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DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES THROUGH POWER PLANT RETROFIT DISTRIBUTION NETWORK. PHASE 2

Volume 3

Final Report for the Period March 1, 1980–January 31, 1984

January 31, 1984

Work Performed Under Contract No. AC02-78CS20071

Public Service Electric & Gas Company
Newark, New Jersey

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PHASE 2

FINAL REPORT

FOR THE PERIOD

1 MARCH 1980 - 31 JANUARY 1984

VOLUME III

REPORT DATE: 31 JANUARY 1984

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DE-AC022-78CS20071

PUBLIC SERVICE ELECTRIC & GAS COMPANY
80 PARK PLAZA
NEWARK, NEW JERSEY 07101

FOREWORD

This is the Final Report of Phase 2 of "District Heating and Cooling Systems for communities through Power Plant Retrofit Distribution Network." It is composed of an Executive Summary and seven volumes:

Executive Summary

Volume I: Detailed Summary

Volume II: Introduction, Load & Service Area Assessment, Institutional Questions, Rates, Financial Considerations

Volume III: Technical Considerations

Volume IV: Cost Estimates, Staged Development Scenarios, Economic Evaluation, Impact on Fuel and the Environment, Alternates to Conventional Heating Systems, Conclusions, Recommendations

Volumes V-VII: Appendices A - C

ACKNOWLEDGEMENTS

The following key personnel contributed to the completion of this report:

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Stone & Webster Management Consultants, Inc.: G. S. Levitt, E. Schiaffino

Numerous contributions by other subcontractor and PSE&G personnel are gratefully acknowledged.

PREFACE

This volume contains the bulk of the technical information in the report, including staged development of district heating systems, central power station retrofit, intermediate and peaking/backup thermal plants, transmission and distribution, user connections, and alternatives to district heating. Discussion of heat pumps, cooling, waste heat recovery, small cogeneration and/or solid fuel-burning plants, solar alternatives to district heating and nuclear district heating are included, with authorship as follows:

- Staged Development: Transflux International, Ltd.
- Station Retrofit: Turbine retrofit feasibility studies by General Electric Company and Westinghouse Electric Corporation. Conceptual station retrofit design by Transflux and Stone & Webster Engineering Corporation (SWEC). Detailed design and cost estimates by SWEC.
- Intermediate Plants: Conceptual design and layout by Transflux. Cost estimate by SWEC.

- Peaking and Backup Plants: Conceptual design and layout by Transflux. Cost estimate by SWEC.

- Transmission and Distribution: Conceptual design and operating analysis by Transflux. Piping costs by SWEC and PSE&G Gas Transmission and Distribution Department (Mr. Ken Depew).

- User Connections: Transflux and SWEC.

- Alternatives to District Heating: Transflux, with the exception of:
  - Solar alternatives: PSE&G R&D Dept. (Mr. H. T. Roman)
  - Nuclear district heating: PSE&G R&D Dept. (Messrs. R. Krauss and J. A. Hynds)

- Landfill Gas Production: PSE&G R&D Dept. (Mr. G. W. Schirra)

- Systems Operations: Transflux

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SECTION 6

TECHNICAL CONSIDERATIONS

6. TECHNICAL CONSIDERATIONS

6.0 INTRODUCTION

The Phase 2 (Detailed Feasibility) District Heating Study began in 1980 and concentrated on the Hudson Generating Station because of its proximity to the concentrated Jersey City and Newark load areas and the new developments planned for the Hackensack Meadowlands. The coal-fired Hudson Unit No. 2 was used as the study basis of a large, regional district heating system for northeastern New Jersey.

To keep capital investment in step with revenues, the staged development of district heating on the European model was adopted. Local heating/cogeneration plants in dispersed areas showing high thermal-load concentrations would be built initially. They would be interconnected first with each other; later with a heating/cogeneration plant of larger magnitude, the 196 MWe Kearny No. 12 combustion turbine complex; and/or with the 600 MWe Hudson Unit No. 2.

The potential for district heating was examined in terms of the total system and two subsystems of overlapping scales:

A. The total system (3.7×10^9 BTU/hr peak) based on Hudson Unit No. 2, Kearny Unit No. 12 and local gas-fired heating and cogeneration plants built up in staged development on the European model.

B. A major district heating site (200 x 10^6 BTU/hr peak) based on a new development or an existing urban housing complex, using landfill gas, natural gas or limited steam extraction from Hudson Unit No. 2

C. A mini district heating site (on the order of 10 x 10^6 BTU/hr peak) based on "stand-alone" cogeneration facilities serving a small number of apartment buildings, and fueled by waste gas, natural gas, or wastes.

The following exhibits, as an introduction to the technical details presented in this section, summarize the highlights of the Phase 2 study.

From the perspective of energy efficiency and use of low cost fuel, the staged development of district heating offers the greatest advantages after all the interconnections with the main thermal source (e.g. power plant) are completed. To facilitate the transition from one stage to another, the development of dispersed district heating/cogeneration sites need to be coordinated. The specifications of the thermal sendout from each site are to fit into an overall plan so it can be eventually interconnected properly into a district heating grid. The investigations completed addressed this aspect, as well as the individual plant design problems in a detailed and conservative manner in line with standard utility practice.

Staged Development and Dispatch Concept

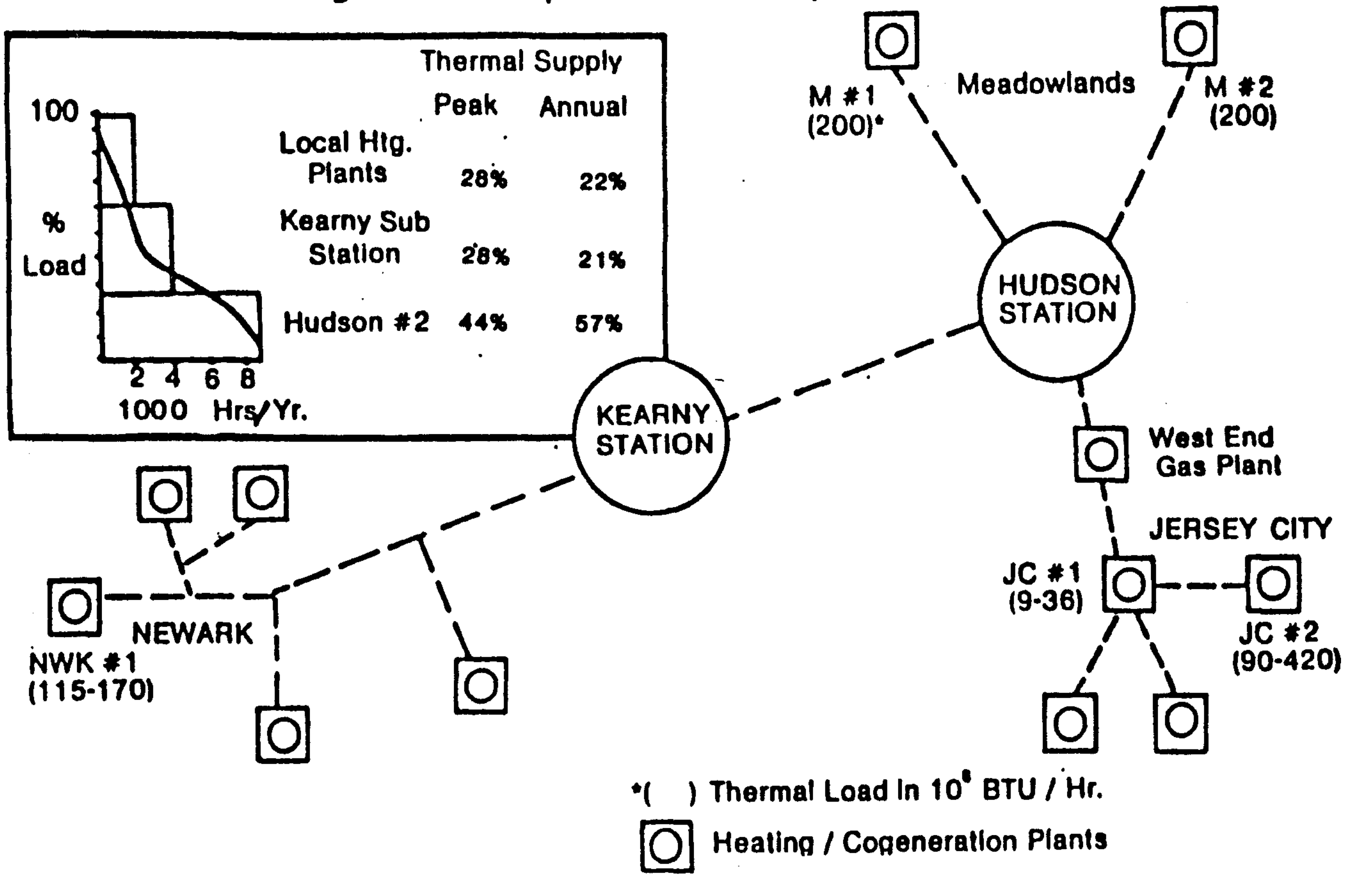


FIG. 1.2

DH SYSTEM TECHNICAL HIGHLIGHTS

SYSTEM AND SUBSYSTEMS	Thermal Capacity Btu/hr* (Peak)	Equivalent Heating Load # Typical Dwellings
A Total DH System	$3,700 \times 10^6$**	185,000
B Major DH Site	200×10^6	10,000
C Mini DH Site	10×10^6	500

THERMAL SOURCES

A - Hudson 2 Steam Unit - 600 MW_e (electric capacity without DH) Coal Fired
Peak DH Output - $1,600 \times 10^6$ Btu/hr (86 MW_e derating by DH use)

- Kearny 12 Gas Turbines (GT) - 196 MW_e Oil/Gas Fired
Peak DH Output - $1,100 \times 10^6$ Btu/hr

B - Package Boilers - 50×10^6 Btu/hr Unit Gas Fired
Peak DH Output - 200×10^6 Btu/hr with 25% back-up

C - Cogeneration Units -(1.2×10^6 Btu/hr + 316 KW_e) /Unit
Types - Diesel, IC Engine, Combustion Turbine
Peak DH Output - 1.2×10^6 Btu/hr/Unit base load
10×10^6 Btu/hr peak thermal load (Multi-Unit)

*3.4×10^6 Btu/hr = $1MW_{th}$
**Annual load: 8.8×10^{12} Btu

THERMAL EXTRACTION

A - Hudson 2 - Steam extraction at IP/LP Crossover (80 psia)*
- Hot Water Sendout: 223°F, Return: 165°F (Peak Load)

Kearny 12 - Heat recovery from exhaust gases
- Hot Water Sendout: 261°F

B - Package Boilers - Hot Water Sendout: 293°F

C - Cogeneration Units - Hot Water Sendout: 290°F (Nominal)

THERMAL CONVEYANCE

Transmission piping: 16" - 42" diameter; 118,600' length
Carbon Steel/Polyurethane/Polyethylene

Distribution piping: 1 1/2" - 12" diameter; 984,000' length
Carbon Steel (primary) and PVC (Secondary)/Foam glass or Polyurethane/Polyethylene

Hydraulic pressure in grid: 70 - 230 psig

DH Flow Rate: 58,700 gpm

*Expanded to 30 psia and 12 psia through turbines for 2-stage heating.

DH SYSTEM TECHNICAL HIGHLIGHTS - (Continued)

CUSTOMER'S SITE*

Hot Water: Space Heating and domestic uses
20,000 Btu/hr per typical dwelling
ΔT_{lm} (DH loop - User's loop) = 56°F

Cooling: 1.5 tons of refrigeration per typical dwelling
35 x 10^3 Btu/hr at 230 - 290°F for absorption cooling

Steam: 8.5 psig steam from 243°F DH water
Higher steam grades with on-site heat pump

*Typical Dwelling Assumptions

Heating: Outside T = 0°F, inside T = 70°F, 5200 Heating Degree Days

Cooling: Outside T = 77°F Wet Bulb, Inside T = 75°F, 1100 Cooling Degree Days
94°F Dry Bulb

Domestic Hot Water: 140°F year round

6.1 THE CONCEPT OF THE STAGED DEVELOPMENT OF DISTRICT HEATING

6.1.1 GENERAL ECONO-TECHNICAL REASONS FOR STAGED DEVELOPMENT

Staged development of district heating is aimed at

a. capturing available heat consumers at the earliest economically justified moment,

b. supplying heat by a method economically justifiable in continuity from its inception,

c. spending only on capital equipment immediately utilized,

d. a fit into the overall development plan of the larger system, including ease of present and future operations, and

e. creating conditions which allow each sub-system to operate individually and in conjunction with all the other systems under all foreseeable conditions including back-up service.

Figure 6.1.1 shows the general outlines of system development. It is a three-stage approach to the construction of a large, widespread district heating system.

Stage I is aimed at starting heat supply operations at the earliest possible time after the total concept has been drawn up and accepted. All potential customers of the future total system can be captured most economically from that point on in time. This step is particularly important in aiming at

new construction
and of
buildings where renewal
of old heating equipment
becomes necessary.

Savings in capital expenses on the part of the owners of those installations will make the district heating option particularly attractive.

Stage II is the first step towards cogenerative district heating. It is a gas turbine or diesel powered electric generation plant equipped with heat recovery equipment to supply hot water and/or steam for users. Non-construction development patterns, load acquisition and physical location of already completed Phase I

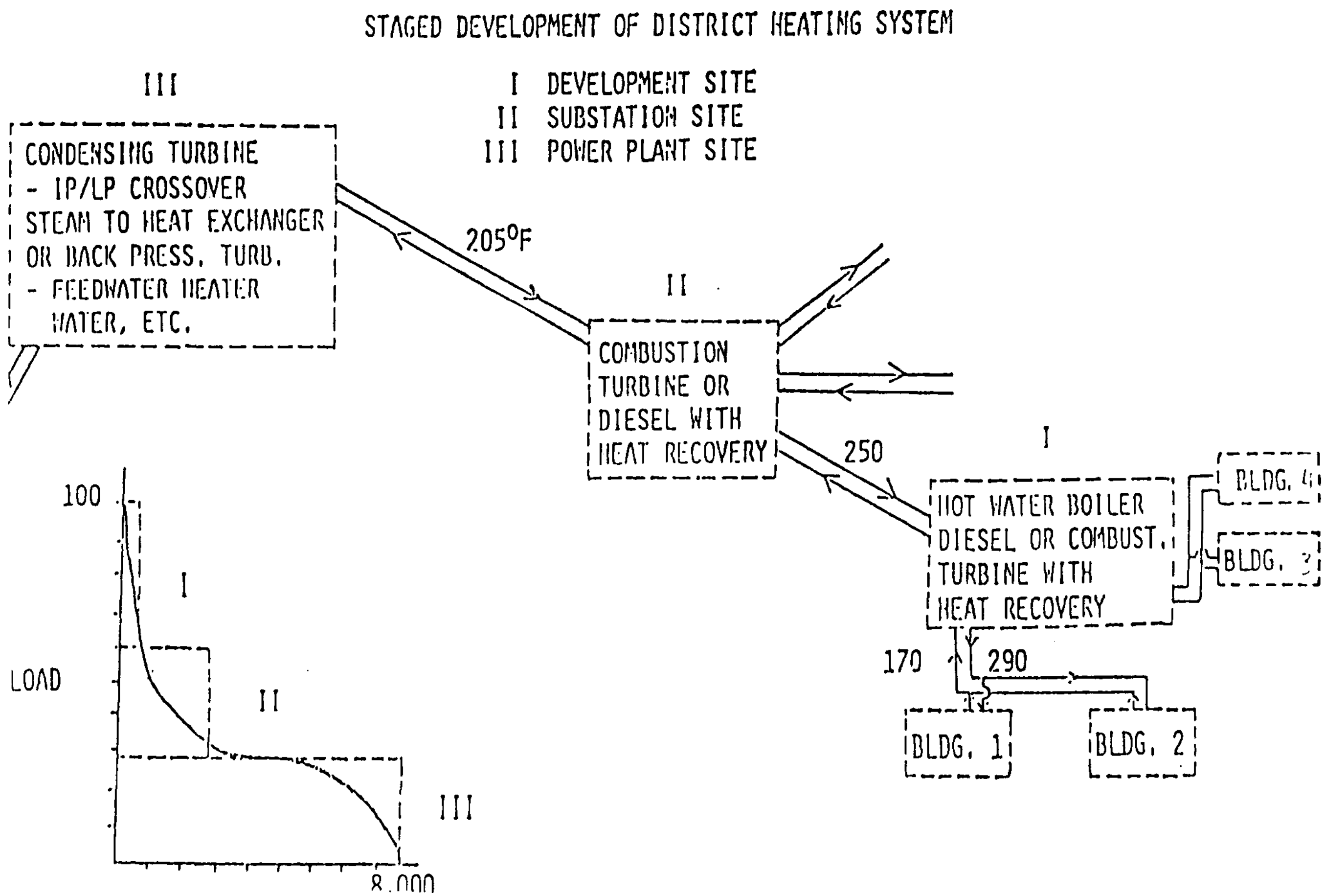

STAGED DEVELOPMENT OF DISTRICT HEATING SYSTEM
I DEVELOPMENT SITE
II SUBSTATION SITE
III POWER PLANT SITE
III
CONDENSING TURBINE
- IP/LP CROSSOVER
STEAM TO HEAT EXCHANGER
OR BACK PRESS. TURB.
- FEEDWATER HEATER
WATER, ETC.
205°F
II
COMBUSTION
TURBINE OR
DIESEL WITH
HEAT RECOVERY
250
I
HOT WATER BOILER
DIESEL OR COMBUST.
TURBINE WITH
HEAT RECOVERY
BLDG. 4
BLDG. 3
170
290
BLDG. 1
BLDG. 2
100
I
LOAD
II
III
8,000

FIG. 6.1.1

installations are the main considerations in the siting and in the timing of construction of these plants.

Stage III - The retrofit of an existing power plant and the construction of the transmission lines should be attempted as Phase III only after considerable base load has already been captured by the other stages. The only important points at the inception of the overall system are the determinations of the technical feasibility of the retrofit, its heat supply capability and its approximate cost. The first pinpoints the particular facility as the future hub of the total system. The heat supply capability of that plant limits the total system heat supply capability and the cost will determine how much load has to be accummulated during the previous phases before construction should proceed, so as to provide sufficient return on investment.

It is recommended that if PSE&G decides to enter the heat supply business, commitments towards DOE and financial commitments towards spending capital should both be geared to acquisition of signed supply contracts rather than to any time frame. Initial success in providing good, reliable service, coupled with a sales effort, could speed development beyond any expectations and so would rapidly increasing fuel costs to building owners. Adverse economic condition would on the other hand slow the process of expansion considerably. The Staged Development option is best suited to cope with either extremes.

6.1.2 SPECIFIC THREE STAGE DEVELOPMENT

The generalized three stage development approach was implemented in the selected supply area with the modifications dictated by the physical installations and conditions planned to be utilized. These factors brought about the following changes:

a) Some of the initial stage heater plants could utilize landfill gas available in their vicinity. This inexpensive fuel may extend the period of isolated operation of these plants since the cogenerative operation may not provide sufficient economic incentive to install the transmission lines and construct the plant retrofit.

b) The selected, Hudson G.S. No. 2 unit can be retrofitted in two stages. The first, partial retrofit stage provides 200000 lb/hr steam, at a relatively low investment. Because of this opportunity the partial retrofit will precede the gas-turbine retrofit.

c) It was found that one of the large existing gasturbine installations at the Kearny G.S. (Unit #12 - 196MW ISO capacity) can be interfaced with the D-H system at its present location less expensively than by relocating it or by purchasing a new unit. The result of this is that additional transmission lines are needed and these will become part of the expenses in the construction of this stage. This combined with the expensive oil fuel needed to operate the unit, make it conceivable that the full Hudson No. 2 retrofit may also precede the gasturbine retrofit. So what are called intermediate and final stages of development may actually happen in a reverse order.

6.1.2.1 The Initial Stage

Gas or oil fired hot water heaters are to be erected within or in close proximity to areas where and when consumers are contractually assured. There is always a multiplicity of units (at least two) in these plants. Sufficient stand-by capability will be provided to supply peak demand even when one of the units is out of service. At this point the heaters will operate on a 120°F+ differential temperature system. The return water temperature will be 170°F max., and the send-out temperature 295°F, both measured at peak demand. The additional 5°F is added to cover line losses. There is no advantage derived for this operation in varying the temperature with load. A combination of temperature and flow control can be instituted for best economy at partial loads.

It is proposed to look at not only water tube packaged heaters but also at the fire tube variety. The latter have capacity limitations, no doubt, but require much lower building profiles. The larger number of units may also limit the required total capacity in spares. So is their reliability due to simple construction.

Where the initial loads are small and scattered they will be initially served by heaters erected at temporary locations to be consolidated later into a larger permanent facility.

The circulating pumps in these plants will have the capacity to provide the required amount of water flow through the heaters, the distribution system and the user equipment and return the water to the plant. 7h The capacity of the system circulating pumps will be increased with the system load at Stages II and III.

Water make-up and treatment facility of a capacity of approximately 3-4% of flow will have to be provided here. It will also be expandable to serve the total system even at the intermediate and final stages of the development.

6.1.2.2 The Intermediate Stage

It is the first cogenerative stage in the system. It can be based on gas turbine-generator or diesel-generator heat recovery units. There are a few basic differences between the two from the standpoint of the heating system. A gas turbine produces just about twice as much heat per unit electric power generated as a diesel does. Also all the heat from the turbine is available at elevated temperatures ($<1000^{\circ}F$). Diesel (gas engine) heat rejection splits between exhaust ($\leq 1000^{\circ}F$) and engine cooling (usually $\leq 200^{\circ}F$). The utilization of this low level heat can present problems and added cost for a high temperature water system. Also the space requirements, operation and maintenance costs would run higher than those of a gas turbine.

While all this points towards gas turbines as the more suitable base, it does not preclude utilization of diesel (gas engines) where for example they are already in existence. (This however is not the case in the PSE&G system.) A further possible incentive for gas turbines is that several units are available within the PSE&G system. Their relative inefficiency and high fuel cost becomes a secondary matter when heat recovery is contemplated. The savings in capital cost, when used at their present location or where their relocation does not prove too costly, can more than compensate for the added fuel cost.

So it was initially decided to concentrate on gas turbines in these studies. Relocation of existing units had been judged uneconomical and/or undesirable. Consequently the available units within the supply area had been investigated. After looking at all aspects of utilizing one of the Essex or Kearny gas turbine units, the Kearny No. 12 gas turbine was selected. It is a high-efficiency machine, regularly used for peak shaving and favorably located within the supply area. The 196MW ISO rated output of this machine is produced by eight engines coupled to four generators. This arrangement allows the efficient meeting of partial loads and minimizes the effect of individual engine outages.

Rapidly deteriorating part load performance, typical of gas turbine units, can be of concern in off-season (spring-fall) when additional power generation is not needed. Therefore more of the fuel used would be debited to heat output. This in turn would rapidly eliminate the higher fuel efficiency of the cogenerative (heat and power) mode of operation as compared to the fuel usage of direct fired heaters.

The heat recovery heaters are heatexchangers cooling flue gas and heating the D-H water directly whenever the power unit is operating. They can be supplementally fired and produce higher temperatures than that of the leaving flue gas (600-850^{0}F) up to 1500^{0}F. They can also be equipped to produce heat even when the power unit is not in operation. In both cases fuel burner grids have to be added and the design has to be modified at added cost. For the latter case, fans and ductwork are also to be added to replace the flue gas flow by air flow during the shut-down of the generator set.

The above measures have a direct effect on the size and on the form stand-by capacity is to be provided. Supplemental firing for example can double the heat output of a waste heat boiler, when the normal operating design temperature on the gas side is increased to 1300^{0}F from 800^{0}F. The cooling range of the flue gas is increased from 500^{0}F to 1000^{0}F without changing the leaving gas temperature of 300^{0}F. The water side of the heater can be designed in two different ways. Either that it will be capable to accept the doubling of flow velocities at certain times or that the tube design is such that parallel-series changeover of clusters is possible at unchanged flow velocities. This alternative can be considered since the average flue gas temperature was increased considerably. In both cases the circulating pumps have to be designed to cope with both conditions (two speed motors, for example). It was decided however not to consider any supplemental firing option in this study.

The operation of the D-H side of the plant is to be designed to accommodate unit by unit operation. The unit heat recovery heatexchangers operate parallel to each other. Return water from the users comes back directly to this plant, by-passing the initial stage plants. The heaters heat the water at peak load from 165^{0}F to 230^{0}F. This represents half the peak load of the system at design flow. The other half of the load is then dispensed by the fired heaters of the initial stage plants where the 230^{0}F water enters, gets heated to 295^{0}F and is then distributed to the users.

Circulation of the water is accomplished by each development stage supplying its own pumping requirements. As stated before, the initial stage plant has pumps to circulate through the local distribution system and end user equipment back to that plant. The intermediate stage plant will have pumps to circulate from the first stage plant to the intermediate plant and back to the first stage plant. This way pumping requirements closely follow system growth and the system design pressure is kept to a minimum.

6.1.2.3 The Final Stage

When the actual connected load on the first two stages is sufficiently developed, the Final Stage construction can commence. The timing of this step is to be defined in terms of peak load and is dependent on the relative costs of generating heat in the different stages, including the effects of additional power generated or power generation lost. As a rule the system heat demand at that point in time should not be less than the total output from the retrofitted plant. Even then the utilization of total capacity is very low (<33%) initially. The first two stages of the system serve only as stand-by. This however may also be a necessity if the retrofitted power plant provides all the heat as a single source. The rule generally accepted for necessary back-up capacity is that it has to match the output of the largest single source witnin the system.

In Phase I of the study, along with the selection of the supply area three power plants had been investigated as potential sources of heat for the system. One, the Kearny G.S., had been rejected because the power generation machinery in that plant does not lend itself to an economical retrofit. The other two stations, Hudson G.S. and Essex G.S., were made part of the Phase II study for final selection. The Essex G.S. investigations and the reasons for its rejection as a source for the D-H system are detailed in Appendix B.

6.1.2.3.1 Hudson G.S.

The selected baseload heat source was the coal fired Hudson No. 2 unit, a double reheat 605MW nameplate capacity turbo-generator set. It is a very efficient, base load unit. This has two consequences. Because of its high efficiency and low cost fuel, replacement of power production lost due to D-H carries a penalty. On the other hand, because it is a base load operation, supply of heat at the required send-out levels is accomplished without forcing the plant to generate above grid-determined generating levels most of the time.

It was decided that the only practical place to bleed steam for D-H is the IP-LP crossovers. Figure 6.1.2 shows the conceptual schematics of the proposed retrofit. The actual schematics and other details are shown in Para. 6.2.

The heating plant itself will be a separate new structure located as near as practical to the No. 2 unit. The previous investigations on the subject clearly pointed to the advantages of two-stage heating of the D-H water. A later computer run on the Syntha II program proved this assumption to be valid for the staged system also. Each stage heater is supplied by its own back pressure turbine-generator set. The throttle pressure of these turbines is the residual pressure at that point starting from the nominal 72.2 psia design load crossover pressure of the main unit. This pressure will be actually maintained by a crossover throttling valve at all allowable main unit load conditions. The nominal back pressure of the two units is different. One is a nominal 21 psia, while the other is 12 psia. Investigations run by the manufacturer of the unit showed that 1.65 million lb/hr steam can be extracted from the crossover at generator loads above 85%. Some of the steam extracted is to be used for feed water heating to replace the losses on the low pressure feed heaters due to reduced LP steam flows. The remainder of the steam extracted could be split evenly between the two units at design load or it will be split so that the generators will be of equal capacity.

In any case the two units will provide 1.6 million BTU/hr for heating at a net combined power generation loss of approximately 90MW and at a slight heat rate increase. This rate increase and the cost of replacing the lost power are the energy costs of the heat generated for D-H. Since a considerable fraction is a waste by-product of power generation, this becomes the main reason why this final stage is so important to the economy of the total system and why it is aimed to carry as much of the base load as practical.

