	
Number	2
Configuration	Turbine, compressor, and generator assembly on a single shaft
Output, MW(e)	
Power-only mode	507
Cogeneration mode	400
Auxiliary power, MW(e)	38
Station output, MW(e)	
Power-only mode	469
Cogeneration mode	362
Number of recuperators	4
Generator rating, MVA	629.2
Station cycle air rate, lb/kWh	
Power-only mode	53.5
Cogeneration mode	94.2
Station heat rate, Btu/kWh	
Power-only mode	10,341
Cogeneration mode	6,798
Thermal efficiency in power-only mode, %	34.1

1.4 Capital Cost Summary

Capital costs estimates were derived by building up the cost item by item for all systems. Estimates were made using vendor-supplied data, contact with supplier representatives of major items (e.g., M.A.N. of Western Germany for the steam cogeneration turbines), and UE&C's capital cost data base. The cost of structures and minor equipment was based on overall systems and plant layouts. Structural commodities and minor equipment costs have been calculated using standard unit cost files and equipment cost files, respectively. The equipment lists and cost summaries have been compiled and processed by UE&C's proprietary codes PEGASUS and CONCICE. The PEGASUS program processes, stores, and lists technical data on equipment and structural commodities. The CONCICE program lists the cost estimate in terms of a generalized code of accounts.

Table 1.3 summarizes the estimated capital costs by major accounts for the five reference designs. The estimated capital costs for the cogeneration plants at High Bridge and Coon Rapids are given in Tables 1.4 and 1.5.

1.5 Economic Assessment Summary

The economic performance of the coal-fired, cogeneration units was measured in terms of the calculated unit costs of bus bar electricity and heat delivered to the load center. The annual generations of heat and electricity by the cogeneration plants were determined by assuming (1) that 60% of the peak heat load would be carried by the cogeneration plant and 40% by the oil-fired hot water generators (HWGs) and (2) that the electrical capacity factor would be limited to 50%.* The annual fixed costs for plants and transmission lines were based on a 15% fixed charge rate.

In order to determine the unit costs of heat and electricity for the cogeneration units, the estimated annual costs of these plants and the associated peaking HWGs were divided into heat generation costs and electricity generation costs. The equal discount method of cogeneration cost allocation was used for this purpose. This method does not require the separate allocation of fixed, fuel, and operation and maintenance (O&M) costs of the cogeneration plant. Instead, the equal discount method requires detailed cost estimates of two separate generation plants (an electricity-only plant and a district heating plant), each having electrical and heat outputs, capacity factors, and reliability equal to those of the cogeneration/district heating plant.

The economic analysis included the performance of the following tasks:

- determination of the district heating system operation characteristics (heat load duration curves, water temperature and flow rates profiles, etc.);

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*NSP's systems planning department assigned 50% as the most likely capacity factor of these coal-fired units in 1989.

Table 1.3. Capital cost account summaries for reference plants in millions of January 1980 dollars

	200 MW(e)–350 MW(t)		400 MW(e)–700 MW(t)		
	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	Closed-cycle gas turbine
Structures and improvements	36.65	39.17	51.01	56.24	65.59
Boiler plant equipment[a]	91.42	80.48	157.02	129.83	151.13[a]
Turbine plant equipment	42.48	42.29	73.21	73.19	65.46
Electric plant equipment	27.82	27.82	36.57	36.57	36.57
Miscellaneous plant equipment	9.78	10.25	11.70	12.31	8.68
Main condenser heat rejection system[b]	8.35	8.50	12.86	13.17	9.88[b]
Transmission plant equipment	2.30	2.30	3.50	3.50	3.50
District heating system	3.82	3.82	5.90	5.90	6.56
Total direct cost	223	215	352	331	347

[a] For CCGT combustor plant equipment.

[b] For CCGT main heat rejection equipment.

Table 1.4. Total project cost of cogeneration plant and transmission line at the High Bridge site in millions of dollars

Cost item	Cogeneration plants				Transmission lines	
	200 MW(e)-350 MW(t)		400 MW(e)-700 MW(t)			
	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	30-in. outside diameter	42-in. inside diameter
Land[a]	1.1	1.1	10.2	10.2	Not included	Not included
Mobile coal and ash equipment[a]	1.1	1.1	1.6	1.6		
Plant cost[a,b]	215.0	207.3	362.0	341.9		
Total direct cost[a]	217.2	209.5	373.8	353.7	2.4	3.3
Indirect cost[a]	47.8	46.1	76.6	72.5	0.5	0.7
Escalation	215.2	207.9	341.1	323.1	3.2	4.1
Allowance for funds during construction	63.8	61.5	131.5	124.7	0.2	0.3
Total project cost[c]	544	525	923	874	6.3	8.4

[a] January 1980 dollars.

[b] Includes spare parts and sales tax.

[c] May 1989 dollars.

Table 1.5. Total project cost of cogeneration plant and transmission line at the Coon Rapids site in millions of dollars

Cost item	Cogeneration plants						Transmission lines	
	200 MW(e)–350 MW(t)		400 MW(e)–700 MW(t)			2 × 200 MW(e)–350 MW(t), pulverized-coal		
	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	Closed-cycle gas turbine		30-in. outside diameter	42-in. inside diameter
Land[a]	10.0	10.0	11.1	11.1	11.1	11.1	Not included	Not included
Mobile coal and ash equipment[a]	2.6	2.6	2.6	2.6	2.6	2.6		
Plant cost[a,b]	231.3	223.7	365.9	345.3	361.7	241.6[c] 189.9[d]		
Total direct cost[a]	243.9	236.3	379.6	359.0	375.4	445.2	53.7	74.9
Indirect cost[a]	53.7	52.0	77.8	73.6	77.0	84.6	11.8	16.5
Escalation	246.7	238.9	357.5	336.6	353.8	448.4	57.9	80.4
Allowance for funds during construction	66.7	64.8	123.1	115.9	121.8	183.8	11.6	16.2
Total project cost[e]	611	592	938	885	928	1162	135	188

[a]January 1980 dollars.

[b]Includes spare parts and sales tax.

[c]Plant 1.

[d]Plant 2.

[e]May 1989 dollars.

- determination of annual gross and net generations of heat and electricity;
- development of heat rate (net turbine, gross plant, and net plant) diagrams;
- determination of fuel consumptions of cogeneration plants, HWGs, and separate generation plants;
- estimation of annual costs of cogeneration plants, HWGs, and separate generation plants;
- allocation of cogeneration costs using the equal discount method;
- estimation of bus bar electricity costs and plant gate heat costs;
- estimation of heat transmission costs;
- estimation of the amount of heat delivered to the load center based on a balance of the transmission line heat losses and gains;
- estimation of cost of heat delivered to the load center;
- estimation of bus bar electricity cost from an 800-MW(e) steam-condensing unit; and
- comparison of unit costs of heat and electricity produced by cogeneration and separate generation plants.

The configuration of the cogeneration/district heating system including the base load and peaking heat sources and the transmission line is shown in Fig. 1.1.

The economic assessment of the new coal-fired, cogeneration units was carried out in terms of May 1989 dollars. This time frame was selected by NSP to allow for licensing, engineering, and construction of the cogeneration plants and the associated transmission lines. Although engineering and construction schedules can be estimated with reasonable accuracy, the durations required to license and obtain construction permits to build major facilities are uncertain. Because of this uncertainty, the time required for these licensing efforts was not included in this comparative engineering assessment.

The estimated total project costs for the cogeneration units and their transmission lines are shown in Tables 1.4 and 1.5 for the High Bridge and Coon Rapids sites, respectively. These costs have been developed for this program by utilizing the estimated total direct costs and adding

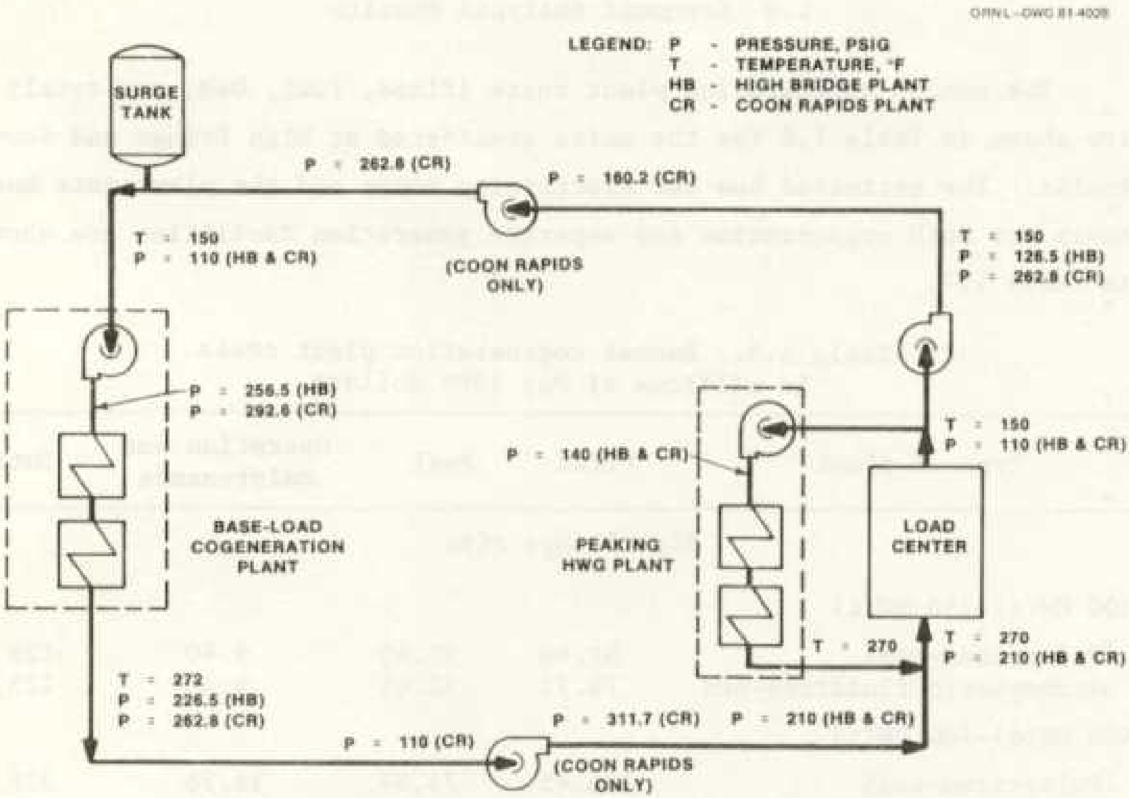

Fig. 1.1. District heating system flow diagram for the 200-MW(e)-350-MW(t) plant located at High Bridge or Coon Rapids and the 228.3-MW(t) hot water generator plant located near the load center.

indirect costs, escalation, and allowance for funds during construction developed by NSP. Escalation and allowance for funds during construction were based on construction schedules estimated by UE&C and on an assumed start-up date of May 1989. The construction schedules for the reference plants were estimated at 34 months and 45 months for the 200- and 400-MW(e) plants, respectively. Allowance for setting piles was added at both sites: three months for the 200-MW(e) units, four months for the 400-MW(e) units. At High Bridge, six more months were added for demolition and site preparation. Annual escalation rates used in this economic assessment were as follows: coal — 10%, oil — 12%, capital and O&M costs — 9% for 1980-84 and 7% for 1985-89.

1.6 Economic Analysis Results

The annual cogeneration plant costs (fixed, fuel, O&M, and total) are shown in Table 1.6 for the units considered at High Bridge and Coon Rapids. The estimated bus bar electricity costs and the plant gate heat costs for both cogeneration and separate generation facilities are shown in Table 1.7.

Table 1.6. Annual cogeneration plant costs in millions of May 1989 dollars

Type of plant	Fixed	Fuel	Operation and maintenance	Total
High Bridge site				
200 MW(e)-350 MW(t)				
Pulverized-coal	81.60	37.45	9.40	128.45
Atmospheric fluidized-bed	78.75	37.45	9.40	125.60
400 MW(e)-700 MW(t)				
Pulverized-coal	138.45	74.89	14.78	228.12
Atmospheric fluidized-bed	131.10	74.89	14.78	220.77
Coon Rapids site				
200 MW(e)-350 MW(t)				
Pulverized-coal	91.65	37.45	9.40	138.50
Atmospheric fluidized-bed	88.80	37.45	9.40	135.65
400 MW(e)-700 MW(t)				
Pulverized-coal	140.70	74.89	14.78	230.37
Atmospheric fluidized-bed	132.75	74.89	14.78	222.42
Closed-cycle gas turbine	139.20	72.85	15.71	227.76
2 × 200 MW(e)-350 MW(t), pulverized-coal	174.30	74.89	18.80	267.99

The unit cost of the heat delivered to the load center has been estimated for each cogeneration plant alternative by adding the heat transmission cost to the corresponding plant gate heat cost. Based on the results of a preliminary estimate of transmission line heat losses and gains due to pumping power, the amount of heat delivered to the load

Table 1.7. Summary of generation costs

Site and type of plant	Bus bar electricity cost [mills/kW(e)h]		Plant gate heat cost ($ per 10^6 Btu)	
	Cogeneration plant	Electricity-only plant	Cogeneration and peaking plant	Heat-only plant
High Bridge site				
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	100.67	144.5	10.91	15.70
Atmospheric fluidized-bed	98.69	144.5	10.69	15.70
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	89.98	123.1	9.61	12.80
Atmospheric fluidized-bed	87.42	123.1	9.34	12.80
Coon Rapids site				
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	107.65	144.5	11.67	15.70
Atmospheric fluidized-bed	105.67	144.5	11.45	15.70
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	90.77	123.1	9.70	12.80
Atmospheric fluidized-bed	88.0	123.1	9.40	12.80
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	81.62	111.2	9.28	12.64
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228-MW(t) oil-fired peaking plant with hot water generators]	104.52	144.5	11.33	15.70

center has been assumed to be equal to the amount of heat generated. Table 1.8 summarizes the key parameters and annual costs of the transmission lines including fixed, maintenance, and pumping power costs. Table 1.9 gives the estimated unit costs of heat delivered to the load center.

Bus bar electricity costs for electricity-only plants [235, 470, and 800 MW(e)] have been estimated and are tabulated in Table 1.10 along with the cogeneration-based electricity costs. The bus bar electricity cost for the 800-MW(e) plant is given for two capacity factors: 70%, which is characteristic of a base-loaded unit on the NSP system, and 43.4%, which enables a direct comparison with the cogeneration units.

Based on these tabular comparisons, the following observations can be made:

1. The total project costs of the cogeneration plants at High Bridge and Coon Rapids vary between \$525 million and \$611 million for the 200-MW(e)-350-MW(t) units and between \$874 million and \$938 million for the 400-MW(e)-700-MW(t) units. The highest total project cost (\$1162 million) corresponds to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids. For comparison, the total project costs of coal-fired, electricity-only PC plants of 235, 470, and 800 MW(e) are \$591 million, \$906 million, and \$1202.5 million, respectively.
2. The comparison among the cogeneration units with respect to the total project cost shows the following:
   - The 200-MW(e)-350-MW(t) PC and AFB units at High Bridge cost \$67 million less than the same units at Coon Rapids, whereas the 400-MW(e)-700-MW(t) units at High Bridge cost only slightly less than the same units at Coon Rapids. The \$67 million cost differential exists because the smaller units are designed to use some of the existing facilities at High Bridge.
   - The units equipped with an AFB boiler (near-horizon technology) result in consistently lower total project costs; however, these results are based on cost estimates that do not include a contingency for cost uncertainties with this technology.

Table 1.8. Summary of heat transmission costs

Cost item	High Bridge plant		Coon Rapids plant		
				42-in. line	
	30-in. line	42-in. line	30-in. line	Steam turbine	Closed-cycle gas turbine
Rated capacity, MW(t)	342.4	684.8	342.4	684.8	710.0
Length to border of service area, km (ft)	1.5 (4,900)	1.5 (4,900)	18.6 (61,000)	18.6 (61,000)	18.6 (61,000)
Number of pipes	2[a]	2[a]	2[a]	2[a]	2[a]
Internal diameter, in.	28.75	42	28.75	42	42
Maximum temperature at heat source, °F					
Supply	270	270	270	270	270
Return	150	150	150	150	150
Total capital cost,[b] millions of May 1989 dollars	6.3	8.4	135.0	188.0	188.0
Total annual cost, millions of May 1989 dollars per year	1.84	2.50	23.41	32.21	32.46
Fixed[c]	0.95	1.26	20.25	28.20	28.20
Maintenance	0.63	0.84	1.35	1.88	1.88
Pumping power	0.26	0.40	1.81	2.13	2.38
Annual heat energy transported					
MW(t)h/year	1,372,000	2,744,000	1,372,000	2,744,000	2,845,000
10^6 Btu per year	4,684,000	9,368,000	4,684,000	9,368,000	9,713,000
Transportation cost					
¢/kW(t)h	0.093	0.063	1.70	1.17	1.14
\$ per 10^6 Btu	0.271	0.186	4.99	3.43	3.34

[a]One supply, one return.

[b]The total capital cost shown does not include the cost of 2500 ft of transmission line within the plant boundary; onsite transmission line cost was included in the cost of each plant.

[c]Based on 15% fixed charge rate.

Table 1.9. Unit cost for heat delivered to load center

Type of plant	Heat cost (May 1989 dollars per 10^6 Btu)		
	At plant gate	Transmission[a]	At border of service area
High Bridge site			
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	10.91	0.27	11.18
Atmospheric fluidized-bed	10.69	0.27	10.96
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	9.61	0.19	9.80
Atmospheric fluidized-bed	9.34	0.19	9.53
Coon Rapids site			
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	11.67	4.99	16.66
Atmospheric fluidized-bed	11.45	4.99	16.44
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	9.70	3.43	13.13
Atmospheric fluidized-bed	9.40	3.43	12.83
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	9.28	3.34	12.62
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228-MW(t) oil-fired peaking plant with hot water generators]	11.33	3.43	14.76

[a]The heat transmission cost is added directly to the plant gate heat cost because the amount of heat delivered was assumed to equal the amount of heat generated.

Table 1.10. Comparison of bus bar costs of electricity produced by cogeneration plants vs those of electricity-only plants

Type of plant	Bus bar electricity cost [mills/kW(e)h]			
	Cogeneration plant[a]	Electricity-only plant		
		Comparatively sized plant[a]	800 MW(e)	
			43.4% capacity factor	70% capacity factor
High Bridge site				
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	100.67	144.5	97.6	71.5
Atmospheric fluidized-bed	98.69	144.5	97.6	71.5
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	89.98	123.1	97.6	71.5
Atmospheric fluidized-bed	87.42	123.1	97.6	71.5
Coon Rapids site				
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	107.65	144.5	97.6	71.5
Atmospheric fluidized-bed	105.67	144.5	97.6	71.5
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators				
Pulverized-coal	90.77	123.1	97.6	71.5
Atmospheric fluidized-bed	88.00	123.1	97.6	71.5
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	81.62[b]	111.20[b]	97.6	71.5
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228-MW(t) oil-fired peaking plant with hot water generators]	104.52	144.5	97.6	71.5

[a]Electrical capacity factor = 43.4% except closed-cycle gas turbine plant.

[b]Electrical capacity factor = 46.7%.

3. The comparison between PC cogeneration units and PC electricity-only units of equivalent size with respect to the total project cost shows the following:
   - Because the 200-MW(e)-350-MW(t) unit at High Bridge utilizes existing facilities, it costs approximately 8% less than the 235-MW(e) unit at a reference site.
   - The 200-MW(e)-350-MW(t) unit at Coon Rapids costs approximately 3% more than the 235-MW(e) unit.
   - The 400-MW(e)-700-MW(t) unit at High Bridge costs approximately 2% more than the 470-MW(e) unit.
   - The 400-MW(e)-700-MW(t) unit at Coon Rapids costs approximately 4% more than the 470-MW(e) unit.
4. The total project costs of the heat transmission lines from plant site to the respective load centers are $6.3 million (30-in. line) and $8.4 million (42-in. line) for the High Bridge site and $135 million (30-in. line) and $188 million (42-in. line) for the Coon Rapids site.
5. The cogeneration-based bus bar electricity costs are 24-32% less than those of electricity-only plants of equivalent size and capacity factor.*
6. The cogeneration-based plant gate heat costs are 24-32% less than those of heat-only plants of equivalent size and capacity.*
7. The cogeneration-based bus bar electricity costs are 14-50% greater than electricity costs from an 800-MW(e) electricity-only condensing unit operating at 70% capacity factor; however, at 43.4% capacity factor, the 800-MW(e) electricity-only unit costs are comparable to those of the cogeneration plants.
8. The comparison among the cogeneration units with respect to the bus bar electricity cost shows the following:
   - A unit cost spread of 23 mills/kWh, the lowest cost (82 mills/kWh) corresponding to the 400-MW(e)-700-MW(t) CCGT at Coon Rapids and

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*The percent savings for electricity and heat due to cogeneration (items 5 and 6, respectively) are identical because the cost allocation was made using the equal discount method.

the highest cost (105 mills/kWh) to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids.

- The cost reductions due to the economy of scale obtained by doubling the size of the cogeneration units (and maintaining the same capacity factors) are approximately 11% at High Bridge and 16% at Coon Rapids.

9. The comparison among the cogeneration units with respect to the cost of heat delivered to the respective load centers shows the following:
   - A unit cost spread of \$5.2 per 10^6 Btu, the lowest cost (\$9.6 per 10^6 Btu) corresponding to the 400-MW(e)-700-MW(t) AFB at High Bridge and the highest cost (\$15 per 10^6 Btu) to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids.
   - The cost reductions due to the economy of scale obtained by doubling the size of the cogeneration units (and maintaining the same capacity factor) are approximately 13% at High Bridge and 21% at Coon Rapids.
10. The heat transmission costs represent approximately 2.8 to 4.5% and 26 to 30% of the cost of heat delivered to the distribution system from the High Bridge and Coon Rapids plants, respectively.

1.7 Conclusions

1. Cogeneration/district heating plants equipped with condensing-tail turbines and full-sized heat rejection systems cost approximately 3% more than comparably sized electricity-only plants.
2. The reduction due to economy of scale [two 200-MW(e) plants vs one 400-MW(e) plant] in the unit cost of heat or electricity is approximately 15%.
3. The cost of bus bar electricity is practically independent of the two sites evaluated.
4. Heat transmission line costs have a significant impact on the cost of delivered heat. The cost of heat delivered to the load center from Coon Rapids is 30 to 50% greater than the cost of heat delivered from High Bridge primarily due to differences in transmission line length.

5. These results indicate that the cogeneration plant operating at its assigned capacity factor will provide heat and electricity at the plant boundary at costs significantly less than (approximately 70% of) the respective costs of comparably sized heat-only or electricity-only plants. This benefit results from better fuel utilization, common use of facilities, and the sale of two products — heat and electricity.

2. DESCRIPTION OF THE ASSESSMENT

In the development of heat sources for a cogeneration-based hot water district heating system, the most readily available sources will be existing steam-condensing electric stations that can be retrofitted for cogeneration. For the Minneapolis-St. Paul area, the High Bridge Station was identified as the most likely candidate, and a detailed evaluation of the potential conversion of the four operating units at High Bridge was completed.[1] These units can provide up to 440 MW(t) through cogeneration.

The next stage in the development of heat sources is the design and construction of new coal-fired, cogeneration units. Conceptual designs of such new units were prepared for 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) plants. The plant designs are documented in Appendixes A and B (microfiche back cover) of this report.

2.1 Purpose

The purpose of this report was to compare the cost of bus bar electricity and heat delivered to the distribution system for the 200-MW(e)-350-MW(t) and 400-MW(e)-700 MW(t) plant designs. The bus bar electricity costs of coal-fired 235-, 470-, and 800-MW(e) steam-condensing, electricity-only plants were also determined for comparison.

2.2 Scope

Conventional engineering economic procedures were used in the economic computations for determining the unit costs of heat and electricity for the cogeneration and the separate generation units. Procedures for establishing district heating system operating characteristics, cogeneration plant heat rate diagrams (for both steam turbines and closed-cycle gas turbines), annual generations of heat and electricity, annual fuel consumptions, annual plant costs, and heat transmission costs were also conventional engineering practices. The mathematical model of the equal discount method of cogeneration cost allocation was used to separate the heat and electricity costs for several cogeneration plants.

The cogeneration units considered include both condensing-tail turbines [200 MW(e)–350 MW(t) and 400 MW(e)–700 MW(t)] and a 400-MW(e)–700-MW(t) CCGT. The cogeneration plants utilizing steam turbines are considered equipped, alternatively, with either PC or AFB steam generators. Two sites in the Minneapolis–St. Paul area, High Bridge and Coon Rapids, are considered for the cogeneration units.

Estimated costs of bus bar electricity and heat delivered to the distribution system are used as the measure of economic performance of cogeneration plants. The bus bar electricity costs of 235-MW(e), 470-MW(e) (directly comparable to the cogeneration units operating in the electricity-only mode), and 800-MW(e) condensing units are determined, and a comparison against the cogeneration-based bus bar electricity costs is made.

2.3 Methodology

To determine the heat and electricity unit costs for the cogeneration units considered, the annual costs of these plants and their associated HWGs are separated into heat generation costs and electricity generation costs by using the equal discount method of cogeneration cost allocation. This method does not require the separate allocation of each of the three major components of the total annual costs: fixed, fuel, and operation and maintenance (O&M). The method requires in each case, however, detailed cost estimates of two separate generation plants, an electricity-only plant and a district heating plant, having a combined electrical and heat output identical to that of the cogeneration/district heating plant. The methodology used includes the sequential determination of the following quantities:

1. operating characteristics of the district heating system cogeneration plants and HWGs:
    - base and peak heat loads, heat load duration curve, etc.,

- water temperature profiles,
- water flow rate profiles, and
- district heating system configuration;

2. annual gross and net generations of heat and electricity of cogeneration plants and their associated HWGs based on the curves of electric load and heat load vs duration;
3. heat rate (net turbine, gross plant and net plant) diagrams for all cogeneration units, including CCGT;
4. annual fuel consumption of the cogeneration plants, HWGs, and separate generation plants;
5. annual costs of the cogeneration plants, HWGs, and separate generation plants: fixed, fuel, and O&M;
6. allocation of the cogeneration costs based on the equal discount method;
7. bus bar electricity costs and plant gate heat costs of the cogeneration plants and their associated HWGs;
8. heat transmission costs for two sizes (30-in. OD and 42-in. ID) and two lengths [1.5 km (4900 ft) and 18.6 km (61,000 ft)] of transmission lines: fixed, maintenance, and pumping power;
9. net amount of heat delivered to the distribution system based on heat losses in transmission lines and heat gains due to pumping power;
10. cost of heat delivered to the distribution system;
11. bus bar electricity cost for a coal-fired, 800-MW(e) steam-condensing unit located in rural Minnesota; and
12. comparison of unit costs of heat and electricity produced by cogeneration and separate generation.

Descriptions of the procedures for determining the items listed above are given in detail in various sections of this report and are also summarized below.

The operating characteristics of the district heating system are determined as a function of the standard (30-year average) climatic conditions of the Twin Cities. Included are base and peak heat loads and water temperature and flow rate profiles as functions of the outside air temperature during the annual cycle. The water supply temperature is assumed to be constant at 270°F during the heating season (when outside air temperature is below 65°F) and at 180°F during the remainder of the year. The maximum water flow rates of the cogeneration plant and the HWGs are assumed to be in the 60% to 40% ratio. At any time during the annual cycle, either the water flow rate is kept constant and the supply/return temperature difference is allowed to vary, or the latter is kept constant and the former is allowed to vary. Table 3.3 gives a summary of operating characteristics of the district heating system as a function of the outside air temperature.

The annual generations of heat and electricity produced by each cogeneration unit and its associated HWGs are calculated on the basis of a heat load vs duration curve assumed to have a maximum corresponding to a cogeneration coefficient of 0.6. In addition, the electrical generation is limited to 50% of the maximum amount that could optionally be produced by the cogeneration plant. The 50% value is only slightly larger than the minimum amount of electricity produced necessarily by cogeneration. Approximately 80% of the ensuing difference was assumed to be produced near or at full electrical capacity during the summer, when the lowest heat loads occur. It is noted that an electricity-only plant of the same electrical capacity would have to operate at a capacity factor of 43.4% (46.7% in the case of CCGT) in order to generate an equivalent amount of electricity (see Sect. 5 for further details). The annual net and gross generations of heat are considered equal. In the case of electricity, the annual net electricity generation is calculated by subtracting the annual auxiliary power requirement from the gross generation. A method employing a weighted average of the auxiliary power as a function of the steam generator load is used.

The net electricity and heat generations of the electricity-only and heat-only plants, respectively, used for comparison are taken by definition equal to the corresponding generations of the cogeneration plant and its associated HWGs. Summaries of the annual electricity and heat generations of the cogeneration and separate generation plants are given in Tables 9.1 and 9.2.

The annual costs (expressed in May 1989 dollars) of the cogeneration plants as well as those of the equivalent separate generation plants are calculated as follows:

1. Fixed costs are calculated based on a fixed charge rate of 15% per year and the respective total project costs (TPC), which include total direct and indirect costs, escalation, and allowance for funds used during construction (interest during construction). The TPCs for the cogeneration plants are based on the total direct costs determined in Appendixes A and B (microfiche). The capital costs for the equivalent electricity-only plants are obtained from the costs determined for the corresponding cogeneration units by deleting the costs of equipment needed to operate the plants in the cogeneration mode. Capital costs are developed for heat-only plants needed to provide (oil-fired) peak heating or (coal-fired) base-load heating. The base-load, heat-only plants are coal-fired (with dry flue gas desulfurization) and designed as low-pressure steam boilers with heat exchangers to provide hot water.

2. Fuel costs are calculated based on annual fuel consumptions and on May 1989 coal and oil prices of \$3.08 per 10^6 Btu and \$19.31 per 10^6 Btu, respectively, estimated for the Twin Cities area. In preparation for estimating the annual fuel consumptions of the cogeneration plants, the net turbine, gross plant, and net plant heat rates are calculated. Heat rate diagrams are presented for both steam and CCGT cogeneration units. Based on annual energy generations and the gross plant heat rates obtained, the annual fuel consumptions are calculated using a method employing weighted averages. Similarly, the annual fuel consumptions of the heat-only and electricity-only plants are calculated.

3. Operation and maintenance costs are calculated for all facilities considered as the sum of both fixed and variable O&M expenses. Equations developed by NSP for estimating O&M costs of large coal-fired, steam electricity plants are used, adjusted properly for cogeneration plants and heat-only plants (see Sect. 8 for further details).

A summary of annual costs for cogeneration plants and corresponding separate generation plants is given in Table 8.1.

The bus bar electricity costs and the plant gate heat costs are determined by using the equal discount method for allocating the total annual operating costs of the cogeneration plants and their associated HWGs. A detailed description of the equal discount method of cost allocation is given in Sect. 6. A summary of the cogeneration-based bus bar electricity and plant gate heat costs along with the corresponding separate generation costs is given comparatively in Table 9.4. Graphical illustrations of the same costs are shown in Figs. 9.1 and 9.2 for the High Bridge and Coon Rapids units, respectively.

The unit cost of heat delivered at border of service area is calculated for each cogeneration unit considered by augmenting the plant gate heat cost with the corresponding heat transmission cost. The latter cost is determined as a function of the fixed, maintenance, and pumping power costs, all calculated in May 1989 dollars.

1. Fixed costs are calculated based on a fixed charge rate of 15% and on the TPC for the transmission line. A total of four TPCs are estimated for two alternative sizes of lines (30-in. OD and 42-in. ID) and two lengths [1.5 km (4900 ft) and 18.6 km (61,000 ft)] for High Bridge and Coon Rapids, respectively.

2. Maintenance costs are estimated to be 1% of the capital costs, based on the Swedish experience with operating hot water transmission lines.

3. Pumping power costs are estimated based on an annual system-wide electricity cost (commercial rate) of 70 mills/kWh and on the annual

pumping power requirements. For each case, the pumping power included accounts only for the head loss in the plant heat exchanges and in the supply and return transmission lines. The pumping power, therefore, does not include the total consumption for entire district heating system. The pressure gradient profiles for the 30-in. OD transmission lines are shown in Fig. 10.2. The utilization times of the maximum water flow rates are determined based on the annually integrated water flow in the transmission lines and the maximum values of the water flow rates. These utilization times are used to determine the annual pumping requirements.

A summary of the transmission costs is given in Table 10.1 for the four transmission lines considered.

The transmission line heat losses are calculated and compared to the heat gains due to pumping power requirements in order to determine the net amount of heat delivered at the border of the distribution system. The heat gains are calculated by accounting for the total pumping power because all pumps (including intermediate pumps for Coon Rapids only) are located outside the distribution system. Although the heat loss vs heat gain comparison indicates that the net amount of heat delivered exceeds slightly the heat produced by the cogeneration plant, the two amounts are assumed to be equal.

The heat transmission costs calculated as well as the costs of heat delivered at the border of the distribution system are summarized in Table 10.2 for all cogeneration units considered.

The total electricity generating cost of a coal-fired, 800-MW(e) steam-condensing unit located in rural Minnesota is calculated for comparison, assuming two capacity factors: 70%, which is characteristic to such base-load units, and 43.4%, which matches the equivalent capacity factor of the steam cogeneration units.

1. Fixed costs are determined based on a fixed charge rate of 15% and on the TPC, including the direct and indirect capital cost, allowance for funds during construction, and escalation up to May 1989. The direct capital cost is developed from a 1980 update of

an 800-MW(e) low-sulfur-coal plant documented by UE&C for the Department of Energy.[2]

2. Fuel costs are determined based on the fuel consumptions corresponding to the assumed capacity factors and a coal cost of \$3.08 per 10^6 Btu.

3. Operation and maintenance costs are determined based on equations developed by NSP for large coal-fired plants.

The total generating costs of the 800-MW(e) condensing unit are compared in Table 12.1 with the bus bar electricity costs of the cogeneration plants and their equivalent electricity-only plants.

3. DETERMINATION OF DISTRICT HEATING SYSTEM OPERATING CHARACTERISTICS

3.1 District Heating System Heat Load Curves

3.1.1 Heat load duration curve

The shape of the annual heat load (space heating and domestic hot water) duration curve is unique for a given location. The main reasons for this uniqueness are (1) that the outside air temperature duration curve used in a district heating system design is taken over a long period of time (usually 30 years) and (2) that the domestic hot water load duration curve remains essentially constant from year to year.

The annual heat load duration curve used in this study is shown in Fig. 3.1, which also shows the monthly heat load duration curves used in the construction of the annual curve. The monthly curves were generated by the University of Minnesota and Oak Ridge National Laboratory and were provided as an input to this study.

3.1.2 Outside air temperature duration curve

The outside air temperature duration curve for Minneapolis-St. Paul was developed based on 30 years of data.[3] The total annual observations of temperatures have been accumulated to obtain the annual durations as shown in Table 3.1. Average temperatures within the five-degree intervals specified were used to plot the outside air temperature duration curve shown in Fig. 3.2.

3.1.3 Heat load vs outside air temperature curve

The heat load vs outside air temperature curve is used for the determination of the annual operating characteristics of the district heating system. Figure 3.2 shows the procedure for determining this curve as a function of the heat load and outside air temperature duration curves. The curve obtained for the relationship between heat load and outside air temperature was linearized by closely matching five linear segments to its shape as shown in Fig. 3.3. The coordinates of the nodal points are given in Table 3.2.

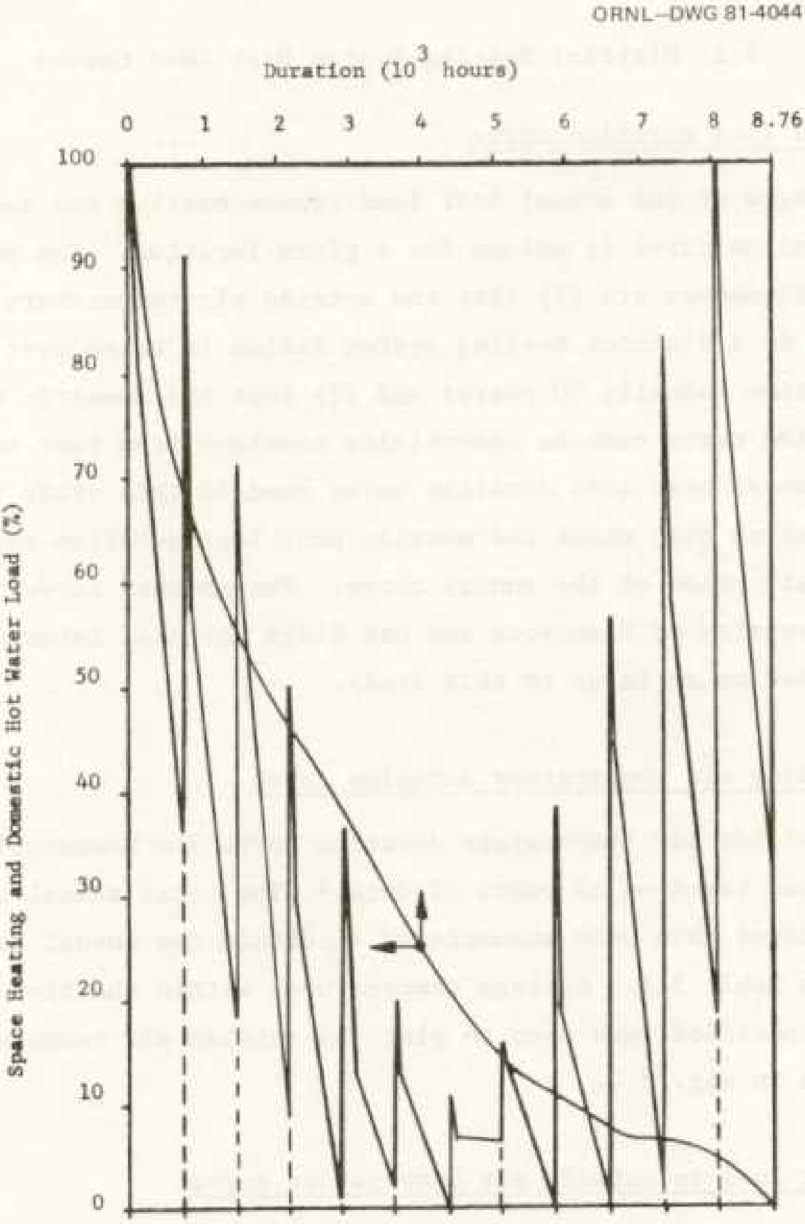

Fig. 3.1. Monthly and annual duration curves for space heating and domestic hot water for the Twin Cities.

Table 3.1. Determination of outside air temperatures vs annual duration

Outside air temperature range (°F)			Total annual observations (h)	Total annual cumulative observations (h)
Low	High	Average		
100	104	102	0	
95	99	97	8	8746
90	94	92	50	8738
85	89	87	136	8688
80	84	82	285	8552
75	79	77	442	8267
70	74	72	613	7825
65	69	67	702	7212
60	64	62	704	6510
55	59	57	614	5806
50	54	52	552	5192
45	49	47	478	4640
40	44	42	487	4162
35	39	37	552	3675
30	34	32	653	3123
25	29	27	591	2470
20	24	22	475	1879
15	19	17	379	1404
10	14	12	313	1025
5	9	7	242	712
0	4	2	190	470
-5	-1	-3	131	280
-10	-6	-8	81	149
-15	-11	-13	45	68
-20	-16	-18	16	23
-25	-21	-23	6	7
-30	-26	-28	1	1

Source: *Facility Design and Planning — Engineering Weather Data*, Reports AFM 88-29, TM 5-785, and NAVFAC P-89, U.S. Departments of the Air Force, the Army, and the Navy, Washington, D.C., July 1978, p. 3-203.

ORNL-DWG 81-4386

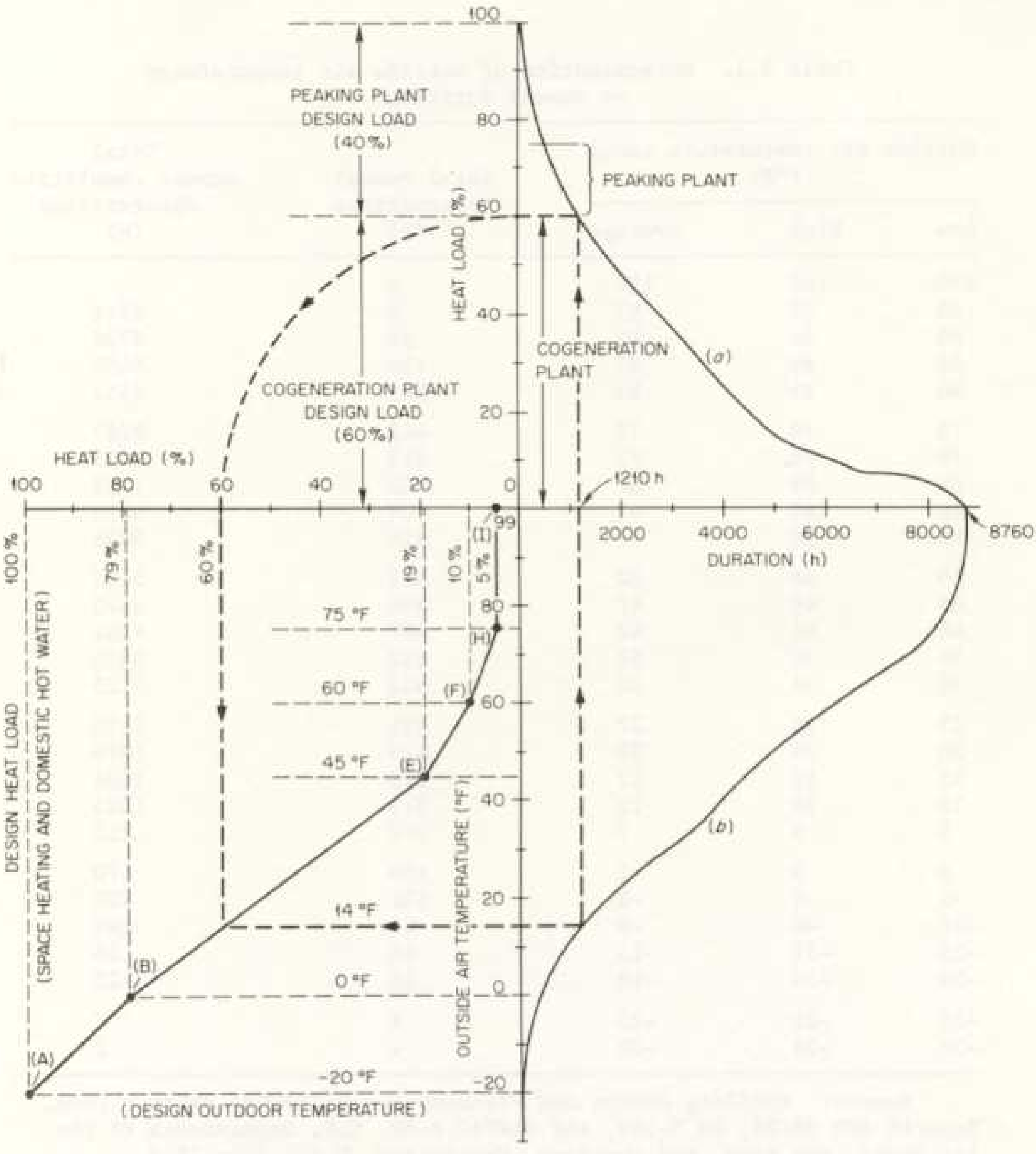

Fig. 3.2. Determination of heat load profile vs outside air temperature. Sources: (*a*) Oak Ridge National Laboratory/University of Minnesota, (*b*) *Facility Design and Planning — Engineering Weather Data*, AFM 88-29, TM 5-785, and NAVFAC P-89 (1978).

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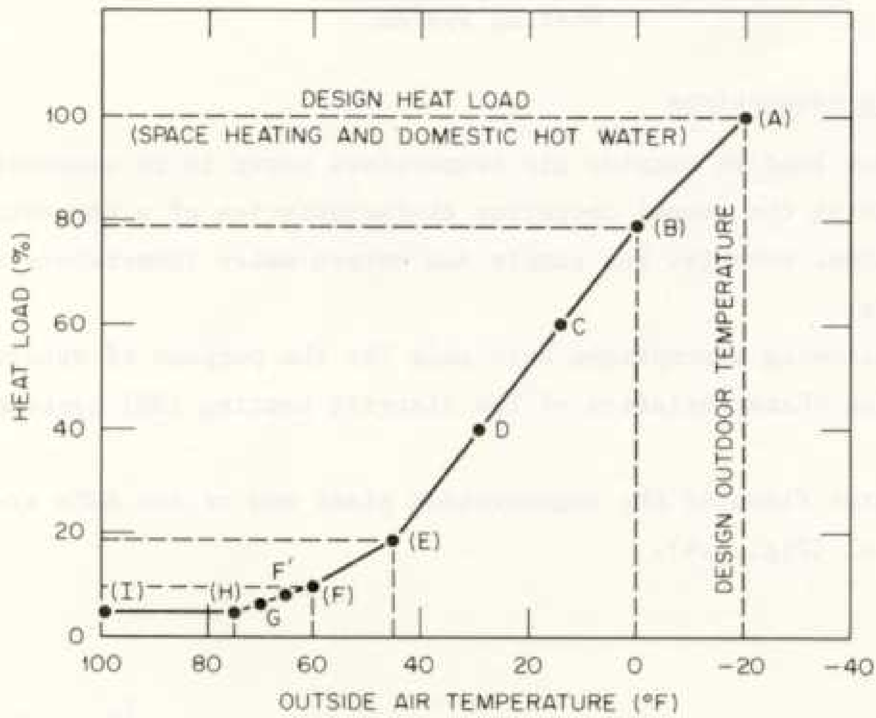

Fig. 3.3. Space heating and domestic hot water heat load vs outside air temperature.

Table 3.2. Coordinates of the nodal points on Figure 3.3 of the linearized district heating system heat load for space heating and domestic hot water vs outside air temperature during annual cycle

Point	Outside air temperature (°F)	Heat load, linearized (%)
(A)	-20	100[a]
(B)	0	79
C	14	60
D	29	40
(E)	45	19
(F)	60	10
F'	65	8.3
G	70	6.7
(H)	75	5
(I)	99	5

[a]The heat load varies linearly between each adjacent pair of points enclosed in parentheses: (A), (B), (E), (F), (H), and (I), for a total of five segments.

3.2 Operating Characteristics of the District Heating System

3.2.1 Basic assumptions

The heat load vs outside air temperature curve is an essential basis for determining the annual operating characteristics of a hot water district heating system, notably, the supply and return water temperature and flow rate profiles.

The following assumptions were made for the purpose of determining the operating characteristics of the district heating (DH) systems:

1. The water flows of the cogeneration plant and of the HWGs are in parallel (Fig. 3.4).

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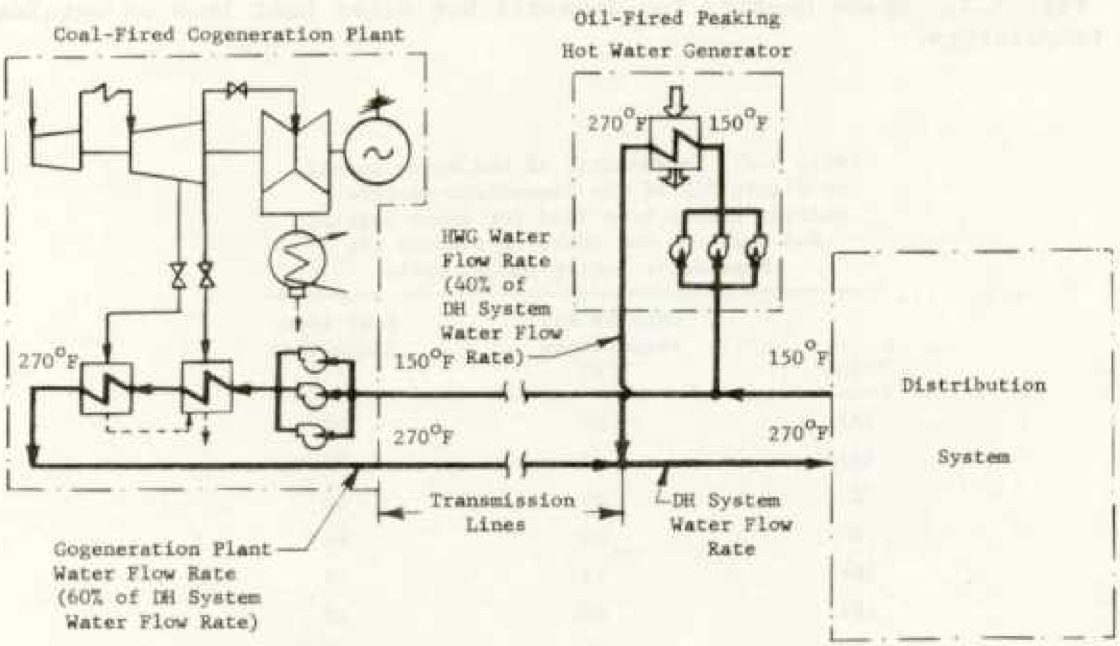

Fig. 3.4. Heat sources and district heating system configuration.

2. The maximum water flow rate fractions are 60% and 40% for the cogeneration plant and HWG flows, respectively; this corresponds to a cogeneration coefficient of 0.60 because the design temperature rises across both the base-load and the peaking plants are taken to be equal.
3. The design return and supply water temperatures are 270°F and 150°F, respectively, for both the cogeneration plant and HWGs.
4. The design outside air temperature for heating is -20°F.
5. The supply water temperature is 270°F during the entire heating season (when outside air temperature is ≤65°F) because of the large fraction of existing steam-heated buildings. For the remainder of the year (when only the domestic hot water heat load is to be covered) the supply water temperature is maintained at 180°F.
6. For heat output control, the water flow rate is kept constant and the supply/return temperature difference is allowed to vary, or the water flow rate is varied and the temperature difference is kept constant.
7. No heat load for summer cooling purposes is considered.