During the course of the study it became evident that under certain conditions of the overall

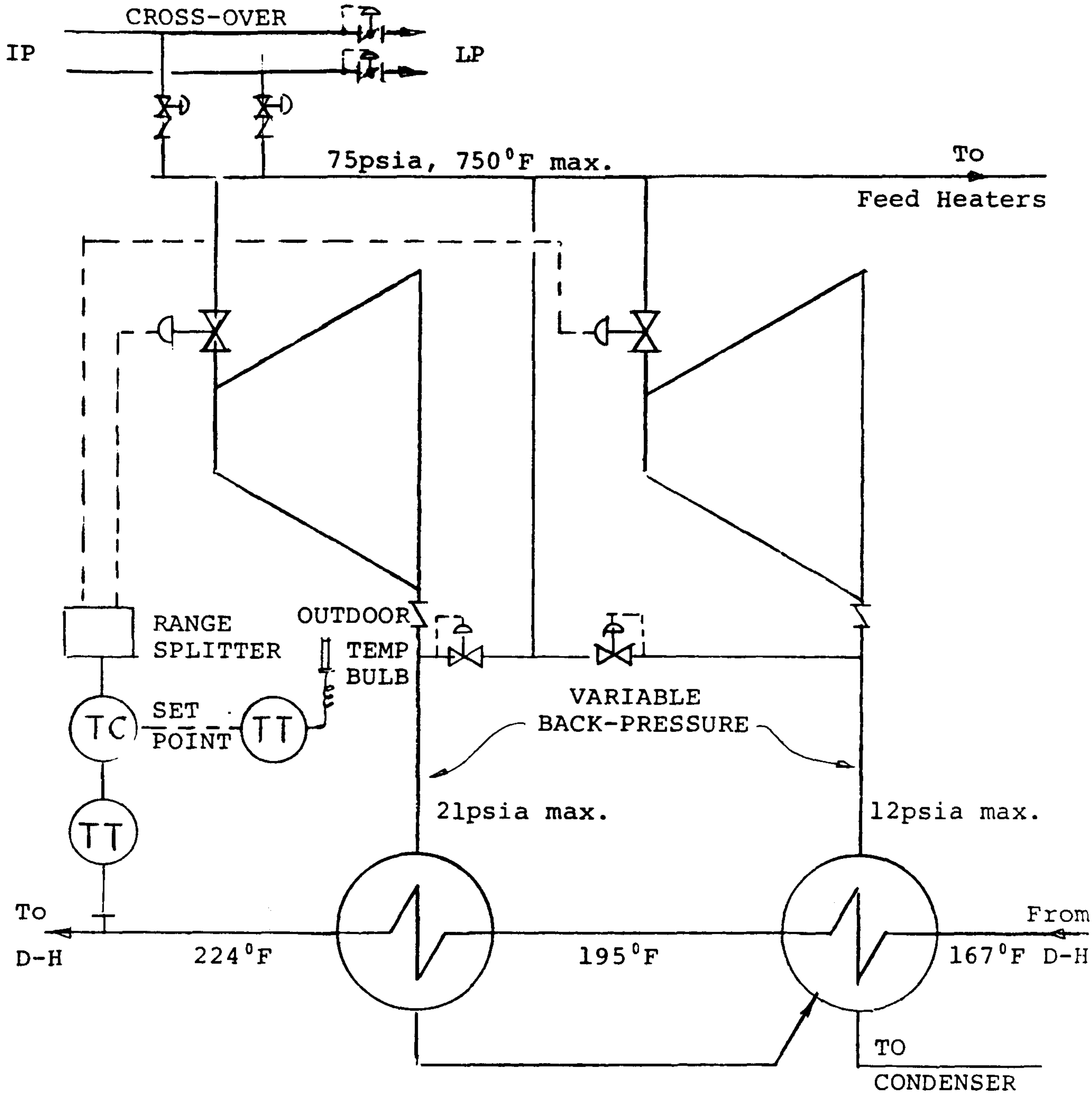


FIG. 6.1.2

ELEMENTARY
CONTROL OF HEATING TURBINES

development it may become desirable to make use of the low cost heat available from the Hudson No. 2 unit at an early stage. Looking for relatively inexpensive ways to extract the heat from the unit, the manufacturer was asked to establish the maximum allowable uncontrolled extraction rate at the cross-over. The result was that 200000 lb/hr steam bleed is acceptable at full load. An intermediate stage--called the "partial retrofit" in the following--was then inserted in the overall development schedule. This retrofit in conjunction with two heater plants of 100 x 10^6BTU/hr peak capacity (150-200 x 10^6BTU/hr installed each) will provide 50% of the heat load at this stage and more than 2/3 of the annual energy requirements.

The No. 1 unit at Hudson is a 400MW oil fired installation. Its inclusion within the D-H system as a full stand-by unit has been considered and rejected. The exception to this decision is an existing crossover--normally used for starting up No. 2 unit--with a capacity of 190000 lb/hr steam flow. This steam is considered as available stand-by capacity should No. 2 unit be unavailable due to planned or unplanned outages.

6.1.2.3.2 Essex G.S.

An alternative to utilizing the Hudson No. 2 unit was to reactivate this station. It could serve the system as its final stage or as an intermediate development before a Hudson retrofit. In this case it would be on stand-by duty after the full development.

It was found that reactivation of the plant for the purpose of district heating operations alone is not an economically attractive alternative at this time. Independent industrial developments along Doremus Ave., requiring steam may change this assessment in the future. Until then, however, this plant is not considered as a potential element of a district heating system.

6.1.3 OPERATION OF THE STAGED D-H SYSTEM

6.1.3.1 Initial Stage Operation - Fired Heaters Only

The number of heaters on line at any time is dependent on outdoor temperature. The domestic hot water and commercial/industrial load present will determine, after some operating experience, a base line load independent of weather. Modulation over that base line will only be weather dependent. The base line itself will also be sliding on a day-by-dat and a time-of-day basis.

The heaters proposed are relatively small units and gas/oil fired. This allows quick start-ups so on-line stand-by will not be necessary considering also the fly wheel effect of the distribution system. This type of operation may not be feasible at the very initial stages of development. At that point on-off operations of a single unit may be required.

6.1.3.2 Intermediate Stage Operation - Fired Heaters and Combustion Turbine Heat Recovery

The gasturbine/diesel waste heat recovery heaters will carry the base load heating the water from 170°F minus heat losses to 230°F plus heat losses. If these losses amount to, let's say, 7% of total peak load then the supply side loss will be approximately 4.5% and the supply side loss will be approximately 4.5% and the return side 2.5%. The leaving water temperature after the heat recovery heatexchangers is then 235.4°F while the return water arrives at 167°F. The peak output of the heat recovery heaters is then 57% of the total system peak. The reason for this arrangement is that the steadiest load on a D-H system is line losses, so it is important to provide it from the most efficient source available.

The waste heat recovery plant operates all year-round, that is 8760 hours minus planned and unplanned outages. In the winter it logs an average of up to 5760 hours at a load factor of 68% and in the summer up to 2000 hours at a load factor of 18%. This is an annual average of 51% not counting the operation of stand-by facilities required. The initial stage heaters operate only 1440 hours annually at a load factor 22.5% over their operating time and 3.7% over the whole year.

Water circulation is kept generally constant. At the 3000 hr low load period during the summer it may be practical to reduce the distribution water flow and increase the temperature differential. This presents some operating cost saving as proven at the European systems.

Manning of these plants could be the most significant operating cost factor. The technology is available and proven to operate both fired heaters and gasturbines automatically and control/supervise them remotely. Acceptance of this principle is crucially important.

Unattended operation of the gasturbines is the prevailing practice within the PSE&G system.

Maintenance and operations supervision to proposed to be in the hands of a central organization, with roving maintenance men making scheduled checks and planned maintenance. This same personnel would also act on emergencies.

6.1.3.3 Final Stage - Hudson #2 Unit Retrofit

Upon its completion the powerplant retrofit takes over the baseload function. The reason for this is again its superior efficiency over the two other stages. In addition, the cheap coal fuel provides an additional incentive to do so.

The completed retrofit with two backpressure turbines and two stage heating will operate year-round at a load factor of 60.6%. It should be noted that this is for the total of both heating stages. The second heating stage and its supply turbine operate only 3500-4000 hours a year. The rest of the time the send-out is reduced to the point that one of the heaters can satisfy it. The additional heat loss of the transmission lines is not significant. It increases the total loss to 8% of peak. So the return water will enter at 165°F and to cover the supply side losses of the total system the leaving water temperature is 215°F for a total rise of 50°F. That is 42% of total peak heat supplied and billed, while the other two stages provide 29% each.

In terms of total heat energy provided annually the breakdown between stages is as follows:

Final stage	80.0%
Intermediate stage	18.4%
Initial stage	6.0%

	100.0%

This leaves no doubt that the proposed system at its final conception is a truly powerplant retrofit based installation. Only a very insignificant part of the total heat supplied does not originate from a cogenerative cycle.

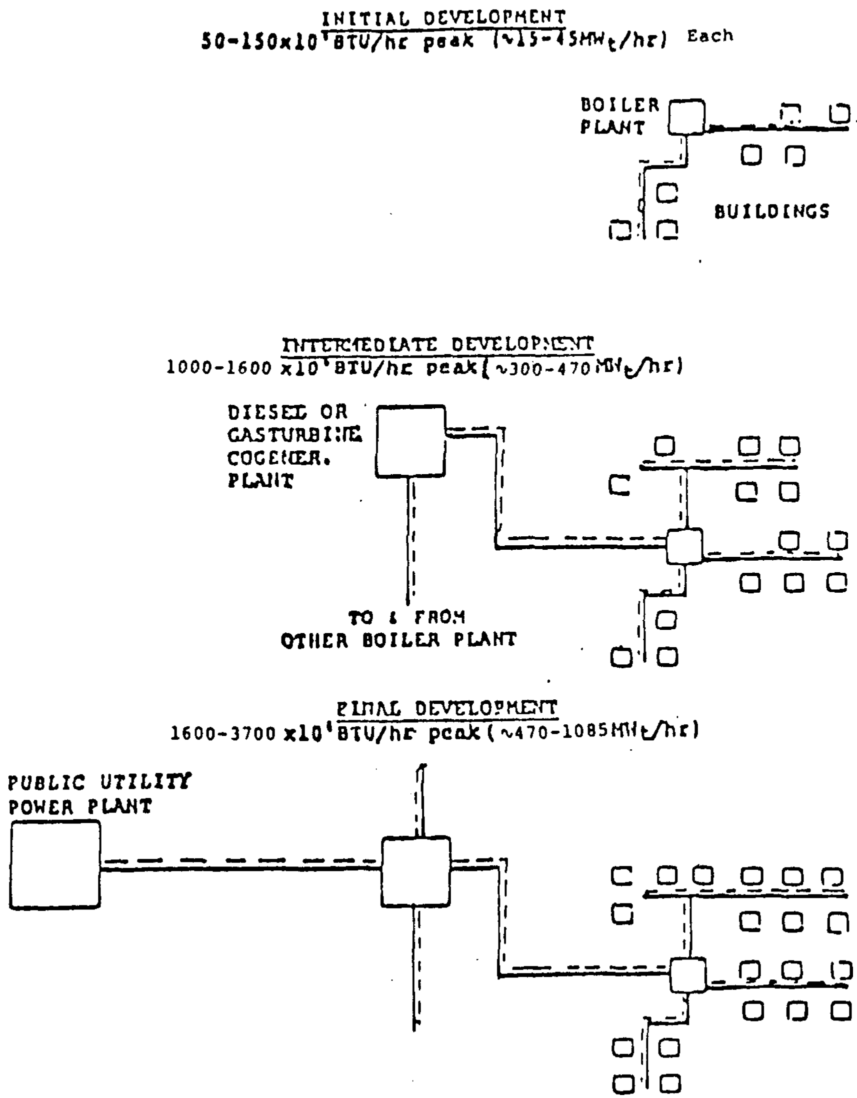
The above figures were developed without consideration to planned and unplanned outages of any of the stages. That becomes quite significant in the final evaluation. This is particularly so because the Hudson #2 unit historical combined total and partial, planned and unplanned annual outage rate is 28% of the time, or 2450 hours annually. Out of this the planned outage of about 700 hours can be scheduled for March/April of each year, that is to a time when heating system loads are low. The rest is not controllable so it will reduce the share of coal generated waste heat to about 60% of total heat supplied.

6.1.3.4 Operation of the Distribution System

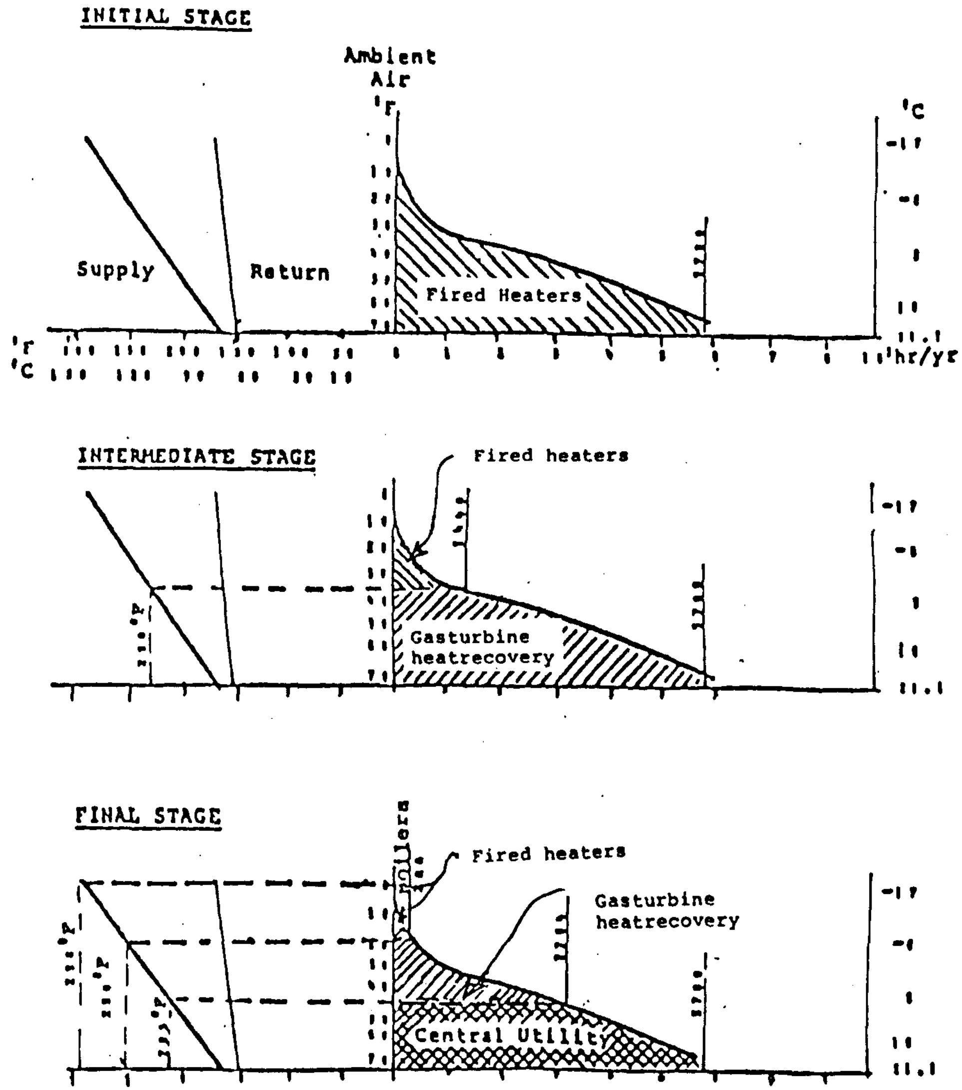
Figure 6.1.3 shows the schematics of the three development stages and correlates the outdoor temperature/load frequency curves with supply and return temperatures. It also describes graphically the stage operations dependent on load and the stage temperatures required at those conditions. This representation is a first simplified approach to system operations.

At a later point a more detailed annual operating pattern was developed. It is shown on Figure 6.1.4. It breaks the load to its major component, as heat-loss, domestic hot water generation load and heating load. Only the last one is outdoor temperature dependent. Domestic hot water consumption and losses are fairly constant over the year. Heat losses for underground pipes, a fairly constant temperature environment, are influenced only by supply and return temperatures. The latter varies within a narrow range. The supply temperature varies widely but one can calculate on an average basis without major distortions of overall operating conditions. One aspect of this operations plan is that at 30% and below load the flow is not maintained constant any-more. At 15% the flow is halved and then it is maintained all summer long.

The effect of this on the supply temperature is shown in more detail on Figure 6.1.5. The temperatures in-dicated are the retrofitted cogeneration plant return (RI) and supply (ST) temperatures along with the load on this stage of the system. Obviously for the close to 3000 hours this stage operates at full load the other two stages (gasturbine, heater plant) operate as well at increasing loads. The supply temperature leaving the first stage becomes the return temperature of the second stage and so on. The return water is always assumed to flow back to the lowest in the string of operating stages.



Development stages
of a large district heating system



Operations in successive
stages of development

FIG. 6.1.3

6.1.4 HUDSON #2 UNIT CHARACTERISTICS

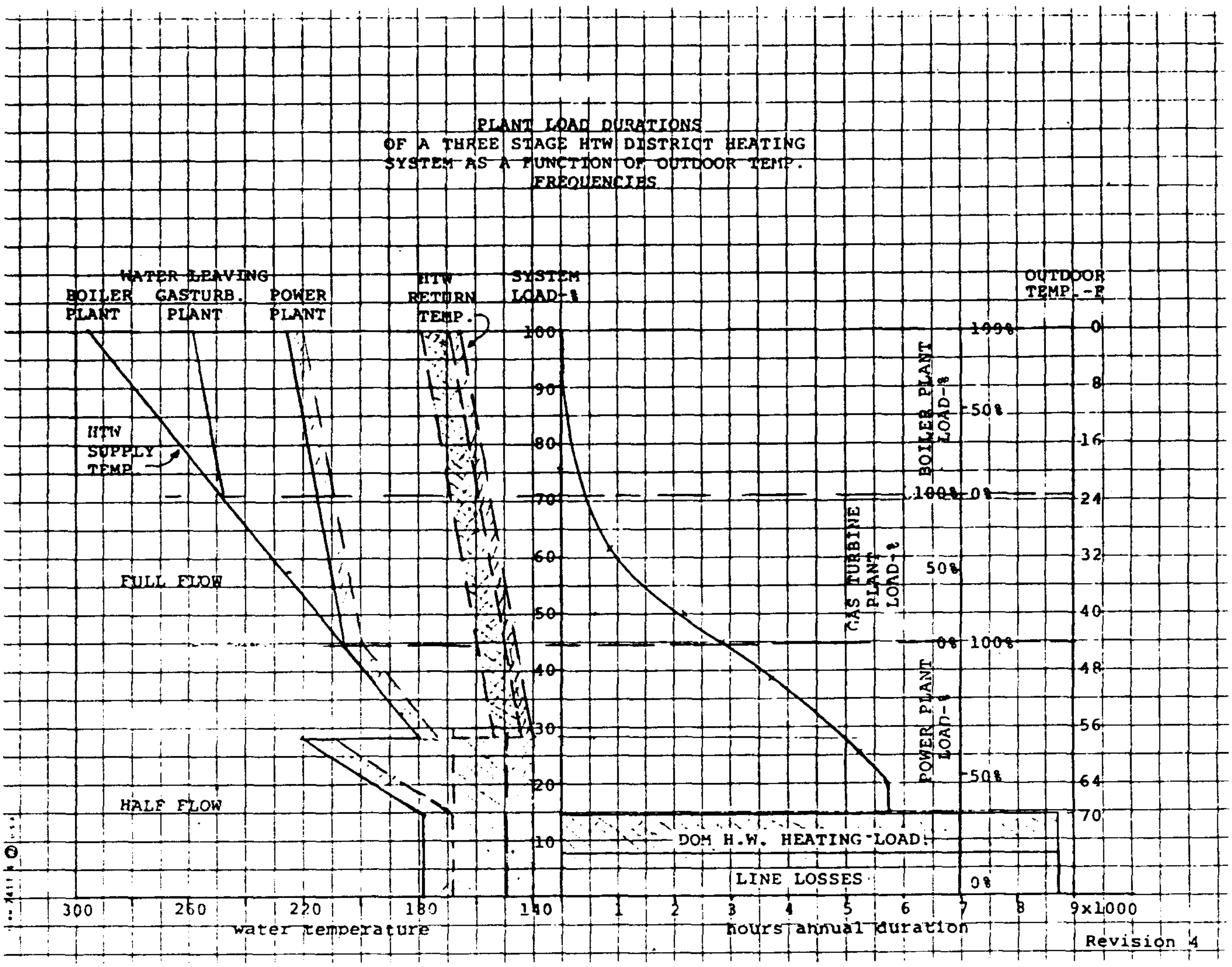
Figure 6.1.6 shows the electric output of Hudson #2 vs. fuel input for each of the three retrofit stages at full thermal production. It can be seen that the extraction of thermal energy requires an increase in fuel and a reduction in electric output capability. For periods of low thermal demand the electric output capability approaches that without a retrofit. Figure 6.1.7 shows the reduction in electric output vs. the thermal production rate.

The characteristics of Hudson #2 were calculated by Stone & Webster Engineering Corporation (SWEC) based on data supplied by the manufacturer. It was necessary for PSE&G to adjust this data slightly so that it would match the characteristics measured in actual operation. This was done by assuming that the characteristics with a zero thermal production rate would match those of currently measured data. The same adjustment factors were used for various rates of thermal production.

6.1.5 RELIABILITY CRITERIA

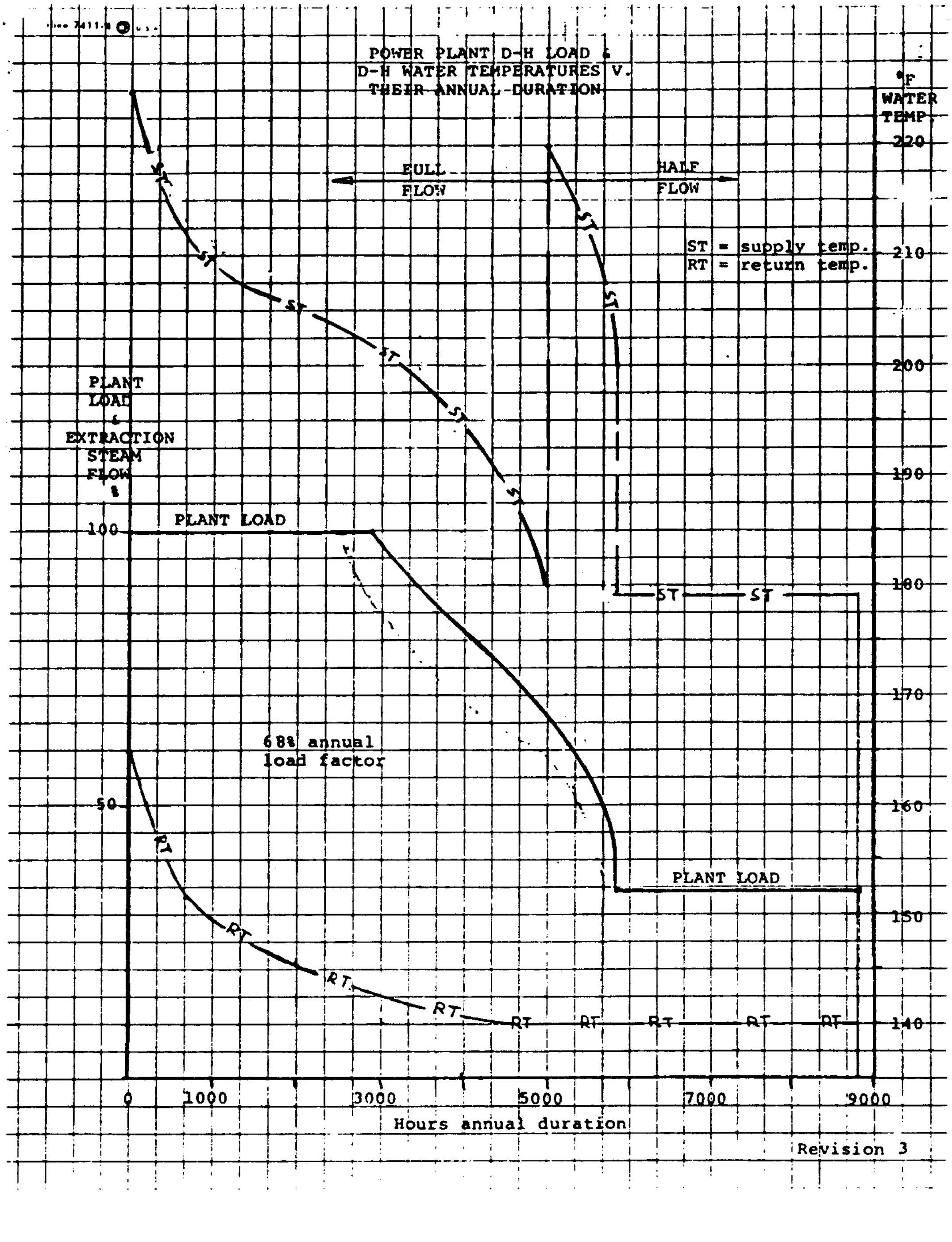
The service territory of PSE&G contains the six largest cities in New Jersey. Of these, Newark and Jersey City are potential sites for district heating located adjacent to the Hackensack Meadowlands. The urban nature of these cities requires a high degree of reliability for electric and gas services. If PSE&G is to provide district heating to these areas, a service reliability comparable to that of our electric and gas systems would be expected. In addition, the generally high reliability of a conventional heating system installed in individual buildings must be considered when evaluating district heating reliability criteria.

On the other hand, the reliability of a hot water district heating system is not as critical as that of an electric or gas system, since there is no pilot light shut-off or danger of equipment damage that must be considered when planning thermal capacity reserves. The fly-wheel effect of the transmission/distribution system also contributes to the reduction of the effects short outages may otherwise create. A shortage in thermal supply capability would result in lower water temperatures and a reduction in heat transfer to customers but would not result in a complete shutdown of the system, or danger to the customer. The reliability then should be based primarily upon meeting customer expectations for reliable service.