3.2.2 Water temperature profiles vs outside air temperature

The annual water temperature (supply and return) profiles were determined as shown in Fig. 3.5. The coordinates of the nodal points connecting the linear segments are given in Table 3.3.

3.2.3 Water flow rates vs outside air temperature

The water flow rate profiles were determined in conjunction with the determination of the water temperature profiles. Figure 3.5 shows the water flow rates profiles of the district heating system, cogeneration plant and HWGs; Table 3.3 lists the coordinates of nodal points.

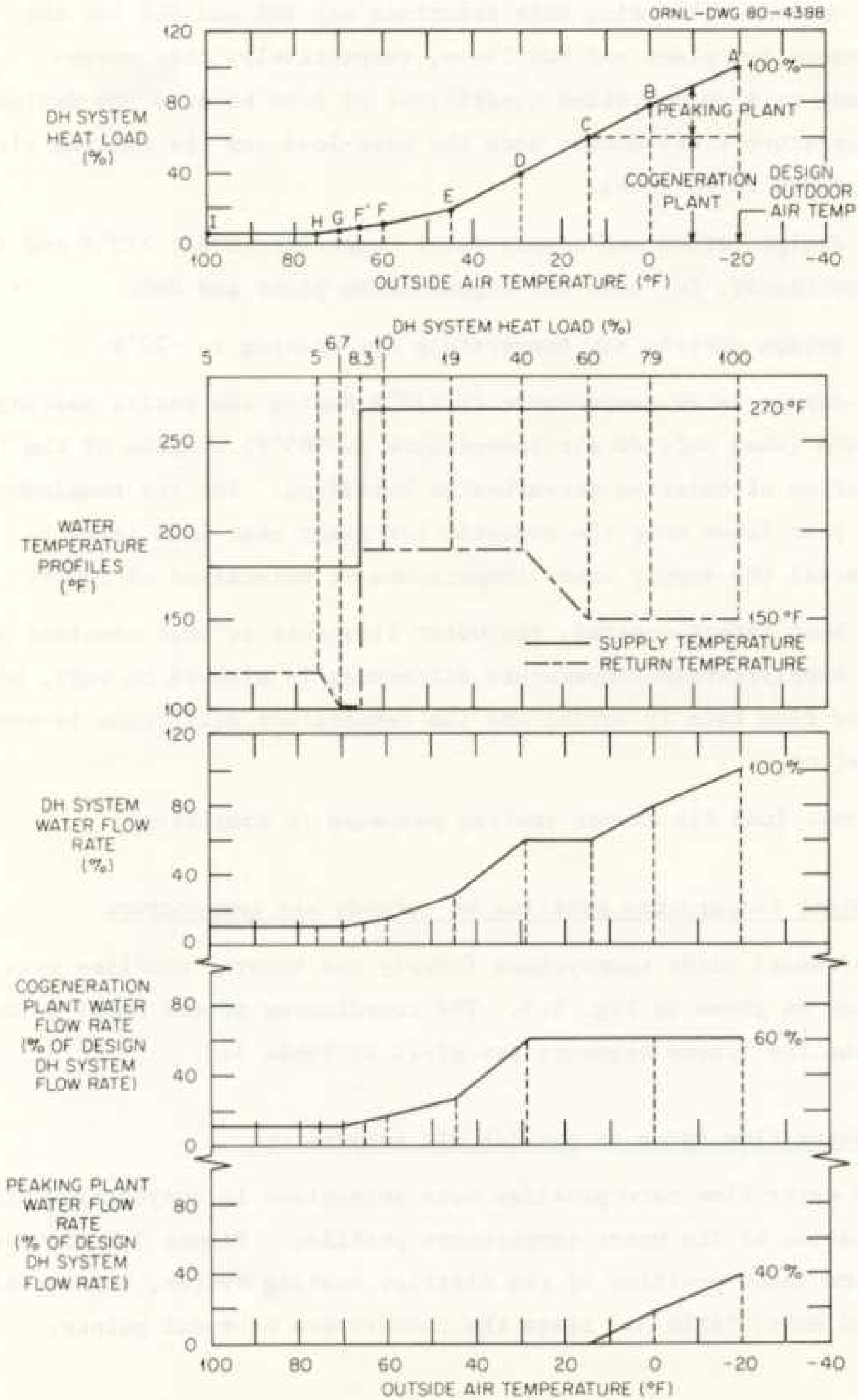

Fig. 3.5. Water temperature profiles and water flow rates as a function of the district heating system heat load.

Table 3.3. Heat load, water temperature profiles, and water flow rates vs outside air temperature

Point[a]	Outside air temperature (°F)	Heat load[b] (% of system design load)			Water temperature[c] (°F)		Water flow rate (% of system design flow rate)			Comments
		Cogeneration plant	Peaking plant	District heating system	Supply	Return	District heating system	Cogeneration plant	Peaking plant	
(I)	99	5	5		180	120	10	10		Domestic hot water only
(H)	75	5	5		180	120	10	10		
G	70	6.7	6.7		180	100	10	10		
F'	>65	8.3	8.3		180	100	12.5	12.5		
	<65	8.3	8.3		270	190	12.5	12.5		Space heating and domestic hot water
(F)	60	10	10		270	190	15	15		
(E)	45	19	19		270	190	28.5	28.5		
D	29	40	40		270	190	60	60		
C	14	60	60	0	270	150	60	60	0	Peaking hot water generator plant operation
(B)	0	79	79	19	270	150	79	60	19	
(A)	−20	100	100	40	270	150	100	60	40	

[a]Points correspond to those shown on Figs. 3.2, 3.3, and 3.5.

[b]Linearized; five segments connecting the points (A), (B), (E), (H), and (I).

[c]The cogeneration plant and peaking plant operate in parallel and have the same supply and return temperatures.

4. COGENERATION PLANT HEAT RATES

Three types of heat rates are of interest in the economic assessment of cogeneration plants: net turbine heat rate, gross plant heat rate, and net plant heat rate. The determination of these heat rates is an involved procedure, especially when their variation over the entire operating range of relevant parameters is desired. Ideally, the problem lends itself to computer treatment if maximum accuracy is sought. For the purposes of this analysis, however, the heat rate diagrams were developed by using specific results obtained from heat balances performed for key modes of operation. Intermediate values connecting the calculated values have been obtained following the procedure outlined for this purpose in ref. 4.

4.1 Net Turbine Heat Rates

Figure 4.1 shows the net turbine heat rate diagram for the 200-MW(e)-350-MW(t) plant. This diagram also applies to the 400-MW(e)-700-MW(t) plant. While recognizing that there is an improvement due to scale from one unit to another, the difference between the two plants has been judged insignificant for the purposes of this assessment and, consequently, has been neglected.

4.2 Gross Plant Heat Rates

The gross plant heat rate is obtained on the basis of the net turbine heat rate by also taking into account the steam generator efficiency and the heat losses in the plant (piping efficiency). The effect of the latter efficiency was neglected. The steam generator efficiency as a function of the steam generator steam output is shown in Fig. 4.2. It is noted that no distinction due to size or type of boiler (PC or AFB) was made among the steam generators of the cogeneration plants considered.

ORNL-DWG 81-4035

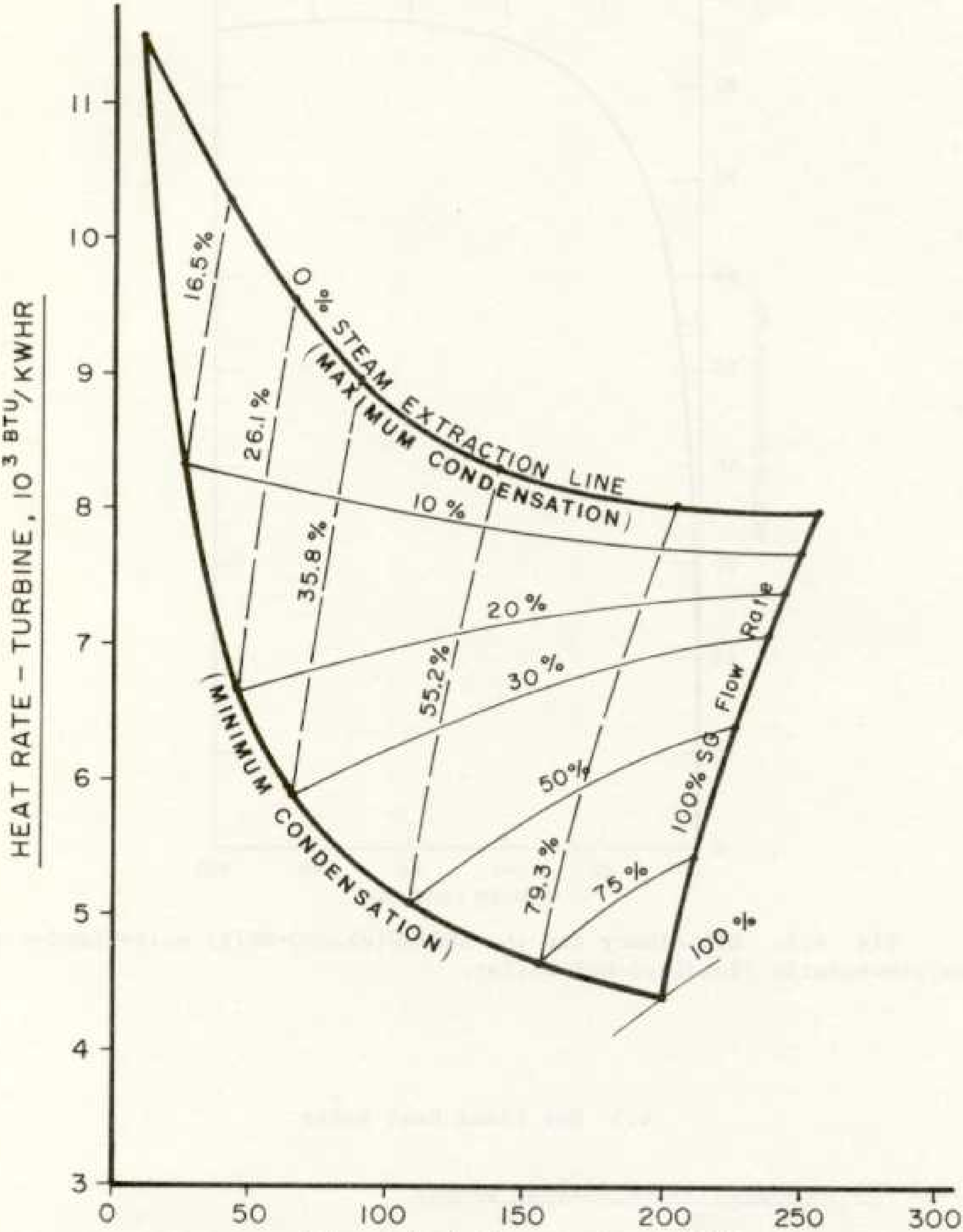

Fig. 4.1. Net turbine heat rate for a cogeneration steam turbine with double extractions and maximum heat load of 342.4 MW(t).

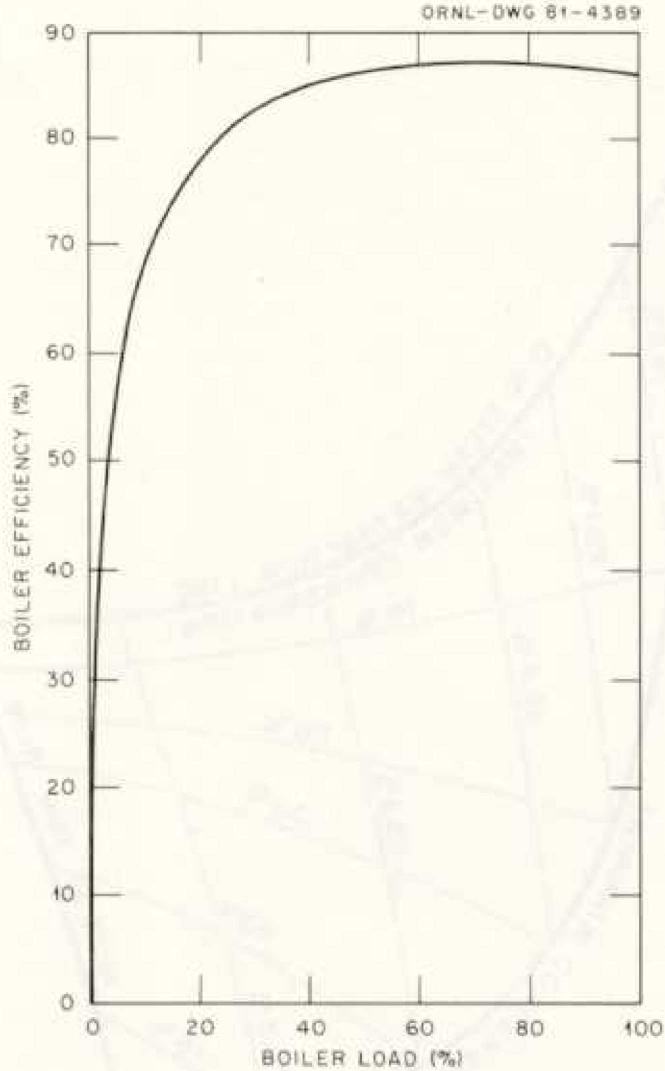

Fig. 4.2. Efficiency for the 200-MW(e)-350-MW(t) pulverized-coal or atmospheric fluidized-bed boiler.

4.3 Net Plant Heat Rates

4.3.1 Steam cogeneration turbine plants

The net plant heat rate is determined on the basis of the gross plant heat rate plus the heat rate penalty for the plant auxiliary power. The net plant heat rate for the 200-MW(e)-350-MW(t) cogeneration plant is given in Fig. 4.3. Table 4.1 lists key values of the net plant heat rate as a function of net plant electric output and heat output.

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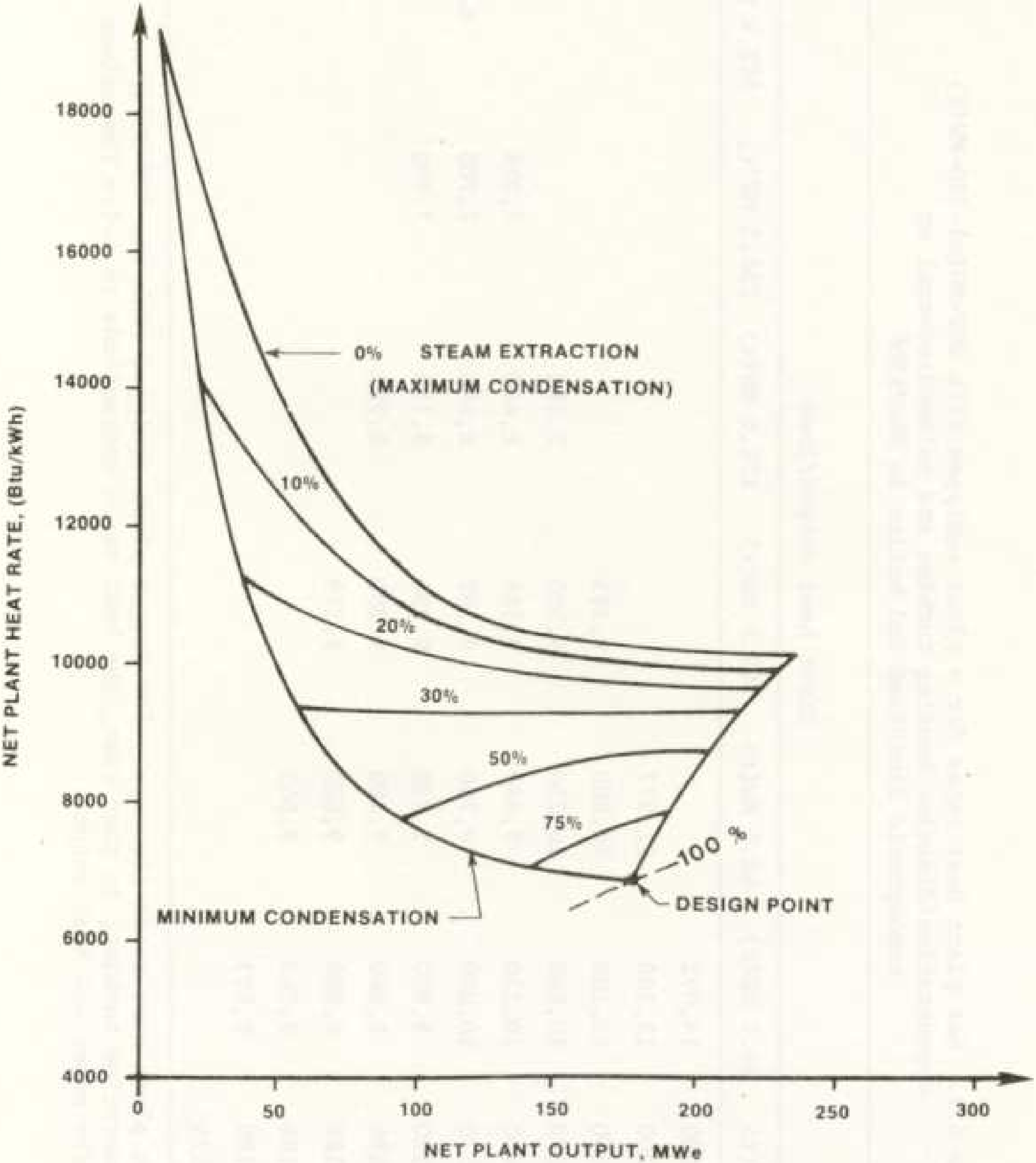

Fig. 4.3. Net plant heat rate for a cogeneration steam turbine with double extraction and maximum heat load of 342.4 MW(t).

Table 4.1. Net plant heat rates for a plant equipped with 200-MW(e)–350-MW(t) cogeneration/district heating turbine and pulverized-coal or atmospheric fluidized-bed boiler in Btu/kWh[a]

Net plant output [MW(e)]	Plant heat output/load						
	0 MW(t)	34.2 MW(t)	68.4 MW(t)	102.6 MW(t)	171.0 MW(t)	256.5 MW(t)	342.4 MW(t)
23.6	17,000	14,072					
37.8	15,100	13,200	11,277				
55.9	13,350	12,100	10,800	9,393			
94.4	11,380	10,980	10,250	9,390	7,761		
141.5	10,480	10,220	9,880	9,386	8,400	7,024	
177.0	10,270	10,000	9,760	9,382	8,680	7,700	6,873
190.9	10,220	9,990	9,720	9,381	8,755	7,900	
205.4	10,196	9,960	9,700	9,380	8,763		
216.8	10,188	9,950	9,670	9,379			
222.5	10,184	9,943	9,663				
228.2	10,180	9,933					
235.0	10,175						

[a]These net plant heat rates also apply for larger plant equipped with the 400-MW(e) – 700-MW(t) cogeneration turbine; in that case, the heat rates corresponds to twice the values indicated for the power and heat output.

The procedure used to construct the net plant heat diagram is outlined below:

1. The boiler load was estimated based on the following assumptions:
   a. The ratio of the electric output loss to the DH system heat load [kW_{loss}/kW(t)] calculated at design point is kept constant throughout the operating range.
   b. The ratio of main steam flow to condenser steam flow, estimated at power-only operation with the design main steam flow, is kept constant throughout the operating range.
2. The turbine output for known boiler load without any DH system heat load was estimated based on Fig. 4.4. with the following relation:

$$\frac{\text{(Turbine output at 100\% boiler load)} \times \text{actual boiler load (\%)}}{\text{heat rate increase (\%)}} .$$

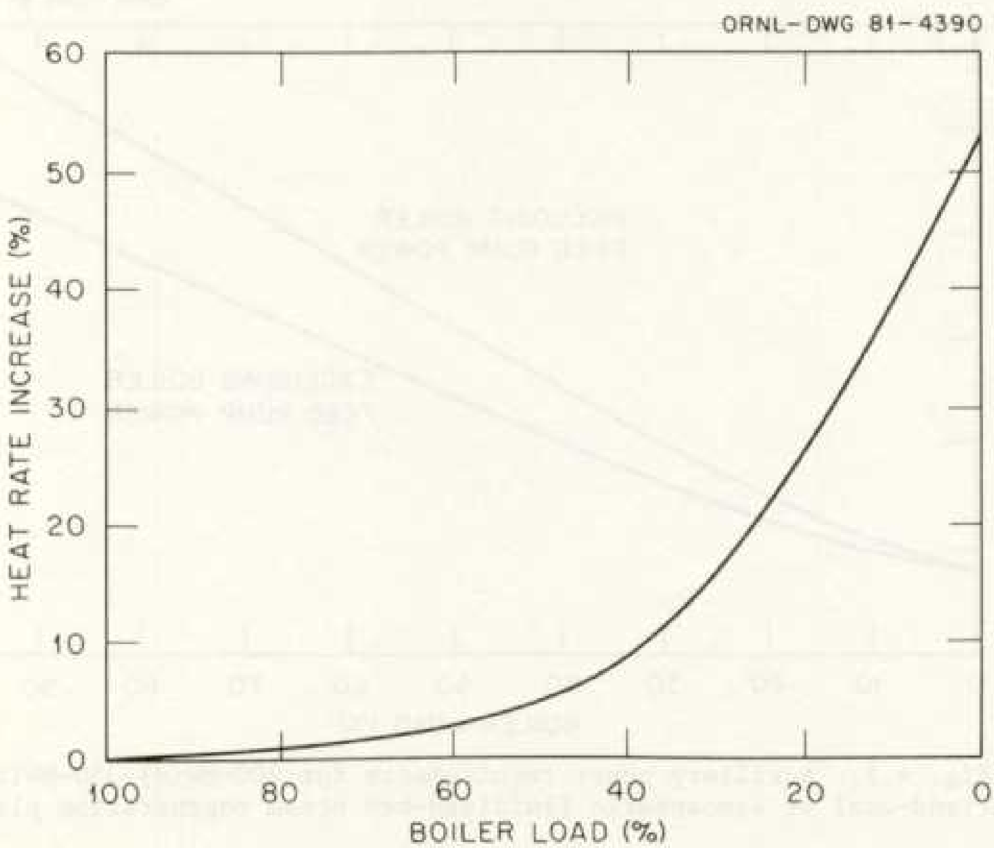

Fig. 4.4. Heat rate change for various boiler loads.

3. The turbine output at the desired DH system heat load equals turbine output at zero DH system heat load minus $[kW_{loss}/kW(t)]kW(t)$.
4. The boiler efficiency and plant auxiliary power can be obtained as a function of the known boiler load from Figs. 4.2 and 4.5, respectively.
5. Finally, the net plant heat rate is

$$\frac{\text{(Cycle heat input)/(boiler efficiency)} - \text{DH system heat load}}{\text{net turbine output} - \text{auxiliary power}} ,$$

where

$$\text{Cycle heat input} = \text{(cycle heat input at boiler design point)} \times \frac{\text{boiler actual load (\%)}}{100} .$$

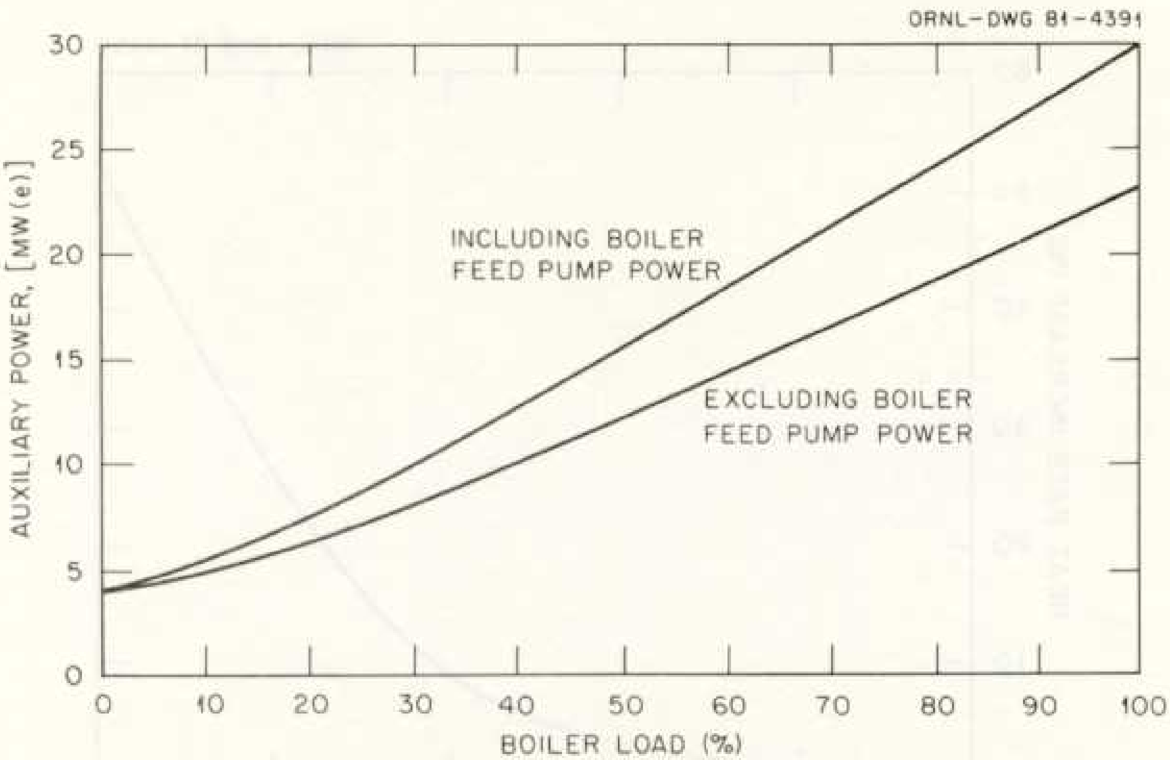

Fig. 4.5. Auxiliary power requirements for 200-MW(e)–350-MW(t) pulverized-coal or atmospheric fluidized-bed steam cogeneration plants.

The following numerical values were used in the calculation of net plant heat rates in reference to the 200-MW(e)–350-MW(t) unit:

- cycle heat input at boiler design point = 2.05×10^9 Btu/h
- $kW_{loss}/kW(t) = 0.33$
- condenser steam flow/main steam flow = 0.642*
- design DH system heat load = 342.4 MW(t)
- maximum electricity output at power-only operation = 257 MW(e).

4.3.2 Closed-cycle gas turbine cogeneration plant

The net plant heat rate for the closed-cycle gas turbine cogeneration plant can be regarded as the heat input chargeable to the net plant electricity generation and can be represented as

$$\text{net plant heat rate} = \frac{\text{heat input to furnace - district heat load}}{\text{net plant output}} ,$$

where heat input to furnace equals heat input to air cycle divided by furnace efficiency, and net plant output equals gross plant output minus auxiliary power.

This basic equation was used for estimating the net plant heat rate for various district heat loads and net plant outputs taking into account the appropriate furnace efficiencies and auxiliary power consumptions.

Figure 4.6 is the cogeneration diagram showing the relationship between the heat loads and gross electricity output, at various furnace loads of the CCGT cogeneration plant. For any specific heat load and gross plant electricity output, the furnace load in percent is obtained from Fig. 4.6. Based on this furnace load, the furnace efficiency and the auxiliary power are obtained from Figs. 4.7 and 4.8, respectively.

Figure 4.9 shows the net plant heat rates for various net plant outputs and plant heat loads. Table 4.2 lists key values of the net plant heat rate as a function of the net plant output and heat demand.

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*Without district heating steam extraction.

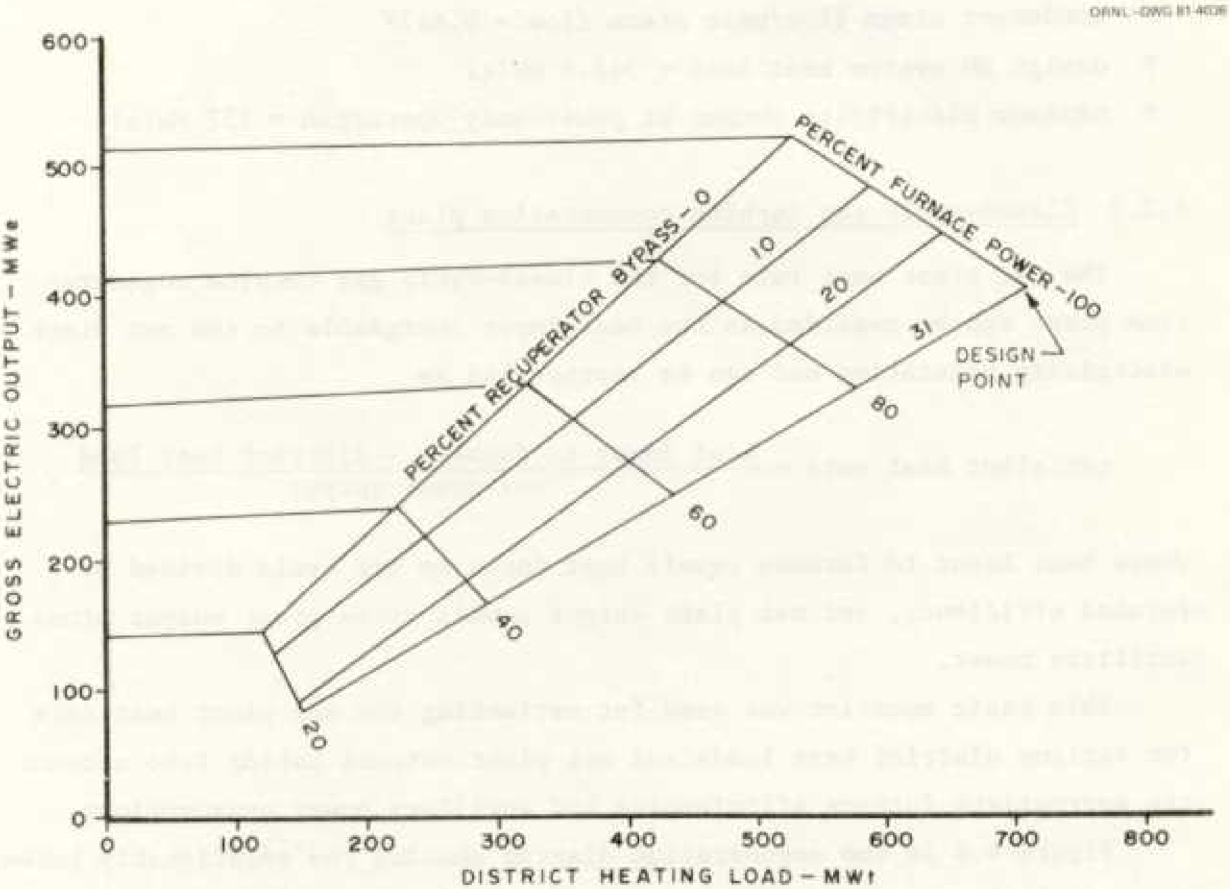

Fig. 4.6. Cogeneration diagram for 400-MW(e)–700-MW(t) closed-cycle gas turbine.

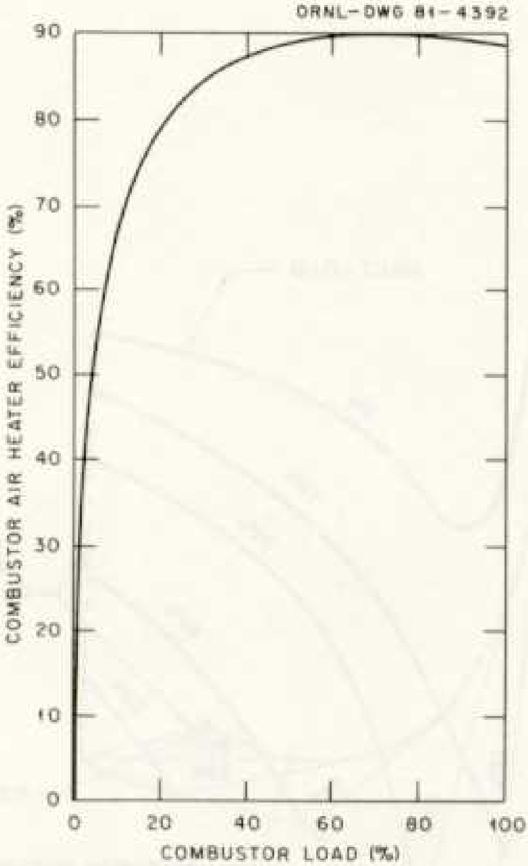

Fig. 4.7. Combustor air heater efficiency for various loads for closed-cycle gas turbine cogeneration plant.

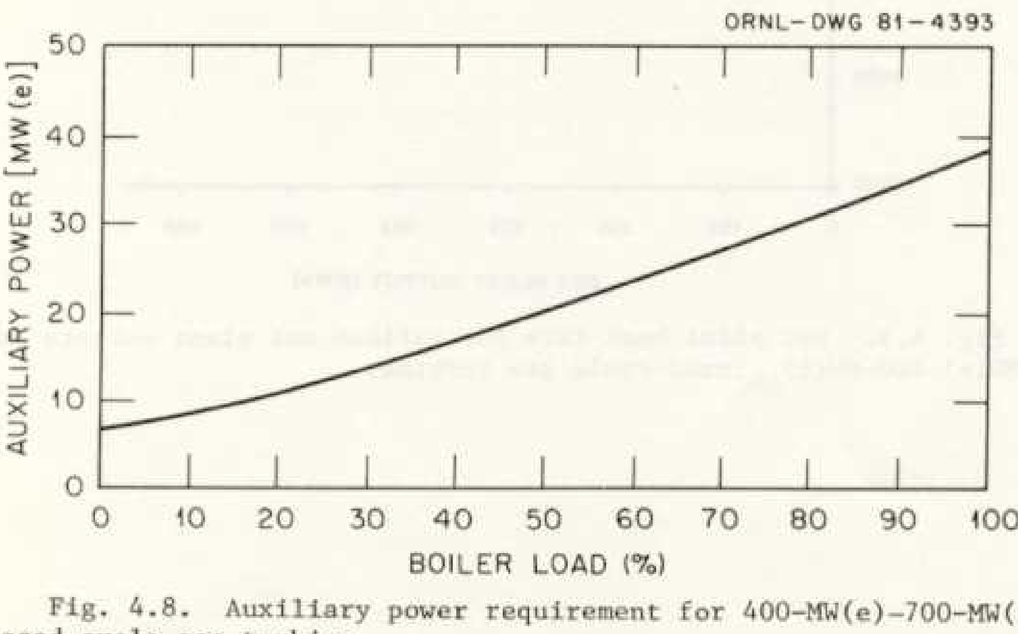

Fig. 4.8. Auxiliary power requirement for 400-MW(e)-700-MW(t) closed-cycle gas turbine.

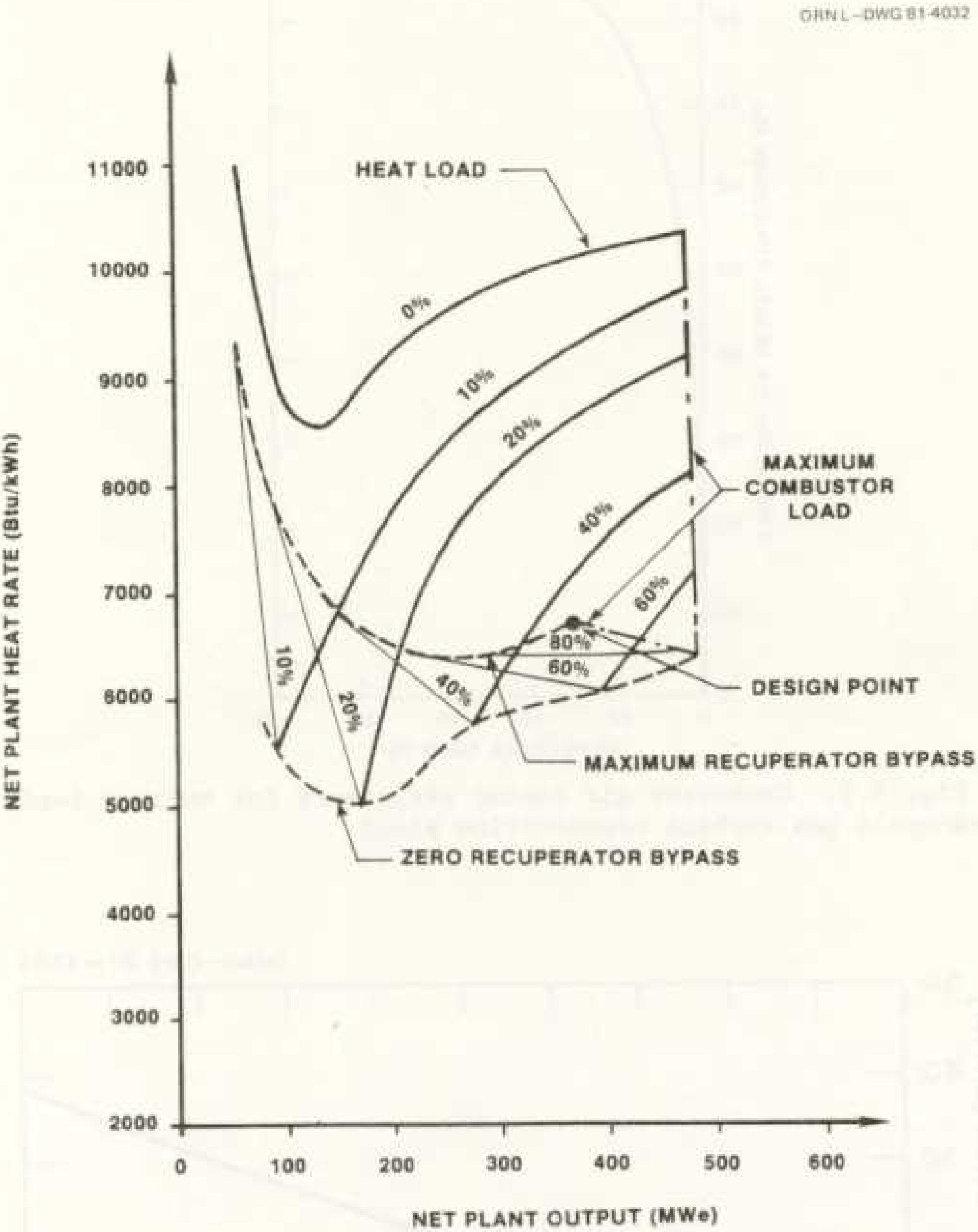

Fig. 4.9. Net plant heat rate for various net plant outputs for 400-MW(e)–700-MW(t) closed-cycle gas turbine.

Table 4.2. Net plant heat rates for the 400-MW(e)-700-MW(t) closed-cycle cogeneration gas turbine plant in Btu/kWh

Net plant electric output [MW(e)]	Plant heat output						
	0 MW(t)	71 MW(t)	140 MW(t)	284 MW(t)	426 MW(t)	568 MW(t)	710 MW(t)
30.9	11,100	11,578					
65.5	10,300	8,400	8,801				
91.1	9,050	5,500	7,800				
142.8	8,600	6,710	6,000	6,852			
158.1	8,770	7,010	5,039	6,720			
218.0	9,410	8,020	6,840	6,240	6,434		
276.2	9,800	8,690	7,830	5,783	6,310		
294.0	9,870	8,820	8,040	6,105	6,290	6,446	
370.0	10,130	9,320	8,645	7,210	6,130	6,400	6,714
398.6	10,205	9,480	8,820	7,520	6,092	6,400	
408	10,220	9,520	8,870	7,620	6,200	6,405	
459	10,330	9,775	9,140	8,020	6,880	6,467	
474	10,360	9,818	9,200	8,100	7,055		
475		9,820	9,218	8,110	7,060		
478			9,252	8,120	7,100		
482				8,170	7,164		

5. ANNUAL GROSS GENERATIONS OF HEAT AND ELECTRICITY

5.1 Basic Assumptions

The shape of the DH system annual heat load duration curve is shown in Fig. 3.1; the heat load is given as a percent of the maximum heat load corresponding to the design outside air temperature for heating of -20°F.

For this study, it is assumed that the 1989 DH system heat load in the Minneapolis–St. Paul area will be large by comparison with the maximum heat output/load of any of the cogeneration units and that 60% of this load will be covered by cogeneration. The mix of cogeneration units will be rather diversified, and these plants will therefore be categorized in a precise loading sequence to ensure the optimum operation.

Information on the cogeneration plants' mix is nonexistent at this time, however, and in order to determine the annual energy generations for the purposes of this comparative assessment, the following assumptions have been made:

1. Each coal-fired cogeneration unit considered operates throughout the year to cover the base load (60% of maximum) of a hot water DH system.
2. Oil-fired HWGs associated with each cogeneration unit considered operate 1210 h/year to cover the peak heat load (40% of maximum) of the DH system.
3. The maximum heat demand of the DH system under consideration is equal to the maximum heat output of the cogeneration unit divided by 0.6 (because the assumed value of the cogeneration coefficient is 0.6).
4. The shape of the heat load duration curve assigned to the cogeneration unit–HWG entity under consideration is that shown in Figs. 3.1 and 3.2.
5. The electricity produced annually by the cogeneration unit under consideration is 50%* of the maximum condensing power that could be

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*NSP's systems planning department assigned 50% as the most likely capacity factor of these coal-fired units in 1989.

produced while covering the assigned base heat load (see Sect. 5.3 for further discussion).

6. Each cogeneration unit is available 100% of the time during the year for meeting the heat load commitments. (In the actual operation of a hot water DH system, the HWGs are used not only to provide heat load peaking but also to substitute for the cogeneration plant when it is unavailable or during the low summer heat loads to enable full utilization of the electrical capacity of the cogeneration unit.)
7. Heat load has precedence over electricity load, and no electric energy replacement costs will be considered.
8. Of the excess electricity generation produced by pure condensation over and above the minimum condensation mode, 80% is generated during the summer at minimum heat load (see Sect. 5.3 for further discussion).

5.2 Annual Gross Heat Generations

The maximum heat outputs (minimum condensation) of the 200-MW(e)-350-MW(t) and the 400-MW(e)-700-MW(t) cogeneration units are 342.4 MW(t) and 684.8 MW(t), respectively. It is noted that ratio of the outputs for the units (electrical as well as thermal) is exactly equal to 2. The maximum heat outputs of the HWGs associated with the two sizes of cogeneration units are 228.3 MW(t) and 456.6 MW(t), respectively.

The maximum heat output of the 400-MW(e)-700-MW(t) CCGT is 710 MW(t). The associated HWG plant has an output of 473.3 MW(t).

The annual heat generations are obtained by integrating the area under the corresponding curves (Figs. 5.1 and 5.2). Table 5.1 shows the heat generations for the steam cogeneration plants (base load), the HWGs (peak load), and the DH system total; Table 5.2 shows the heat generations for the CCGT plant and its HWGs.

5.3 Annual Gross Electricity Generation

The annual gross electricity generation can be obtained by combining the gross electric power-heat load curve (cogeneration diagram) with the base-load portion (below 60% of maximum) of the heat load duration curve.

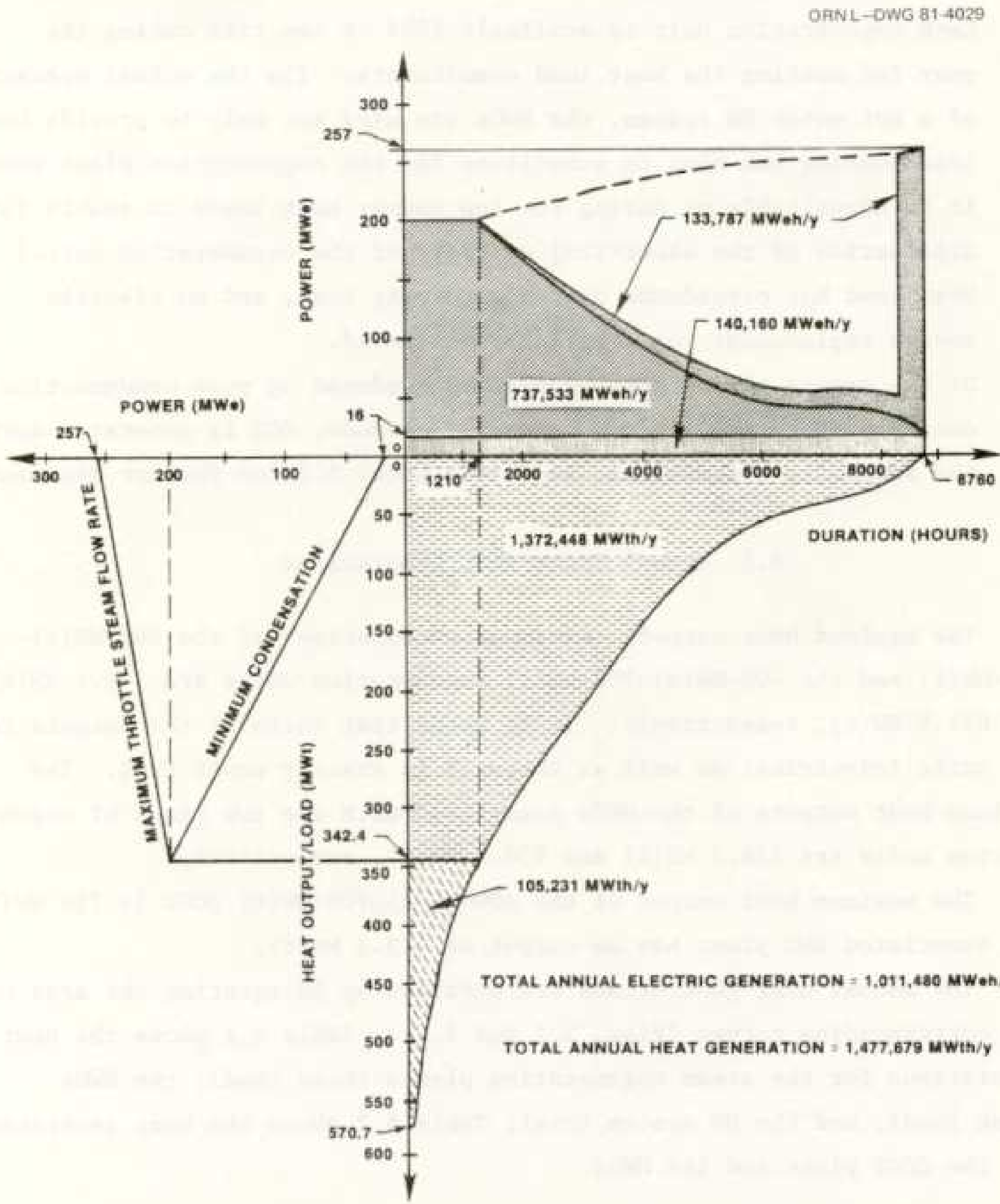

Fig. 5.1. Gross annual generation of electricity and heat for the 200-MW(e)-350-MW(t) unit.

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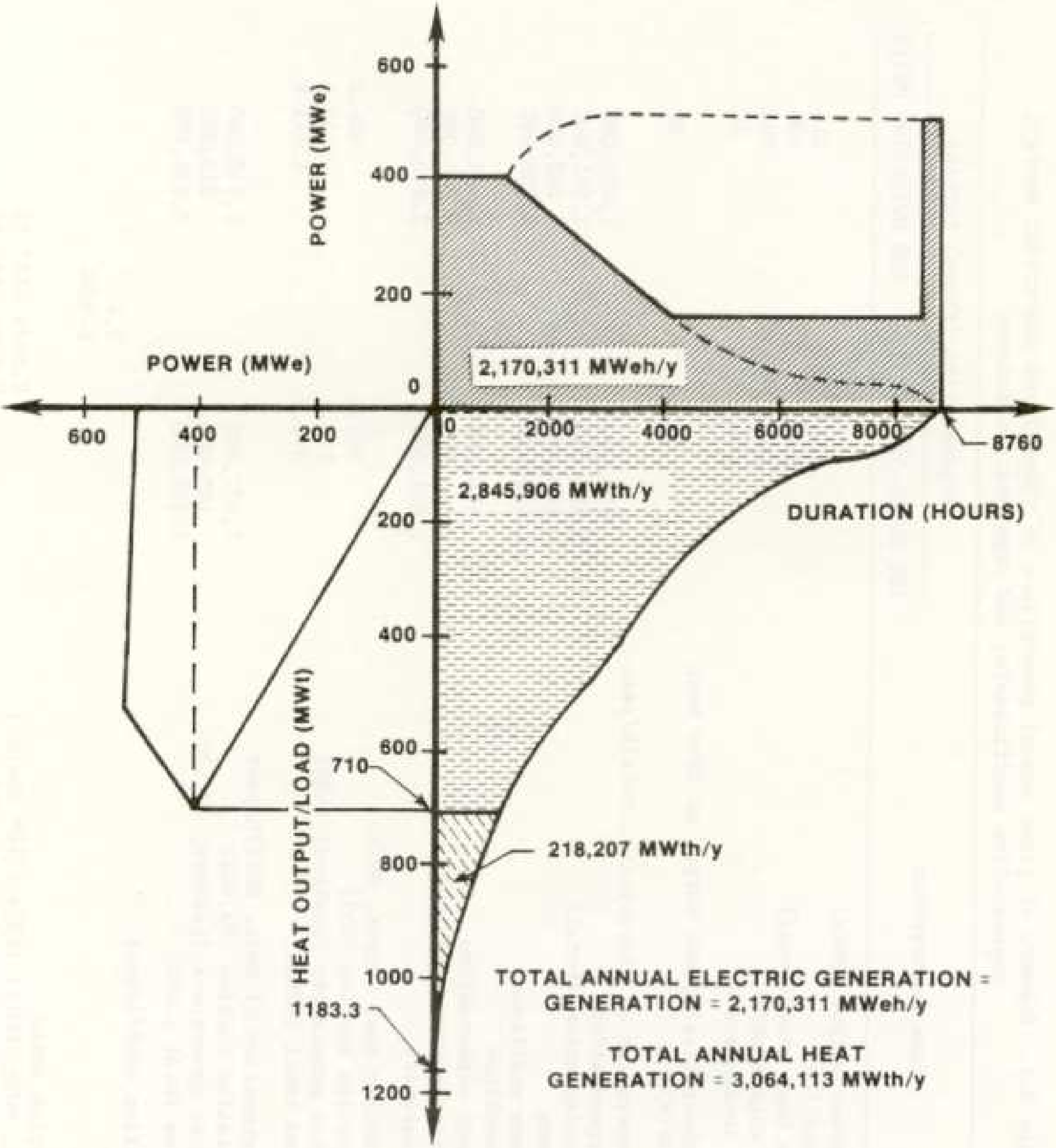

Fig. 5.2. Gross annual generation of electricity and heat for the 400-MW(e)–700-MW(t) closed-cycle gas turbine.