PLANT LOAD DURATIONS
OF A THREE STAGE HTW DISTRICT HEATING
SYSTEM AS A FUNCTION OF OUTDOOR TEMP.
FREQUENCIES
WATER LEAVING
BOILER PLANT
GASTURB. PLANT
POWER PLANT
HTW RETURN TEMP.
SYSTEM LOAD-%
OUTDOOR TEMP.-F
HTW SUPPLY TEMP.
FULL FLOW
HALF FLOW
BOILER PLANT LOAD-%
GAS TURBINE PLANT LOAD-%
POWER PLANT LOAD-%
DOM H.W. HEATING LOAD
LINE LOSSES
water temperature
hours annual duration
9x1000
Revision 4

FIG. 6.1.4



POWER PLANT D-H LOAD &
D-H WATER TEMPERATURES V.
THEIR ANNUAL-DURATION
°F
WATER
TEMP.
220
210
200
190
180
170
160
150
140
FULL
FLOW
HALF
FLOW
ST = supply temp.
RT = return temp.
PLANT
LOAD
&
EXTRACTION
STEAM
FLOW
%
100
50
PLANT LOAD
68% annual
load factor
ST
RT
0
1000
3000
5000
7000
9000
Hours annual duration
Revision 3

FIG. 6.1.5

FIG. 6.1.6

HUDSON #2 ELECTRIC GENERATION vs FUEL INPUT
FOR THREE STAGES OF RETROFIT and MAXIMUM THERMAL PRODUCTION

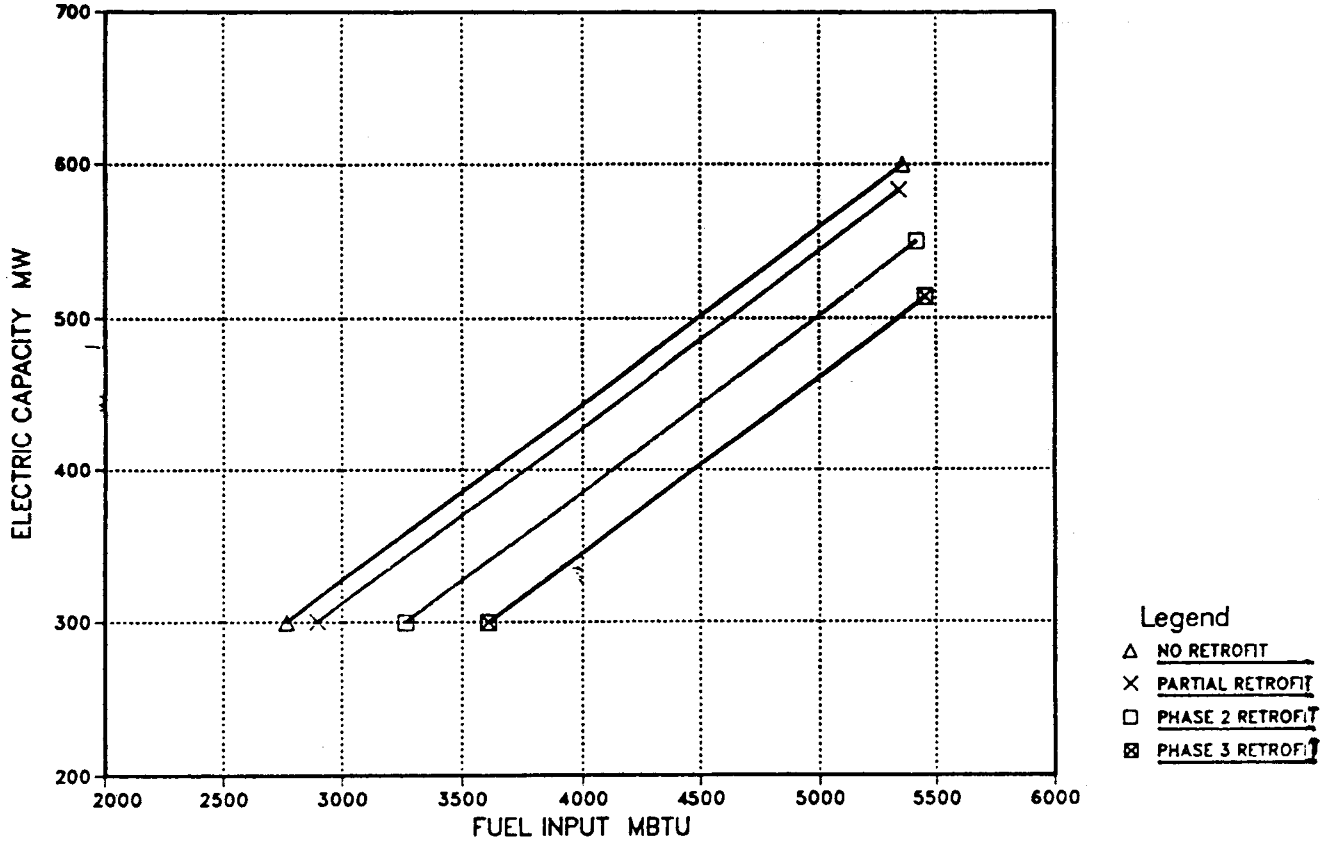
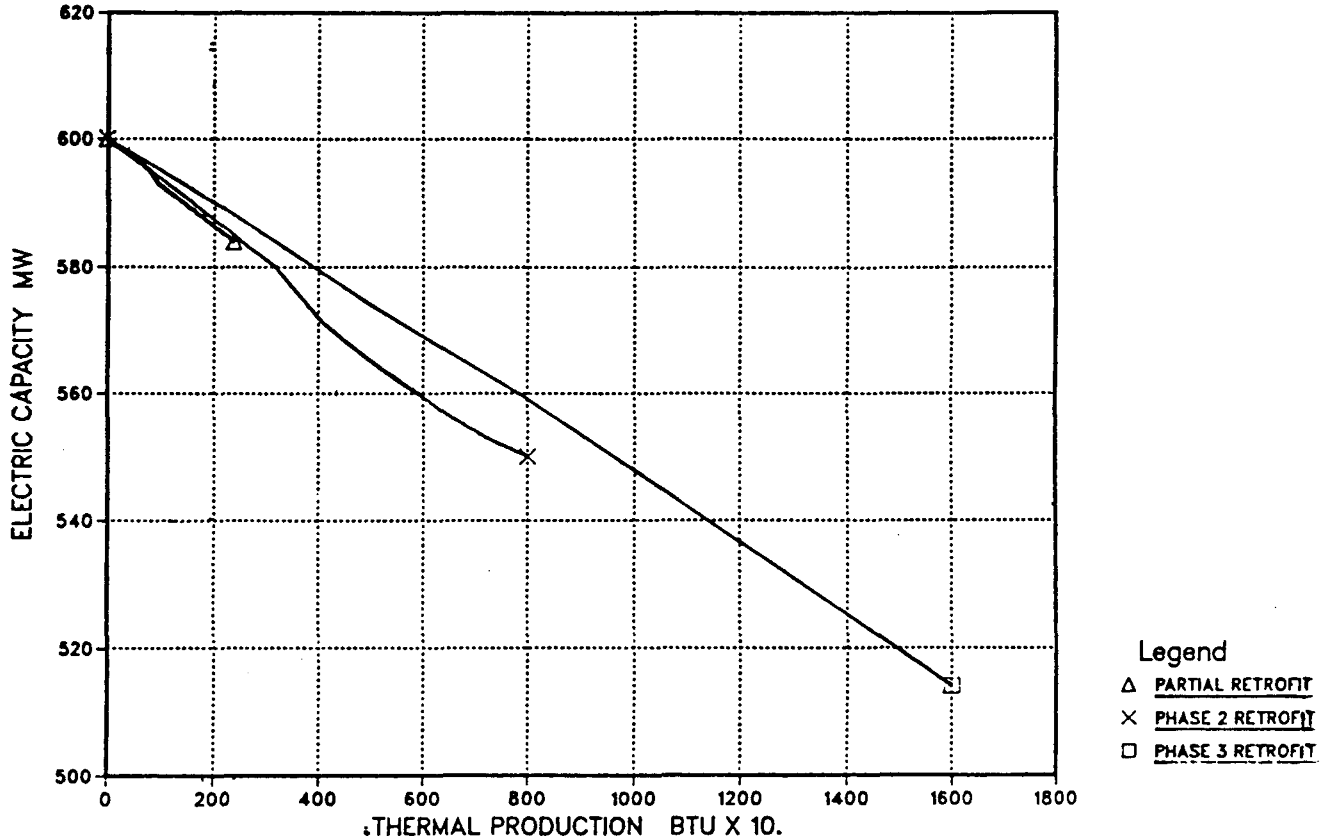


FIG. 6.1.7

HUDSON #2 ELECTRIC CAPABILITY VS THERMAL PRODUCTION
FOR THREE STAGES OF RETROFIT



The main criterion used for this study is based on the European practice of providing reserve capacity equal to the thermal capability of the largest single supply source and to the largest unit of any group of circulators.

This reliability criterion was applied to each of the heat islands as well as the full system when the individual islands are interconnected.

The reliability of the thermal transmission and distribution systems were considered high enough so that they need not be considered in this analysis. This is consistent with reliability evaluations made for the PSE&G natural gas system. The distribution systems in their final development will be looped just as the gas system is.

If a decision is made to implement a district heating system, the reliability criteria may have to be reviewed and expanded in the light of customer acceptance and of experience with system operation.

6.2 Station Retrofit

6.2.1 Summary

6.2.1.1 INTRODUCTION

This report describes the results of the Phase 2 Feasibility Study in connection with retrofitting existing generating units to supply heat for district heating. The study was performed by Stone & Webster Engineering Corporation (SWEC) for Public Service Electric & Gas Company (PSE&G), with funding by the Department of Energy. The retrofit concept is based on extracting steam from turbine cross-overs to heat district heating water. Back-pressure turbines are used to reduce the pressure of the extracted steam to the required heater pressure. This approach minimizes electrical capacity losses of the units during district heating operation and avoids major retrofitting of the existing turbines. The retrofitted units retain the ability to operate near their peak electrical generating capacity when there is no district heating load.

The study involves conceptual engineering and cost estimate for retrofitting Hudson Units 1 & 2 and Essex Unit 1 to provide district heating water heating capability at the two stations. The technical feasibility of extracting steam from the turbine cross-overs was investigated by Westinghouse Electric Corporation and General Electric Company, the turbine suppliers for the Hudson and the Essex units respectively, through study contracts awarded by PSE&G. The study of heat cycle modifications, development of conceptual design, and cost estimating of the plant retrofits were undertaken by Stone & Webster Engineering Corporation. No attempt has been made in optimization or to work out engineering details. Economic justification for district heating is not covered in this report.

6.2.1.2 CONCLUSIONS AND RECOMMENDATIONS

The results of the study show that the retrofit concept described in this report is technically feasible, and that there is sufficient space available at both the Hudson and the Essex Stations to accommodate the added equipment and piping within reasonable distance from the existing units. The study also shows that the described retrofit scheme with new back-pressure trubine-generators is the preferred choice over an alternate scheme with no back pressure turbines.

During the early stage of the Phase 2 Study, Hudson Unit 1 was removed from consideration by PSE&G because of the difficulty of routing steam and condensate pipings through Unit 2 to the new water heating plant, to be located east of Unit 2. Some time later, Exxex Unit 1 was also removed from the study by PSE&G. Since much work has been done on Essex Unit 1, the information developed for this unit is included in this report. The following recommendations pertain only to Hudson Unit 2.

The recommended retrofit scheme for Hudson Unit 2 involves the modification of the existing turbine cross-overs with the installation of two butterfly pressure control valves and the connection of two extraction steam lines to the cross-over pipes upstream of the valves. The steam lines will supply steam from the cross-overs to two new back-pressure turbine-generators. Steam exhausted from the turbines is condensed in district heating water heaters which provide two stages of heating of the district heating water. Drains from the heaters are cooled in an external drain cooler before returning to the condenser. New heater drain pumps are provided to pump the heater drains from the district heating water heaters. A new feedwater heater train, to be installed in parallel to the existing low-pressure feedwater heaters, will share the feedwater heating load during district heating operation.

A new water-treating system, which produces softened dealkalized and deaerated water, will supply make-up to the district heating water system. The major equipment in the recommended water treatment plant consists of a single train of carbon filter, weak acid cation exchanger, heater, and vacuum deaerator. Waste water generated from the water treatment system will be neutralized prior to being discharged.

A water heating plant will be provided to house the new equipment, which includes the back-pressure turbine-generators, heaters, pumps, switch gears, motor control centers, control room, and the water treatment system. This building measures approximately 206 feet long by 165 feet wide. It will be located between the No. 1 and the No. 2 Fuel Oil Tanks, directly east of the turbine laydown area.

The study shows that 1.65 million pounds steam per hour can be extracted from the Hudson Unit 2 turbine cross-overs. With the above steam flow, approximately 28.5 million pounds water per hour (59,600 GPM) can be heated from a return temperature of 165 F to the supply temperature of 221 F. During operation of the unit with maximum throttle flow and maximum steam extraction for water heating, the reduction in generation is approximately 92 MW. During operation of the unit with maximum throttle flow and no district heating load, the loss in generation, due to pressure drop through the butterfly valves, is about 275 KW. The resulting heat rate penalty is about 5 Btu/KW-Hr.

The capital cost required to retrofit Hudson Unit 2, including the water heating plant, electrical equipment, and the water treatment system, was estimated to be approximately forty-three million dollars. The above cost does not include site work, roads, and the turbine manufacturer's scope of work in connection with modification of the existing turbine and the associated control systems. These latter costs were developed separately by PSE&G and Westinghouse Electric Corporation.

6.2.1.3 GENERAL RETROFIT SCHEME

The plant retrofit schemes developed for both the Hudson and the Essex units are similar, and require the modification of the existing turbine cross-overs and the addition of a new heater train parallel to the exising low-pressure heaters. The modification of the cross-overs includes the installation of a TEE section and a butterfly valve on each of the cross-over pipes. From the branch outlets of the TEEs, upstream of the butterfly valves, two steam lines connect the cross-overs to new back-pressure turbines. The exhaust ends of the turbines are piped to new district heating water heaters. Drain flows from all the new heaters are returned to the condenser.

On each of the extraction steam lines, a motor-operated shut-off valve and an air-operated non-returnvalve are provided. During operation with no steam extraction from the cross-overs, the butterfly valves will be fully open; both the motor-operated shut-off valves and the air-operated non-return valves will be closed. During operation when steam is extracted from the cross-overs, the butterfly valves will be partially closed; the motor operated shut-off valves and the air operated non-return valves will be fully open to pass the extracted steam flow.

The design temperature of the district heating water leaving the retrofit plant is 221 F. To obtain this water temperature, the maximum steam pressure needed at the water heaters is only 21 psia (using a terminal temperature difference of 10 degrees F). Since the steam pressure at the turbine cross-overs is much higher than this pressure, back-pressure turbines are used in the retrofit scheme to generate additional power and to reduce the steam pressure.

6.2.2 PLANT DESCRIPTION

6.2.2.1 HUDSON UNIT 2

Hudson Unit 2 is a coal fired unit. It was placed in service in 1968. The unit has a tandem-compound six-flow turbine built by Westinghouse Electric Corporation. The turbine nameplate rating is 620 MW. This rating includes power developed in the feed pump turbines. Rated steam conditions at the main turbine are 3500 psig and 1000 F, with reheat to 1025 F and 1050 F. Steam to this turbine is supplied by a once-through supercritical-pressure steam generator. The maximum guaranteed turbine throttle flow is 3,704,643 pounds per hour at the rated steam conditions. With valves-wide-open and five-percent over-pressure, the turbine could pass a flow of 4,105,000 pounds per hour. Two half-size boiler feed pumps are driven by auxiliary turbines, powered by steam taken from the high-pressure turbine exhaust. Two half-size motor driven boiler feed booster pumps are also provided. The condenser has two separate welded steel shells. Each shell receives its cooling water from its respective circulating water pump. There are no cross connections between the circulating water pumps and the shells, nor are there connections between the shells except the common connection to the LP turbine exhaust hoods. Two new vacuum pumps have been installed recently. The vacuum pumps have sufficient capacity to maintain the condenser pressure at 0.6 Inch Hg. absolute during low load. A full flow condensate polisher is provided upstream of the secondary condensate pump suction. The polisher has four mixed-bed units, one of which serves as a standby. The heat cycle has eight stages of feedwater heating. There are four low pressure heaters and an external drain cooler upstream of the deaerator.

There are three pairs of high pressure heaters in two parallel trains downstream of the boiler feed pumps.

Fig. 6.2.4 shows the heat balance of the unit operating at maximum throttle flow with no steam extraction from the cross-overs. The gross generation in the figure is 652 MW. The maximum test output of Hudson Unit 2 was 651.4 MW gross. Presently the capacity of the unit is limited at 625 MW gross and 600 MW net due to the limitation on particulate emissions imposed by the state operating permit.

Hudson Unit 2 does not come down on load except during weekends, and two hours each night to deslag the boiler. During these periods, the unit operates at the minimum load of 300 MW. In the future when new pulverizers will be installed and additional nuclear generating capacity will be available in the PSE&G system, the minimum load for Hudson Unit 2 will be reduced to 150 MW.

6.2.2.2 ESSEX UNIT 1

Essex Unit 1 was originally a coal fired unit. It was placed in service during 1947. The unit had a tandem compound double-flow turbine with eight stages of extractions for feedwater heating. The turbine was built by General Electric Company and had a nameplate rating of 100 MW. Steam conditions at the turbine was 1250 psig and 1000 F, with no reheat. Following a plant explosion, the turbine was rebuilt by General Electric in 1973. The rebuilt turbine has provision for only seven stages of feedwater heating. As a result, one of the low pressure heaters, Heater 13, was deleted and physically removed. The steam conditions of the rebuilt turbine are 1200 psig and 950 F. The turbine rating is 105 MW. This unit does not have a deaerator. Essex Unit 1 was retired from

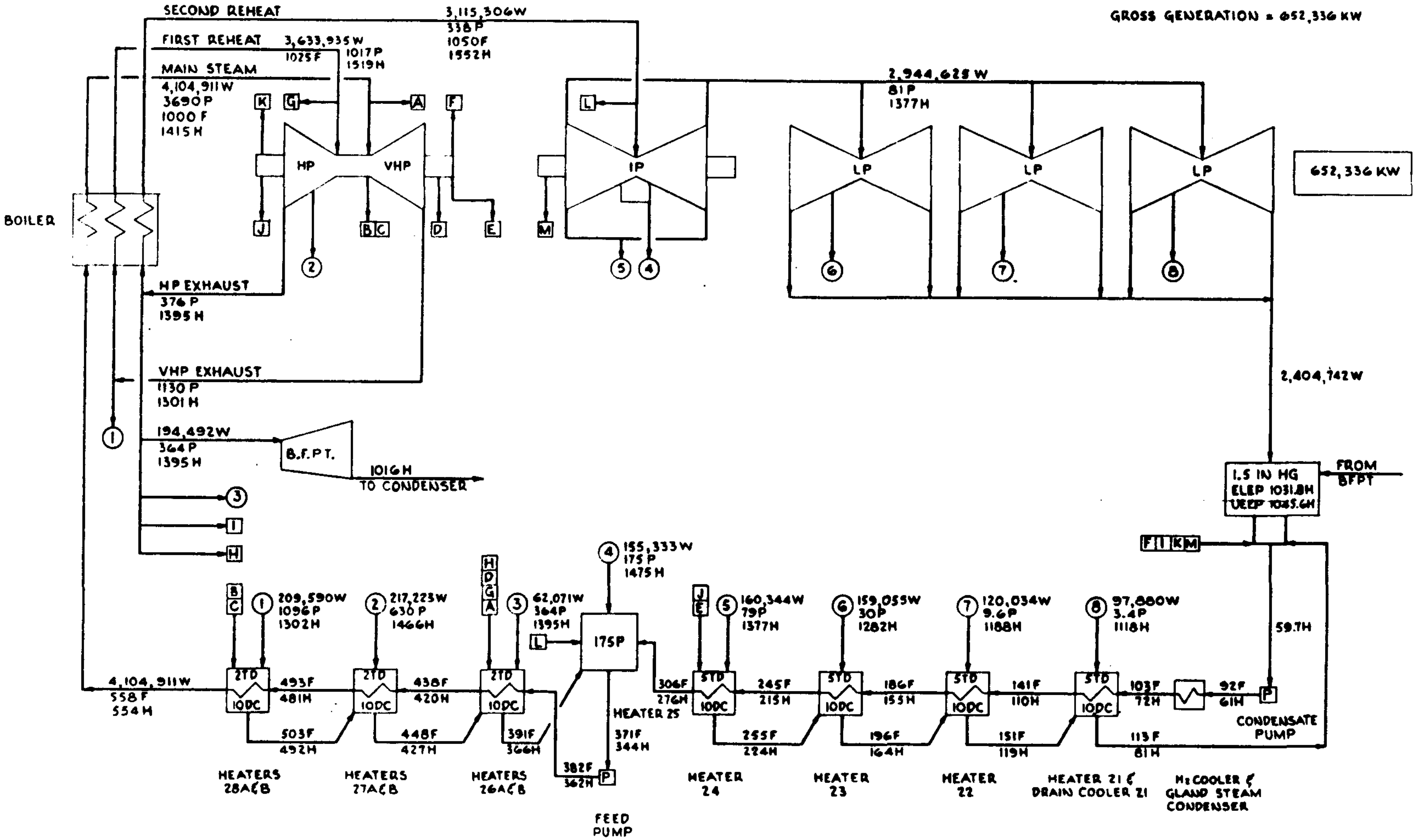


FIG. 6.2.4

LEAKAGES

A. 41,049W
B. 102,769W
C. 49,339W
D. 62,318W
E. 4201W
F. 1710W
G. 17,472W
H. 18,371W
I. 3,024W
J. 4,258W
K. 1,718W
L. 15,347W
M. 2,570W

KEY

W – LB/HR
P – PSIA
F – °F
H – BTU/LB

HUDSON GENERATING STATION UNIT 2
HEAT BALANCE AT MAX. THROTTLE FLOW
NO DISTRICT HEATING

STONE & WEBSTER ENGINEERING CORP.

DWG. NO. 13222.01 - HB - H2-1

DESIGNED BY R.J. PATEY
DRAWN BY R. PATEY

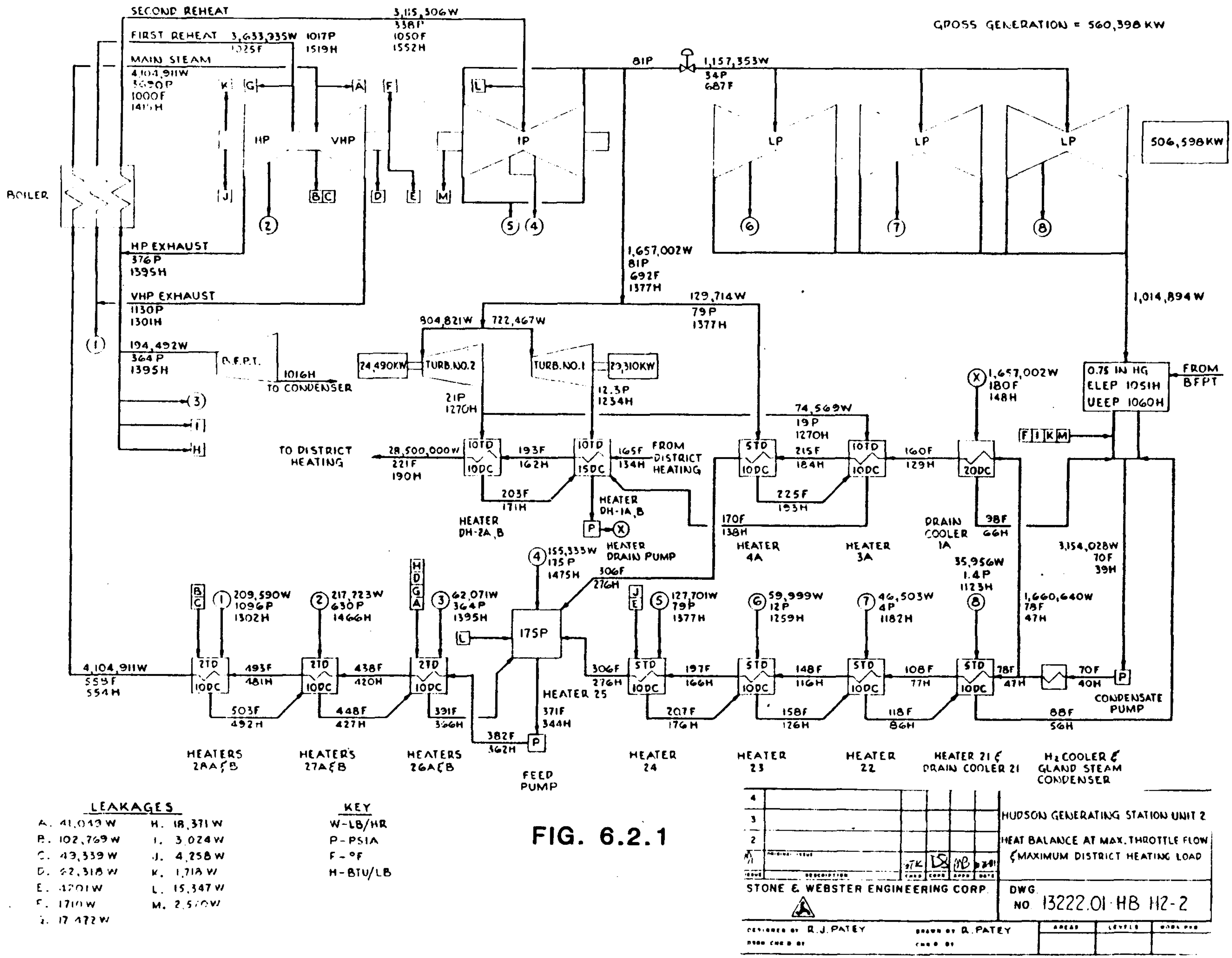
service in the late nineteen seventies. Before it was retired, the unit had been converted to burn oil.

6.2.3 HUDSON UNIT 2 PLANT RETROFIT

6.2.3.1 CONCEPTUAL DESIGN

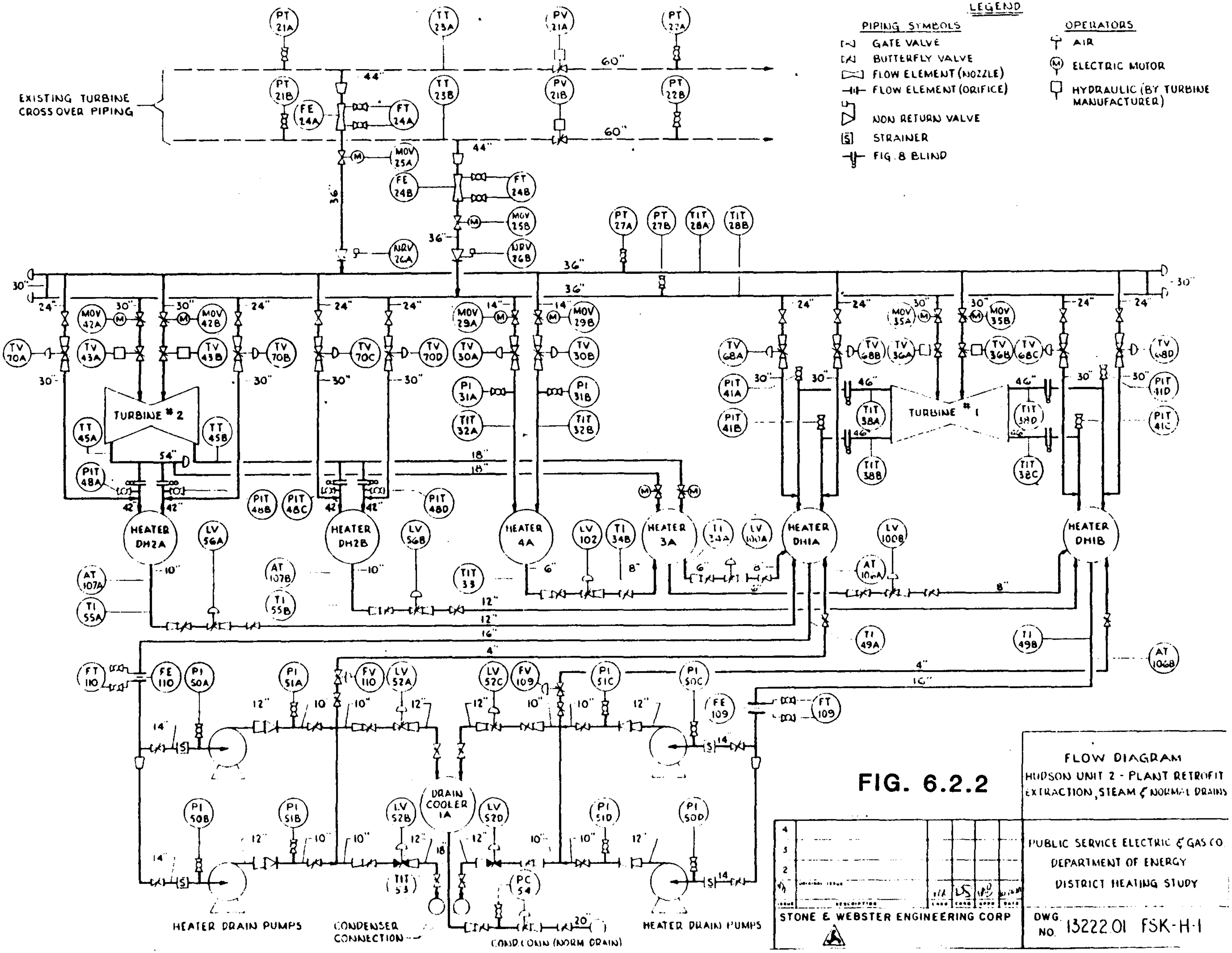
The plant retrofit scheme for Hudson Unit 2 provides for two stages of heating of the district heating water. Two back-pressure turbine-generators, (No. 1 & No. 2), rated 36 MW and 30 MW respectively, are powered by steam extracted from the cross-overs of the main unit at the conditions of 81 psia and 692 F. The exhaust pressures of the two turbines are 21 psia and 11.5 psia respectively. Steam from the turbine exhausts is condensed in shell and tube heat exchangers, or heaters, which heat the district heating water. It was estimated, based on a study performed by Westinghouse Electric (Appendix A), that 1.65×10^6 pounds steam per hour can be extracted from the main turbine cross-overs. With the above steam flow, approximately 28.5×10^6 pounds water per hour (59,600 GPM) can be heated from a return temperature of 165 F to the supply temperature of 221 F. Fig.6.2.1 shows the heat balance of the unit operating at maximum throttle flow with maximum steam extraction from the cross-overs for district heating.