Table 5.1. Summary of gross annual generations of thermal and electrical energy, cogeneration coefficients, and cogeneration indeces

Item description	Cogeneration (steam) turbine	
	200 MW(e)-350 MW(t)	400 MW(e)-700 MW(t)
Maximum power output, MW(e)		
Zero heat load	257	514
Maximum heat load (total)	200	400
Pure cogeneration	184	368
Pure condensation	16	32
Minimum theoretical power output at zero heat load, MW(e)	16	32
Annual generation of electricity, MW(e)h/year		
Pure cogeneration	738,000	1,475,000
Pure condensation (total)	1,285,000	2,571,000
Minimum	140,000	280,000
Maximum additional	1,145,000	2,290,000
Total combined		
Minimum condensation	878,000	1,755,000
Maximum condensation (100%)	2,023,000	4,046,000
50% capacity	1,011,000	2,023,000
Maximum hourly heat output, MW(t)		
Cogeneration turbine (60%)	342.4	684.0
Hot water generators (peakers) (40%)	228.3	456.6
System total (100%)	570.7	1,141.4
Annual generation of heat, MW(t)h/year		
Cogeneration turbine (92.88%)	1,372,000	2,745,000
Hot water generators (peakers) (7.12%)	105,000	210,000
System total (100%)	1,478,000	2,955,000
Cogeneration coefficient		
Hourly	0.6	
Annual	0.9288	
Cogeneration index		
Hourly, MW(e)/MW(t) [kW(e)/(10^6 Btu/h)]	0.5374 (157.5)	
Annual, MW(e)h/MW(t)h [kW(e)h/(10^6 Btu)]	0.5374 (157.5)	

Table 5.2. Summary of gross annual energy generation of electricity and heat for 400-MW(e)–700-MW(t) closed-cycle gas turbine

Maximum power output, MW(e)	
Zero heat load	512
526-MW(t) heat load	521
Maximum heat load	408
Annual generation of electricity, MW(e)h/year	
Minimum generation	1,634,000
Maximum generation (100%)	4,340,000
50% capacity	2,170,000
Maximum hourly heat output, MW(t)	
Cogeneration turbine (60%)	710.0
Hot water generators (peakers) (40%)	473.3
System total (100%)	1183.3
Annual generation of heat, MW(t)h/year	
Cogeneration turbine (92.88%)	2,846,000
Hot water generators (peakers) (7.12%)	218,000
System total (100%)	3,064,000
Cogeneration coefficient	
Hourly	0.6
Annual	0.9288
Cogeneration index	
Hourly, MW(e)/MW(t) [kW(e)/(10^6 Btu/h)]	0.5746 (168.4)
Annual, MW(e)h/MW(t)h [kW(e)h/(10^6 Btu)]	0.5740 (168.2)

5.3.1 Cogeneration (power vs heat output/load) diagram

Figure 5.3 shows the cogeneration steam turbine diagram, which gives the gross power output as a function of the heat output/load and the steam flow rate to condenser. This diagram was developed based on heat balances given in Appendix B (microfiche). A detailed description of the procedure for constructing this diagram is given in ref. 2. A similar diagram in which all numerical values given are multiplied by 2 is applicable to the 400-MW(e)–700-MW(t) steam cogeneration unit.

The power vs heat output diagram for the 400-MW(e)–700-MW(t) CCGT unit is shown in Fig. 4.6.

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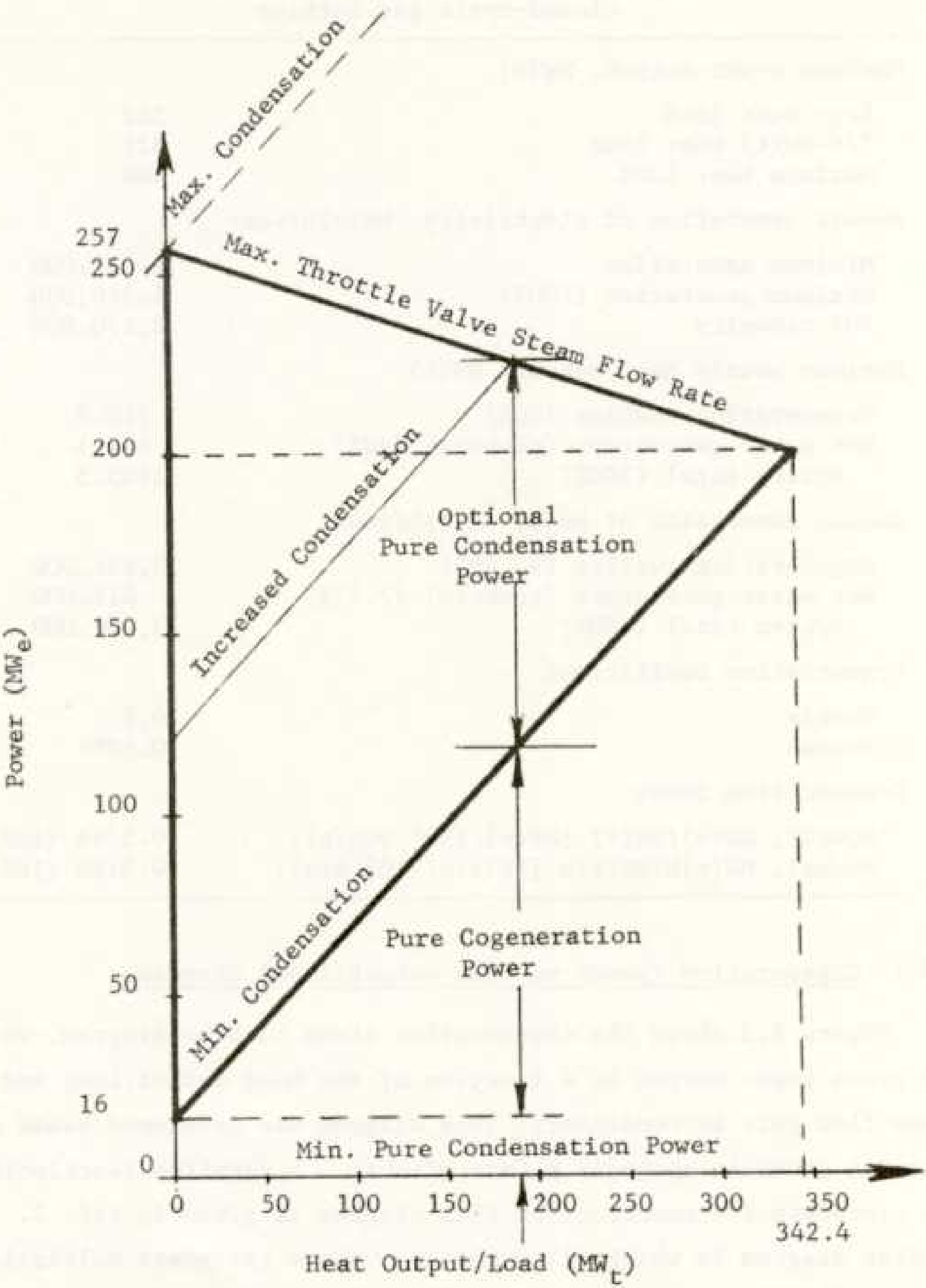

Fig. 5.3. Power vs heat output/load diagram for the 200-MW(e)-350-MW(t) cogeneration/district heating steam turbine.

5.3.2 Minimum condensing power generation (steam units)

By definition, minimum condensing power generation is produced when the base heat load is satisfied by the cogeneration turbine while the condensing flow is kept at its minimum value. This is a theoretical quantity. For the two cogeneration turbines considered, this generation is given in Table 5.1.

5.3.3 Maximum (optional) condensing power generation (steam units)

By definition, maximum condensing power generation is produced when the maximum throttle steam flow rate is maintained while meeting the heat load requirements. This quantity is also a theoretical one; as such, it is labeled 100% output (Table 5.1).

5.3.4 Minimum electric power generation (CCGT unit)

By definition, minimum electric power generation (Fig. 4.6 and Table 5.2) is produced when the maximum recuperator by-pass flow is maintained at all times while meeting the heat load requirements.

5.3.5 Maximum (optional) electric power generation (CCGT unit)

The maximum electric power generation (Table 5.2) is produced when the furnace load is maintained at its maximum value at all times regardless of the heat load requirements.

5.3.6 Annual gross electricity generation

By initial assumption (Sect. 5.1, item 5), the annual electricity generations were taken to be equal to 50% of the maximum power generations defined in Subsects. 5.3.3 and 5.3.5.

The electricity generation of the two steam cogeneration units considered is given in Table 5.1 for maximum condensation at 50% capacity. Figure 5.1 also indicates this amount as total annual electricity generation for the 200-MW(e)-350-MW(t) unit. Table 5.2 gives the annual electricity generation of the CCGT.

The 50% capacity factor (CF) as defined here is not equivalent to the conventional CF (the ratio between actual annual generation and the product of maximum power output times 8760 h/year). If this latter definition is applied to the subject cogeneration turbines, values of 43.4 and 46.7% are obtained for the steam cogeneration plants and the CCGT cogeneration plant, respectively. In this report, the latter figures have been calculated only for purposes of comparison with electricity-only plants of equivalent size. The conventional definition of the CF must be altered to account for the different nature of the denominator used in the CF ratio, thus yielding a value of 50% rather than 43.4%. The CF of the CCGT (46.7%) is slightly better than that of the steam turbine (43.4%) because of the more favorable value of the annual CCGT cogeneration index [0.5740 MW(e)h/MW(t)h] shown in Table 5.2 as compared with the annual steam cogeneration index [0.5374 MW(e)h/MW(t)h] shown in Table 5.1.

The above heat and electricity generations are both gross generations. Net energy generations are calculated in Sect. 9.

6. DESCRIPTION OF THE EQUAL DISCOUNT METHOD OF ALLOCATION OF ELECTRICAL AND THERMAL COGENERATION COSTS

6.1 Description

The equal discount method[5] allocates the cogeneration benefits to both the heat users and the electricity users. The total annual cost of the cogeneration plant and the associated oil-fired HWG for peaking is divided directly into two shares; one allocated to the production of electricity and the other to the production of heat.

This method does not require separate allocation of each of the three major components (fixed, fuel, and O&M costs) of the total annual operating cost. The method requires, however, detailed cost estimates of two separate generation plants — a power plant and a DH plant — having reliability as well as electrical and thermal outputs, respectively, equal to those of the cogeneration-based DH plant. The separate generation of heat and electricity is assumed to take place in an optimum manner.

The cogeneration costs are divided in relation to the alternative costs of separate generation. If ΔA is the cogeneration savings, that is, the difference between the sum of the alternative costs and the total cogeneration cost, a discount is calculated as the ratio between ΔA and the sum of the alternative costs. The annual costs allocated to the cogeneration-based electricity and heat are then calculated by applying the discount equally to the alternative costs of separately generated electricity and heat, respectively. Thus, the equal discount method can be regarded as the result of negotiations between two equal parties.

6.2 Mathematical Model

To calculate the alternative costs of separate generation of heat and electricity in a DH station and a condensing power station, respectively, the equal discount method requires that the separate generation plants have net capacities and annual outputs identical to those of the cogeneration plant and its associated oil-fired HWG for peaking.

In the case of separate generation, the ratio between the base load heat capacity (coal-fired) and the peak load heat capacity (oil-fired) is assumed to equal the ratio between the cogeneration-based heat capacity (coal-fired) and the peak load heat capacity (oil-fired) assumed for the cogeneration mode. Therefore, the oil-fired HWGs used for meeting the peak heat load are identical in both cases.

The net production capacities and annual generations are as follows:

Condensing power station:

- Net electrical capacity = net electrical capacity of cogeneration plant at zero heat load, or

$$P_{PP}^{net} = P_{HPP}^{net} \ @ \ q = 0 \ .$$

- Net electricity generation = net electricity generation of cogeneration plant (pure cogeneration + pure condensation), or

$$E_{PP}^{net} = E_{HPP}^{net} = (E_{HPP}^{cg} + E_{HPP}^{cd})^{net} \ .$$

District heating station, base load, coal-fired heating plant:

- Net heat capacity = net heat capacity of cogeneration plant at minimum condensing steam flow rate, or

$$q_{HP}^{base} = q_{HPP}^{cg} \ .$$

- Net heat generation = net cogeneration based heat generation, or

$$Q_{HP}^{base} = Q_{HPP}^{cg} \ .$$

District heating station, peak load, oil-fired heating plant (HWG plant):

- Net heat capacity = net heat capacity of HWGs associated with the cogeneration plant, or

$$q_{HP}^{peak} = q_{cg}^{peak} = q_{\mathrm{HWG}} \ .$$

- Net heat generation = net heat generation of HWGs associated with the cogeneration plant.

Based on these assumptions, the annual operating costs of the separate generation facilities are calculated as follows:

$$A^{e}_{sep} = A_{pp} = \text{annual operating cost of electricity-only plant, and}$$

$$A^{t}_{sep} = A^{base}_{HP} + A_{\mathrm{HWG}} = \text{annual operating cost of heat-only plants.*}$$

To determine the bus bar electricity cost and the combined base and peaking plant gate heat cost, the equal discount method requires the calculation of the following quantities:

- Annual cost for separate generation in \$/year:

$$A_{sep} = A^{e}_{sep} + A^{t}_{sep} = A_{PP} + A^{base}_{HP} + A_{\mathrm{HWG}} \; .$$

- Annual cost of combined generation† (cogeneration plant and associated peaking HWGs) in \$/year:

$$A_{cg} = A_{HPP} + A_{\mathrm{HWG}} \; .$$

where

A_{HPP} = annual operating cost of cogeneration plant

A_{HWG} = annual operating cost of peaking HWGs.

- Cogeneration savings in \$/year:

$$\Delta A = A_{sep} - A_{cg} \; .$$

---

*The exponent t in A^{t}_{sep} stands for thermal energy, that is, heat.

†In cases where cogeneration-based district heating requires additional interconnections of smaller distribution systems as compared with conventional district heating, the annual operating cost of such interconnections must also be included. For the purpose of this economic analysis, the physical layouts of the transmission and distribution systems have been assumed to be identical for both the cogeneration-based and conventional district heating systems. The base-load, coal-fired heat-only plant has been assumed to be also remote from the service area. In both cases, the peaking HWGs are located in the vicinity of the consumer. Thus, no additional interconnection costs have been charged to the cogeneration-based district heating alternative.

- Cogeneration discount (the equal discount rate) in %:

$$D = 100\left(\frac{\Delta A}{A_{sep}}\right).$$

- Cost share of electric generation in \$/year:

$$A^e_{cg} = A^e_{sep}\left(1 - \frac{D}{100}\right).$$

- Cost share of heat generation in \$/year:

$$A^t_{cg} = A^t_{sep}\left(1 - \frac{D}{100}\right).$$

- Cost share of heat generation (cogeneration plant only) in \$/year:

$$A^t_{HPP} = A_{HPP} - A^e_{cg}\text{ , or alternatively,}$$

$$A^t_{HPP} = A^t_{cg} - A_{\mathrm{HWG}}\ .$$

- Bus bar electricity cost in mills/kWh:

$$c^e = 1000\left(\frac{A^e_{cg}}{E_{HPP}}\right).$$

- Plant gate heat cost (average for cogeneration plant and peaking HWGs) in dollars per 10^6 Btu:

$$c^t_{pg} = 10^6\left(\frac{A^t_{cg}}{Q_{HPP} + Q_{\mathrm{HWG}}}\right)\ .$$

The cost of heat delivered to the consumers (expressed in dollars per 10^6 Btu) can be determined by adding the transmission and distribution costs to the plant gate heat cost:

$$c^t_{del} = c^t_{pg}\left(\frac{Q_{HPP} + Q_{\mathrm{HWG}}}{Q_{del}}\right) + \left(\frac{A_{tl} + A_{ds}}{Q_{del}}\right)10^6\ ,$$

where

A_{tl} = annual cost of the transmission line

A_{ds} = annual cost of the distribution system

Q_{del} = heat delivered to consumers [heat generated − (transmission + distribution) losses].

The cost of heat transmitted to the border of the service area (expressed in dollars per 10^6 Btu) is calculated as:

$$c^t_{trans} = c^t_{pg}\left(\frac{Q_{HPP} + Q_{\mathrm{HWG}}}{Q_{trans}}\right) + \left(\frac{A_{tl}}{Q_{trans}}\right)10^6 \ ,$$

where

Q_{trans} = heat delivered to the distribution system (heat generated − transmission losses only).

A graphical representation of the cogeneration costs allocation procedure employed by the equal discount method is shown in Fig. 6.1.

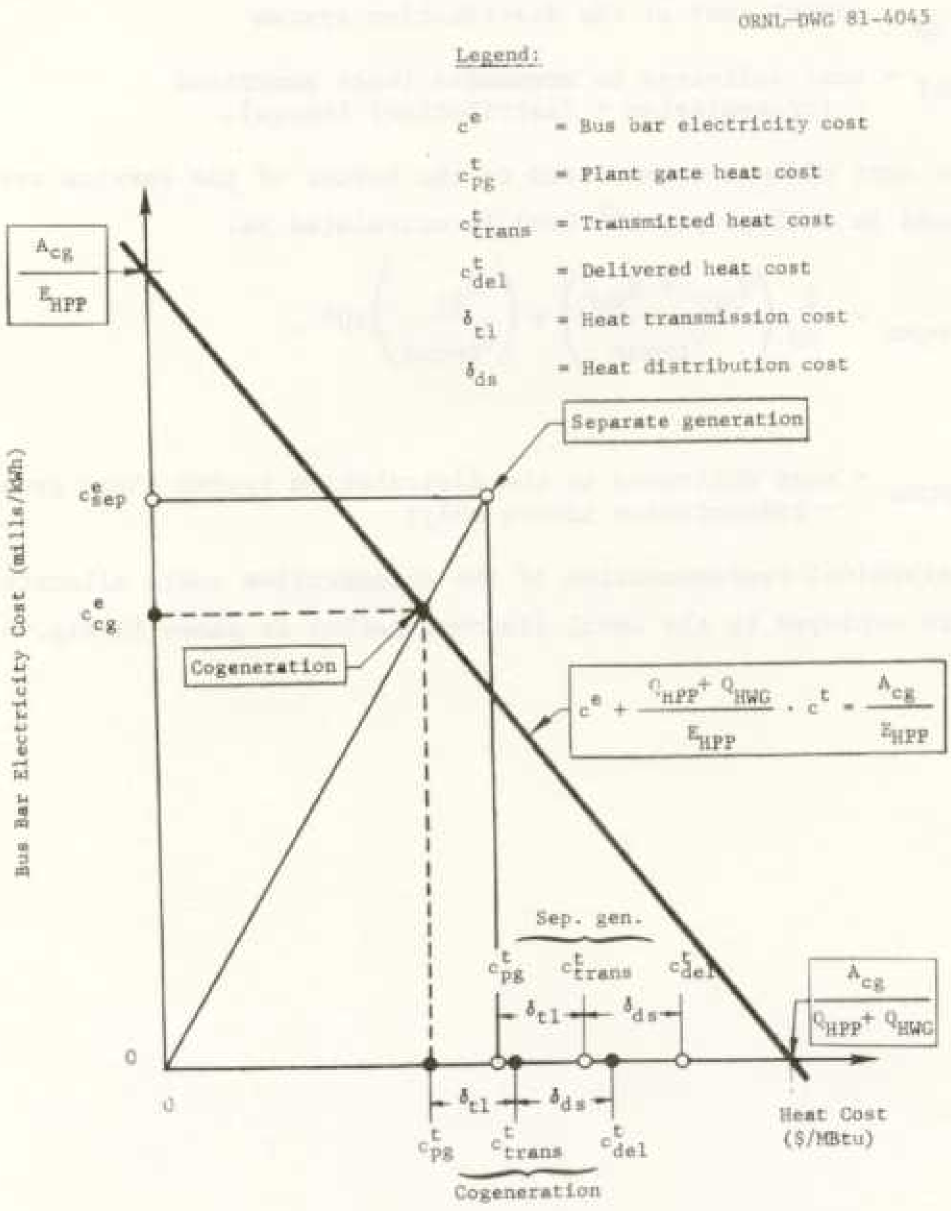

Fig. 6.1. Procedure used by the equal discount method for allocating the cogeneration/district heating costs.

7. ESTIMATED TOTAL PROJECT COSTS

7.1 Cogeneration Plants

The total project costs were developed for this program by utilizing the total direct cost determined by UE&C and adding indirect costs, escalation, and allowance for funds during construction developed by NSP. Escalation and allowance for funds during construction were based on construction schedules estimated by UE&C and on an assumed start-up date of May 1989. The construction schedules for the reference plants were estimated at 34 months and 45 months for the 200-MW(e)-350-MW(t) and the 400-MW(e)-700-MW(t) plants, respectively. Allowance for setting piles was added at both sites: three months for the smaller units, four months for the larger. At High Bridge, six more months were added for demolition and site preparation.

Total direct costs, reported Appendix A and B (microfiche) for the 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) designs, respectively, are determined as the sum of the plant cost estimate, land, mobile coal and ash equipment, spare parts, and sales tax. Total direct costs for the units at High Bridge and Coon Rapids are summarized in Table 7.1; total project costs are summarized in Table 7.2.

Table 7.1. Cogeneration/district heating plant total direct costs in millions of January 1980 dollars

Unit type	High Bridge	Coon Rapids
200 MW(e)-350 MW(t)		
Pulverized-coal	217.2	243.9
Atmospheric fluidized-bed	209.5	236.3
400 MW(e)-700 MW(t)		
Pulverized-coal	373.8	379.6
Atmospheric fluidized-bed	353.7	359.0
Closed-cycle gas turbine		375.4
2 × [200 MW(e)-350 MW(t), pulverized-coal]		445.2

Table 7.2. Cogeneration/district heating plant total project cost in millions of dollars

	High Bridge				Coon Rapids					
	200 MW(e)–350 MW(t)		400 MW(e)–700 MW(t)		200 MW(e)–350 MW(t)		400 MW(e)–700 MW(t)			2 × 200 MW(e)–350 MW(t), pulverized-coal
	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	Pulverized-coal	Atmospheric fluidized-bed	Closed-cycle gas turbine	
Land[a]	1.1	1.1	10.2	10.2	10.0	10.0	11.1	11.1	11.1	11.1
Mobile coal and ash equipment[a]	1.1	1.1	1.6	1.6	2.6	2.6	2.6	2.6	2.6	2.6
Plant cost[a,b]	215.0	207.3	362.0	341.9	231.3	223.7	365.9	345.3	361.7	241.6[c] 189.9[d]
Total direct cost[a]	217.2	209.5	373.8	353.7	243.9	236.3	379.6	359.0	375.4	445.2
Indirect costs[a]	47.8	46.1	76.6	72.5	53.7	52.0	77.8	73.6	77.0	84.6
Escalation	215.2	207.9	341.1	323.1	246.7	238.9	357.5	336.6	351.8	448.4
Allowance for funds during construction	63.8	61.5	131.5	124.7	86.7	64.8	123.1	115.9	121.8	183.8
Total project cost[e]	544	525	923	874	611	592	938	885	928	1162

[a] January 1980 dollars.

[b] Includes spare parts and sales tax.

[c] Plant 1.

[d] Plant 2.

[e] May 1989 dollars.

7.2 Electricity-only Plants

The capital costs for the electricity-only plants, required for cost allocation, were obtained from the capital cost estimates reported in Appendixes A and B (microfiche) by deleting the costs of equipment needed to operate the plants in the cogeneration mode. The resulting electricity-only plants have a net generation of 235 MW(e) and 470 MW(e), respectively. The total direct costs and the total project costs for these plants are shown in Table 7.3.

Also shown in Table 7.3 are the cost elements of an 800-MW(e) low-sulfur-coal plant. These costs were developed from a 1980 update of an 800-MW(e) low-sulfur-coal plant documented by UE&C for the Department of Energy.[1]

For all of the electricity-only plants, UE&C provided the total direct cost, and NSP developed the indirect costs, escalation, and allowance for funds during construction.

7.3 Heat-only Plants

Costs were developed for heat-only plants needed to provide for the peak heating requirements of each cogeneration plant and to provide base heating requirements for the heat-only plants used to develop the equal discount cost allocation. The peak heating units are oil-fired with maximum capacity of 228.3 MW(t) and 456.6 MW(t). The base-loaded, heat-only plants are coal-fired (with dry flue gas desulfurization) with maximum capacity of 342.4 MW(t) and 684.8 MW(t). All units were designed as low-pressure steam boilers with heat exchangers to provide hot water because there is not experience in the U.S. or in Europe with HWGs of this size, and the costs associated with a station made up of multiple hot water heaters are prohibitive. The costs developed for heat-only plants are shown in Table 7.4.

Table 7.3. Total project costs of electricity-only plants in millions of dollars

Cost item	235 MW(e) (net)	470 MW(e) (net)	800 MW(e) (net)
Land[a]	10.0	11.1	5.7
Mobile coal and ash equipment[a]	2.6	2.6	3.2
Plant cost[a]	223.0	352.5	486.1
Total direct cost[a]	235.6	366.2	495.0
Indirect cost[a]	51.8	75.1	91.5
Escalation	239.1	345.8	446.0
Allowance for funds during construction	64.5	118.9	170.0
Total project cost[b]	591	906	1,203

[a]January 1980 dollars.

[b]May 1989 dollars.

Table 7.4. Total project costs of heat-only plants in metropolitan area in millions of dollars

Cost item	342-MW(t) coal-fired heating plant[a]	228-MW(t) oil-fired peaking plant[b]	685-MW(t) coal-fired heating plant[a]	457-MW(t) oil-fired peaking plant[b]
Land[c]	10.0	0.2	11.1	0.2
Mobile coal and ash equipment[c]	2.6		2.6	
Plant cost[c]	101.1	20.7	143.6	34.2
Total direct cost[c]	113.7	20.9	157.3	34.4
Indirect cost[c]	25.0	4.6	32.2	7.1
Escalation	120.0	22.7	158.1	35.2
Allowance for funds during construction	26.3	4.8	42.4	9.3
Total project cost[d]	285	53	390	86

[a] At a suburban metropolitan area site.

[b] At an urban metropolitan area site.

[c] In January 1980 dollars.

[d] In May 1989 dollars.

7.4 Thermal Transmission Lines

The direct costs for the transmission lines for the 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) cogeneration plants were described in Vols. II and III, respectively (see Appendix). The direct costs are summarized in Table 7.5. The total project costs shown in Table 7.6 include indirect costs, escalation during construction, and allowance for funds during construction developed by NSP. Easement and land costs are excluded.

Table 7.5. Direct cost estimates of transmission lines in millions of January 1980 dollars[a]

Thermal capacity	Site	
	High Bridge	Coon Rapids
350 MW(t) (30-in. OD lines)	2.4	53.7
700 MW(t) (42-in. ID lines)	3.3	74.9

[a]Excludes easement and land costs.

Table 7.6. Total project costs of underground thermal transmission lines in millions of dollars

Cost item	High Bridge site		Coon Rapids site	
	30-in. OD line	42-in. ID line	30-in. OD line	42-in. ID line
Direct cost[a,b]	2.4	3.3	53.7	74.9
Indirect cost[b]	0.5	0.7	11.8	16.5
Escalation	3.2	4.1	57.9	80.4
Allowance for funds during construction	0.2	0.3	11.6	16.2
Total cost[c]	6.3	8.4	135	188

[a]Excludes easement and land costs.

[b]In January 1980 dollars.

[c]In May 1989 dollars.

3.3 / 4900 $673/ft

74.9 / 61000 = $1227

$1375/ft

8. ANNUAL COSTS OF NEW COGENERATION PLANTS AND SEPARATE GENERATION PLANTS

The total annual cost of an energy generating facility is computed as a function of the following components: annual operating and maintenance cost, annual fuel cost, and annual fixed cost.

In this section, the total annual operating costs are calculated in May 1, 1989, dollars for all of the cogeneration plants and separate generation plants considered.

8.1 Annual Operating and Maintenance Cost

Operating and maintenance (O&M) costs can be divided into fixed and variable expenses. The fixed O&M costs are a function of the rated capacity of the facility. The variable O&M costs vary with the facility production levels and consist of the routine, day-to-day expenditures required to operate the facility.

The fixed and variable O&M costs (adjusted for inflation) of all facilities considered have been determined based on equations developed by NSP for large coal-fired steam electric plants.

The escalation rates used are 8% for 1979-80, 9% for 1980-84, and 7% for 1984 and beyond.

The O&M costs of cogeneration plants have been assumed to be 5% greater than those of electricity-only plants.

The equations developed by NSP for electricity-only plants using the following adjustments have been modified to determined the O&M costs of heat-only plants.

- coal-fired, base-load heating plant: 60% of electricity-only costs,
- oil-fired, peak-load heating plant: 30% of electricity-only costs, and
- an equivalent electrical capacity was determined assuming an overall electricity plant efficiency of 34%.

8.1.1 Fixed O&M costs (May 1989 dollars)

Coal-fired, electricity-only plants:

\$24.91/kW(e)	235-MW(e) unit
\$16.75/kW(e)	470- and 483-MW(e) units

Coal-fired, cogeneration plants:

\$26.15/kW(e)	200-MW(e)-350-MW(t) unit
\$17.59/kW(e)	400-MW(e)-700-MW(t) units, including CCGT

Heat-only plants

- coal-fired, base-load plants:

\$5.08/kW(t)	342.4-MW(t) unit
\$3.42/kW(t)	684.8- and 710.0-MW(t) units

- Oil-fired, HWG plants:

\$2.54/kW(t)	228.3-MW(t) unit
\$1.71/kW(t)	456.6- and 473.3-MW(t) units

8.1.2 Variable O&M costs (May 1989 dollars)

Coal-fired, electricity-only plants [235-, 470-, and 483-MW(e) units]:

1.37 [MW(e) HO] + 1.14 [MW(e) cap. × Op. h],

Coal-fired, cogeneration plants [both 200-MW(e)-350-MW(t) and 400-MW(e)-700-MW(t) units, including CCGT unit]:

1.44 [MW(e) HO] + 1.14 [MW(e) cap. × Op. h],

Heat-only plants:

- coal-fired, base-load plant [342.4-, 684.8-, and 710.0-MW(t) units]:

  0.82 [MW(t) HO] + 0.41 [MW(t) cap. × Op. h],

- Oil-fired, base-load plant [228.3-, 456.6-, and 473.3-MW(t) units]:

  0.41 [MW(t) HO] + 0.12 [MW(t) cap. × Op. h],

where

MW HO = annual electric (e) or thermal (t) generation, in MWh/year;

MW cap. = electric (e) or thermal (t) capacity, in MW;

Op. h = 8760 h/year × availability factor (0.80).

The total annual O&M costs have been calculated as the sum of the fixed and variable O&M costs and are given in Table 8.1 for all facilities considered.

Table 8.1. Summary of annual costs for cogeneration plants and corresponding separate generation plants in millions of May 1989 dollars

Type of plant	Fixed A_A	Fuel A_F	Operation and maintenance $A_{O\&M}$	Total A
High Bridge cogeneration plants				
200 MW(e)–350 MW(t)				
Pulverized-coal	81.60	37.45	9.40	128.45
Atmospheric fluidized-bed	78.75	37.45	9.40	125.60
400 MW(e)–700 MW(t)				
Pulverized-coal	138.45	74.89	14.78	228.12
Atmospheric fluidized-bed	131.10	74.89	14.78	220.77
Coon Rapids cogeneration plants				
200 MW(e)–350 MW(t)				
Pulverized-coal	91.65	37.45	9.40	138.50
Atmospheric fluidized-bed	88.80	37.45	9.40	135.65
400 MW(e)–700 MW(t)				
Pulverized-coal	140.70	74.89	14.78	230.37
Atmospheric fluidized-bed	132.75	74.89	14.78	222.42
Closed-cycle gas turbine	139.20	72.85	15.71	227.76
2 × [200 MW(e)–350 MW(t), pulverized-coal]	174.30	74.89	18.80	267.99
Electricity-only plants				
235 MW(e)	88.65	31.50	8.95	129.10
470 MW(e)	135.90	63.00	14.07	212.97
483 MW(e)[a]	137.25	67.52	14.84	219.61
Heat-only plants				
342.2 MW(t), coal-fired	42.75	17.27	3.43	63.45
228.3 MW(t), oil-fired[b]	7.95	7.88	0.66	16.49
Total [570.7 MW(t)]	50.70	25.15	4.14	78.99
684.8 MW(t), coal-fired	58.50	34.54	5.71	98.75
456.6 MW(t), oil-fired[b]	12.90	15.76	0.93	29.59
Total [1151.4 MW(t)]	71.40	50.30	6.77	128.47
710.0 MW(t), coal-fired[a]	60.00	35.81	5.92	101.73
473.3 MW(t), oil-fired[a,b]	13.20	16.34	0.97	30.51
Total [1183.3 MW(t)][a]	73.20	52.15	6.89	132.24

[a]Refers to closed-cycle gas turbine alternative.

[b]Oil-fired, peaking hot water generators are used with both base-load, heat-only plants and cogeneration plants.

8.2 Annual Fuel Cost

All cogeneration plants, electricity-only plants, and base-load heat-only plants considered in the analysis utilize low-sulfur coal. The peaking HWGs utilize residual fuel oil. These plants are considered to be located in the metropolitan Minneapolis-St. Paul area, where the coal and oil prices in May 1989 dollars are estimated at \$3.08 and \$19.31 per 10^6 Btu, respectively.*

To determine the annual fuel costs for all facilities considered, the annual fuel consumptions were determined on the basis of the respective energy generations (whether electricity or heat) and plant efficiencies. A method employing weighted averages of such efficiencies was used based on discrete energy quantities generated during the annual cycle. Figures 4.1 through 4.5 show the heat rate diagrams and boiler efficiency and auxiliary power curves used for the steam cogeneration units. Figures 4.6 through 4.9 show the similar curves used for the CCGT unit.

Either gross or net plant heat rates can be used to determine the annual fuel consumption as long as the corresponding annual electricity generation is considered. Gross plant heat rates were used to determine the annual fuel consumption of the cogeneration plants; net plant heat rates were used to determine the annual fuel consumption of the electricity-only plants.

The procedure for determining the total annual fuel consumptions of the facilities considered can be summarized as follows.

Coal-fired, electricity-only plants:

$$B_{PP} = \sum_{i=1}^{n} \left(E_{PP} \times b_{plant}^{net}\right)_i = E_{PP} \times b_{plant}^{net} ,$$

---

*NSP December 1979 fuel costs forecast.

where

B_{PP} = annual fuel consumption for electricity-only plant,

$\left(E_{PP}\right)_i$ = net electrical energy generated during time interval i,

$\left(b^{net}_{plant}\right)_i$ = average net plant heat rate during time interval i,

E_{PP} = total net annual electrical energy generation,

b^{net}_{plant} = annual average net plant heat rate,

n = number of time intervals considered.

Coal-fired, cogeneration (heat and power) plants:

$$B_{HPP} = B^{e}_{HPP} + B^{t}_{HPP} ,$$

where

B_{HPP} = annual fuel consumption for cogeneration plant,

B^{e}_{HPP} = annual fuel consumption for electricity generation

$$= \sum_{i=1}^{n} \left(\frac{E_{HPP} \times b^{net}_{turbine}}{\eta_{SG}} \right)_i = E_{HPP} \times b^{gross}_{plant} ,$$

$\left(E_{HPP}\right)_i$ = gross electrical energy generated during time interval i,

$\left(b^{net}_{turbine}\right)_i$ = average net turbine heat rate during time interval i,

$\left(\eta_{SG}\right)_i$ = average steam generator efficiency during time interval i,

E_{HPP} = total gross annual electrical energy generation,

b^{gross}_{plant} = annual average gross plant heat rate,

n = number of time intervals considered,

B^{t}_{HPP} = annual fuel consumption for heat (thermal energy) generation

$$= \sum_{i=1}^{n} \left(\frac{Q_{HPP}}{\eta_{SG}}\right)_i = \frac{Q_{HPP}}{\eta_{SG}} ,$$

$\left(Q_{HPP}\right)_i$ = heat generated during time interval i,

Q_{HPP} = total annual heat generation,

η_{SG} = annual average steam generator efficiency.

Heat-only plants:

- Coal-fired, base-load plant:

  B_{HP}^{base} = annual fuel consumption for heat generation (determined similarly to B_{HPP}^{t} in the case of cogeneration plants).

- Oil-fired, peaking HWG:

  B_{HWG} = annual fuel consumption for covering the peak heat load (determined similarly to B_{HPP}^{t} in the case of cogeneration plants).

The total fuel consumptions for separate generation/district heating (B_{sep}) and for cogeneration/district heating (B_{cg}) are:

$$B_{sep} = B_{PP} + B_{HP}^{base} + B_{\mathrm{HWG}}$$

and

$$B_{cg} = B_{HPP} + B_{\mathrm{HWG}} .$$

A summary of the annual fuel consumptions calculated for the steam cogeneration plants is given in Table 9.1 along with the net energy generations. A similar summary for the CCGT plant is given in Table 9.2. The annual fuel costs for all facilities considered are given in Table 8.1.

8.3 Annual Fixed Cost

The annual fixed cost is a function of total capital cost of the facility and the fixed charge rate. The components of the fixed charge rate include cost of capital, depreciation, property insurance, federal income taxes, and state and local taxes.

The value of the fixed charge rate depends on the economic analysis mode considered, that is, constant dollar mode or current dollar mode. For the purpose of this assessment, the current dollar mode (nominal dollar mode) of economic analysis is used and a fixed annual charge rate of 15% is employed throughout. The current dollar mode of economic analysis assumes that the purchasing value of the dollar changes over time. Thus, cost escalations on the estimated capital costs are assumed to exist and are included in a single escalation-during-construction-cost account. Similarly, cost escalations on estimated O&M costs and fuel costs are assumed to exist and are included within the respective cost accounts.

The total project costs in May 1, 1989, dollars for all facilities considered are given in Sect. 7. The resulting annual fixed costs are shown in Table 8.1.

8.4 Total Annual Cost

The total annual operating costs of the cogeneration plants and of the separate generation plants are shown in Table 8.1.

9. BUS BAR ELECTRICITY COSTS AND PLANT GATE HEAT COSTS

9.1 Annual Net Energy Generation

9.1.1 Cogeneration plants

To calculate the bus bar electricity cost and the plant gate heat cost, the net annual electricity generation and net annual heat generation must be calculated. The net heat generation was assumed to be equal to the gross heat generation for all cogeneration plants. The net electricity generation was determined by subtracting the annual auxiliary power consumption from the gross electricity generation. For each cogeneration plant, the annual auxiliary power consumption was determined by using weighted averages of the auxiliary power based on discrete gross energy quantities generated during the annual cycle. It was assumed that the auxiliary power is a function of the steam generator load, rather than a function of the electricity load only, to account for the combined generation of both heat and electricity.

The procedure used for determining the annual net electricity generation can be summarized as follows:

$$E_{HPP}^{net} = E_{HPP}^{gross} - E_{HPP}^{aux} ,$$

where

$$E_{HPP}^{aux} = \sum_{i=1}^{n} \left(P_{HPP}^{aux} \times \Delta h \right)_i ,$$

$\left(P_{HPP}^{aux} \right)_i$ = f(steam generator load) = average value of the auxiliary power during time interval i,

$(\Delta h)_i$ = number of operating hours during the time interval i,

n = number of time intervals considered during the annual cycle.

The net heat and net electricity generations calculated for the cogeneration plants analyzed are shown in Tables 9.1 and 9.2.

Table 9.1. Summary of annual net energy generations and fuel consumptions of 200-MW(e)–350-MW(t) cogeneration plants and equivalent separate generation plants[a]

Type of plant	Fuel consumption (10^{12} Btu/year)	Heat generation [MW(t)h/year]	Electricity generation [MW(e)h/year]
	Separate generation		
Electricity only [235 MW(e) net]	10.2272		893,208
Heat only			
Coal-fired base load [342.4 MW(t)]	5.6063	1,372,448	
Oil-fired hot water generators [228.3 MW(t)]	0.4081	105,231	
Total separate generation	16.2416	1,477,679	893,208
	Cogeneration and hot water generators		
Electricity generation	6.6440		893,208
Heat generation (base load)	5.5142	1,372,448	
Total [200-MW(e)–350-MW(t)] cogeneration plant	12.1582	1,372,448	893,208
Hot water generators [228.3 MW(t)]	0.4081	105,231	
Total cogeneration and hot water generators	12.5663	1,477,679	893,208
Total fuel savings by cogeneration	3.6753 (30%)		

[a]Multiply each numerical value shown except percentage of fuel savings by 2 to obtain the values corresponding to the case of the 400-MW(e)–700-MW(t) unit.

Table 9.2. Summary of annual net energy generations and fuel consumptions of the 400-MW(e)–700-MW(t) closed-cycle gas turbine cogeneration plant and equivalent separate generation plants

Type of plant	Fuel consumption (10^{12} Btu/year)	Heat generation [MW(t)h/year]	Electricity generation [MW(e)h/year]
Separate generation			
Electricity only [483 MW(e) net]	21.923		1,975,000
Heat only			
Coal-fired base load [710 MW(t)]	11.625	2,846,121	
Oil-fired hot water generators [473.3 MW(t)]	0.846	218.208	
Total separate generation	34.394	3,064,329	1,975,000
Cogeneration and hot water generators			
Electricity generation	12.599		1,975,000
Heat generation	11.055	2,846,121	
Total [400-MW(e)–700-MW(t)] cogeneration plant	23.654	2,846,121	1,975,000
Hot water generators [473.3 MW(t)]	0.846	218,208	
Total cogeneration and hot water generators	24.500	3,064,329	1,975,000
Total fuel savings by cogeneration	9.894 (40%)		

9.1.2 Electricity-only plants

By definition, the net energy generation of the electricity-only plants was taken to be equal to the net energy generation of the cogeneration plants against which the comparison was made. Because the auxiliary power consumptions of electricity-only plants are smaller than those of the comparative cogeneration plants, the gross electricity generations are different. Thus, the fuel consumptions of the electricity-only plants were based on their net electricity generations and net plant heat rates, rather than on gross electricity generations and gross plant heat rates as the fuel consumptions of cogeneration plants were determined.

The net electricity generations of the electricity-only plants are equal to those of the corresponding cogeneration plants shown in Tables 9.1 and 9.2.

9.1.3 Heat-only plants

As with the cogeneration plants, the net heat generations were assumed to be equal to the gross heat generations for both the coal-fired, base-load and oil-fired, peak-load heat-only plants.

The net heat generations of the heat-only plants are shown in Table 9.1.

9.2 Unit Costs of Bus Bar Electricity and Plant Gate Heat

Using the equal discount method of cost allocation, which was described in Sect. 6, the bus bar electricity costs and plant gate heat costs are calculated in Table 9.3 for all cogeneration/district heating plant alternatives at the High Bridge and Coon Rapids sites.

The cogeneration-based costs are also summarized in Table 9.4 along with the corresponding separate generation costs of the bus bar electricity and plant gate heat.

The intercepts on the c_e and c_t axes are needed to represent graphically the relationships between the cogeneration costs and the separate generation costs. Table 9.4 lists the quantities c_e^* (c_e intercept)

Table 9.3. Determination of cogeneration unit costs for bus bar electricity and plant gate heat in May 1, 1989, dollars

Type of plant	Annual operating cost (10^6): Electricity-only A_{PP}	Annual operating cost (10^6): Heat-only $A_{HP} = A_{HP}^{base} + A_{HWG}$	Annual operating cost (10^6): Total separate generation A_{sep}	Annual operating cost (10^6): Cogeneration and peaking $A_{cg} = A_{HPP} + A_{HWG}$	Cogeneration savings over separate generation $A_{sep} - A_{HPP}$ (10^6)	Discount $\frac{\text{Savings}}{A_{sep}} \times 100$ (%)	Electricity share $A_{cg}^e = \left(1 - \frac{\text{Discount}}{100}\right) A_{PP}$ (10^6)	Heat share $A_{cg}^t = \left(1 - \frac{\text{Discount}}{100}\right) A_{HP}$ (10^6)	Annual electricity generation E_{HPP} [MW(e)h]	Annual heat generation $Q_{HPP} + Q_{HWG}$ [MW(t)h]	Bus bar electricity cost c_e^{cg} [mills/kW(e)h]	Plant gate heat cost c_t^{cg} ($ per 10^6 Btu)
					High Bridge site							
200 MW(e)-350 MW(t)												
Pulverized-coal	129.10[a]	78.99[b]	208.09	144.94[c]	63.15	30.35	89.92	55.02	893,208	1,477,679	100.67	10.91
Atmospheric fluidized-bed	129.10[a]	78.99[b]	208.09	142.09[c]	66.00	31.72	88.15	53.94	893,208	1,477,679	98.69	10.69
400 MW(e)-700 MW(t)												
Pulverized-coal	212.97[d]	128.47[e]	341.44	257.71[f]	83.73	24.52	160.74	96.97	1,786,416	2,955,358	89.98	9.61
Atmospheric fluidized-bed	212.97[d]	128.47[e]	341.44	250.36[f]	91.08	26.68	156.16	94.20	1,786,416	2,955,358	87.42	9.34
					Coon Rapids site							
200 MW(e)-350 MW(t)												
Pulverized-coal	129.10[a]	78.99[b]	208.09	154.99[c]	53.10	25.52	96.16	58.83	893,208	1,477,679	107.65	11.67
Atmospheric fluidized-bed	129.10[a]	78.99[b]	208.09	152.14[c]	55.95	26.89	94.39	57.75	893,208	1,477,679	105.67	11.45
400 MW(e)-700 MW(t)												
Pulverized-coal	212.97[d]	128.47[e]	341.44	259.96[f]	81.48	23.86	162.15	97.81	1,786,416	2,955,358	90.77	9.40
Atmospheric fluidized-bed	212.97[d]	128.47[e]	341.44	252.01[f]	89.43	26.19	157.19	94.82	1,786,416	2,955,358	88.00	9.40
Closed-cycle gas turbine	219.61[g]	132.24[h]	351.85	258.27[i]	93.58	26.60	161.20	97.07	1,975,000	3,064,330	81.62	9.28
2 × [200 MW(e)-350 MW(t), pulverized-coal]	258.20[j]	157.98[k]	416.18	300.97[l]	115.21	27.68	186.72	114.25	1,786,416	2,955,358	104.52	11.33

[a] 257-MW(e) [235-MW(e) net] coal-fired power plant.

[b] 342.4-MW(t) coal-fired (base) and 228.3-MW(t) oil-fired (peaking) heating plants.

[c] Includes a 228.3-MW(t) oil-fired (peaking) heating plant.

[d] 514-MW(e) [470-MW(e) net] coal-fired power plant.

[e] 684.8-MW(t) coal-fired (base) and 456.6-MW(t) oil-fired (peaking) heating plants.

[f] Includes a 456.3-MW(t) oil-fired (peaking) heating plant.

[g] 521.0-MW(e) [483.0 MW(e) net] coal-fired power plant.

[h] 710.0-MW(t) coal-fired (base) and 473.3-MW(t) oil-fired (peaking) heating plants.

[i] Includes a 473.3-MW(t) oil-fired (peaking) heating plant.

[j] Two 257-MW(e) [235-MW(e) net] coal-fired power plants.

[k] Two 342.4-MW(t) coal-fired (base) and two 228.3-MW(t) oil-fired (peaking) heating plants.

[l] Includes two 228.3-MW(t) oil-fired (peaking) heating plants.