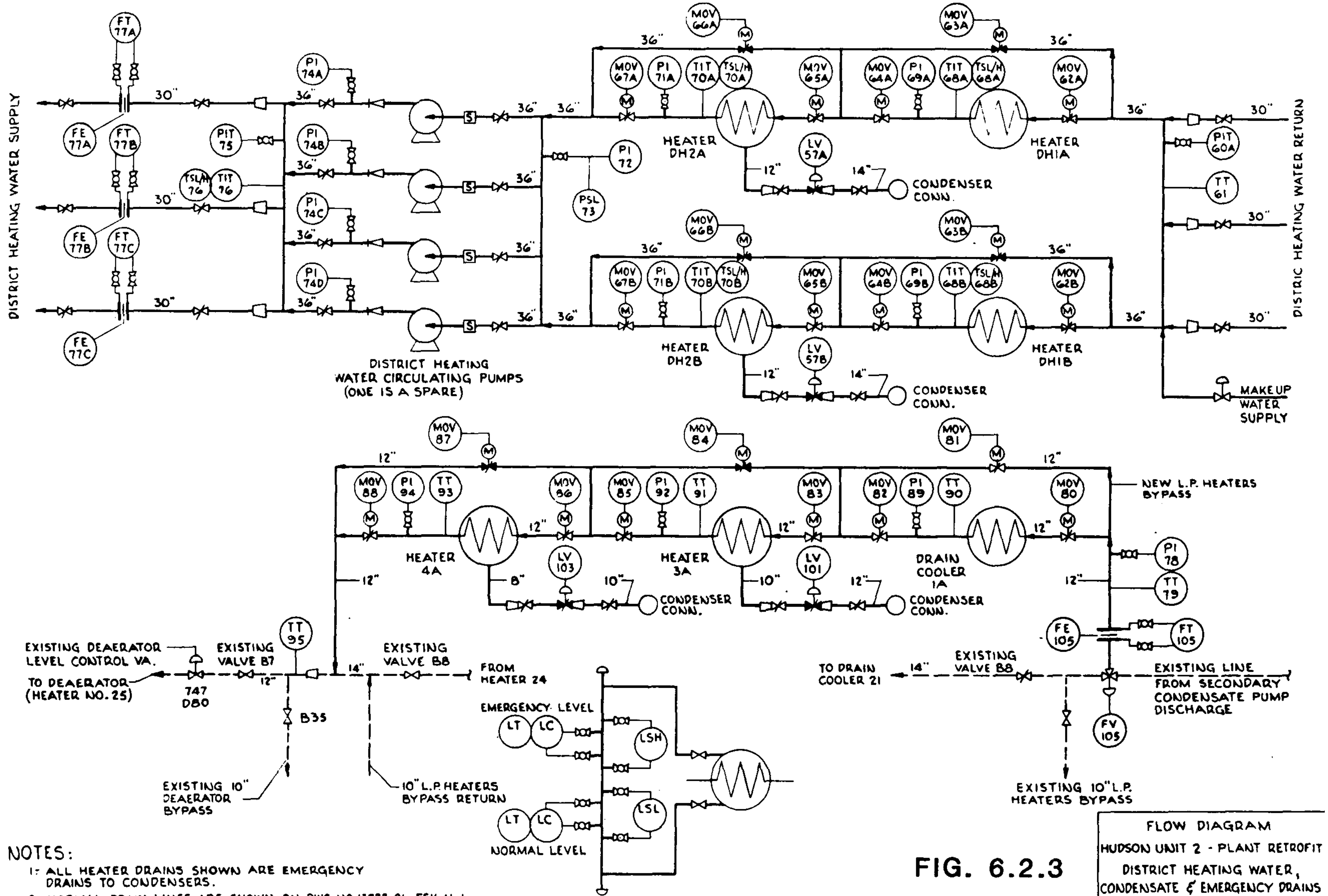
The flow diagrams of the water heating system at the Hudson Station are shown in Fig.6.2.2&6.2.3. Two parallel trains of heaters (Heaters DH2A & DH2B, and Heaters DH1A & DH1B) are provided to heat the district heating water. The water is delivered by four circulating pumps, each rated 22,000 GPM at 450 feet, one of which serves as a standby. Each pump is preceded by a single-basket strainer. District heating water leaving the retrofit plant is conveyed through three 30 inch lines. The flow through each line is monitored by a flow element. A separate new heater train, consisting of two condensate heaters (Heater 4A & Heater 3A) and an external drain cooler (Drain Cooler 1A), is



GROSS GENERATION = 560,398 KW
SECOND REHEAT
3,115,506 W
338 P
1050 F
1552 H
FIRST REHEAT 3,633,935 W 1017 P 1519 H
1025 F
MAIN STEAM
4,104,911 W
1000 F
81 P
1,157,353 W
34 P
687 F
BOILER
HP
VHP
IP
LP
LP
LP
506,598 KW
HP EXHAUST
376 P
1395 H
VHP EXHAUST
1130 P
1301 H
194,492 W
364 P
1395 H
B.F.P.T.
1016 H
TO CONDENSER
1,657,002 W
81 P
692 F
1377 H
129,714 W
79 P
1377 H
1,014,894 W
804,821 W
722,467 W
24,490 KW
TURB. NO. 2
TURB. NO. 1
23,310 KW
21 P
1270 H
12.3 P
1234 H
1,657,002 W
180 F
148 H
0.75 IN HG
ELEP 1051 H
UEEP 1060 H
FROM BFPT
74,569 W
19 P
1270 H
TO DISTRICT HEATING
28,500,000 W
221 F
190 H
193 F
162 H
165 F
134 H
FROM DISTRICT HEATING
215 F
184 H
160 F
129 H
203 F
171 H
225 F
193 H
HEATER DH-2A, B
HEATER DH-1A, B
HEATER DRAIN PUMP
170 F
138 H
HEATER 4A
HEATER 3A
DRAIN COOLER 1A
98 F
66 H
155,333 W
175 P
1475 H
306 F
276 H
3,154,028 W
70 F
39 H
35,956 W
1.4 P
1123 H
209,590 W
1096 P
1302 H
217,723 W
630 P
1466 H
62,071 W
364 P
1395 H
175 P
127,701 W
79 P
1377 H
59,999 W
12 P
1259 H
46,503 W
4 P
1182 H
1,660,640 W
78 F
47 H
4,104,911 W
558 F
554 H
493 F
481 H
438 F
420 H
306 F
276 H
197 F
166 H
148 F
116 H
108 F
77 H
78 F
47 H
70 F
40 H
503 F
492 H
448 F
427 H
391 F
366 H
382 F
362 H
HEATER 25
371 F
344 H
207 F
176 H
158 F
126 H
118 F
86 H
88 F
56 H
CONDENSATE PUMP
HEATERS 28A & B
HEATERS 27A & B
HEATERS 26A & B
FEED PUMP
HEATER 24
HEATER 23
HEATER 22
HEATER 21 & DRAIN COOLER 21
H_2 COOLER & GLAND STEAM CONDENSER
LEAKAGES
A. 41,013 W
B. 102,769 W
C. 43,339 W
D. 62,318 W
E. 4201 W
F. 1710 W
G. 17,472 W
H. 18,371 W
I. 3,024 W
J. 4,258 W
K. 1,718 W
L. 15,347 W
M. 2,570 W
KEY
W - LB/HR
P - PSIA
F - °F
H - BTU/LB
HUDSON GENERATING STATION UNIT 2
HEAT BALANCE AT MAX. THROTTLE FLOW & MAXIMUM DISTRICT HEATING LOAD
STONE & WEBSTER ENGINEERING CORP.
DWG. NO. 13222.01-HB H2-2
R. J. PATEY
R. PATEY

FIG. 6.2.1


LEGEND
PIPING SYMBOLS
GATE VALVE
BUTTERFLY VALVE
FLOW ELEMENT (NOZZLE)
FLOW ELEMENT (ORIFICE)
NON RETURN VALVE
STRAINER
FIG. 8 BLIND
OPERATORS
AIR
ELECTRIC MOTOR
HYDRAULIC (BY TURBINE MANUFACTURER)
EXISTING TURBINE CROSSOVER PIPING
TURBINE #2
TURBINE #1
HEATER DH2A
HEATER DH2B
HEATER 4A
HEATER 3A
HEATER DH1A
HEATER DH1B
DRAIN COOLER 1A
HEATER DRAIN PUMPS
CONDENSER CONNECTION
COND. CONN (NORM DRAIN)
FLOW DIAGRAM
HUDSON UNIT 2 - PLANT RETROFIT
EXTRACTION, STEAM & NORMAL DRAINS
PUBLIC SERVICE ELECTRIC & GAS CO.
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY
STONE & WEBSTER ENGINEERING CORP
DWG. NO. 13222.01 FSK-H-1
FIG. 6.2.2



TYPICAL STANDPIPE ARRANGEMENT FOR HEATER LEVEL CONTROL

NOTES:

1: ALL HEATER DRAINS SHOWN ARE EMERGENCY DRAINS TO CONDENSERS.
2: NORMAL DRAIN LINES ARE SHOWN ON DWG. NO. 13222.01-FSK-H-1.

FIG. 6.2.3

4					
3					
2					
M	ORIGINAL ISSUE	GTK	DR	AB	[illegible]
ISSUE	DESCRIPTION	CHKD	COND	APPD	DATE

STONE & WEBSTER ENGINEERING CORP.

FLOW DIAGRAM
HUDSON UNIT 2 - PLANT RETROFIT
DISTRICT HEATING WATER, CONDENSATE & EMERGENCY DRAINS

PUBLIC SERVICE ELECTRIC & GAS CO.
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY

DWG. NO. 13222.01-FSK-H-2

provided on an L-P heater by-pass line. This by-pass line branches off from the main condensate line upstream of Drain Cooler 21 through a new three-way valve, runs parallel to the existing low-pressure feedwater heaters, and rejoins the main condensate line after Heater 24, upstream of the deaerator. The two condensate heaters admit steam from the cross-overs and from the No. 2 Turbine exhaust respectively. The new heater train provides additional heating capacity for the condensate stream and prevents overloading of Heater 24 and the deaerator during district heating operation. The three-way valve regulates the amount of condensate flow by-passing the low-pressure heaters such that the by-pass flow matches the extraction steam flow from the cross-overs.

The butterfly valves to be installed on the turbine cross-over pipes will be pressure control valves. The valves will be modulated to maintain the intermediate-pressure (IP) turbine exhause pressure within allowable limits. Maintaining of this pressure is necessary to insure adequate cooling steam flow through the low-pressure (LP) turbine and to prevent excessive steam temperature from developing at both the LP inlet and the LP exhaust. The valves will be specified to fail open. Stops to prevent complete closure will be provided to insure that mimimum steam flow to the LP turbine can be obtained at all times. The valves will have hydraulic actuators and will be able to open fully in 1.5 seconds. This response time is needed to prevent unacceptable pressure transients at the IP exhaust in the event of tripout of both back-pressure turbines.

Extraction steam from the cross-overs is conveyed to the two back-pressure turbines through two 36 Inch lines. Each of the lines is provided with a flow element, an atmospheric relief valve, a motor operated shut-off valve, and an air operated non-return valve. The motor operated valves are programed to close in the event that the measured extraction steam flow is greater than the allowable extraction steam flow, such as in the case of a pipe rupture. The atmospheric relief valves protect the main turbine and Heater 24 from overpressure in the event of malfunction of the butterfly pressure control valves.

A backup steam supply system is provided for the district heating water heaters. In the event that the back-pressure turbines are not available, steam to the heaters is obtained from the cross-overs through pressure reducing valves.

Drains from Heaters DH2A & DH2B are cascaded to Heaters DH1A & DH1B in their respective trains. Four 50-percent capacity heater drain pumps are provided, two of which serve as standby, to pump the heater drains from Heaters DH1A & DH1B to Drain Cooler 1A. Each of the pumps is rated 1960 GPM at 150 feet. The heater drain is cooled in the drain cooler before returning to the condenser. Drain from the higher pressure Condensate Heater 4A is cascaded to Condensate Heater 3A. Drain from the latter heater is returned to the condenser. Emergency drain lines to the condenser are provided for all the heaters except Heaters DH1A & DH1B. Drains from these two heaters can be disposed of to the condenser directly through the heater drain pumps.

A major consideration in the development of the retrofit scheme for Hudson Unit 2 is to insure a high quality of feedwater entering the once-through steam generator. With this objective in view, the conceptual design of the plant retrofit requires that all the heater drains to be returned to the condenser and pumped through the full flow condensate polisher. Preliminary calculations show that the existing polisher has adequate capacity to sustain a 3/4 inch heater tube failure for several hours while maintaining acceptable feedwater quality. However, in the event of a heater tube failure, a heater should be taken out of service as soon as possible. For this purpose, remote capability to isolate and bypass a heater has been provided.

The back-pressure turbines will have external butterfly stop valves and external butterfly control valves. Presently inlet control valves integral with the turbines and of the size needed to pass the required volume flow rate are not available. External valves have been used in similar size low-pressure turbines for geothermal steam applications. According to one turbine manufacturer, the efficiency of the turbines will be in the mid 80-percent range. The performance of the turbines is based on a four-percent pressure drop through the double inlet valves, (there is no turbine bowl pressure drop). Synchronizing of the turbine-generator is accomplished while the turbine is running at no load flow. Once the generator is locked in with the outside frequency, load on the turbine can be raised. The back-pressure turbine will be specified to include overspeed protection which trips the turbine at 110-percent of the rated speed.

A study was made to determine if back-pressure turbines can be justified economically. This study compares the proposed retrofit scheme, ie., with two back-pressure turbines, with an alternate scheme with no back-pressure turbines. To be conservative, an efficiency of 75-percent was used for the back-pressure turbines. For the alternate scheme, pressure reducing valves were used in the place of the back-pressure turbines to reduce the pressure of the extraction steam to the district heating water heaters. The maximum difference in generation between the two schemes is 37,700 KW in favor of the proposed scheme (based on heat balance calculation). The capacity factor of the two back-pressure turbines was estimated to be about 40-percent. Using the following economic factors, the capitalized fuel cost saving obtainable by adopting the proposed scheme was determined

Cost of Money (ie., Discount Rate)	11 percent
Fuel Price Escalation Rate	9 percent
Carrying Charge	14 percent
1982 Replacement Energy Cost	$ 0.05 /KW-Hr.
Plant Life	30 years

The fuel cost saving amounts to over 100 million dollars and is several times the estimated capital cost of the back-pressure turbine-generators and the ancillary equipment. The replacement energy cost shown above was based on the projected average PJM (Pennsylvania, New Jersey, & Maryland Interchange) running rate for 1982. The fuel price escalation rate was based on anticipated price increases for No. 6 fuel oil.

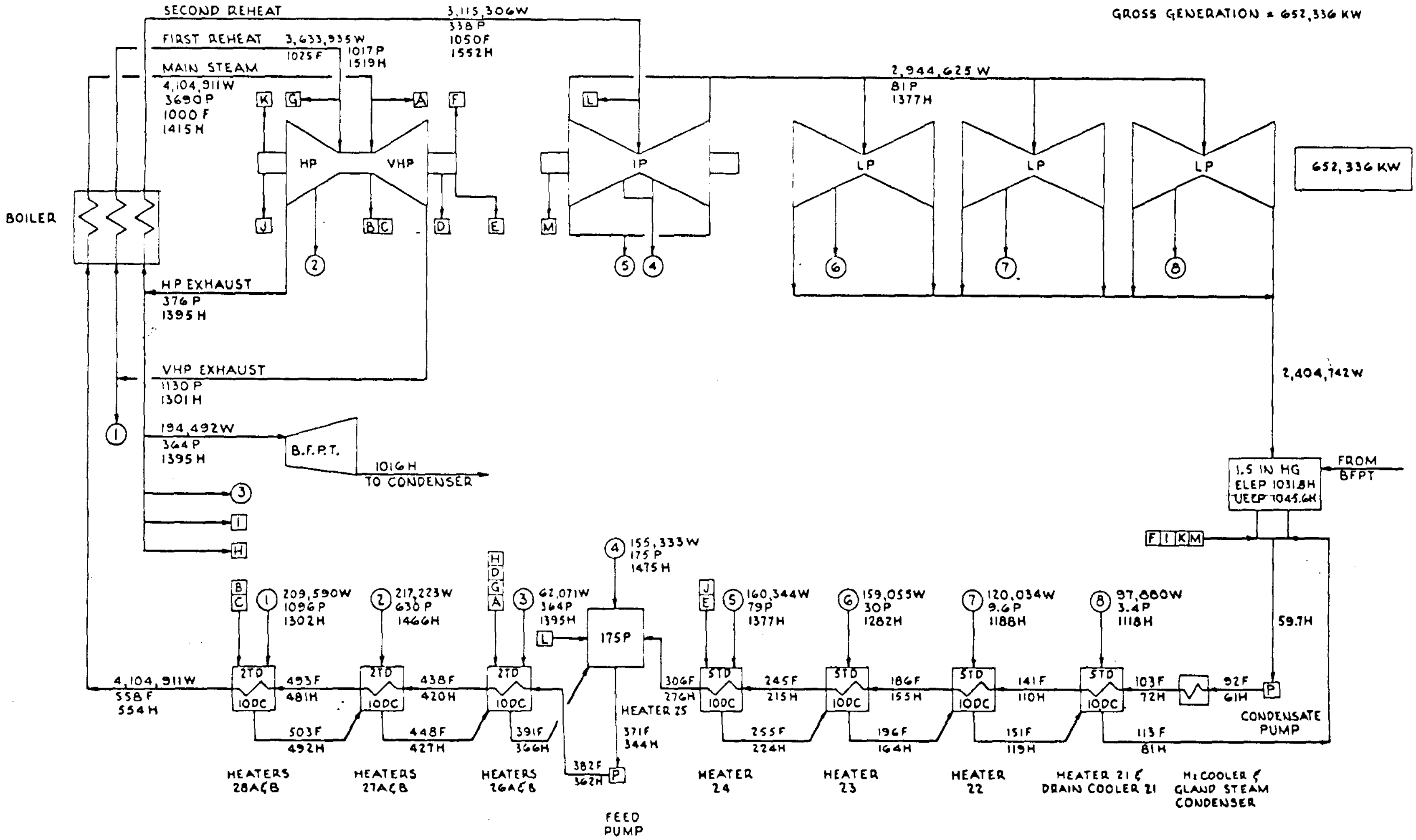
6.2.3.2 OPERATION

During operation when a large quantity of steam is extracted from the cross-overs, the LP turbine extraction pressures become very low. The extraction steam flows to the low-pressure heaters are also very low. As a consequence, the temperature of the condensate entering Heater 24 is much lower than the corresponding condensate temperature when the unit is operating without district heating. The temperature of the condensate leaving Heater 24, however, is not affected by steam extraction from the cross-overs, since steam to Heater 24 is taken from the turbine upstream of the cross-over pipes. To prevent overloading Heater 24 and the deaerator during district heating operation, the condensate heating load is shared between the new heater train and the existing low-pressure heaters.

Based on the study by Westinghouse, the cross-over steam extraction flow of 1.65 x 10^6 pounds per hour can be maintained from the valves-wide-open and 5-percent over-pressure condition down to 74 percent maximum guaranteed throttle flow. Below 74 percent maximum guaranteed throttle flow, the extraction steam flow from the cross-overs must be reduced to maintain adequate cooling flow through the LP turbine and to prevent excessive LP inlet and LP exhaust temperatures. The maximum allowable extraction steam flows at the different throttle flows are shown in Fig. 6.2.4.

The existing low pressure heaters at Hudson Unit 2 were arranged for gravity draining. Two heater drain pumps presently pump the drain flow from Heater 21 to Drain Cooler 21. During operation when steam is extracted from the cross-overs for water heating, the heater pressures of Heaters 21, 22, and 23 will be lower than the corresponding heater pressures when the unit is operating without water heating; however, the drain flows from these heaters will also be reduced. Preliminary calculations show that the pressure differences between the successive heaters are adequate for proper draining. Also the existing heater drain pumps have sufficient capacity under the district heating mode of operation.

Recently new vacuum pumps were installed on Hudson Unit 2 to increase the capacity for air removal from the condenser. With the new pumps, the condenser pressure can be brought down to as low as 0.6 Inch Hg. absolute at low load. Low condenser pressure will be experienced during winter when large amount of steam is extracted from the cross-overs for water heating.



LEAKAGES

A. 41,049 W
B. 102,769 W
C. 49,339 W
D. 62,318 W
E. 4201 W
F. 1710 W
G. 17,472 W
H. 18,371 W
I. 3,024 W
J. 4,258 W
K. 1,718 W
L. 15,347 W
M. 2,570 W

KEY

W – LB/HR
P – PSIA
F – °F
H – BTU/LB

FIG. 6.2.4

4						HUDSON GENERATING STATION UNIT 2
3						HEAT BALANCE AT MAX. THROTTLE FLOW
2						NO DISTRICT HEATING
A	ORIGINAL ISSUE	GTK	DR	MB		
ISSUE	DESCRIPTION				DATE	

STONE & WEBSTER ENGINEERING CORP.

DWG. NO. 13222.01 - HB - H2 - 1

In a fully developed district heating system, the water heating plant at the Hudson Station will have a capacity factor of about 40 percent. This capacity factor corresponds to approximately 3,500 hours of full load operation per year. During the periods of full load operation, the district heating water flow, the extraction steam flow, and the district heating water temperature rise will all remain constant. At lower load, both the district heating water flow and the water temperature rise will be reduced. During periods of very low heating load, Turbine No. 2, which supplies steam to the second stage Heaters DH2A & DH2B, will be shut down, leaving Turbine No. 1 running.

The Westinghouse study shows that the butterfly valves on the cross-overs will have a pressure drop of about 0.3 psi when the unit is operating at maximum throttle flow and rated steam conditions, with no steam extraction from the cross-overs. The loss in generation due to this pressure drop is less than 0.05 percent, or about 275 KW. The resulting heat rate penalty is about 5 Btu/KW-hr. With maximum throttle flow and maximum extraction from the cross-overs, the pressure drop through the butterfly valves is approximately 49 psi and the reduction in generation is about 92 MW. The reduction in generation during district heating operation will vary with the amount of steam extracted and the IP exhaust pressure. Fig.6.2.14 shows the relationship between boiler output and generation of the retrofitted unit at different percent district heating loads. In this figure, the generation is the total electrical output of the unit, including the back-pressure turbine-generators, prior to deducting the plant auxiliary power requirements.

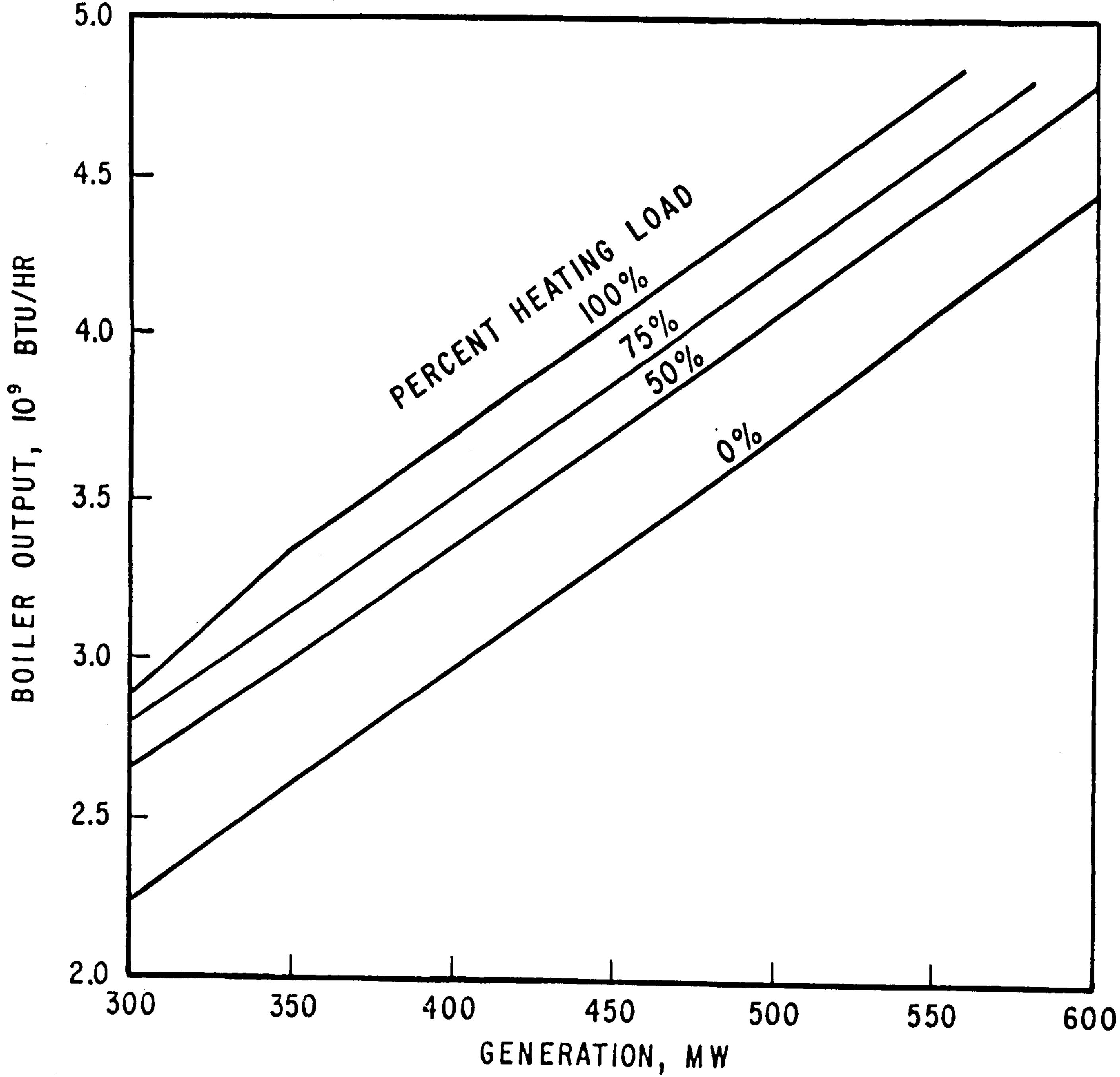


FIG. 6.2.14
BOILER OUTPUT VS. GENERATION

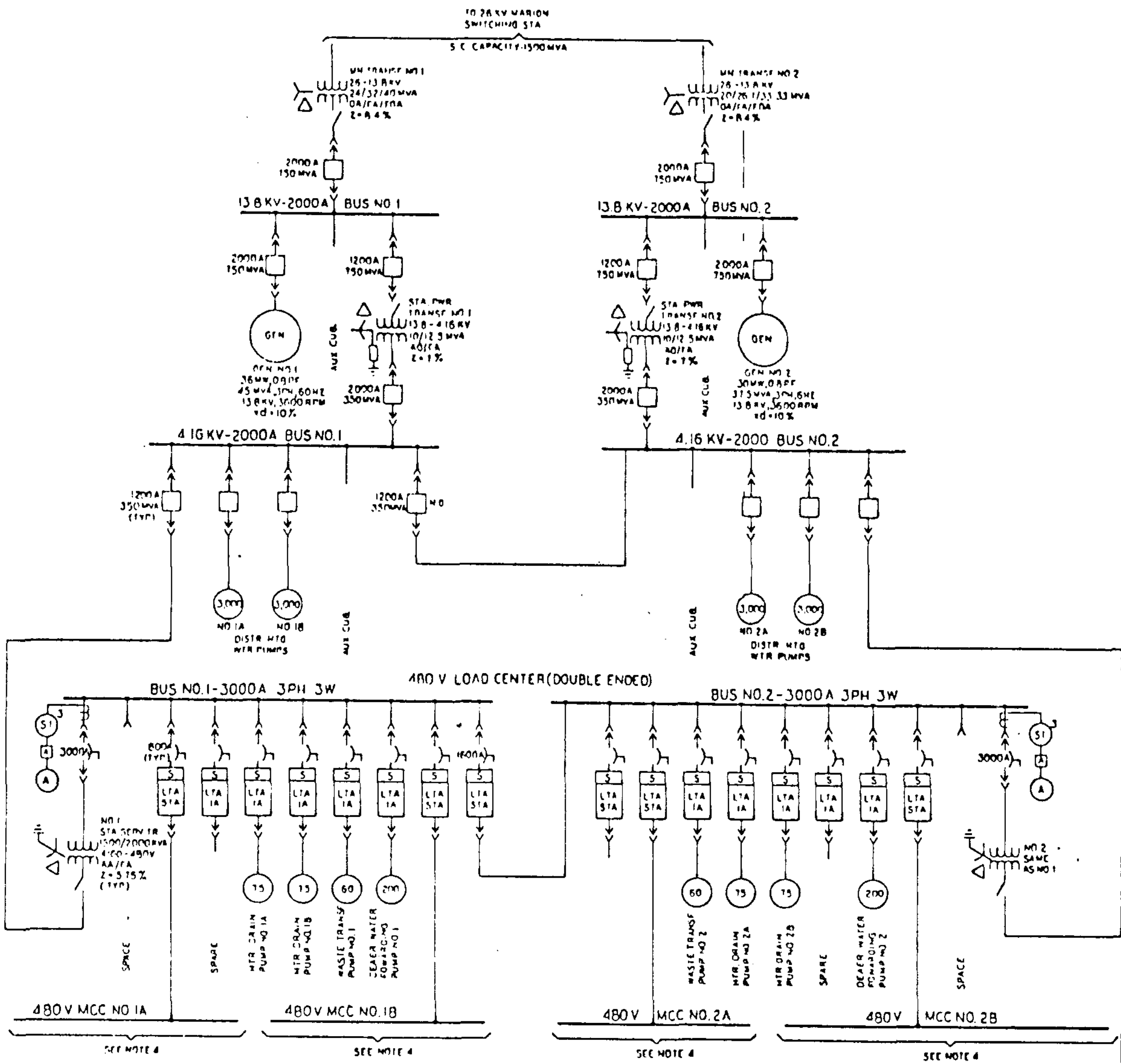
6.2.3.3 ELECTRICAL SYSTEM

Power Distribution

The two new generators to be driven by the back-pressure turbines will be hydrogen cooled, rated 45,000 KVA and 37,500 KVA respectively, 0.8 PF, 13.8 KV, 3600 RPM, 3-Phase, 60 Hertz. Each generator will be grounded through its own neutral grounding transformer and resistor. Fig. 6.2.5 shows the one line diagram for the new equipment.