Table 9.4. Summary of generation costs

Type of plant	Bus bar electricity cost [mills/kW(e)h]			Plant gate heat cost (\$ per 10^6 Btu)		
	Cogeneration plant c_e^{cg}	Electricity-only plant c_e^{sep}	Intercept[a] c_e^*	Cogeneration and peaking plant c_t^{cg}	Heat-only plant c_t^{sep}	Intercept[b] c_t^*
High Bridge site						
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators						
Pulverized-coal	100.67	144.5	162.27	10.91	15.70	28.74
Atmospheric fluidized-bed	98.69	144.5	159.08	10.69	15.70	28.17
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators						
Pulverized-coal	89.98	123.1	144.26	9.61	12.80	25.55
Atmospheric fluidized-bed	87.42	123.1	140.15	9.34	12.80	24.82
Coon Rapids site						
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators						
Pulverized-coal	107.65	144.5	173.52	11.67	15.70	30.73
Atmospheric fluidized-bed	105.67	144.5	170.33	11.45	15.70	30.17
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators						
Pulverized-coal	90.77	123.1	145.52	9.70	12.80	25.77
Atmospheric fluidized-bed	88.00	123.1	141.07	9.40	12.80	24.98
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	81.62	111.2	130.80	9.28	12.64	24.70
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228 MW(t) oil-fired peaking plant with hot water generators]	104.52	144.5	168.48	11.33	15.70	29.84

[a] Intercept $c_e^* = A_{HPP}/E_{HPP}$ in constructing $c_e = f(c_t)$.
[b] Intercept $c_t^* = A_{HPP}/Q_{HPP}$ in constructing $c_e = f(c_t)$.

and c_t^* (c_t intercept) used in constructing the diagrams shown in Figs. 9.1 and 9.2 (c_e^* is the unit cost of electricity if all costs are allocated to electricity generation; similarly, c_t^* is the unit cost of heat if all costs are allocated to the heat generation).

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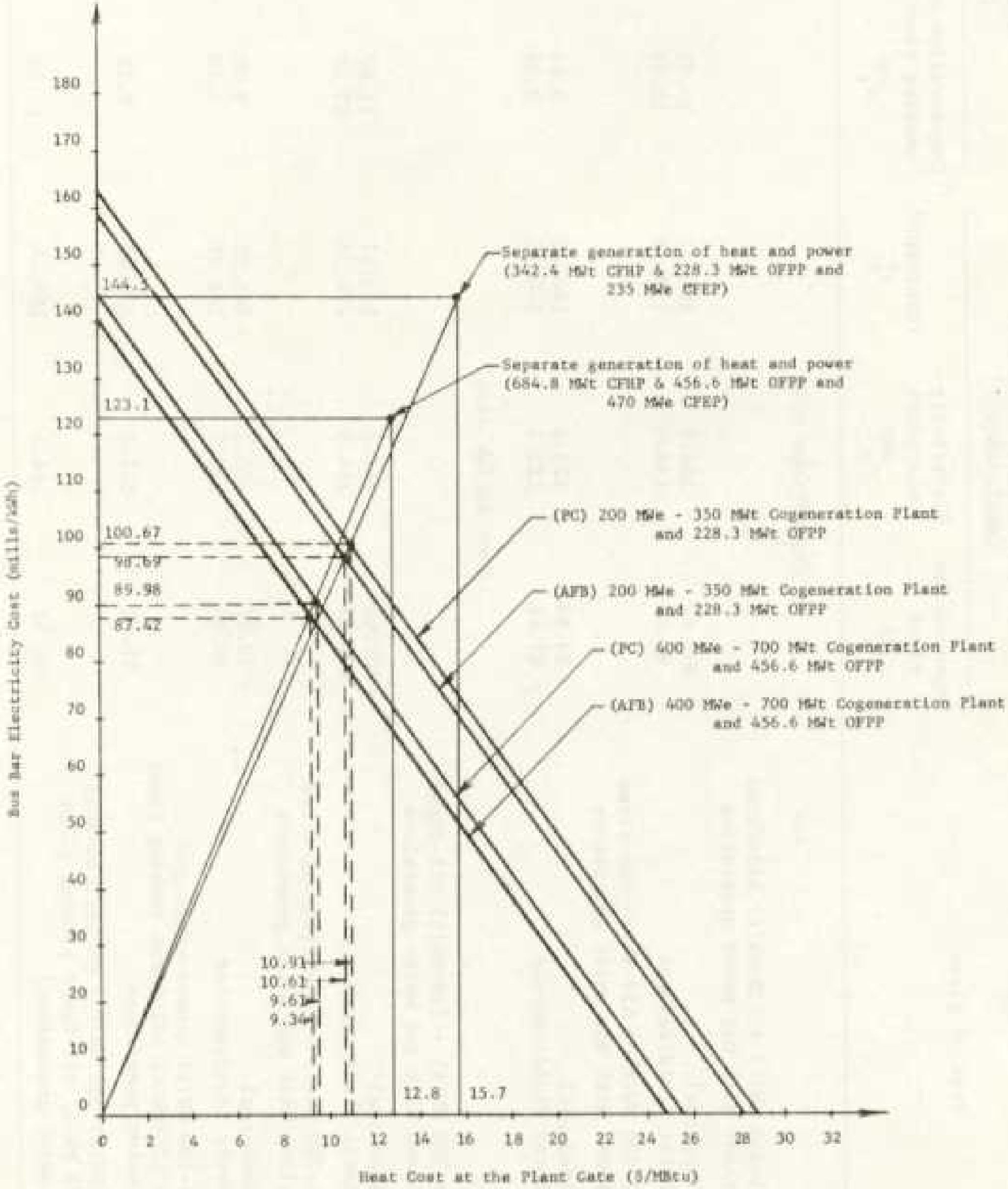

Fig. 9.1. Determination of bus bar electricity and plant gate heat unit costs for cogeneration/district heating units located at High Bridge.

Figure 9.1 enables a comparison of the bus bar electricity costs and the plant gate heat costs for the cogeneration units located at High Bridge. Figure 9.2 shows the comparison of the same unit costs for the cogeneration plants located at Coon Rapids.

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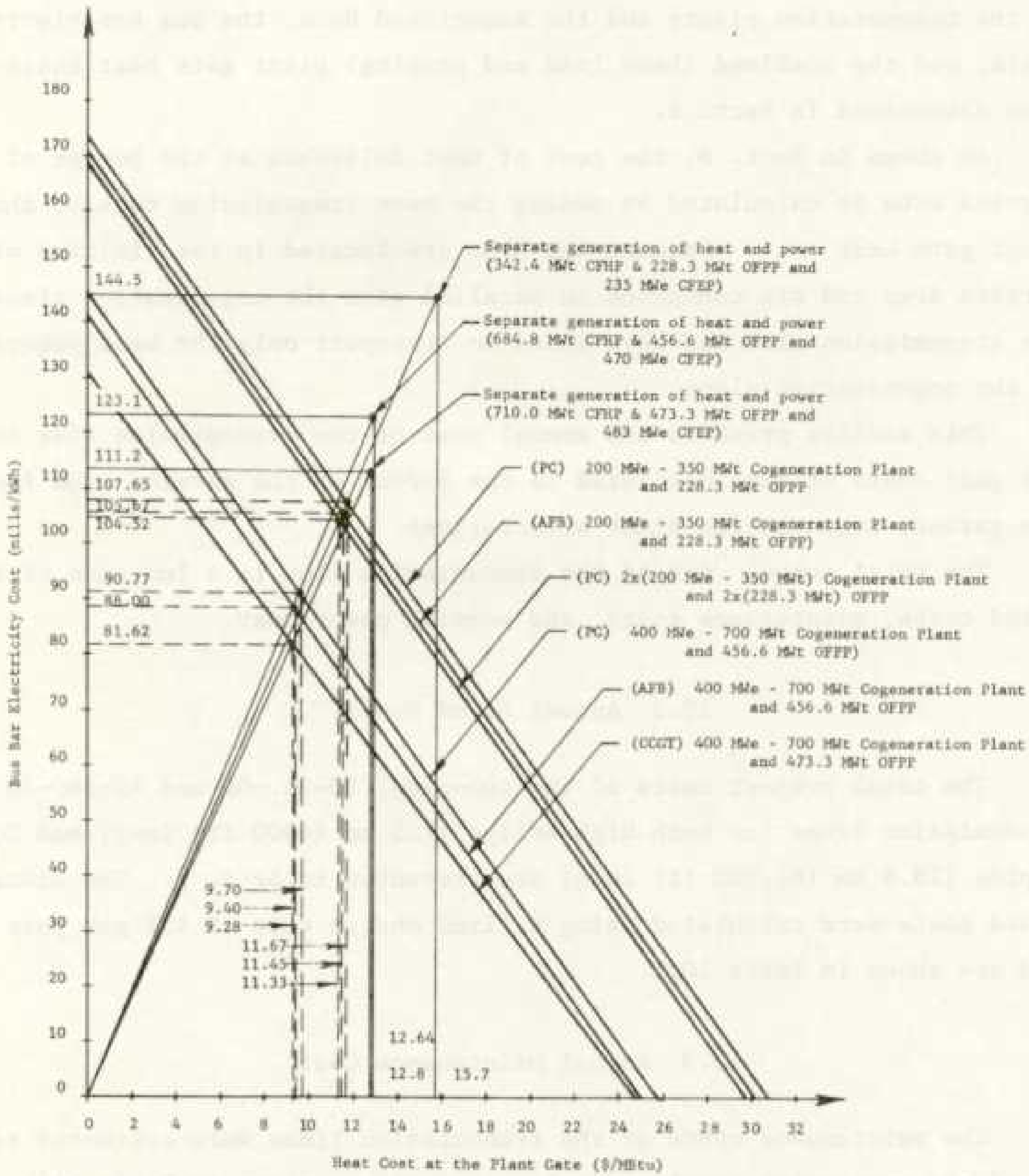

Fig. 9.2. Determination of bus bar electricity and plant gate heat unit costs for cogeneration/district heating units located at Coon Rapids.

10. UNIT COST OF HEAT DELIVERED AT BORDER OF SERVICE AREA

10.1 Introduction

The assessment of the various cogeneration plants has been limited to the annual costs of the cogeneration plants, the HWGs for peaking heat load, and the transmission lines. The costs associated with the operation of the cogeneration plants and the associated HWGs, the bus bar electricity costs, and the combined (base load and peaking) plant gate heat costs have been determined in Sect. 8.

As shown in Sect. 6, the cost of heat delivered at the border of the service area is calculated by adding the heat transmission cost to the plant gate heat cost. Because the HWGs are located in the vicinity of the service area and are connected in parallel with the cogeneration plant, the transmission line has been sized to transport only the heat generated in the cogeneration plant.

This section presents the annual cost of the transmission line and the unit costs of heat delivered to the border of the service area from the various cogeneration plant alternatives.

The total annual cost of the transmission line is a function of the fixed costs, maintenance costs, and pumping power cost.

10.2 Annual Fixed Costs

The total project costs of the two-pipe, 30-in.-OD and 42-in.-ID transmission lines for both High Bridge [1.5 km (4900 ft) long] and Coon Rapids [18.6 km (61,000 ft) long] are presented in Sect. 7. The annual fixed costs were calculated using a fixed charge rate of 15% per year and are shown in Table 10.1.

10.3 Annual Maintenance Cost

The maintenance costs of the transmission lines were estimated as 1% of the respective total capital costs and are shown in Table 10.1. This estimate is based on the Swedish experience on operating hot water transmission lines as indicated in ref. 6.

Table 10.1. Summary of heat transmission costs

Cost item	High Bridge plant		Coon Rapids plant		
			30-in. line	42-in. line	
	30-in. line	42-in. line		Steam turbine	Closed-cycle gas turbine
Rated capacity, MW(t)	342.4	684.8	342.4	684.8	710.0
Length to border of service area, km (ft)	1.5 (4,900)	1.5 (4,900)	18.6 (61,000)	18.6 (61,000)	18.6 (61,000)
Number of pipes	2[a]	2[a]	2[a]	2[a]	2[a]
Internal diameter, in.	28.75	42	28.75	42	42
Maximum temperature at heat source, °F					
Supply	270	270	270	270	270
Return	150	150	150	150	150
Total capital cost,[b] millions of May 1989 dollars	6.3	8.4	135.0	188.0	188.0
Total annual cost, millions of May 1989 dollars per year	1.84	2.50	23.41	32.21	32.46
Fixed	0.95	1.26	20.25	28.20	28.20
Maintenance	0.63	0.84	1.35	1.88	1.88
Pumping power	0.26	0.40	1.81	2.13	2.38
Annual heat energy transported					
MW(t)h/year	1,372,448	2,744,896	1,372,448	2,744,896	2,845,913
10^6 Btu per year	4,684,165	9,368,330	4,684,165	9,368,330	9,713,100
Transportation cost					
¢/kW(t)h	0.134	0.091	1.706	1.174	1.141
\$ per 10^6 Btu	0.393	0.267	4.998	3.438	3.342

[a] One supply, one return.

[b] The total capital cost shown does not include the cost of 2500 ft of transmission line within the plant boundary; onsite transmission line cost was included in the cost of each plant.

10.4 Annual Pumping Power Cost

The annual pumping power cost was calculated on the basis of the annual pumping power consumption and the electricity cost at a commercial rate.

The annual pumping power consumption was determined as a function of the pressure drop in the plant heat exchangers and along the transmission lines (both supply and return) and the utilization time of the design flow rate.

10.4.1 Pressure gradient in the district heating system

The DH system flow diagram is shown in Fig. 10.1. Figure 10.2 shows the pressure gradient in the DH system for the case of 30-in. transmission

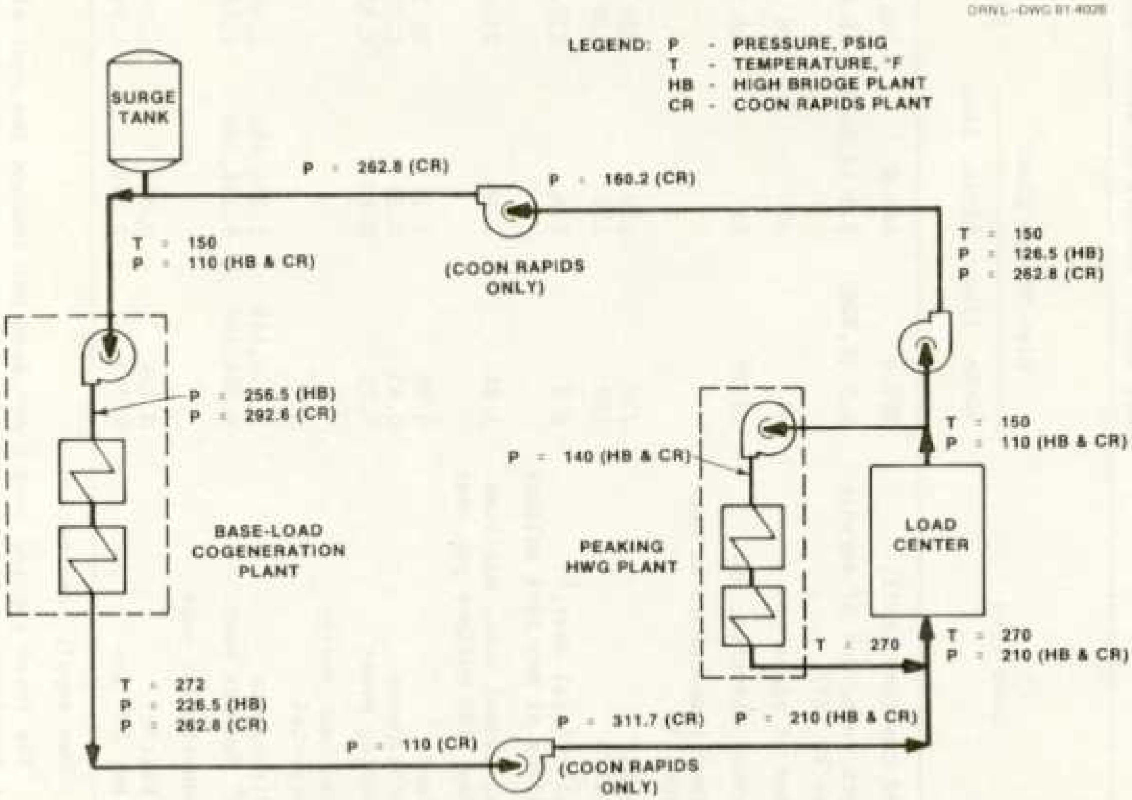

Fig. 10.1. District heating system flow diagram for the 200-MW(e)-350-MW(t) plant located at High Bridge or Coon Rapids and the 228.3-MW(t) hot water generator plant located near the load center.

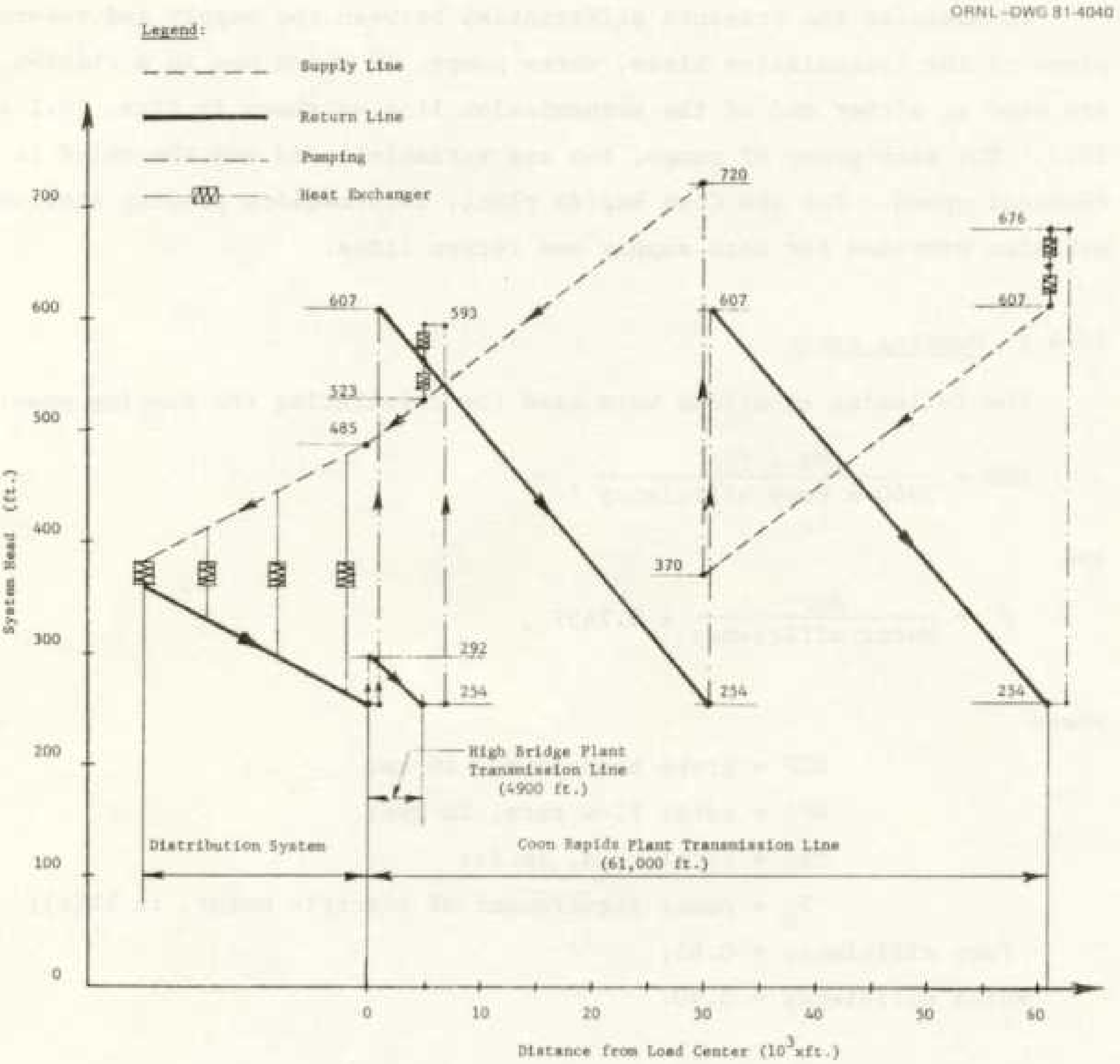

Fig. 10.2. District heating system pressure gradient for the 200-MW(e)–350-MW(t) plant located at High Bridge or Coon Rapids.

line for the High Bridge and Coon Rapids plants. Because the hot water system operates at a temperature close to or above 212°F, it must be pressurized to prevent the water in the system from flashing into steam. The system is maintained at an elevated pressure so that the lowest pressure point in the system has a pressure above the vapor pressure of the water. System pressurization is usually accomplished in a pressurized expansion tank utilizing a gaseous medium such as air, nitrogen, or steam.

To minimize the pressure differential between the supply and return pipes of the transmission lines, three pumps, of which one is a standby, are used at either end of the transmission line as shown in Figs. 10.1 and 10.2. For each group of pumps, two are variable speed and the third is constant speed. For the Coon Rapids plant, intermediate pumping stations are also provided for both supply and return lines.

10.4.2 Pumping power

The following equations were used for calculating the pumping power:

$$BHP = \frac{WFR \times THD}{3960 \times \text{Pump efficiency}} ,$$

and

$$P_M = \frac{BHP}{\text{Motor efficiency}} \times 0.7457 ,$$

where

BHP = brake horsepower, in hp;
WFR = water flow rate, in gpm;
THD = total head, in ft;
P_M = power requirement of electric motor, in kW(e);
Pump efficiency = 0.85;
Motor efficiency = 0.90.

30-in.-OD transmission lines. The maximum water flow rate was calculated to be 20,145 gpm for the 30-in.-OD (28.75-in.-ID) lines at 10 fps water velocity [342.4 MW(t)]. The head loss at this velocity was calculated to be 0.7804 ft per 100 ft resulting in a total (supply and return) head loss of 76 and 952 ft for High Bridge and Coon Rapids, respectively.

Assuming a 15-psig pressure drop for each of the two district heating heat exchangers of the cogeneration plant, the total head loss for the 30-in.-OD line to and from the distribution system amounts to 146 and 1022 ft for the High Bridge and Coon Rapids plants, respectively.

The maximum power requirements for the 30-in.-OD transmission lines are 724 and 5068 kW(e) for the High Bridge and Coon Rapids plants, respectively.

42-in.-ID transmission lines (steam turbines). The maximum water flow rate was calculated to be 40,177 gpm for the 42-in.-ID transmission lines at 9.3 fps water velocity [684.8 MW(t)]. The head loss at this velocity was calculated to be 0.438 ft per 100 ft resulting in a total (supply and return) head loss of 43 and 535 ft for High Bridge and Coon Rapids, respectively.

Assuming a 15-psig pressure drop for each of the two district heating heat exchangers of the cogeneration plant, the total head loss for the 42-in.-ID line to and from the distribution system amounts to 113 and 605 ft for the High Bridge and Coon Rapids plants, respectively.

The maximum power requirements for the 42-in.-ID transmission lines are 1118 and 5984 kW(e) for the High Bridge and Coon Rapids plants, respectively.

42-in.-ID transmission lines (CCGT). The maximum water flow rate was calculated to be 41,820 gpm for the 42-in.-ID transmission lines at 9.7 fps water velocity [710 MW(t)]. The head loss at this velocity was calculated to be 0.474 ft per 100 ft resulting in a total (supply and return) head loss of 579 ft only.

Assuming a 15-psig pressure drop for each of the two district heating heat exchangers of the cogeneration plant, the total head loss for the 42-in.-ID line to and from the distribution system amounts to 649 ft for the Coon Rapids plant.

The maximum power requirement for the 42-in.-ID transmission line is 6681 kW(e) for the CCGT at the Coon Rapids plant.

10.4.3 Utilization time of maximum water flow rates

The water flow rate vs duration curve is shown in Fig. 10.3. This curve was determined by combining the water flow rate vs outside air temperature curve (Figs. 3.5 and 10.4) and the outside air temperature vs duration curve (Fig. 3.2) in a fashion similar to the procedure shown in Fig. 3.2.

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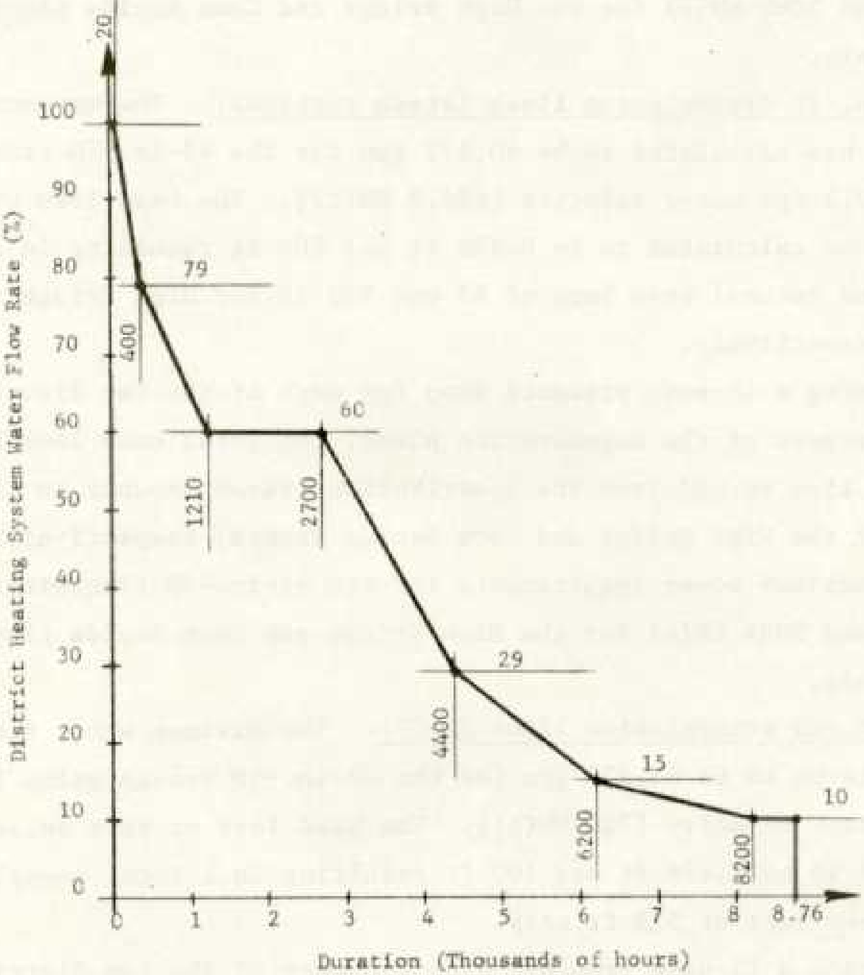

Fig. 10.3. District heating system water flow rate duration curve.