In order to minimize short circuit duty on the 13.8 KV equipment, two separate 13.8 KV Switchgear Buses will be provided, one for each generator. Each bus will consist of 2000A generator circuit breaker, 1200A feeder breaker to station power transformer for the district heating auxiliary loads, and 2000A main circuit breaker through which generator output will be connected through the main transformer to the 26 KV Station Switchyard (not shown on the drawings). Additional switchgear cubicles will be provided to house generator protective relays, main transformer protection, metering, and synchronizing controls. All 13.8 KV circuit breakers will have 750 MVA short circuit interrupting capacity, and 13.8 KV, 2000A bus shall be braced for a minimum of 800 MVA short circuit withstand capacity.

Main transformers will be outdoor, OA/FA/FOA type, 26 KV WYE-13.8 KV Delta, 3-Phase, 60 Hertz, 200 KV BIL. Rating for Generator No. 1 Main Transformer will be 24/32/40 MVA and 20/26.7/33.34 MVA for the Generator No. 2. Bushing current transformers and lightning arresters will be provided for each transformer. 15 KV, 2000A disconnect switch, grounding type, will be provided for each main transformer isolation.



REFERENCES:

ELECTRICAL SYMBOLS S&W STD-ME-10-4 THRU STD-ME-10-8

NOTES:

1. PROTECTION, RELAYING, METERING, SYNCHRONIZING AND CONTROLS ARE NOT SHOWN.
2. ALL 800AF CIRCUIT BREAKERS ON 480V LOAD CENTER SHALL BE OF 42,000 AMPERE INTERRUPTING AND SHORT-TIME CAPABILITY AT 480V, SIMILAR TO G.E. TYPE AKR-30H.
3. 13.8KV BUS TO BE BRACED FOR 800 MVA.
4. EACH MOTOR CONTROL CENTER WILL HAVE THE FOLLOWING EQUIPMENT:

COMBINATION STARTERS CIRCUIT BKR TYPE:
FVNR NEMA SIZE 3 – 3
SIZE 2 – 2
SIZE 1 – 5
FVR NEMA SIZE 2 – 3
SIZE 1 – 5

CIRCUIT BREAKERS:
225 AF – 1
100 AF – 3

SPACES FOR FUTURE USE:
FVNR NEMA SIZE 1 – 2
CKT BKR 100 AF – 2

FIG. 6.2.5

SYSTEM					
M1	7/14/81	ORIGINAL ISSUE	JM		
NO.	DATE	DESCRIPTION OF ISSUE	BY	CHK	APPD

ONE LINE DIAGRAM
HUDSON UNIT 2 – PLANT RETROFIT

PUBLIC SERVICE ELECTRIC & GAS CO
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY

M J MANOLIO

13222.01	ESK-H-1	1

The district heating loads and required auxiliary loads will be supplied through two station power transformers to two 4.16 KV buses. Each transformer will be rated 13.8 KV-4.16 KV, 10/12.5 MVA, OA/FA, 3-Phase, 60 Hertz, each of sufficient capacity for the total auxiliary load.

Each transformer will be supplied from separate 13.8 KV bus, and will be connected to its own 4.16 KV bus. The normally open, 1200A air circuit breaker will be provided, to tie the two 4.16 KV buses in case one station power transformer should be out of service.

Start-up power will be supplied from the 26 KV switchyard, through main transformers to the station power transformers.

During normal operation, each generator will supply station auxiliary power to its own 4.16 KV section, and excess power will be delivered to the electrical grid at the 26 KV switchyard through main transformers.

Two sections of 4160 V switchgear, one double ended 480 KV load center and four 480 V motor control centers will be provided to distribute power to auxiliary and district heating loads.

Each 4160 V switchgear will consist of 2000A, 350 MVA main and 1200A air circuit breaker and 1200A, 350 MVA feeder breakers.

Each switchgear cubicle will contain current transformers and protective relays as required. Separate switchgear cubicle will be provided to house potential transformers, auxiliary relays and metering.

Power from the 4160 V switchgear will be supplied to large motors (300 HP and above) and to the load center. The 480 V load center will be double ended.

Each station service transformer will be sized adequately for the total 480 V load, should one transformer be out of service. In this case the normally open tie circuit breaker will close to connect both sections of the 480 V load center.

Each low voltage section of the load will consist of air circuit breakers with static trips, with long time and short time or instantaneous trips, as applicable, to obtain trip coordination.

Load center will supply large 480 V loads including motors 60 HP and larger, and motor control centers (two per each 480 V bus section).

Four motor control centers will be provided, consisting of starters and air circuit breakers to supply smaller motors (50 HP and less), motor operated valves, lighting and power transformers and welding receptacles.

125 VDC System

For control of the 13.8 KV generator breakers, 4.16 KV breakers, 480 V load center air circuit breakers and emergency lighting and two 120 V DC motors for the emergency bearing oil pumps, a 125 V DC battery, battery charger and DC distribution switchboard will be provided. The battery will be of the lead-acid type, adequately sized for 2 hours duty cycle in case of power failure. Battery charger will be of the static type. The 125 V DC distribution switchboard will contain relays and meters for protection and monitoring of the system.

120/208 V Regulated Power Supply

For control and instrumentation circuits requiring regulated safe power, regulated power system will be provided. It will consist of two 30 KVA, 480-208/120 V dry type transformers, two 22.5 KVA voltage regulators, automatic transfer switch of mechanical or static type, as required, and 120/208 V AC distribution power panel. One transformer and voltage regulator will be supplied from new motor control center No.1A. The back-up power to the other transformer and regulator will be brought from new 480 V motor control center No.2A.

Grounding

Grounding will be provided for new building and equipment. A ground loop consisting of 4/0 bare copper cable and grounding rods will be installed around the perimeter of new building and interconnected with the existing station ground loop. All electrical equipment, building steel etc. will be grounded in accordance with PSE&G grounding standards and practice.

Raceways and Underground Ducts

All main power cable, 15 KV and 5 KV will be run in galvanized steel conduits. Separate galvanized steel trays will be used for 480 V power, control and instrument cable, except conduit will be used for local runs from tray to equipment.

Underground ducts consisting of plastic conduit encased in concrete will be used for long runs outdoors as required.

Wire and Cable

All cable will be fire retardant, EPR insulation with neoprene jacket, stranded copper. Insulation levels as follows:

15 KV-1/c cable, shielded for all 13.8 KV CKTS ungrounded service

5 KV-1/c cable, shielded for all 4160 V CKTS grounded service

All other power cable will be 600 V insulation, single or multiconductor.

All control cable will be copper, stranded, 600 V EPR insulation, neoprene jacket, multiconductor cable. Instrument cable will be shielded, 300 V EPR insulation, neoprene jacket, No.16 AWG single pair, or No.18 AWG multipair.

Thermocouple cable will be chromel-constantan, shielded, 300 V insulation.

Lighting

All new indoor areas will be illuminated in accordance with the latest requirements of IES Levels of Illumination. High intensity discharge (HID) lamps of suitable type, will be used for all high bay and low bay areas. Incandescent fixtures will be used for other areas and for all emergency lighting. Illumination will be provided in accordance with current OSHA requirements for all exit facilities and means of egress. Normal a-c lighting system will be supplied from motor control center through 480-120/208 volt 30 KVA transformer, dry type, and lighting distribution panels. Emergency lights will be supplied from the 125V DC battery through separate DC panel board, which will be automatically energized on a-c power failure. Egress lighting and exit signs will consist of internally illuminated exit signs which will be normally powered from a-c circuit, but on a-c power failure will be automatically transfered to 125 V DC battery power. Convenience receptacles will be provided as required. Branch circuits supplying receptacles in wet and conductive areas will be provided with ground fault circuit interrupter (GFCI) protection. Outdoor areas will be illuminated with high intensity discharge (HID) lamps or incandescent lamps.

Lighting and receptacle wire will be solid copper for No. 12 and No. 10 AWG and stranded for No. 8 AWG and larger, and will have THWN thermoplastic 75°C insulation, moisture and heat resistant 600 V rating.

All lighting conduit will be minimum 3/4 inch and will be galvanized steel, EMT for indoor areas, and rigid galvanized steel for outdoor areas.

Public Address System

Public address system will be installed and connected to the existing system. The paging system will match the existing system as to paging and party-line channels.

Raceways and space for public telephones will be provided, as per requirements to be established.

6.2.3.4 CONTROL SYSTEM

Sufficient instrumentation and control devices are provided to operate the district heating water heating system in a safe and reliable manner, and to perform the basic diagnostic and performance calculations. The primary instrumentation is shown on the flow diagrams in Figures 3-2 & 3-3.

The district heating water heating system is designed for automatic operation with minimum operator interface. The main control room operator is not required to operate the water heating plant equipment, but only those systems that affect the power generation, including the two back-pressure turbine-generators. The monitoring and control devices for the extraction steam and the back-pressure turbine-generators will be located in the main control room on a separate free standing panel. The functions of this panel will include recording of extraction steam flow, pressure, and temperature; control of pressure regulating valves PV21A and 21B; control of extraction line isolation valves MOV25A and 25B; and control and power distribution of the back-pressure turbine-generators. In addition, the main control room panel will also have trouble alarm and critical parameter indications for equipment which interacts with the main plant operation, such as the district heating water heaters and heater drains to condenser.

All the new equipment, except for the extraction steam and the back-pressure turbine-generators, will be primarily monitored and controlled from a control room in the new water heating plant designed to house the district heating water equipment. The control room size will be approximately 15 ft. x 20 ft. It will contain at least three free standing control panels, with controls grouped as follows:

1. Heater temperature controls and drain flow controls

2. District heating water monitoring and control

3. District heating plant auxiliaries control, such as Heating, Ventilation and Air Conditioning Systems, Fire Protection Systems and Water Treatment Systems, etc.

The extraction steam pressure is controlled by modulating butterfly valves PV21A and PV21B in the cross-over piping. Normally, the demand for extraction steam to the district heating system must be satisfied first and the balance steam flow is sent to the LP turbine, except when the steam demand at the operating load is more than that permitted for safe operation of the LP turbine.

The control system to be incorporated uses the impulse chamber pressure (Very High Pressure Turbine first stage pressure) as an index of the throttle flow to set the limits on the maximum allowable extraction steam flow at the various loads. At a given impulse chamber pressure, an upper and a lower bounds of the IP exhaust pressure are computed. The operator can position the cross-over valves PV21A & 21B to control the extraction steam flow within the above range of IP exhaust pressure. The valve's opening will increase automatically if the upper limit is reached or will decrease if the lower limit is reached. Additional overrides are provided to open up the valves automatically if the LP inlet pressure (as a function of the impulse chamber pressure) tends to fall below a preset limit and the IP and the LP exhaust temperatures tend to exceed the preset limits.

The district heating water flow rate through the system is essentially constant at normal loads, but is reduced at lower loads. The district heating system load demand is satisfied by varying the district heating water supply temperature, based on the return water temperature and the outside ambient temperature. The steam flow to each district heating water heater is controlled based on a steam flow demand index computed from the following parameters:

a. Water temperature at the inlet to the heater. This temperature varies according to the outside ambient temperature, the number of heaters in service, and the return water temperature.

b. Desired water temperature at the outlet of the heater (Set Point). The setpoint at the outlet of a heater is a sliding number based on the outside ambient temperature and the number of heaters in service.

c. Water flow through the heaters.

The steam flow demand indexes for Heaters DH1A & 1B and Heaters DH2A & 2B control the steam flow and the electrical output of Backpressure Turbines-Generator Nos. 1 and No. 2 respectively. The temperature setpoint for the water leaving Heaters DH1A & 1B is approximately the average of the system supply and return water temperatures.

The L-P heater by-pass flow is regulated by the three-way flow control valve FV105. The by-pass flow is adjusted to match the extraction steam flow from the cross-overs. The steam flow to Condensate Heater 4A is regulated by control valves TV 30A, 30B to maintain the heater outlet water at the temperature of the condensate leaving Heater 24, (See Fig. 3-1). The drain temperatures at the outlets of Drain Cooler 1A and Heater 3A are not controlled.

If a heater's water level rises to a high level, the inlet drain valve will close. If a heater's level drops too low, the outlet drain valve will close. If the levels in Heaters DH1A & 1B, DH2A & 2B, or 3A rise too high, the associated back pressure turbine will be tripped.

The drain flow from each heater, in general, has two independent paths for discharge. For each heater, a "normal" and an "emergency" level transmitter/controllers are provided. In addition, separate low level and high level switches are provided for alarm to warn against an impending heater problem. The following tabulation shows the "normal" and the "emergency" drains from each heater.

Heater No.	Normal Drain to	Controller/ Valve	Emergency Drain to	Controller/ Valve
DH1A	Drain Cooler 1A	LC/LV52A	Condenser	LC/LV52B
DH1B	Drain Cooler 1A	LC/LV52C	Condenser	LC/LV52D
DH2A	Heater DH1A	LC/LV56A	Condenser	LC/LV57A
DH2B	Heater DH1B	LC/LV56B	Condenser	LC/LV57B
3A	Condenser	LC/LV100	Condenser	LC/LV101
4A	Heater 3A	LC/LV102	Condenser	LC/LV103
Drain Cooler 1A	Condenser	PC/PV54	--	--

Drain flows from Heaters DH1A and 1B are pumped to Drain Cooler 1A or the condenser by the redundant heater drain pumps. Only two of the four heater drain pumps will be operated at a given time. A minimum flow recirculation line is provided around each pair of heater drain pumps to essure that flow through the operating drain pump does not fall below the low flow limit.

The pressure of the district heating water flowing through the tubes of the heaters is higher than the steam and condensate pressure in the shell. In the event of a tube leakage, the district heating water will enter the condensate system. A water sampling and conductivity detection system is provided to continuously monitor the drain flow from each district heating water heater.

If an abnormal level of impurities is detected in the drain flow from a heater, an alarm will be sounded and the heater will be automatically isolated, if so desired. Since all the heater drains return to the condenser and are pumped through the polisher, the high quality of the feedwater will be maintained.

The flow rates of the district heating water leaving and returning to the retrofit plant are continuously monitored. The difference of the two flow rates is a measure of the system leakage. The make-up water flow control valve is modulated to supply the makeup flow equal to the leak rate.

System Monitoring and Control

The following monitoring and control functions are provided.

1. Extraction steam pressure control with flow limiting constraint (main control room).

2. Flow rate, pressure and temperature of steam extracted from each cross-over (main control room).

3. Back-pressure turbine-generators No. 1 and No. 2 integrated control and supervisory system (main control room).

4. Pressure and temperature of exhaust steam from each back-pressure turbine (main control room).

5. Inlet and outlet temperatures of district heating water at each heater.

6. Total flow of district heating water through the system.

7. Pressures and temperatures of supply and return district heating water.

8. High and low temperature (sliding) alarms for water at the outlet of each heater.

9. Control, monitoring, and protection of district heating water circulating pumps.

10. Control, monitoring, and protection of heater drain pumps.

11. Level control of water in the heater shell with split level drain flow controllers and low level/high level alarms.

12. Control of the L-P heater by-pass flow.

13. Monitoring and control of electrical equipment in the district heating water heating plant and ties to the switchyard.

14. Monitoring and control of auxiliary systems, such as instrument air, HVAC, and fire protection systems.

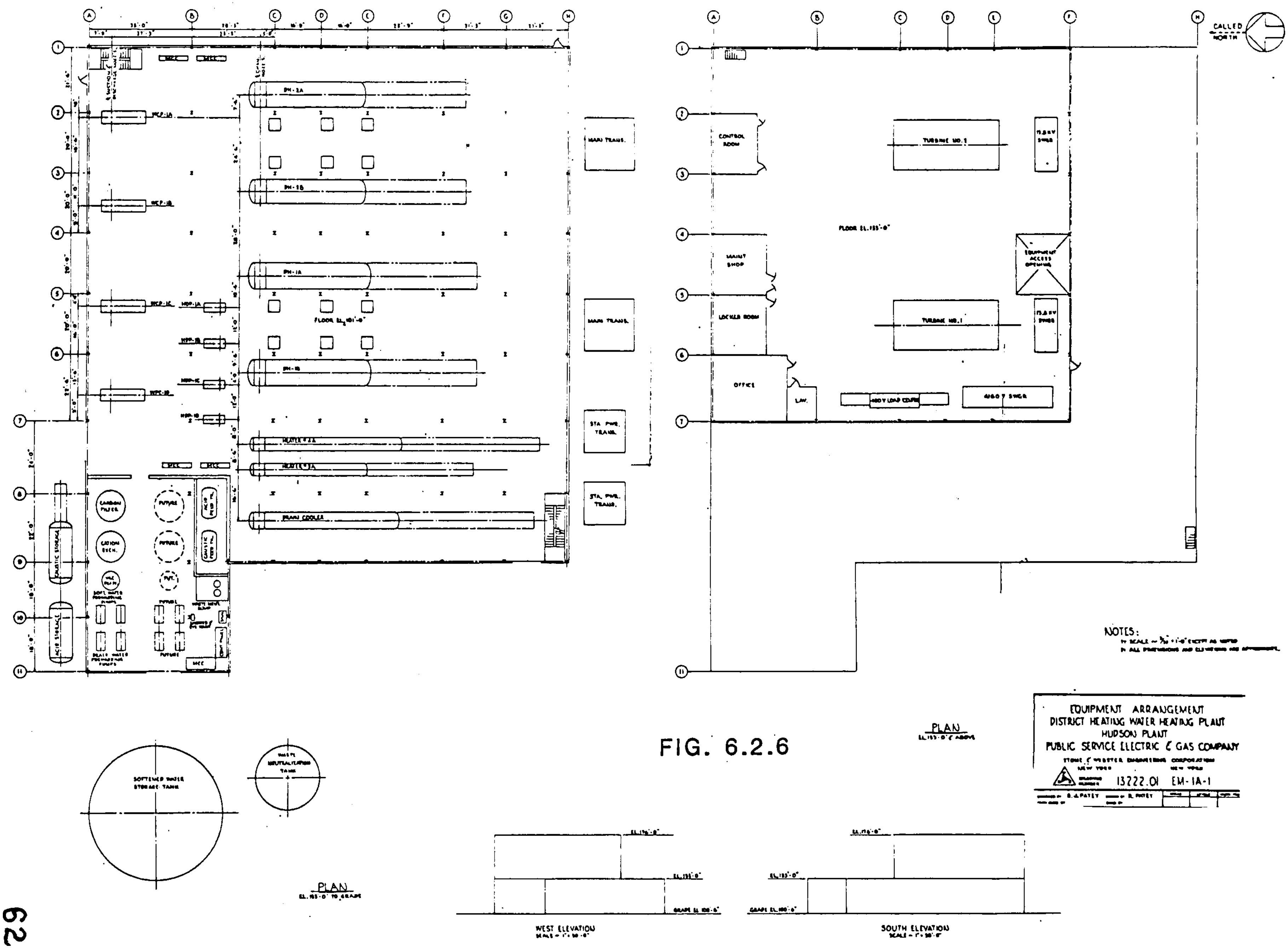
15. Monitoring of water quality in the drain line of each heater.

Additional instrumentation for detailed diagnostic and efficiency calculations are not included, but can be provided to assess the performance of all major equipment.

6.2.3.5 WATER HEATING PLANT ARRANGEMENT

All of the district heating water heaters, the condensate heaters, together with the back-pressure turbine-generators, pumps, electrical equipment, and water treatment facilities, will be housed in a new water heating plant, to be located between the No. 1 and the No. 2 Fuel Oil Tanks, directly east of the turbine laydown area. The only equipment to be located inside the existing turbine building consists of steam and condensate piping, drain lines, and the associated valves. The two extraction steam lines from the cross-overs will be located partly outdoors. Fig. 6.2.6 & 6.2.7 show the equipment arrangement inside this building.

The water heating plant measures approximately 206 feet long by 165 feet wide. It consists of two levels. The back-pressure turbine-generators and the electrical equipment are located on the upper level, or the operating level. A control room is also located on this level. The heaters, pumps, and the water treating equipment are located on the lower level. The building is equipped with an overhead bridge crane with a 50-ton main hook and a 10-ton auxiliary hook. (The crane capacity was determined by the component weights of the back-pressure turbine-generators). The roof of the upper level is at an elevation 75.5 feet above grade. The roof of the lower level is at an elevation 32.5 feet above grade. The building is constructed of a steel frame with insulated corrugated metalic sidings and poured concrete roof slabs with built-up roofing. The foundation of the building will be placed on piles. An underground pipe tunnel is provided to accommodate the pipings between the water heating plant and the existing turbine building, as shown in Fig. 6.2.8.



CALLED NORTH
MAIN TRANS.
STA. PWR. TRANS.
CARBON FILTER
CATION EXCH.
FUTURE
CAUSTIC STORAGE
ACID STORAGE
DRAIN COOLER
CONTROL ROOM
MAINT SHOP
LOCKER ROOM
OFFICE
LAV.
TURBINE NO. 1
NOTES:
PLAN
SOFTENED WATER STORAGE TANK
WASTE NEUTRALIZATION TANK
PLAN
WEST ELEVATION
SOUTH ELEVATION
EQUIPMENT ARRANGEMENT
DISTRICT HEATING WATER HEATING PLANT
HUDSON PLANT
PUBLIC SERVICE ELECTRIC & GAS COMPANY
13222.01 EM-1A-1

FIG. 6.2.6

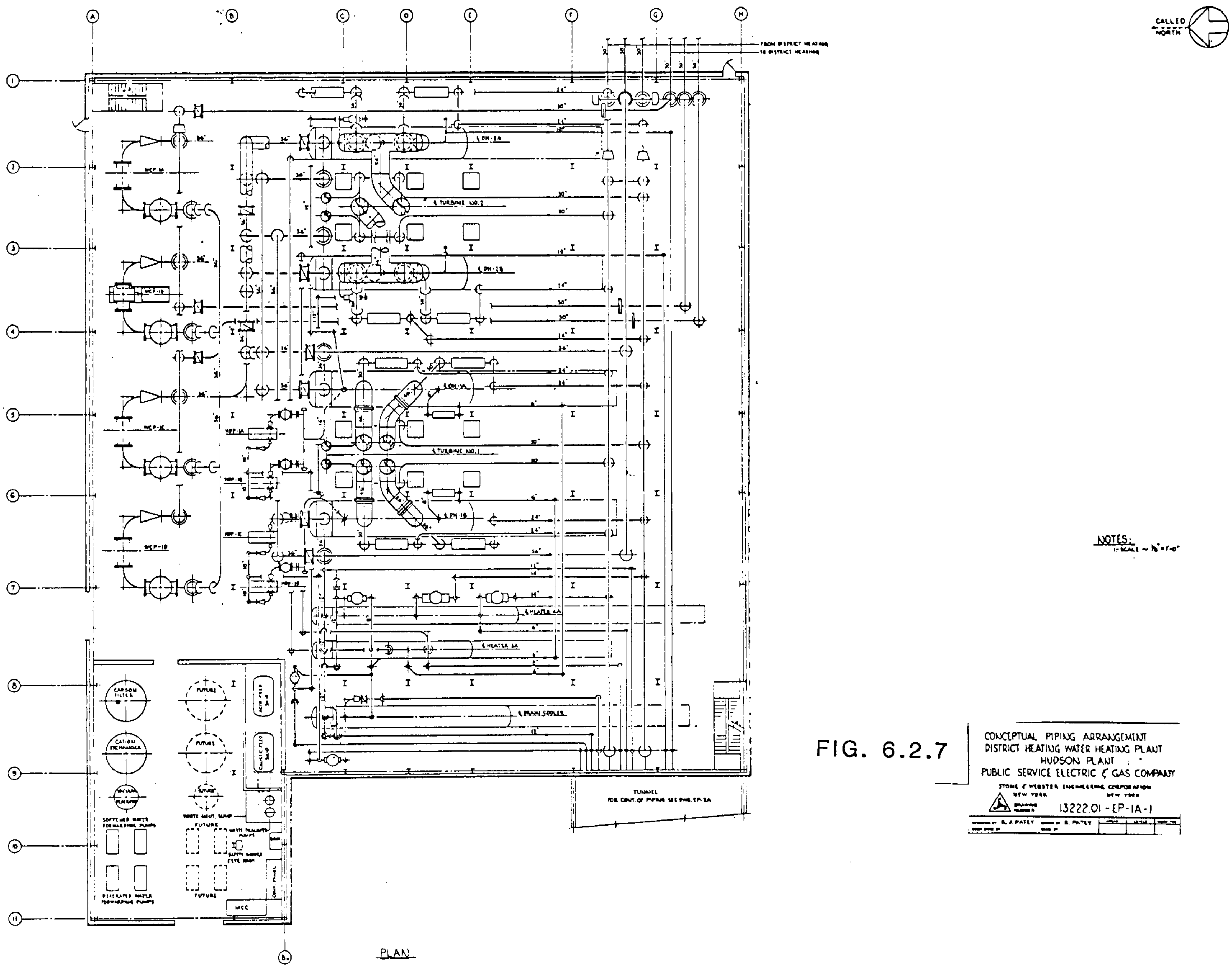


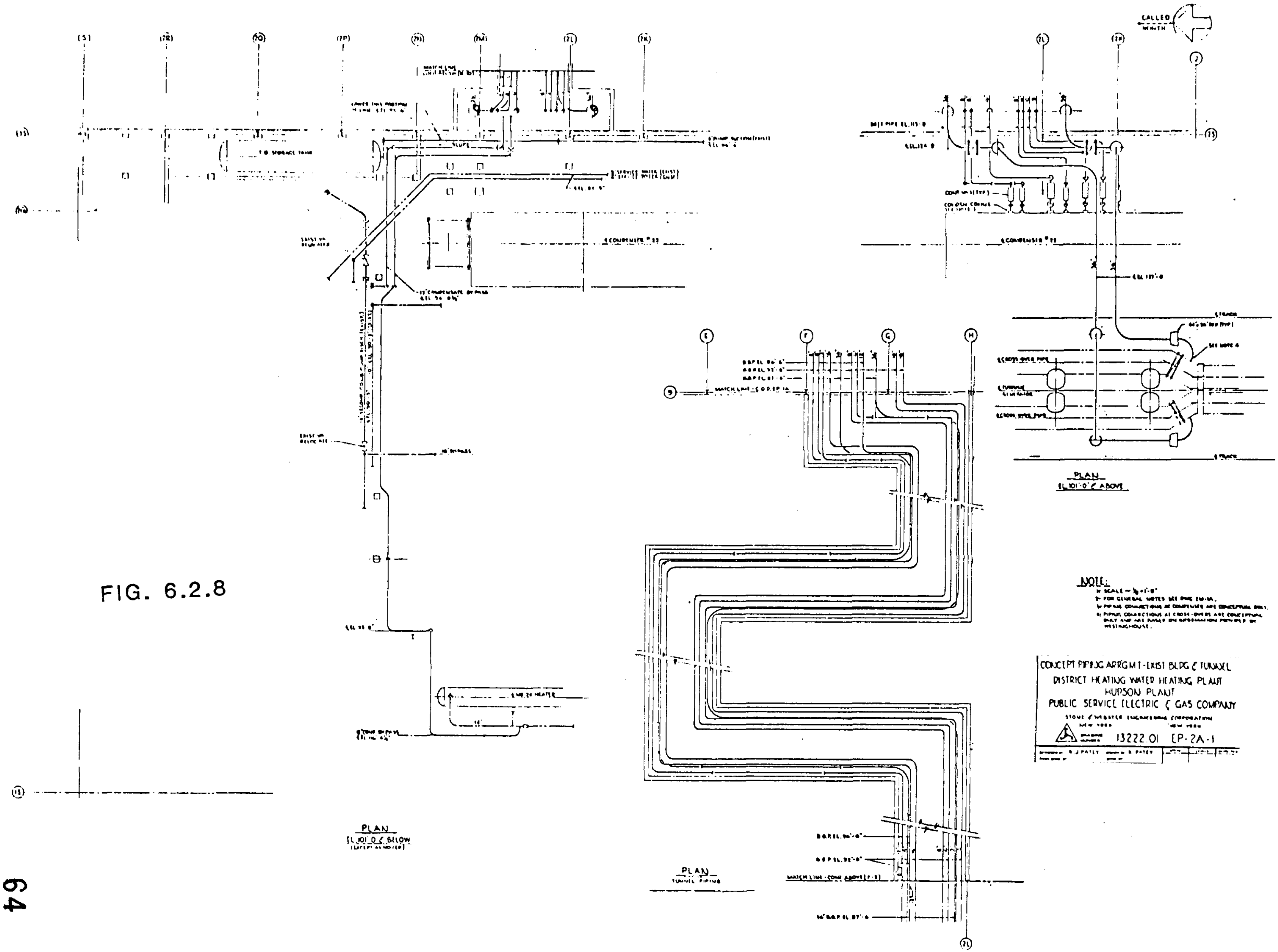
FIG. 6.2.7

CONCEPTUAL PIPING ARRANGEMENT
DISTRICT HEATING WATER HEATING PLANT
HUDSON PLANT
PUBLIC SERVICE ELECTRIC & GAS COMPANY

STONE & WEBSTER ENGINEERING CORPORATION
NEW YORK NEW YORK

13222.01 - EP - 1A - 1

R. J. PATEY B. PATEY



CALLED NORTH
ECOMPENSATE #13
PLAN
EL 101'-0" & ABOVE
PLAN
EL 101'-0" & BELOW
PLAN
TUNNEL PIPING
NOTE:
CONCEPT PIPING ARR'G'M'T - EXIST BLDG & TUNNEL
DISTRICT HEATING WATER HEATING PLANT
HUDSON PLANT
PUBLIC SERVICE ELECTRIC & GAS COMPANY
STONE & WEBSTER ENGINEERING CORPORATION
NEW YORK
13222.01 EP-2A-1

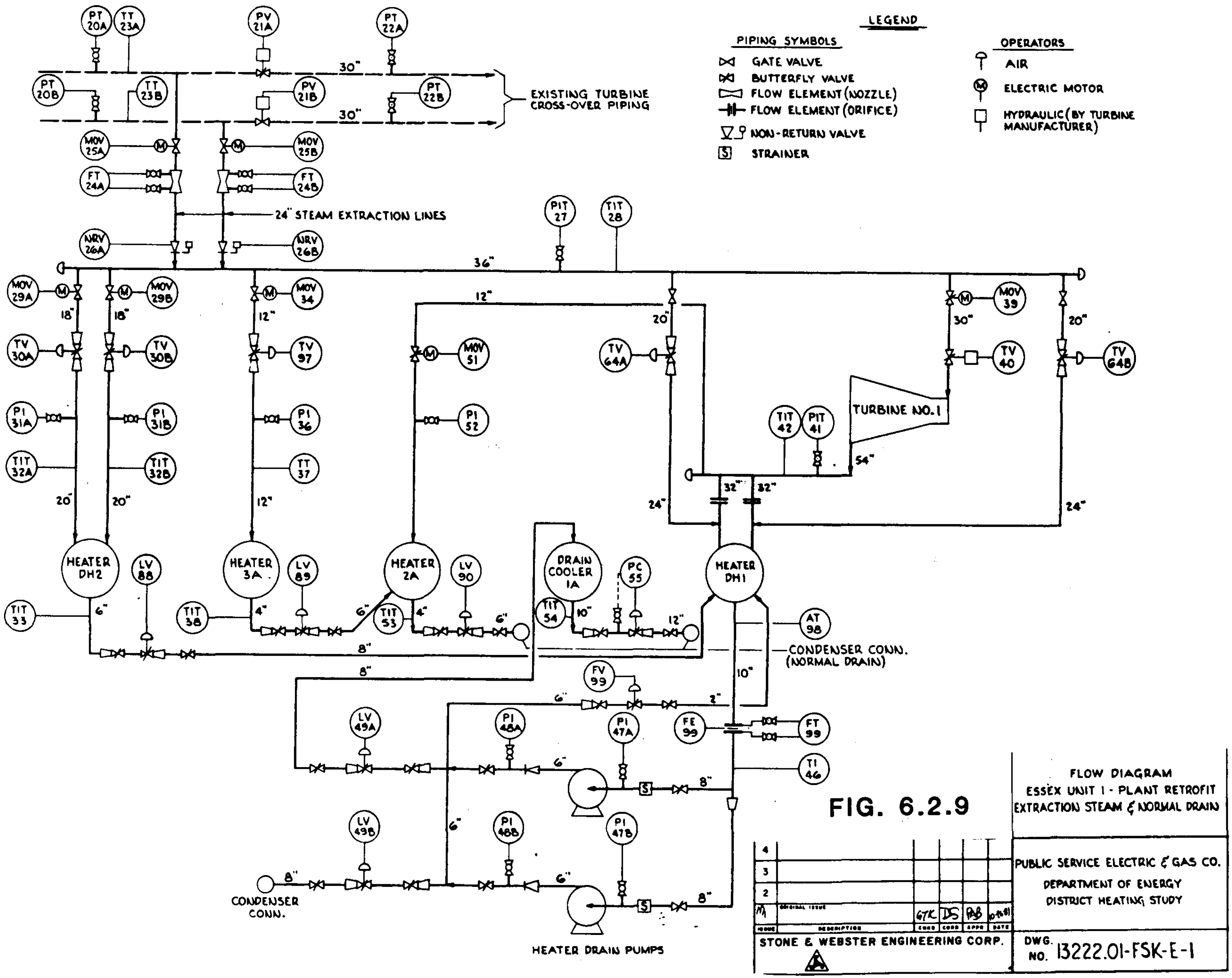
FIG. 6.2.8

6.2.4 ESSEX UNIT 1 PLANT RETROFIT

6.2.4.1 CONCEPTUAL DESIGN

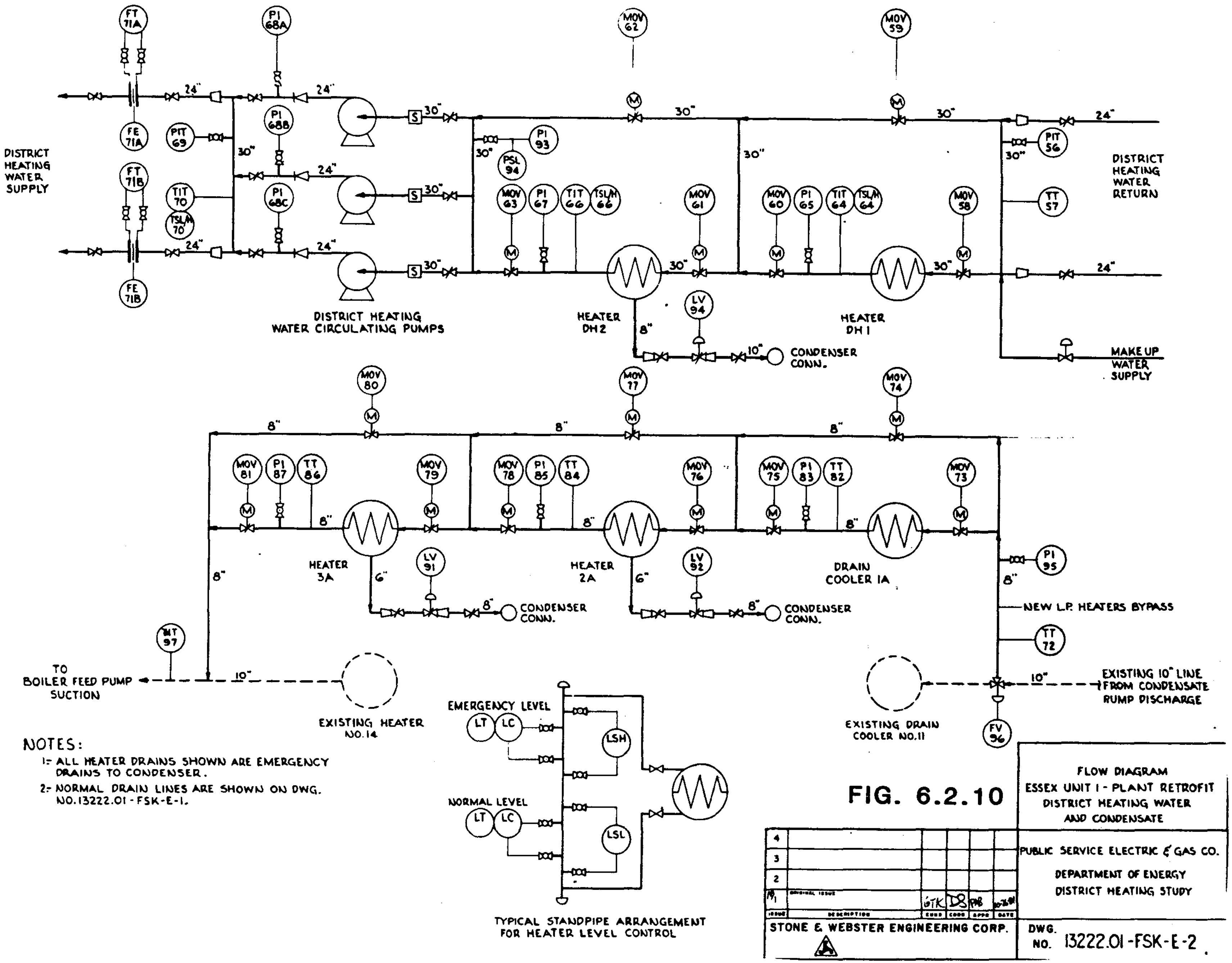
The plant retrofit scheme for Essex Unit 1 provides for two stage heating of the district heating water. A 6 MW back-pressure turbine-generator is provided. Steam to the turbine is taken from the cross-overs of the main unit at the conditions of 53 psia and 300 F. The turbine exhausts at 10.5 psia. Steam from the turbine exhaust is condensed in a shell and tube heat exchanger, or district heating water heater. The district heating water leaving this heater is further heated in a second stage heater to the required supply temperature. Steam to this heater also comes from the cross-overs. It was estimated, based on a study performed by General Electric Company, that a maximum flow of 600,000 pounds steam per hour can be extracted from the main turbine cross-overs at maximum throttle flow. With the above steam flow, approximately 9.5×10^6 pounds of water per hour (19,900 GPM) can be heated from a return temperature of 165 F to the supply temperature of 221F.

The flow diagrams of the district heating water heating system at the Essex Station are shown in Fig.6.2.9 & 6.2.10.Heaters DH2 and DH1 are the two district heating water heaters. Three circulating pumps, each rated 11,000 GPM at 450 feet, are provided of which one serves as a standby. Each pump is preceded by a single-basket strainer. District heating water leaving the retrofit plant is conveyed through two 24 Inch lines. The flow through each line is monitored by a flow element. A separate train of heaters, consisting of two condensate heaters (Heater 3A & Heater 2A) and an external drain cooler (Drain Cooler 1A), is provided on an L-P heater by-pass line. The by-pass line branches off from the main condensate line upstream of existing Drain Cooler 11



LEGEND
PIPING SYMBOLS
GATE VALVE
BUTTERFLY VALVE
FLOW ELEMENT (NOZZLE)
FLOW ELEMENT (ORIFICE)
NON-RETURN VALVE
STRAINER
OPERATORS
AIR
ELECTRIC MOTOR
HYDRAULIC (BY TURBINE MANUFACTURER)
EXISTING TURBINE CROSS-OVER PIPING
24" STEAM EXTRACTION LINES
TURBINE NO. 1
HEATER DH2
HEATER 3A
HEATER 2A
DRAIN COOLER 1A
HEATER DH1
CONDENSER CONN. (NORMAL DRAIN)
CONDENSER CONN.
HEATER DRAIN PUMPS
FLOW DIAGRAM
ESSEX UNIT 1 - PLANT RETROFIT
EXTRACTION STEAM & NORMAL DRAIN
PUBLIC SERVICE ELECTRIC & GAS CO.
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY
STONE & WEBSTER ENGINEERING CORP.
DWG. NO. 13222.01-FSK-E-1

FIG. 6.2.9


DISTRICT HEATING WATER SUPPLY
DISTRICT HEATING WATER CIRCULATING PUMPS
DISTRICT HEATING WATER RETURN
HEATER DH 2
HEATER DH 1
CONDENSER CONN.
MAKE UP WATER SUPPLY
HEATER 3A
HEATER 2A
DRAIN COOLER 1A
NEW L.P. HEATERS BYPASS
TO BOILER FEED PUMP SUCTION
EXISTING HEATER NO.14
EXISTING DRAIN COOLER NO.11
EXISTING 10" LINE FROM CONDENSATE PUMP DISCHARGE
EMERGENCY LEVEL
NORMAL LEVEL
TYPICAL STANDPIPE ARRANGEMENT FOR HEATER LEVEL CONTROL
NOTES:
1- ALL HEATER DRAINS SHOWN ARE EMERGENCY DRAINS TO CONDENSER.
2- NORMAL DRAIN LINES ARE SHOWN ON DWG. NO.13222.01-FSK-E-1.
FLOW DIAGRAM
ESSEX UNIT 1 - PLANT RETROFIT
DISTRICT HEATING WATER AND CONDENSATE
PUBLIC SERVICE ELECTRIC & GAS CO.
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY
STONE & WEBSTER ENGINEERING CORP.
DWG. NO. 13222.01-FSK-E-2
FIG. 6.2.10

through a new three-way valve, runs parallel to the existing low-pressure feedwater heaters, and rejoins the main condensate line downstream of Heater 14. The two condensate heaters admit steam from the cross-overs and from the back-pressure turbine exhaust respectively. The new heater train provides additional heating capacity for the condensate stream and prevents overloading of existing Heater 15 during district heating operation. The three-way valve regulates the amount of condensate flow by-passing the low-pressure heaters such that the by-pass flow matches the extraction steam flow from the cross-overs.

Extraction steam from the cross-overs is conveyed to the water heating system through two 24 Inch lines. Each of the lines is provided with a flow element, an atmospheric relief valve, a motor operated shut-off valve, and an air operated non-return valve. The motor operated valves are programed to close in the event that the actual extraction steam flow is greater than the allowable extraction steam flow. During operation when the water heating plant is shut down, the motor operated valves will be closed. An alternate steam supply from the cross-overs to Heater DH1 is provided, similar to those provided for the Hudson Plant retrofit.

Drain flow from Heater DH2 is cascaded to Heater DH1. Two full capacity heater drain pumps are provided, one of which serves as a standby, to pump the drain flow from Heater DH1 to Drain Cooler 1A. Each pump is rated 1300 GPM at 100 feet. The drain flow is cooled in the drain cooler before returning to the condenser. Drain flow from the higher pressure Condensate Heater 3A is cascaded to Condensate Heater 2A. Drain from the latter heater is returned to the condenser. Emergency drain lines to the condenser are provided for all the heaters except heater DH1. Drain from this heater can be disposed of to the condenser directly through the heater drain pumps.

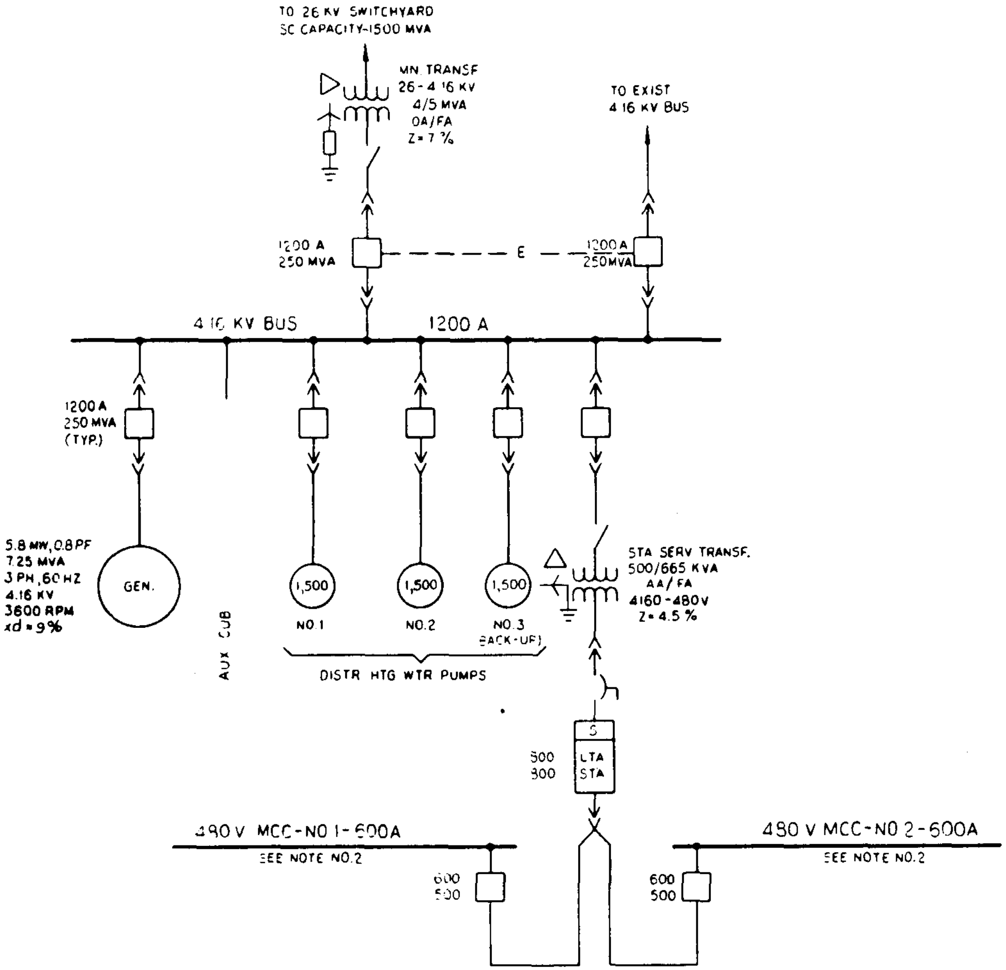
The back-pressure turbine is provided with external butterfly stop valve and external butterfly control valve. The turbine is similarly to those provided for the Hudson Plant retrofit.

6.2.4.2 ELECTRICAL SYSTEM

Power Distribution

The generator to be driven by the back-pressure turbine is rated at 7,250 KVA, 0.8 PF, 4.16 KV, 3-Phase and 60 Hertz. It will be air cooled and will run at 3600 RPM. The generator will be grounded through neutral grounding transformer and resistor. Fig.6.2.11 shows the one line diagram for the new equipment.

The generator output will be connected through the generator air circuit breaker to the 4.16 KV bus, which will consist of 1200A, 250 MVA circuit breakers feeding the district heating equipment load, and a 1200A main air circuit breaker through which the generator output will be connected through the main transformer to the 26 KV station switchyard (not shown on the diagram). A tie circuit breaker to the station's existing 4.16 KV bus will be provided for alternate start-up power supply to the district heating equipment should the main transformer be out of service. Additional switchgear cubicles will be provided to house the generator protective relays, potential transformer and main transformer protection, metering, and synchronizing controls, and tie breaker controls, metering, and synchronizing controls.



REFERENCES:

ELECTRICAL SYMBOLS STD-ME-10-1 THRU 10-8

NOTES:

1. PROTECTION, RELAYING, METERING, SYNCHRONIZING AND CONTROLS ARE NOT SHOWN.

2. EACH MOTOR CONTROL CENTER WILL HAVE THE FOLLOWING EQUIPMENT:

COMBINATION STARTERS, CKT BKR TYPE:

FVNR NEMA SIZE 3 — 2
SIZE 2 — 7
SIZE 1 — 13

FVR NEMA SIZE 2 — 3
SIZE 1 — 9

CIRCUIT BREAKERS - MOLDED CASE:

600 AF — 500 AT MAIN — 1
225 AF — 2
100 AF — 4

SPACES FOR FUTURE USE

FVNR NEMA SIZE 1 — 3

FIG. 6.2.11

ONE LINE DIAGRAM
ESSEX GENERATING STATION

ISSUE	DESCRIPTION	CHKD	COOR	APPD	DATE
4					
3					
2					
1	ORIGINAL ISSUE	MJM			9/4/81

PUBLIC SERVICE ELECTRIC & GAS CO.
DEPARTMENT OF ENERGY
DISTRICT HEATING STUDY

STONE & WEBSTER ENGINEERING CORP.

DWG. NO. 13222.01-ESK-E-1-1

Start-up power will normally be supplied from the 26KV switchyard to the 4.16 KV bus through the main transformer, rated 4/5 MVA, OA/FA, 26 KV - 4.16 KV, 3 Phase, 60 hertz, and 200 BIL.

During normal operation, the generator will supply plant auxiliary power. Any excess power will be delivered to the electrical grid at the 26 KV switchyard.

The 480 V district heating equipment load will be supplied through station service transformer, rated 500/665 KVA, AA/FA, 4160 V- 480 V, to the 480 V load center and two 480 V motor control centers.

Power to large motors (300 HP and above) will be supplied directly from the 4.16 KV switchgear. All smaller motors, station lighting and power supply will be supplied from the 480 V load center or the 480 V motor control centers.

125V DC System

For control of the 4.16 KV switchgear, 480V load center air circuit breakers and emergency lighting, a 125V D.C. battery, battery charger and D.C. distribution switchboard similar to those for Hudson Unit 2 will be provided.

120/208V Regulated Power Supply

For control and instrumentation circuits requiring regulated safe power, regulated power system will be provided. It will consist of two 30KVA, 480-208/120V dry type transformers, two 22.5KVA voltage regulators, automatic transfer switch mechanical or static type as required, and 120/208V A.C. distribution power panel. One transformer and voltage regulator will be supplied from the new motor control center. The back-up power to the other transformer and regulator will be brought from the exising 480V motor control center.

Miscellaneous Systems

Miscellaneous systems such as grounding, raceways and underground ducts, wire and cable, lighting, and public address system will be similar to those provided for Hudson Unit 2.

6.2.4.3 CONTROL SYSTEM

The control and instrumentations provided for Essex Unit 1 are similar to those provided for Hudson Unit 2. The primary instrumentation is shown on the flow diagrams in Fig.6.2.9&6.2.10. A separate control room will be provided in the new water heating plant designed to house the district heating water equipment.

The steam flow demand index for Heater DH1 controls the steam flow and the electrical output of the single back-pressure turbine-generator. Control valves TV30A, 30B regulate the steam flow to Heater DH2 to obtain the required district heating water supply temperature. Steam flow to Heater 3A in the L-P heater by-pass line is regulated by control valve TV97 to maintain a high enough feedwater temperature entering Heater 15 to prevent overloading of this heater. The condensate flow in the L-P heater by-pass line is regulated by the three-way flow control valve FV96 to match the extraction steam flow from the cross-overs.

The drains from each heater, in general, have two independent paths for discharge. For each heater, a "normal" and an "emergency" level transmitter/controllers are provided. In addition, separate low level and high level switches are provided for alarm. The following tabulation shows the "normal" and the "emergency" drains from each heater.