As described in Sect. 3, the cogeneration plant is connected in parallel with the HWGs. Thus, the water flow coming from the cogeneration plant through the transmission line is combined with the water flow from the peaking HWGs (when in service) to make up the total water flow supplied to the distribution system (Fig. 3.4).

The utilization times of the maximum water flow rates (Fig. 10.5) are as follows:

- DH system (distribution system) — 3253 h/year,
- transmission line (cogeneration plant) — 5089 h/year, and
- HWGs — 500 h/year.

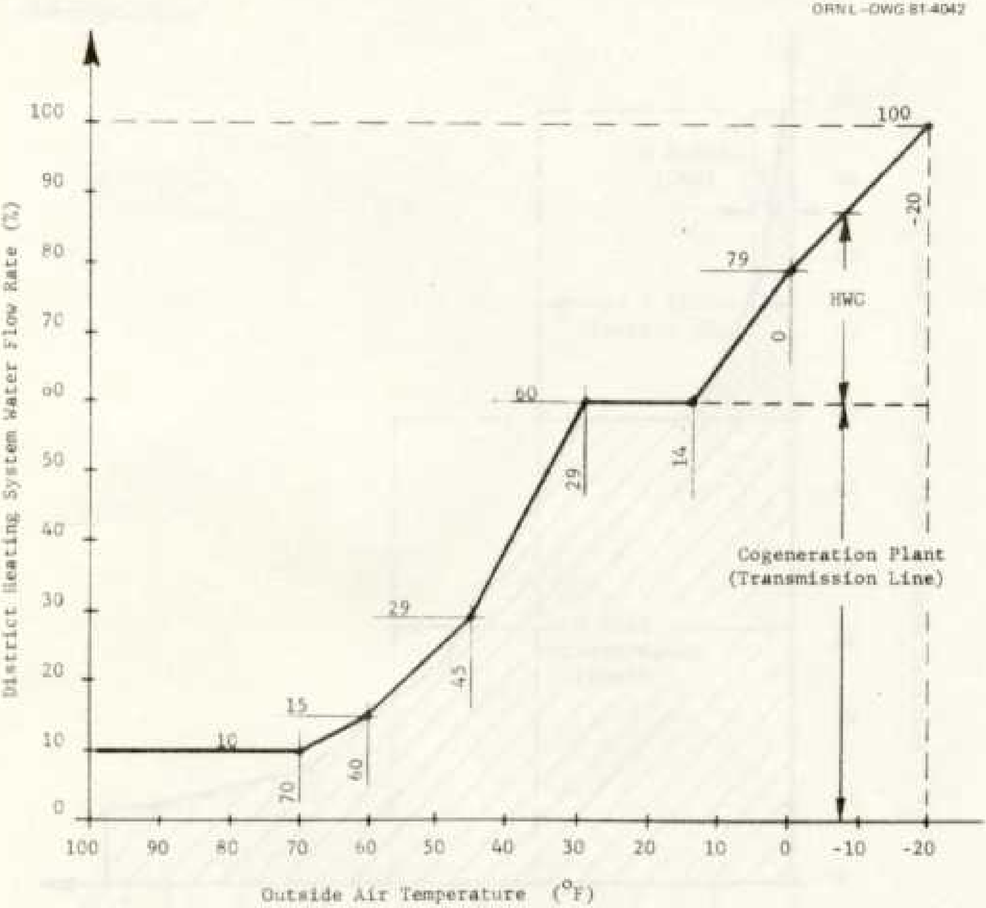

Fig. 10.4. District heating system water flow rate as a function of the outside air temperature.

These utilization times were determined as the ratios between the total integrated water flows during the annual cycle and the respective maximum water flow rates and apply to all plants considered.

10.4.4 Annual pumping power consumption for heat transmission

Using the pumping power determined for the rated water flow rates and the utilization time of 5089 h/year, the annual pumping power consumptions for heat transmission (including in-plant losses) are:

- High Bridge plant:

  30-in.-OD lines: 3,684,436 kW(e)h/year.

  42-in.-ID lines: 5,689,502 kW(e)h/year.

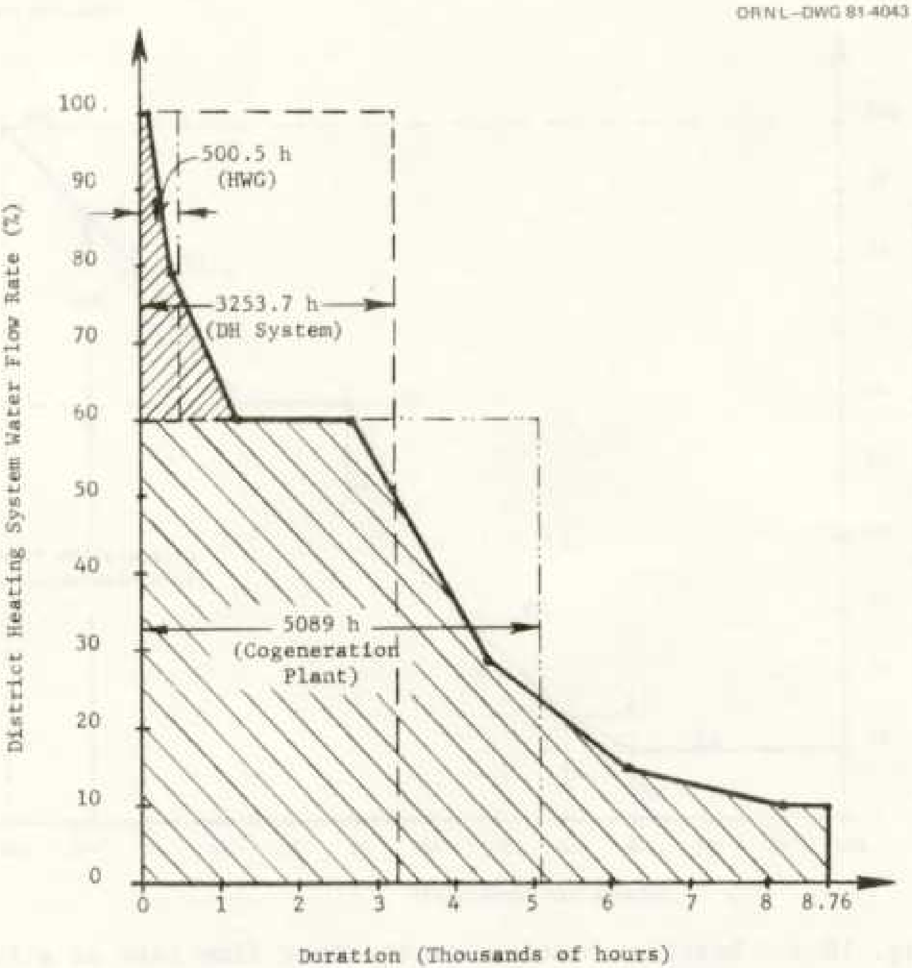

Fig. 10.5. Utilization times of the water flow rates (district heating system, cogeneration plant/transmission line, and peaking hot water generators).

- Coon Rapids plant:

    30-in.-OD lines: 25,791,052 kW(e)h/year.

    42-in.-ID lines:

        Steam turbines: 30,452,576 kW(e)h/year.

        CCGT: 33,999,600 kW(e)h/year.

The annual pumping power costs were determined based on an assumed system-wide electricity cost (commercial rate) of 70 mills/kW(e)h.

The costs are as follows:

- High Bridge plant:
  - 30-in.-OD lines: $257,911/year.
  - 42-in.-ID lines: $398,265/year.
- Coon Rapids plant:
  - 30-in.-OD lines: $1,805,374/year.
  - 42-in.-ID lines:
    - Steam turbines: $2,131,680/year.
    - CCGT: $2,380,000/year.

10.5 Total Annual Cost of Transmission Line

The annual heat transmission cost is obtained as the sum of the fixed cost, maintenance cost, and pumping power cost as shown in Table 10.1.

10.6 Annual Amount of Heat Transmitted

The amount of heat delivered at the end of the transmission line differs from the amount of heat produced by the cogeneration plant for two reasons: first, because of the transmission line heat losses, and second, because of the heat gains due to the pumping power expended to overcome the head loss along the transmission lines. Depending upon the thermal insulation design, the heat gains due to the pumping power contribute more or less substantially to minimizing the overall heat transmission losses.

This subsection presents the results of preliminary estimates of the magnitudes of the heat losses and heat gains which determine the amount of heat transmitted annually through the transmission lines.

10.6.1 Transmission line heat losses

Fiberglass insulation 3 in. and 2 in. thick for the supply and return lines, respectively, was assumed. For the design water temperature of 270°F (supply) and 150°F (return) and 40°F temperature of the outside surface of the insulation (underground piping), the calculated heat losses of the 30-in.-OD lines are 174.2 Btu/h per ft for the supply line and 121.3 Btu/h per ft for the return line.

Thus, the total transmission heat losses to and from the border of the distribution system for the 30-in.-OD lines at design conditions are:

- High Bridge plant: 1,447,112 Btu/h [424 kW(t)].
- Coon Rapids plant: 18,024,053 Btu/h [5281 kW(t)].

Because the 30-in.-OD transmission lines are used in conjunction with cogeneration units with a maximum heat output of 342.4 MW(t), these transmission heat losses amount to 0.12% and 1.54% for the High Bridge and Coon Rapids plants, respectively.

10.6.2 Transmission line heat gains

Figure 10.1 shows the assumed pressure gradient curves of the entire DH system. A 100-psig pressure drop across the distribution system was chosen arbitrarily for the purpose of this estimate. To calculate the heat delivered to the distribution system at the end of the transmission line, the heat gain due to the entire pumping power consumed must be considered because all the pumps are located outside the distribution system. Thus, in addition to the brake horsepower to overcome the head loss in the cogeneration plant heat exchangers and in the transmission line, the brake horsepower due to the head loss across the distribution system must be included in the heat gain calculation.

For the 30-in.-OD lines, the total heat gains are 1683 and 5588 kW(t) for the High Bridge and Coon Rapids plants, respectively.

10.6.3 Comparison of transmission line heat losses and heat gains

The heat losses and the heat gains previously estimated for the 30-in.-OD transmission lines associated with the 200-MW(e)–350-MW(t) cogeneration units are, therefore:

- High Bridge: heat gain [1683 kW(t)] > heat loss [424 kW(t)].
- Coon Rapids: heat gain [5588 kW(t)] > heat loss [5281 kW(t)].

The results of these comparisons suggest that the amount of heat delivered to the distribution system is actually greater than that produced by the heat sources, because the heat gains resulting from compression work more than offset the transmission line heat losses.

Nevertheless, for the purpose of this economic comparison of cogeneration units and potential sites for their locations, it was assumed that the heat losses in the transmission line are balanced by the compression work resulting from pumping power. No credit was given for the apparent increase in net heat available because of the approximate nature of the estimate.

Because of the conclusion reached with respect to the results of the heat losses and heat gains estimated for the 30-in.-OD lines, the heat losses and the heat gains of the 42-in.-ID lines have not been calculated, although it is recognized that the balance of these latter quantities is slightly different. Instead, the assumption that the transmission heat losses are offset by the heat gains due to pumping power was also made for the 42-in.-ID lines.

For the purpose of determining the unit heat transmission cost (procedure shown in Sect. 6), therefore, the amount of heat delivered to the distribution system is assumed to be equal to the amount of heat generated by the heat sources (cogeneration plus peaking HWGs).

10.7 Unit Cost of Transmitted Heat

The heat transportation costs are calculated in both ¢/kW(t)h and dollars per 10^6 Btu as shown in Table 10.1. Finally, the unit costs of heat delivered to the distribution system are calculated by adding the heat transportation costs to the respective plant gate heat costs as shown in Table 10.2.

Table 10.2. Unit cost for heat delivered to load center

Type of plant	Heat cost (May 1989 dollars per 10^6 Btu)		
	At plant gate	Transmission[a]	At border of service area
High Bridge site			
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	10.91	0.39	11.30
Atmospheric fluidized-bed	10.69	0.39	11.08
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	9.61	0.27	9.88
Atmospheric fluidized-bed	9.34	0.27	9.61
Coon Rapids site			
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	11.67	5.00	16.67
Atmospheric fluidized-bed	11.45	5.00	16.45
400 MW(e)-350 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators			
Pulverized-coal	9.70	3.44	13.14
Atmospheric fluidized-bed	9.40	3.44	12.84
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	9.28	3.34	12.62
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228-MW(t) oil-fired peaking plant with hot water generators]	11.33	3.44	14.77

[a]The heat transmission cost is added directly to the plant gate heat cost because the amount of heat delivered was assumed to equal the amount of heat generated.

11. ELECTRICITY GENERATING COST OF AN 800-MW(e) COAL-FIRED CONDENSING UNIT

The bus bar electricity costs determined in Sect. 8 for the new coal-fired, cogeneration units of 200 MW(e)-350 MW(t) and 400 MW(e)-700 MW(t) enable a comparison among these units when located either at High Bridge or Coon Rapids locations. However, a decision as to which unit or combination of units should be selected for possible inclusion in plans for future expansion of the NSP system cannot be made without examining the merits of such cogeneration units against those of large steam-condensing units.

To enable such a comparison, this section presents the total generating costs for an 800-MW(e) coal-fired condensing unit located at a rural Minnesota site. The bus bar electricity cost is calculated assuming two capacity factors (CF): 70%, which is usually the norm for a base-load unit, and 43.4%, which matches the CF assumed in Sect. 8 for the steam cogeneration units.

11.1 Capital Cost

The capital costs are summarized in Table 7.3.

11.2 Annual Costs

The annual operating costs of the 800-MW(e) condensing unit have been calculated in May 1989 dollars by the procedure used in Sect. 8 for the electricity-only plants.

11.2.1 Annual fixed cost

Based on the total project cost of $1,202.5 million and a fixed charge rate of 15% per year, the annual fixed cost is calculated to be $180.38 million per year.

11.2.2 Annual O&M costs

The O&M costs consist of fixed and variable O&M expenses:

- Fixed O&M costs: $6,878,554/year at $8.6/kW(e).
- Variable O&M costs: $7,627,422/year at 43.4% CF and $12,302,293/year at 70.0% CF.
- Total O&M costs: $14,505,976/year at 43.4% CF and $19,180,847/year at 70.0% CF.

11.2.3 Annual fuel cost

The annual fuel cost is calculated as a function of the net electricity generation, net plant heat rate, and fuel cost.

- Net electricity generation: 3.0415×10^9 kWh/year at 43.4% CF and 4.9056×10^9 kWh/year at 70.0% CF.
- Net plant heat rate: 10,877 Btu/kWh at 43.4% CF and 10,002 Btu/kWh at 70.0% CF.
- Annual fuel consumption: 3.3082×10^{13} Btu/year at 43.4% CF and 4.9066×10^{13} Btu/year at 70.0% CF.
- Annual fuel costs (based on a coal price of $3.08 per 10^6 Btu): $101,892,560/year at 43.4% CF and $151,123,280/year at 70.0% CF.

The total annual operating costs of the 800-MW(e) coal-fired condensing unit for the two capacity factors assumed are, therefore:

$296,773,536/year at 43.4% CF and
$350,679,127/year at 70.0% CF.

11.3 Total Generating Cost

The total generating (bus bar) electricity cost is obtained as the ratio between the total annual operating cost and the net electricity generation. The total generating cost for the two capacity factors considered are:

97.6 mills/kWh at 43.4% CF and
71.5 mills/kWh at 70.0% CF.

12. ELECTRICITY GENERATING COST COMPARISON BETWEEN COGENERATION UNITS AND ELECTRICITY-ONLY UNITS

The bus bar electricity costs for the cogeneration units and 235-, 470-, 473-, and 800-MW(e) condensing units are listed in Table 12.1. All the costs shown are in May 1, 1989 dollars.

The electricity generating costs for the 800-MW(e) condensing unit are given for two assumed capacity factors: 43.4%, which matches the capacity factor for the cogeneration plants, and 70%, which is characteristic of a base-load condensing unit.

The generating cost of the electricity-only plants equivalent in size and output to the cogeneration plants is also shown in Table 12.1. These electricity-only plants were used in the process of allocating the cogeneration costs.

In addition to the total generating costs, Table 12.1 shows how the cogeneration-based electricity costs compare as a percentage of their separate generation counterparts.

The cogeneration costs are favorable when compared with the costs of electricity-only plants of equivalent size and output. However, the generating costs of the large condensing unit are less than those of the cogeneration plants. The main reasons for the difference are due to the economy of scale and better capacity utilization (70% vs 43.4% for steam turbines or vs 46.7% for CCGT).

Table 12.1. Comparison of bus bar costs of electricity produced by cogeneration plants vs those of electricity-only plants

Type of plant	Bus bar electricity cost [mills/kW(e)h]				Cogeneration-based electricity cost (% of electricity-only cost)		
	Cogeneration plant[a]	Electricity-only plant			Comparatively sized plant	800 MW(e)	
		Comparatively sized plant[a]	800 MW(e)			43.4% capacity factor	70% capacity factor
			43.4% capacity factor	70% capacity factor			
High Bridge site							
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators							
Pulverized-coal	100.67	144.5	97.6	71.5	69.7	103.1	140.8
Atmospheric fluidized-bed	98.69	144.5	97.6	71.5	68.3	101.1	138.0
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators							
Pulverized-coal	89.98	123.1	97.6	71.5	73.1	92.2	125.8
Atmospheric fluidized-bed	87.42	123.1	97.6	71.5	71.0	89.6	122.3
Coon Rapids site							
200 MW(e)-350 MW(t) + 228-MW(t) oil-fired peaking plant with hot water generators							
Pulverized-coal	107.65	144.5	97.6	71.5	74.5	110.3	150.6
Atmospheric fluidized-bed	105.67	144.5	97.6	71.5	73.1	108.3	147.8
400 MW(e)-700 MW(t) + 457-MW(t) oil-fired peaking plant with hot water generators							
Pulverized-coal	90.77	123.1	97.6	71.5	73.7	93.0	127.0
Atmospheric fluidized-bed	88.00	123.1	97.6	71.5	71.5	90.2	123.1
400-MW(e)-700-MW(t) closed-cycle gas turbine + 473-MW(t) oil-fired peaking plant with hot water generators	81.62[b]	111.20[b]	97.6	71.5	73.4	83.6	114.2
2 × [200 MW(e)-350 MW(t), pulverized-coal] + 2 × [228-MW(t) oil-fired peaking plant with hot water generators]	104.52	144.5	97.6	71.5	72.3	107.1	146.2

[a]Electrical capacity factor = 43.4% except closed-cycle gas turbine plant.

[b]Electrical capacity factor = 46.7%.

13. OBSERVATIONS AND CONCLUSIONS

13.1 Observations

Based on these tabular comparisons, the following observations can be made:

1. The total project costs of the cogeneration plants at High Bridge and Coon Rapids vary between \$525 million and \$611 million for the 200-MW(e)-350-MW(t) units and between \$874 million and \$938 million for the 400-MW(e)-700-MW(t) units. The highest total project cost (\$1162 million) corresponds to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids. For comparison, the total project costs of coal-fired, electricity-only PC plants of 235, 470, and 800 MW(e) are \$591 million, \$906 million, and \$1202.5 million, respectively.

2. The comparison among the cogeneration units with respect to the total project cost shows the following:

   - The 200-MW(e)-350-MW(t) PC and AFB units at High Bridge cost \$67 million less than the same units at Coon Rapids, whereas the 400-MW(e)-700-MW(e) units at High Bridge cost only slightly less than the same units at Coon Rapids. The \$67 million cost differential exists because the smaller units are designed to use some of the existing facilities at High Bridge.

   - The units equipped with an AFB boiler (near-horizon technology) result in consistently lower total project costs; however, these results are based on cost estimates that do not include a contingency for cost uncertainties with this technology.

3. The comparison between PC cogeneration units and PC electricity-only units of equivalent size with respect to the total project cost shows the following:

   - Because the 200-MW(e)-350-MW(t) unit at High Bridge utilizes existing facilities, it costs approximately 8% less than the 235-MW(e) unit at a reference site.

- The 200-MW(e)-350-MW(t) unit at Coon Rapids costs approximately 3% more than the 235-MW(e) unit.
- The 400-MW(e)-700-MW(t) unit at High Bridge costs approximately 2% more than the 470-MW(e) unit.
- The 400-MW(e)-700-MW(t) unit at Coon Rapids costs approximately 4% more than the 470-MW(e) unit.

4. The total project costs of the heat transmission lines from plant site to the respective load centers are $6.3 million (30-in. line) and $8.4 million (42-in. line) for the High Bridge site and $135 million (30-in. line) and $188 million (42-in. line) for the Coon Rapids site.
5. The cogeneration-based bus bar electricity costs are 24-32% less than those of electricity-only plants of equivalent size and capacity factor.*
6. The cogeneration-based plant gate heat costs are 24-32% less than those of heat-only plants of equivalent size and capacity factor.*
7. The cogeneration-based bus bar electricity costs are 14-50% greater than the cost of electricity from an 800-MW(e) electricity-only condensing unit operating at 70% capacity factor; however, at 43.4% capacity factor, the 800-MW(e) electricity-only unit costs are comparable with those of the cogeneration plants.
8. The comparison among the cogeneration units with respect to the bus bar electricity cost shows the following:
   - A unit cost spread of 23 mills/kWh, the lowest cost (82 mills/kWh) corresponding to the 400-MW(e)-700-MW(t) CCGT at Coon Rapids and the highest cost (105 mills/kWh) to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids.

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*The percent savings for electricity and heat due to cogeneration (items 5 and 6, respectively) are identical because the cost allocation was made using the equal discount method.

- The cost reductions due to the economy of scale obtained by doubling the size of the cogeneration units (and maintaining the same capacity factors) are approximately 11% at High Bridge and 16% at Coon Rapids.

9. The comparison among the cogeneration units with respect to the cost of heat delivered to the respective load centers shows the following:

   - A unit cost spread of \$5.2 per 10^6 Btu, the lowest cost (\$9.6 per 10^6 Btu) corresponding to the 400-MW(e)-700-MW(t) AFB at High Bridge and the highest cost (\$15 per 10^6 Btu) to the two 200-MW(e)-350-MW(t) PC units at Coon Rapids.

   - The cost reductions due to the economy of scale obtained by doubling the size of the cogeneration units (and maintaining the same capacity factor) are approximately 13% at High Bridge and 21% at Coon Rapids.

10. The heat transmission costs represent approximately 2.8 to 4.5% and 26 to 30% of the cost of heat delivered to the distribution system from the High Bridge and Coon Rapids plants, respectively.

13.2 Conclusions

1. These results indicate that the cogeneration plant operating at its assigned capacity factor will provide heat and electricity at the plant boundary at costs significantly less than (approximately 70% of) the respective costs of comparably size heat-only or electricity-only plants. This benefit results from better fuel utilization, common use of facilities, and the sale of two products — heat energy and electricity.

2. Heat transmission line costs have a significant impact on the cost of delivered heat. The cost of heat delivered to the load center from Coon Rapids is 30 to 50% greater than the cost of heat delivered from High Bridge primarily due to differences in transmission line length.

3. Cogeneration/district heating plants equipped with condensing-tail turbines and full-sized heat rejection systems cost approximately 3% more than comparably sized electricity-only plants.

4. The reduction due to economy of scale [two 200-MW(e) plant vs one 400-MW(e) plant] in the unit cost of heat or electricity is approximately 15%.

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AN ASSESSMENT OF NEW COAL-FUELED, COGENERATION POWER PLANTS FOR ELECTRICITY PRODUCTION AND HOT WATER DISTRICT HEATING

APPENDIXES

Appendix A (Labeled volume II on microfiche): 200-MW(e)-350-MW(t) Cogeneration Plants, Conceptual Designs and Capital Cost Estimates

Appendix B (Labeled volume III on microfiche): 400-MW(e)-350-MW(t) Cogeneration Plants, Conceptual Designs and Capital Cost Estimates

Microfiche enclosed