Heater No.	Normal Drain to	Controller/ Valve	Emergency Drain to	Controller/ Valve
DH1	Drain Cooler 1A	LC/LV49A	Condenser	LC/LV49B
DH2	Heater DH1	LC/LV88	Condenser	LC/LV94
2A	Condenser	LC/LV90	Condenser	LC/LV92
3A	Heater 2A	LC/LV89	Condenser	LC/LV91
Drain Cooler 1A	Condenser	PC/PV55	--	--

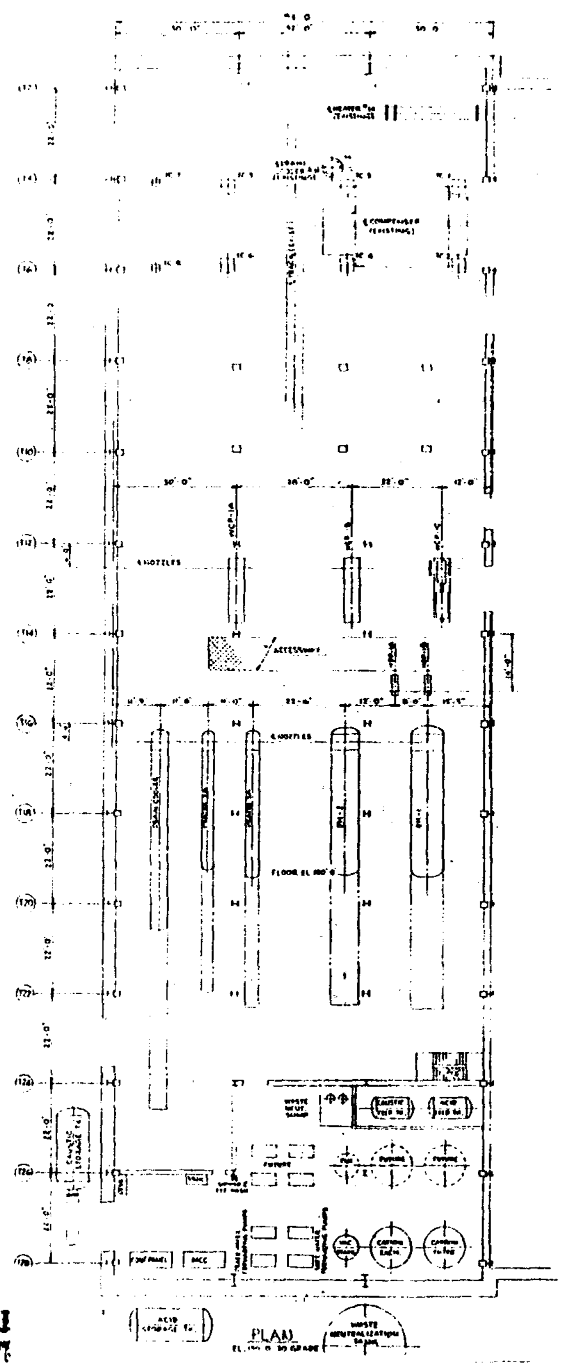
If a heater's water level rises to a high level, the inlet drain valve will close. If a heater's level drops too low, the outlet drain valve will close. If the level in Heater DH1 or Heater 2A rises too high, the back-pressure turbine will be tripped.

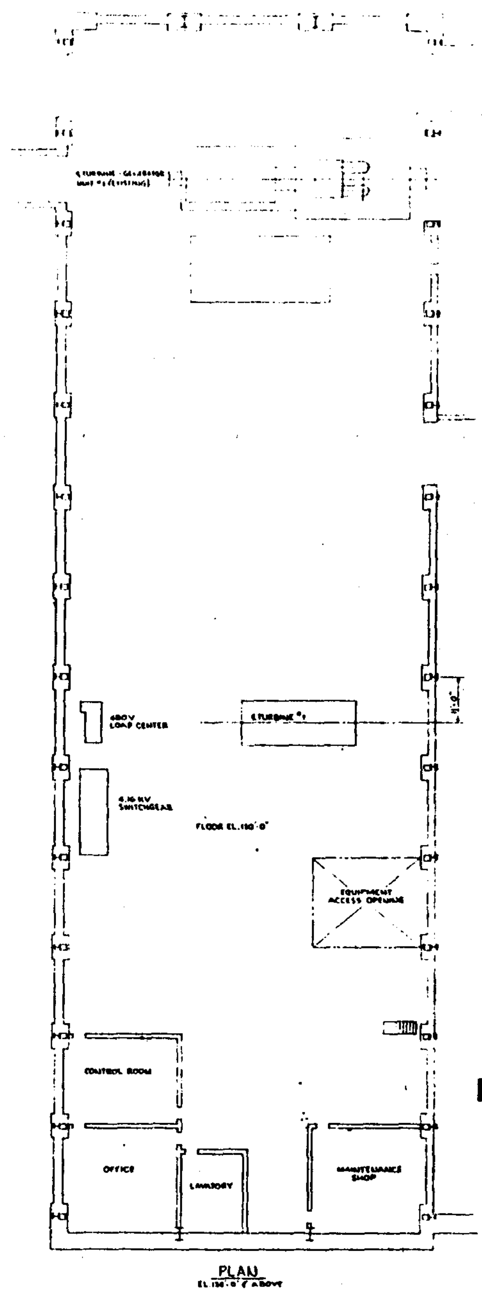
A water sampling and conductivity detection system is provided to continuously monitor the drain flow from each district heating water heater. If an abnormal level of impurities is detected in the drain flow from a heater, an alarm will be sounded and the heater will be automatically isolated, if so desired.

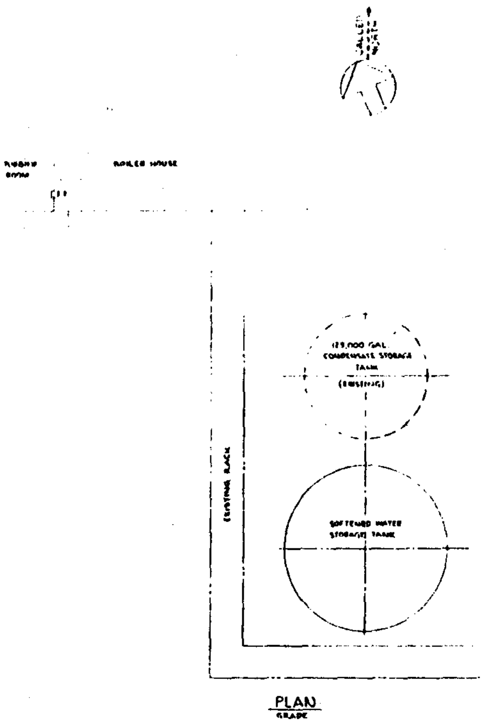
6.2.4.4 WATER HEATING PLANT ARRANGEMENT

All of the district heating water heaters, the condenser heaters, together with the back-pressure turbine-generator, pumps, electrical equipment, and water treatment facilities, will be housed in a new water heating plant to be built at the location of the exising turbine room. Fig6.2.12&6.2.13show the equipment arrangement inside this building.

The water heating plant measures approximately 228 feet long by 92 feet wide. It consists of two levels. The back-pressure turbine-generator and the electrical equipment are located on the upper level, or the operating level. A control room is also located on this level. The heaters, the pumps, and the water treating equipment are located on the lower level. The building is equipped with an overhead bridge crane with a 20-ton main hook and a 5-ton auxiliary hook. The roof of the upper level is at an elevation of 75 feet above grade. The upper level is at an elevation 30 feet above grade. The building is constructed of steel frame with insulated corrugated metalic sidings and poured concrete roof slabs with built-in roofing.



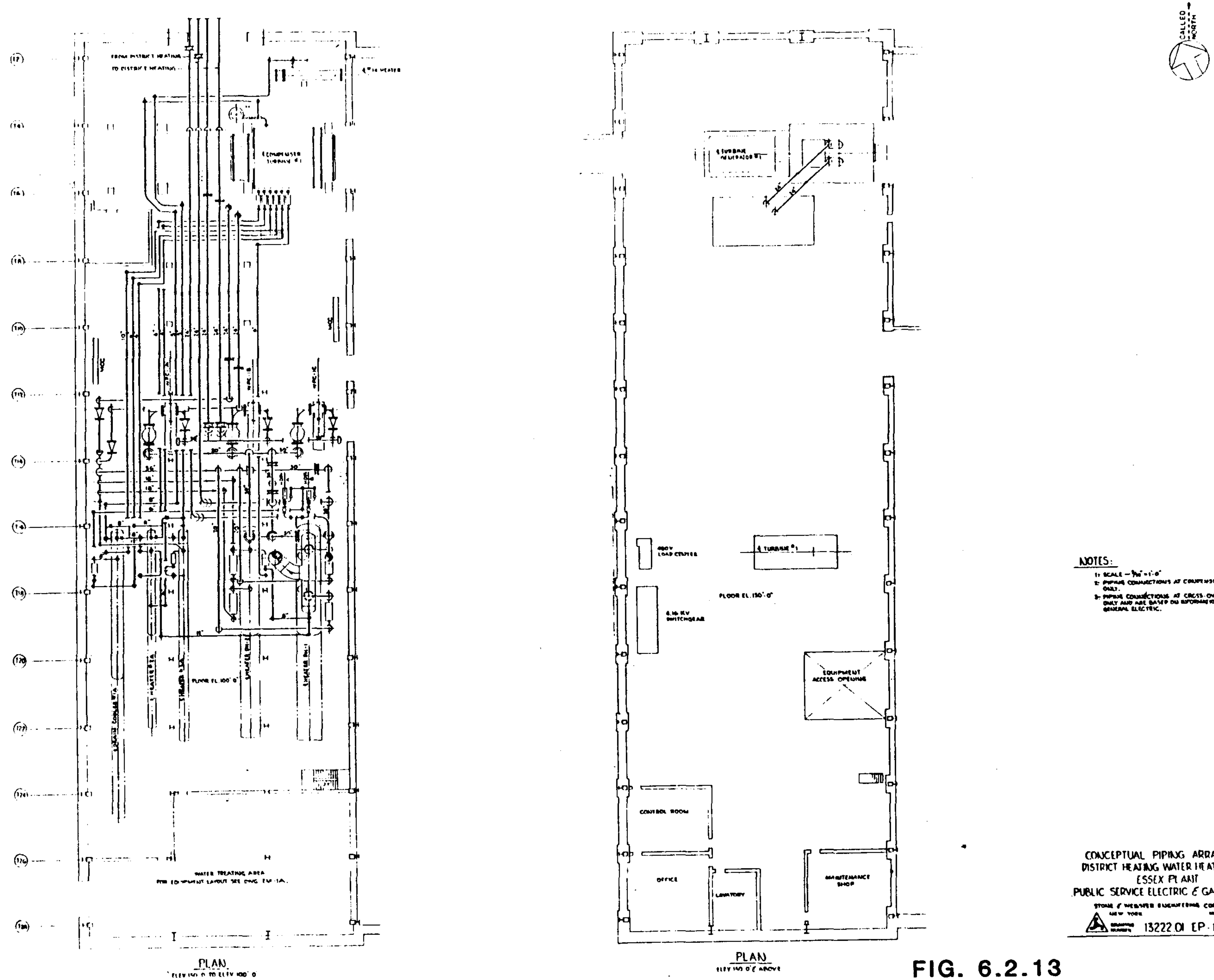




NOTES:

FIG. 6.2.12

EQUIPMENT ARRANGEMENT
DISTRICT HEATING WATER HEATING PLANT
ESSEX PLANT
PUBLIC SERVICE ELECTRIC & GAS COMPANY
STONE & WEBSTER ENGINEERING CORPORATION
NEW YORK
13222.01 EM-1B-1



NOTES:

1. SCALE — 3/16" = 1'-0"
2. PIPING CONNECTIONS AT CONDENSER ARE CONCEPTUAL ONLY.
3. PIPING CONNECTIONS AT CROSS-OVERS ARE CONCEPTUAL ONLY AND ARE BASED ON INFORMATION PROVIDED BY GENERAL ELECTRIC.

CONCEPTUAL PIPING ARRANGEMENT
DISTRICT HEATING WATER HEATING PLANT
ESSEX PLANT
PUBLIC SERVICE ELECTRIC & GAS COMPANY
STONE & WEBSTER ENGINEERING CORPORATION
13222.01 EP-1B-1

FIG. 6.2.13

6.2.5 WATER TREATMENT

6.2.5.1 INTRODUCTION

The efficient performance of a district heating system relies heavily on the quality of the district heating water. In addition, a sufficient quantity of makeup water of the proper quality must be provided to account for losses from the system. The quality of the makeup water must be compatible with minimal corrosion and scale formation in the piping and heat exchange equipment.

6.2.5.2 MAKEUP WATER FLOW RATE

Makeup water must be furnished to replace normal system leakage. The quantity of leakage from the system is a function of many variables, including network piping length, pipe diameter, operating pressure and temperature, and installation methods. The influence that each variable has on leakage is estimated based upon empirical data.

The district heating system will be developed in three phases. The fully developed system will include a base loaded retrofited plant, ie, Hudson Station (Essex Station was deleted from the study), several intermediate stations, and several peaking stations. Each of these stations will be provided with makeup water treatment equipment.

The peaking stations will be developed first and will be used initially to serve small geographical areas on a "stand-alone" basis. Since the effect of leakage is greatest in the local distribution network, it is estimated that five percent of the loop flow rate will be needed for makeup. Although results

TABLE 6.2-I

MAKEUP WATER FLOW RATES

Station	Water Source	Network Flow Rate (gpm)	Makeup Flow Rate (gpm)
Hudson	Jersey City Water Work	60,000	750
Essex	City of Newark Water Dept.	20,000	250
Intermediate	Hackensack Water Co.	4,000	200
Peaking	Hackensack Water Co.	2,000	100

TABLE 6.2-II

RAW WATER CHARACTERISTICS

Station	Water Source	Chloride ppm as Cl	Hardness ppm as $CaCO_3$	Alkalinity ppm as $CaCO_3$	D.O.(1) ppm as O_2
Hudson	Jersey City Water Work	19-29	35-45	25-35	-
Essex	City of Newark Water Dept.(2)	5-17.3	29-44	11.26	-
Intermediate	Hackensack Water Co.(3)	37-50	112-155	71-93	6.6-14.3
Peaking	Hackensack Water Co.(3)	37-50	112-155	71-93	6.6-14.3

(1) When the value was not reported, it was assumed to be greater than 8.0 ppm.

(2) The Wanaque Water Treatment Plant was assumed to be the source of water.

(3) The New Milford Water Purification Plant was assumed to be the source of water.

6.2.5.3 MAKEUP WATER QUALITY REQUIREMENTS

The quality of the makeup water must ensure minimal corrosion and scale formation in piping and heat exchangers. The first requirement can be met by from a survey by Oliker (Reference 2) on district heating in the Soviet Union indicate that makeup water requirements varied from 0.12 to 2.0 percent of the circulating flow rate, it was decided to use five percent due to the small size of the distribution system initially supplied by the peaking plants, (the percentages indicated in Oliker's study were based on large distribution system). Makeup supply of five percent will also be provided at the intermediate stations once they are brought on line, with the peaking station makeup capacity placed in reserve.

All makeup to the system will be provided for by the retrofited plant once it is in operation. The retrofited plant will have the capacity to provide a maximum makeup of 1.25 percent of the total network flow. With the retrofited plant in operation, the makeup capacity at the intermediate and the peaking stations will be held in reserve for unusual intermittent demands such as that required by line breaks and system maintenance operations.

Table 6.2-I shows the system makeup flow rates based upon the above criteria. The raw water to the makeup treatment systems will be supplied by different sources, as indicated in the table. The characteristics of the raw water makeup for each plant are given in Table 6.2-II.

deaeration (removing dissolved oxygen and carbon dioxide) while the second requirement can be met by the removal of hardness and the associated alkalinity. Scale formation is promoted when the temperature of the water is increased, since the solubility of most scale forming constituents decreased as temperature incresases. District heating has been used extensively in the Soviet Union. The water quality requirements for the proposed district heating system, Table 6.2-III, are based on published Soviet standards (Reference 1).

TABLE 6.2-III

MAKEUP WATER QUALITY REQUIREMENTS

Parameter	Water Temperature Range, °F to 167°F	168-212	213-392
Dissolved oxygen, ppm as O_2	0.1	0.1	0.05
Free Carbon Dioxide	Absent	Absent	Absent
Suspended Solids, ppm	5	5	5
Carbonate Hardness, ppm as $CaCO_3$	75	35	35
Sulfate - Calcium Hardness	-	-	Units not to exceed the $CaSO_4$ solubility product

6.2.5.4 ALTERNATIVE TREATMENT METHODS

The purpose of makeup water treatment is to limit internal corrosion and scaling in the district heating piping networks. The treatment of the makeup water consists of the removal of scale forming constituents (calcium, magnesium), alkalinity which promotes scale formation, and corrosive gases (carbon dioxide, oxygen). Pretreatment for the removal of suspended solids, residual chlorine, and organics is necessary to limit fouling of the downstream equipment.

The following treatment methods were considered:

1. Removal of suspended solids, residual chlorine, and organics

   a. Activated carbon filtration

2. Removal of scale forming constituents

   a. Sodium zeolite softening, alone and with sodium cycle dealkalization

   b. Strong acid cation exchange, alone and with strong base anion exchange

   c. Weak acid cation exchange.

3. Removal of corrosive gas

   a. Atmospheric degasifier

   b. Vacuum degasifier

   c. Heated vacuum degasifier (deaerator)

   d. Chemical scavenging

Carbon Filtration

The purpose of carbon filtration is threefold: to remove particulate matter originating in the municipal supply and distribution systems, to eliminate residual chlorine concentrations, and to remove dissolved organic compounds.

Particulate removal is important since carrying-over of particulates to the resin media shortens the active exchange period (run length). Ion exchange resin capacity is lost by fouling of the exchange sites with particulates.

Removal of residual chlorine is necessary to prevent oxidation attack of the exchange resin. Failure to adequately control residual chlorine can lead to reduction in exchange capacity and premature resin failure.

Carbon filtration will protect the ion exchange unit from fouling by dissolved organic compounds. This is particularly important since the municipal supply in the district heating system area is unfiltered. Organic fouling, once present, is irreversible under normal operating conditions and will necessitate the replacement of the ion exchange resins.

<u>Sodium Zeolite Softening</u>

This treatment method employs a strong acid form cation exchange resin using a sodium chloride brine solution as the regenerant. This method results in an exchange of divalent (hardness) cations for the monovalent sodium placed in the resin matrix during regeneration.

The principal advantage of this process is the low cost of the regenerant brine solution.

Sodium zeolite softening, alone, is not capable of removing the alkalinity associated with the hardness cations. Where necessary, alkalinity removal is usually accomplished by adding a brine regenerated dealkalizing anion exchanger downstream of the sodium zeolite softener. The addition of this second treatment step for removal of alkalinity effectively doubles the cost of the ion exchange system and results in a doubling of regenerant brine use.

Strong Acid Cation Exchange

This treatment method employs a strong acid cation exchange resin and is similar to sodium zeolite softening, except that sulfuric acid (or another strong acid) replaces brine as the regenerant. Hardness and other cations are replaced by hydrogen ions during the sevice run. This causes a lowering of the pH and the conversion of alkalinity to free carbon dioxide.

The principal advantage of the strong acid cation exchanger is that it is capable of removing cations associated with noncarbonate hardness. Monovalent cations (such as sodium and potassium) are also removed, although it is not necessary to remove them because they do not contribute to the hardness concetration and their removal is not necessary to achieve the desired water quality.

The disadvantages associated with the strong acid cation exchanger include its limited exchange capacity between regenerations (usually less than half that of a weak acid cation exchanger) and the inefficient regeneration cycle. The regeneration of a strong acid cation exchanger requires much more acid than does the regneration of a weak acid exchanger.

Weak Acid Cation Exchange

The weak acid cation exchange method employs a cation exchange resin which selectively removes divalent hardness cations in preference to monovalent species. It is similar to the strong acid cation exchanger in the conversion of carbonate alkalinity to carbon dioxide gas. The weak acid exchanger does not permit noncarbonate hardness removal. Therefore, it is necessary to increase the influent alkalinity to decrease noncarbonate hardness concentrations.

The advantages of the weak acid exchanger over the strong acid exchanger are:

1. The quantity of regeneration acid needed is much less.

2. The bed volume requirements are much less.

3. Waste neutralization requires less caustic.

Deaeration

Several methods of deaeration were investigated, including chemical scavenging and two methods of heated vacuum deaeration. Chemical scavenging with sodium sulfite was found to be not cost effective when compared to heated vacuum deaeration. Also, chemical scavenging does not remove the free carbon dioxide. An unheated vacuum deaeration unit is not capable of reducing oxygen and carbon dioxide gas to the required limits.

The two methods of heated vacuum deaeration are preheating of the influent through a heat exchanger and injection of steam into the vacuum deaerator. The use of heat exchanger to preheat the influent to the vacuum deaerator eliminates the loss of steam from the plant.

6.2.5.5 RECOMMENDED TREATMENT SYSTEM

The recommended makeup water treatment system, which will be duplicated in each location, is shown in Figure 5-1. The system consists of a single treatment train with redundancy provided only for the various pumps within the train.

Raw water feed enters the top of the carbon filter and flows through the carbon bed where suspended solids and dissolved organics are removed. The water exits the carbon filter at the bottom and flows to the weak acid cation exchanger. Prior to entering the exchanger, dilute caustic is added to the water to maintain the exchanger effluent at a pH of 5.0. Adding the caustic increases the alkalinity and enhances the removal of carbonate hardness by the weak acid cation exchanger. Effluent from the weak acid cation exchanger flows into a cold storage tank which has a 6-hour storage capacity.

The effluent from the cold storage tank flows through a shell and tube heat exchanger where the temperature of the makeup water is heated to 180°F. A temperature element coupled with a controller controls a flow valve which moderates the amount of heating steam to the heat exchanger. The heated makeup water flows through a pressure control valve before entering a vacuum deaerator. Vacuum pumps are provided to maintain vacuum in the deaerator. Noncondensible gases are vented to the atmosphere. Water vapor is condensed in a separate heat exchanger which uses the water from the cold storage tank as the cooling medium. After the cooling water passes through the heat exchanger, it is discharged into the vacuum deaerator feed line.

The softened dealkalized and deaerated water is discharged from the bottom of the deaerator to the suction of the district heating water makeup pumps. The pumps are activated on system demand with a flow control valve moderating the flow to the district heating system. Upstream of the pumps, dilute caustic is added to the makeup water to maintain the effluent at a pH between 8.0 and 10.

Regeneration of the weak acid cation exchanger will require taking the carbon filter and cation exchanger out of service. Softened and deaerated water will be used for diluting the sulfuric acid used in regeneration and for rinsing. A conductivity element will signal a controller which will allow the exchanger to return to service.

6.2.5.6 WASTEWATER TREATMENT

Wastewater discharged from the water treatment system must conform with 40CFR423, titled USEPA Effluent Limitation Guidelines, New Source Performance Standards, Steam Electric Power Generating Point Source Category. The discharged wastewater will consist of spent regenerant acid and is categorized as "low volume waste" under 40CFR423. The recommended treatment method is neutralization. Treated wastes will be suitable for direct discharge to receiving water bodies or to municipal sewage systems. Carbon filter backwashing wastes will be discharged to the sewer system without treatment. Treated waste effluent characteristics will be compatible with processing by municipal biological treatment if discharge is to a sanitary sewage system.

To neutralize the low volume waste, the wastewater will be collected in a waste neutralization sump. Waste transfer pumps will be activated based on the level in the sump and pump the waste water to a waste neutralization tank. Neutralization occurs as a batch process. The contents of the tank will be continuously recirculated when the tank level is high enough. The recirculation line contains a pH analyzing element which signals a controller, allowing either concentrated sulfuric acid or 50 percent caustic soda to be added to the neutralization tank. When the contents of the tank are within a pH range of 6.0 to 9.0, the contents will be discharged.

6.2.5.7 MAINTENANCE OF WATER QUALITY

The quality of the water produced from the proposed makeup water treatment system should preclude the need for addition of chemicals to the district heating loop for controlling corrosion and scaling. Normal system operation under pressure will prevent the entrainment of air/oxygen and associated corrosion. However, should the system lose pressure, entrainment of oxygen may occur. The recirculating water should be monitored daily for pH and concentrations of dissolved oxygen, calcium, sulfate, hardness, alkalinity and suspended solids. The chemistry of the recirculating water should remain relatively stable since concentration due to evaporation normally will not occur, and since leakage will act as an effective blowdown.

As a precaution, a separate chemical feed system should be provided for the temporary addition of scale inhibiting chemicals such as polyphosphate. The addition of sodium sulfite as an oxygen scavenger should not be required during normal operation. However a sodium sulfite system should be provided as a standby.

The pH of the system should be kept between 8.0 and 10.0. Should the system's pH fall below 8.0, additional caustic should be added to the recirculating water from the same caustic feed system used for adding caustic to the makeup water. When the pH of the recirculating water increases above 10.0, the dilute caustic feed rate to the makeup line (after the deaerator) can be reduced.

The system's head losses should be monitored and compared with the original head losses attributable to pipe friction. Increasing head losses usually signal scale buildup, and cleaning of a portion of the system may be necessary.

A method of cleaning commonly used in the Sovient Union consists of aerated water flush to remove soft scales. If this is not sufficient, an acid solution with corrosion inhibiters is added to the water. Subsequent flushing of the system will be required.

REFERENCES

1. National Institute of Heat Engineering (USSR), "Standards for Process Design of Thermal Power Stations and Heating Networks," Moscow, 1975.

2. Oliker, J., "District Heating Survey: Piping Corrosion is Key to System Reliability," Power Magazine, October 1980.

6.2.6 COST ESTIMATE

6.2.6.1 SUMMARY

The cost estimate summaries of the Hudson Unit 2 and the Essex Unit 1 plant retrofits are shown in Tables 6.2-IV & 6.2-V. The estimate is an order-of-magnitude estimate for engineering, design, and construction of the facilities required to retrofit the Hudson and the Essex units. The scope is limited to the modifications and additions to the existing facilities as described in the previous sections. All the figures in the tables are present day costs, with no allowance for escalation. All labor is assumed to be subcontracted. The estimate reflects a continuous period to perform all the required work. No allowances were made for site work, demolition of existing structure and equipment, and rehabilitation and startup of retired equipment. These costs were developed separately by PSE&G. Also not included are the costs connected with the turbine manufacturers' scope of work, ie., modifications of the existing turbines and the associated control systems. These costs were developed by the turbine manufacturers (see Appendix A).

6.2.6.2 DIRECT COSTS

<u>Craft Rates</u>

Craft rates were determined using the 1981 Means Labor Rates for Newark, New Jersey, area.

<u>Water Heating Plant Buildings</u>

Cost estimate of the buildings to house the new equipment, including the back-pressure turbine-generators, was based on preliminary drawings showing the type and the number of piles, foundation sizes and layouts, structural steel quantities, insulated metal siding, roof and deck construction, concrete, etc.

Mechanical Equipment

Prices of the major equipment, such as the turbine-generators, heaters, pumps and motors, etc., were obtained from equipment manufacturers. Labor manhours for installation were estimated.

Piping and Valves

Flow diagrams and piping layout drawings were used as the basis for cost estimate. Piping cost was priced using vendor's catalogue and current published discounts wherever applicable. Prices not given in the catalogue were estimated on a dollars per pound basis. Valve prices were obtained from vendors. Labor for installation of piping and valves were obtained from Stone & Webster's Standard Manhour Piping Manual.

Insulation

Insulations for piping and equipment were priced on a dollars per linear foot basis, using previous quotes escalated to present day and regionalized for Newark, New Jersey.

Electrical Equipment

Electrical one line diagrams were used as the basis for cost estimate. Prices of the major equipment, such as the main transformers, station power transformers, 13.8 KV and 4.16 KV breakers, 480 Volt load centers, etc. were obtained from equipment manufacturers. Cable, conduit, lighting and grounding material costs were estimated along with labor to install all the electrical items.

Controls

Flow diagrams were used as the basis for cost estimate. Both the material cost and the labor for installation were developed in house.

Water Treatment System

Both the material cost and the labor for installation of the water treatment system were developed in house.

6.2.6.3 OTHER COSTS

Indirect costs (ie., home office engineering and support) were estimated using historical data and calculated at 14-percent of the direct construction cost. Distributable costs (ie., construction management and field indirect costs) were estimated using historical data and calculated at 8-percent of the direct construction cost. A ten percent contingency was added to cover undefined items, design changes, ect. The level of accuracy of the estimate is $^{+}$15 percent.

6.2.6.4 SPECIAL CONSIDERATIONS FOR ESSEX PLANT

To avoid in-depth investigations of the structural adequacy and rehabilitation requirements of the existing turbine building to house the new equipment, the following assumptions were used in developing the building cost for Essex.

1. The portion of the existing turbine room superstructure and associated mechanical equipment for Turbine Nos. 2,3,4,5, & 6, including slab on

grade, will be demolished by others to the top of the existing pile caps.

2. Load tests on ten existing piles will be performed to insure the acceptability of the existing piles.

3. New perimeter and interior grade beams will be installed on the existing pile caps.

4. A new building will be built using the existing piles and pile caps.

5. Temporary concrete-block wall will be constructed at Column Line T8. The wall will be of full height of the building to protect the Unit 1 turbine-generator during the demolition of the existing building and the construction of the new building.

TABLE 6.2-IV

COST ESTIMATE OF

HUDSON UNIT 2 PLANT RETROFIT

(In 1,000 1981-Dollars)

	MATERIAL	LABOR	TOTAL
Water Treatment Plant	1,082.	311.	1,393.
Mechanical Equipment	12,601.	1,245.	13,846.
Piping	3,628.	1,827.	5,455.
Insulation	166.	276.	442.
Valves	1,825.	330.	2,155.
Misc. Mechanical (Building Services)	71.	103.	174.
Electrical Equipment	2,181.	469.	2,650.
Electrical Feeders	301.	621.	922.
Lighting	142.	249.	391.
Grounding	75.	53.	128.
Transformer Slab & Fence	9.	21.	30.
Instruments	663.	516.	1,179.
Sub-Structure (Building)	272.	210.	482.
Sub-Structure (Tunnel)	166.	230.	396.
Super-Structure (Building)	1,448.	908.	2,356.
Sub-Total	24,630.	7,369.	31,999.
Indirects			4,480.
Distributables			2,560.
Sub-Total			39,039.
Contingency			3,904.
Total Estimated Cost			42,943.

TABLE 6.2-V

COST ESTIMATE OF

ESSEX UNIT 1 PLANT RETROFIT

(In 1,000 1981-Dollars)

	MATERIAL	LABOR	TOTAL
Water Treatment Plant	585.	221.	806.
Mechanical Equipment	4,194.	232.	4,426.
Piping	932.	528.	1,460.
Insulation	55.	92.	147.
Valves	874.	129.	1,003.
Misc. Mechanical (Building Services)	66.	96.	162.
Electrical Equipment	613.	153.	766.
Electrical Feeders	77.	125.	202.
Lighting	135.	236.	371.
Grounding	41.	26.	67.
Transformer Slab & Fence	4.	3.	7.
Instruments	426.	331.	757.
Sub-Structure (Building)	20.	116.	136.
Super-Structure (building)	1,299.	864.	2,163.
Sub-Total	9,321.	3,152.	12,473.
Indirects			1,746.
Distributables			998.
Sub-Total			15,217.
Contingency			1,522.
Total Estimated Cost			16,739.

6.3 INTERMEDIATE STAGE PLANT(S) (GASTURBINE)

6.3.1 Purpose of Plants

Random load development met originally by "heater plants" reaches a point in time when further extension of those plants is not practical and/or economical. At this point of the D-H system growth a gasturbine plant with heatrecovery facilities will provide cogeneration of heat and electric power and therefore a cheaper source of heat than the heater plants. Since it is a less expensive source of heat, it will take over the supply of base heat load while the heater plants will supply peaks and act as stand-by.

6.3.2 Unit Selection

There are a large number of gasturbines installed within the PSE&G power system. Some of the smaller units, because of their lesser efficiency, are used infrequently. A number of these are the so-called Econo-Pac gasturbine generators, made by Westinghouse (Model W-251G). These units have an ISO rating of 20.4MW on gas fuel and 19.9MW on oil. The generators of the units are rated 28000kVA @ a power factor of .85 operating on 13800V. The low ambient maximum capability is 38000kVA. These units are completely air cooled.

The fuel consumption of the unit is 270×10^{6}BTU/hr (LHV) at ISO conditions and at full load. This and the previous values are given at zero intake and exhaust losses. Equipping them with intake silencers for residential locations and heatrecovery equipment and exhaust silencer will reduce both the rating and the efficiency of the unit. On the other hand, as part of a heating system most of the annual operating hours will be logged during the winter. The improvement in heat rate and in output capability at low ambient temperatures is considerable. At 5^{0}F ambient the capability increases by 42% and the heat rate reduces by 12%.

Based on these machines, there were two gasturbine/ heatrecovery plants proposed: One each in the Newark/ Harrison and in the Jersey City/Hoboken area (see Fig. 6.3.1).

POWER GENERATING STATION

D-H HEATER PLANT AND SUPPLY AREA

GASTURBINE PLANT W/HEATRECOVERY

D-H TRANSMISSION MAIN

FIG. 6.3.1

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PSE&G - DOE D/H STUDY		
3 STAGE DISTRICT HEATING DEVELOPMENT - SUPPLY AREAS AND PLANT LOCATIONS		
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The units which can be utilized in these plants are equipment owned by PSE&G and relocated for the purpose from their present location. The units available for consideration are as follows:

Linden #3	15MW	Pratt & Whitney	gas fired
Linden #5 - 8	27MW	Westinghouse	oil/gas fired
Essex #9	60MW	"	" "
Kearny #9	15MW	Pratt & Whitney	gas fired
Bergen	15MW	" "	" "
Bayonne	(2)-19MW	" "	oil fired
Burlington	15MW	" "	" "
National Park	18MW	" "	" "

An evaluation of the age, efficiency and condition of these machines followed, along with an order of magnitude estimate of the technical difficulty and cost of relocation. It became evident that considering all these aspects, relocation was not an attractive proposition.

The effort then shifted to the large multi-machine units at Essex and Kearny. Essex units #10 and #11 and Kearny Unit #12 are Westinghouse, so called "Twin-Pack" combustion turbine generators. Each of two 22MW ISO combustion turbines drive a common 50MVA generator and four pairs of them form a unit. Their combined rating is 190-196MW. The units at Essex have dual fuel capability--gas or oil--while the Kearny unit is gas fired only. There are slight differences in the models used. The Model C turbine at Kearny has a higher efficiency than the Model A at Essex and also a better reliability record. Partly for this reason, but mainly because of its location, the Kearny No. 12 unit has been included in the final development scheme of the D-H system.

The unit ISO rating is 8 x 22 MW = 176 MW, but it is capable of generating 196 MW in the winter, when most of its use is concentrated as part of the D-H system. Its heat rate is 13500 BTU/kWh at rated conditions. With the attachment of a heatrecovery section, imposing about 6" W.G. pressure drop, plus duct losses, the heat rate will increase and the total output decrease somewhat. The calculated recoverable heat from the unit at full load was established as 1100×10^6 BTU/hr.

6.3.3 Plant Layout

Figure 6.3.2 shows the proposed layout based on Econo-Pack (Westinghouse) units.

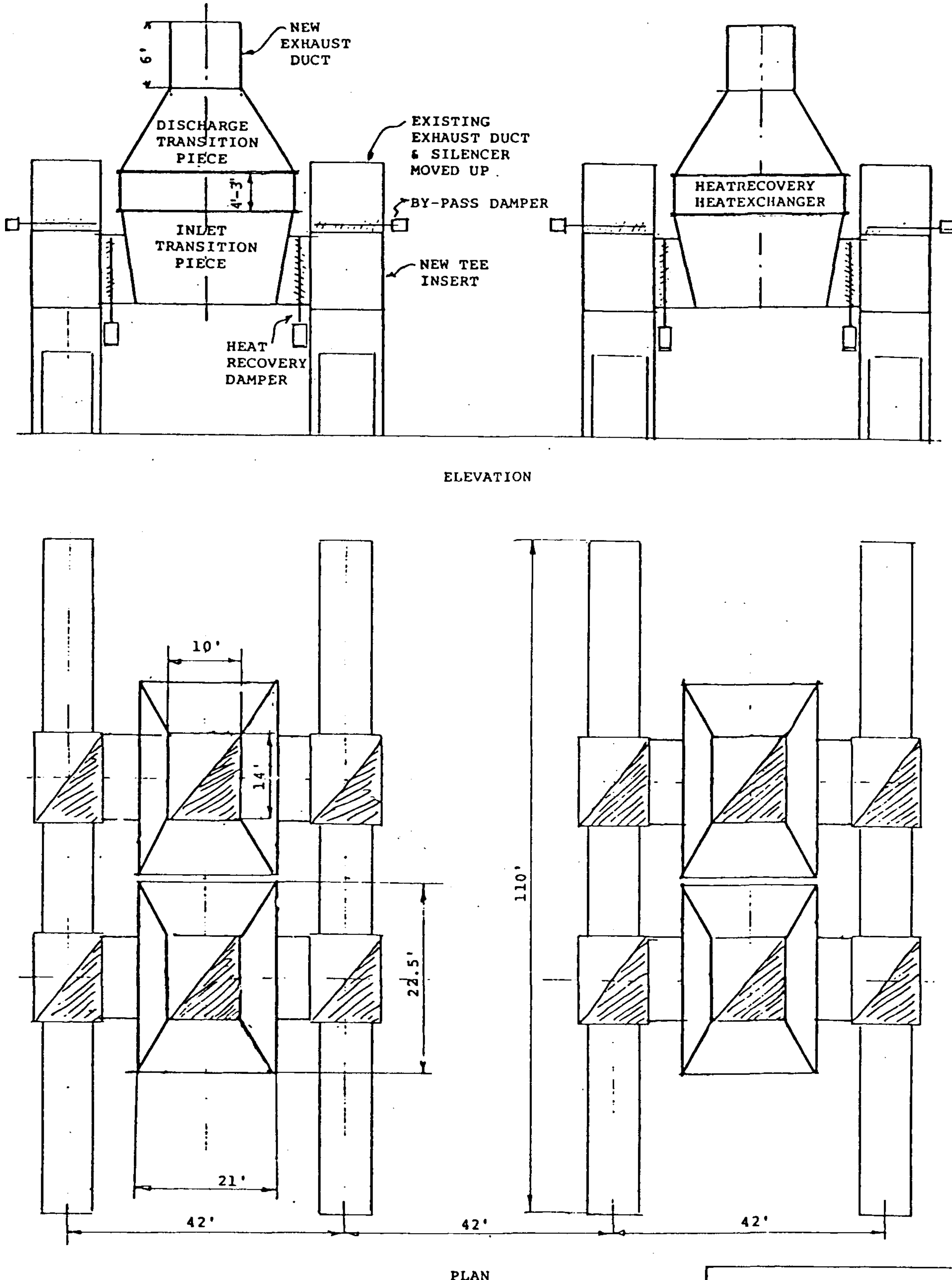


FIG. 6.3.2

TRANSFLUX International Limited 2500 LEMOINE AVENUE, FORT LEE, NJ 07024			
PSE&G-DOE D-H STUDY			
KEARNY #12 COMBUSTION TURBINE RETROFIT LAY-OUT			
NOV. 81	NO.		REV. 0

No scale

The unit, as is, is a basically outdoor installation with the components in their customary service enclosures. The heat recovery heat exchangers will stand elevated above the electrical rooms. Freeze protection has to be provided in the form of electric heaters and small circulators.

The main controls and supervisory equipment along with the circulating pumps are located in a prefabricated building with minimal heating for freeze protection. The present location is in the middle of a large, free yard area, some distance away from the main plant and other equipment.

The existing exhaust ducts and silencers will be left in place and serve as by-pass. The damper layout allows normal operation without heatrecovery or maintenance of one unit while the other is operating.

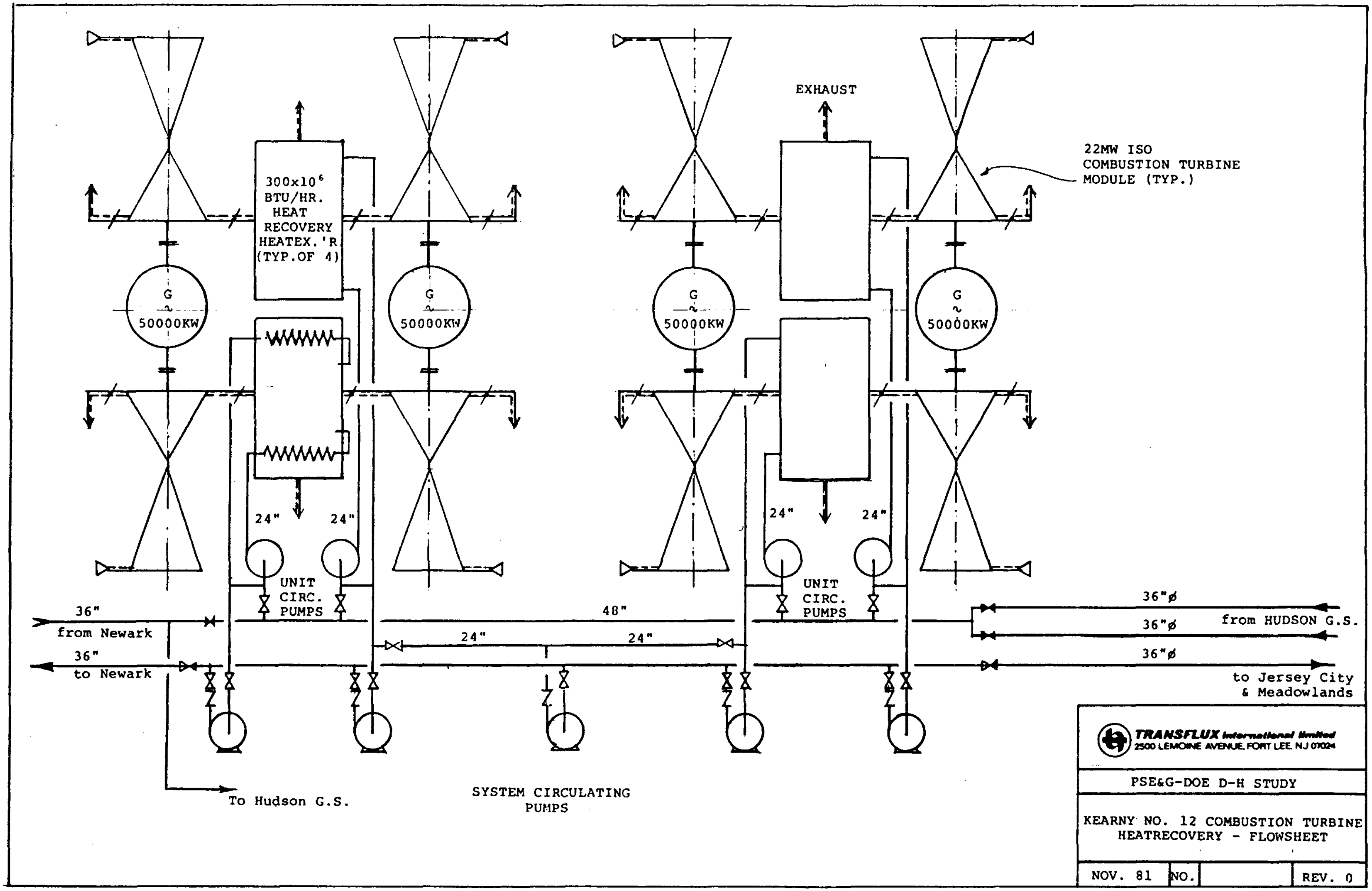
6.3.4 Plant Piping Schematics

Figure 6.3.3 shows the proposed piping schematics of the plant.

The plant is piped to two 36" returns. One from the Newark, the other from the Jersey City area. Similarly two supply lines leave connecting to these areas. At the final stage of system development, as the Hudson plant is retrofitted for D-H, an additional 36" line combined with the line serving previously as the Jersey City return will bring the total flow to this plant but there will be no change in the supply lines. Should Hudson come on line, partially or fully retrofitted before this unit is incorporated into the system, the two lines may be replaced by a single 42"ø connection. At that point the return from Newark by-passes this plant as it is directed straight towards Hudson.

The circulating pumps are sized to match the heat exchangers and each handles one-quarter of the total flow. A fifth pump acts as a stand-by. The pump head is to match the pressure drop of a heat exchangers and that of the piping (supply and return) between this plant and the farthest of the heater plants it connects to.

The general piping arrangement and control method is identical to that of the HTW heater plants. Ambient temperature sets the required leaving water temperature. Failure to do so starts the next unit, as preselected, until the control value is satisfied. The start-up control circuitry of each gasturbine is expanded by the addition of damper controls, circulating pump starting devices and safety features associated with heat recovery.


EXHAUST
22MW ISO
COMBUSTION TURBINE
MODULE (TYP.)
300x10⁶
BTU/HR.
HEAT
RECOVERY
HEATEX.'R
(TYP.OF 4)
G
50000KW
G
50000KW
G
50000KW
G
50000KW
24"
24"
24"
24"
UNIT
CIRC.
PUMPS
UNIT
CIRC.
PUMPS
36"
from Newark
36"
to Newark
48"
24"
24"
36"ø
36"ø
from HUDSON G.S.
36"ø
to Jersey City
& Meadowlands
To Hudson G.S.
SYSTEM CIRCULATING
PUMPS
TRANSFLUX International limited
2500 LEMOINE AVENUE, FORT LEE, NJ 07024
PSE&G-DOE D-H STUDY
KEARNY NO. 12 COMBUSTION TURBINE
HEATRECOVERY - FLOWSHEET
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NO.
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FIG. 6.3.3

Additional equipment as water treatment and pressurization might also be located here, if extension of these facilities at the already existing heater plants is not deemed desirable or is not cost efficient.

The plant is assumed to operate without permanent attendance and it is remotely supervised and controlled.

6.3.5 Operation and Controls

The units will be fully automatic and remotely controlled. The controls which basically operate dependent on ambient temperature will have overrides. These overrides will allow the operator to

- use the units for power generation only by bypassing the heatrecovery units.

- shut a unit off or prevent it from starting when the load is not sufficient to operate efficiently (approx. <50%).

- load a unit to generate more power than called for by heating load alone.

- select units in preference.

The temperature control system will mix the circulating flow of the heating system so as to satisfy the temperature called for by the controller. Electric power generation side control will also be normally dependent on heat requirements except when the grid calls for more power from the particular unit(s).

The best combined load conditions will also be controlled when multiple units are operating.

The heatrecovery circulating pumps will start along with the gasturbine start-up. Loss of a pump will either shut the unit off or, if power generation is on electric power dispatch, will switch it to by-pass stack. Failure of any unit will bring one of the idle units on line, if any. Should no unit be available, the HTW heater plant will receive water colder than called for. This will automatically activate additional fired-heater output or bring an additional heater on the line.

6.3.6 Plant Construction

The selected gasturbines are in position, so manufacture and installation of the heatrecovery units and pumps will set the time requirement for construction.

Presently those are available on a 26-30 week basis and another 8-12 is needed for their installation. Therefore this facility can be constructed within a year from order of equipment.

6.4 PEAKING AND BACK-UP PLANTS
(Initial development phase of a staged system)

6.4.1 PURPOSE OF "HEATER PLANTS"

The district heating development plan identified potential service areas. Within those, customers will materialize on a random and one to few-at-a-time basis. Particularly new constructions have to be supplied as their schedule dictates it. The method to meet these objectives in an economical way is to provide heat from a nearby and relatively low first cost installation. The "HTW heater plant" is such a facility.

The second, at least as important function of these plants is to provide back-up heat supply capability to the system at a low cost. The location of these plants in the midst of major load concentrations provides stand-by capability not only for loss of generating capacity but also for loss of transmission lines and/or pumps.

6.4.2 NUMBER AND SIZE OF PLANTS

The number and size of these plants at this study stage cannot be firmly stated. They were defined on the basis of the total heat supply capability of the future powerplant retrofit and on the basis of area coverage by a single facility.

The first constraint gives us the total output of all plants, as shown in Sect. 6.2, as 28% of total system output, that is

$$3.7 \times 10^9 \times .28 = 1.036 \times 10^9 \text{BTU/hr.}$$

The supply area to be covered by any one of these plants is about one square mile and the total area within the proposed boundaries is about 11 square miles. On this basis, eleven of the heater plants will be required. The average minimum capacity requirement of 94 million BTU/hr has been increased to 100 million for areas of lower and to 120 million for areas of higher load concentrations. This additional rating covers uneven load development as well as possible deterioration of unit output below its rated value. This overdesign provides a close to 20% margin over the minimum figure.

The stand-by capability of the system will also be provided in the form of fired hot water heaters. The required total back-up at any time during the gradual development shall be able to replace the output of the largest single source. This source is the Hudson G.S. extraction providing up to 1600 million BTU/hr. In order to provide this back-up, each heater plant installed capacity will be twice the output calculated above. This will amount to 2400 million BTU/hr total installed capacity. Out of this 1350 million BTU/hr is stand-by. Another 240 million can possibly be produced during the short, few hour duration, peak load periods by overfiring the units by 10%.

The average plant size thus proposed is then

5 plants of 240 million BTU/hr
and 6 plants of 200 million BTU/hr

total, normal heat output capacity.

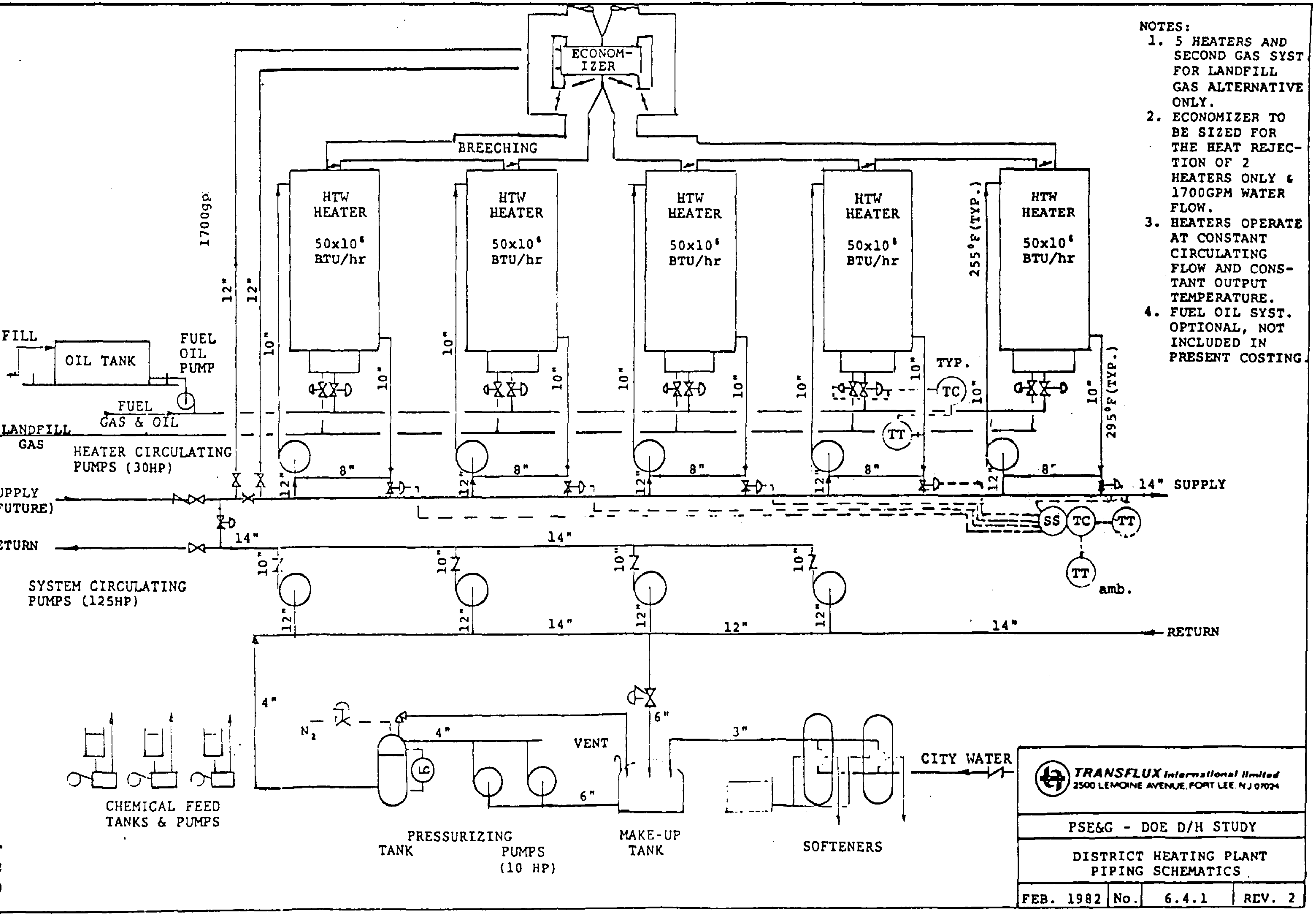
No plant will be built with less than two units installed initially. One of these will be stand-by. Whenever the individual plant output reaches the capability of a unit, another unit will be added, up to four units to a plant. Only under special circumstances will a fifth unit be added, instead of locating another plant at a close by, but distinctly different location to relieve the load.

6.4.3 PIPING SCHEMATICS

Drawing 6.4.1 shows schematically the equipment and piping of a typical plant.

Each high temperature water heater has its own circulating pump. It is sized to circulate at a flow of water in excess of that circulated in the district heating system. The units are controlled to maintain a constant set outlet temperature of about 307°F. The fuel input is controlled by that temperature. The units are natural gas fuel fired watertube packaged units with their own forced draft fan, ignition and combustion controls and safeties mounted on individual panels associated with the unit.

All the heaters are connected to a common breeching which leads to an economizer sized to recover the heat from the flue gases coming from any two of the four units. When more than two units are operating, a bypass duct with dampers will handle the excess flow. A common stack for all units will discharge the flue gases at an approximate height of not more than 50 ft. if environmental considerations do not force the use of higher stacks. The economizer on its water side takes


ECONOMIZER
BREECHING
HTW HEATER 50x10⁶ BTU/hr
1700gp
12"
10"
8"
14" SUPPLY
255°F (TYP.)
295°F (TYP.)
TYP.
TC
TT
SS
amb.
FILL
OIL TANK
FUEL OIL PUMP
FUEL GAS & OIL
LANDFILL GAS
HEATER CIRCULATING PUMPS (30HP)
SUPPLY (FUTURE)
RETURN
14"
SYSTEM CIRCULATING PUMPS (125HP)
12"
4"
6"
3"
N2
VENT
LC
CITY WATER
CHEMICAL FEED TANKS & PUMPS
PRESSURIZING TANK
PUMPS (10 HP)
MAKE-UP TANK
SOFTENERS
NOTES:
1. 5 HEATERS AND SECOND GAS SYST FOR LANDFILL GAS ALTERNATIVE ONLY.
2. ECONOMIZER TO BE SIZED FOR THE HEAT REJECTION OF 2 HEATERS ONLY & 1700GPM WATER FLOW.
3. HEATERS OPERATE AT CONSTANT CIRCULATING FLOW AND CONSTANT OUTPUT TEMPERATURE.
4. FUEL OIL SYST. OPTIONAL, NOT INCLUDED IN PRESENT COSTING.
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DISTRICT HEATING PLANT PIPING SCHEMATICS
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incoming D-H supply water flow coming from the previous stage and heats it before the stream enters any of the heater units.

A control valve in each heater circuit mixes the flow from the district heating system to that of the heater in accordance with the supply temperature required momentarily by the users. This temperature is controlled by the ambient temperature. The warmed up water enters a set of four system circulating pumps which in turn circulate the water through the local distribution system and customer heat exchanger equipment, returning it to the plant. In the first stage of development, or during system upset conditions, the return water is directed back to the entering supply line directly by a bypass arrangement. During normal operation the return water by-passes this plant and returns directly to the previous stages of the system, that is to the gas-turbine plant or to the power plant.

In order to prevent flashing of the hot water, a pressurizing system maintains 70 psig constant pressure on the suction header of the system circulating pumps. A large low pressure receiver is part of this system and water is pumped into the system as required from this storage. Excess water from the pressurizing tank due to expansion is returned to this receiver. Usually the excess water is produced during the warm-up of the system due to the increase in specific volume.

Softeners to provide makeup water for the system take city water, treat it and feed it into the receiver mentioned above. A nitrogen cover will prevent oxygen entrapment during storage. The capacity of these softeners is proposed to be 4% of the normal flow through the plant when all four units are operating in an emergency condition, that is 150-200 gpm per plant.

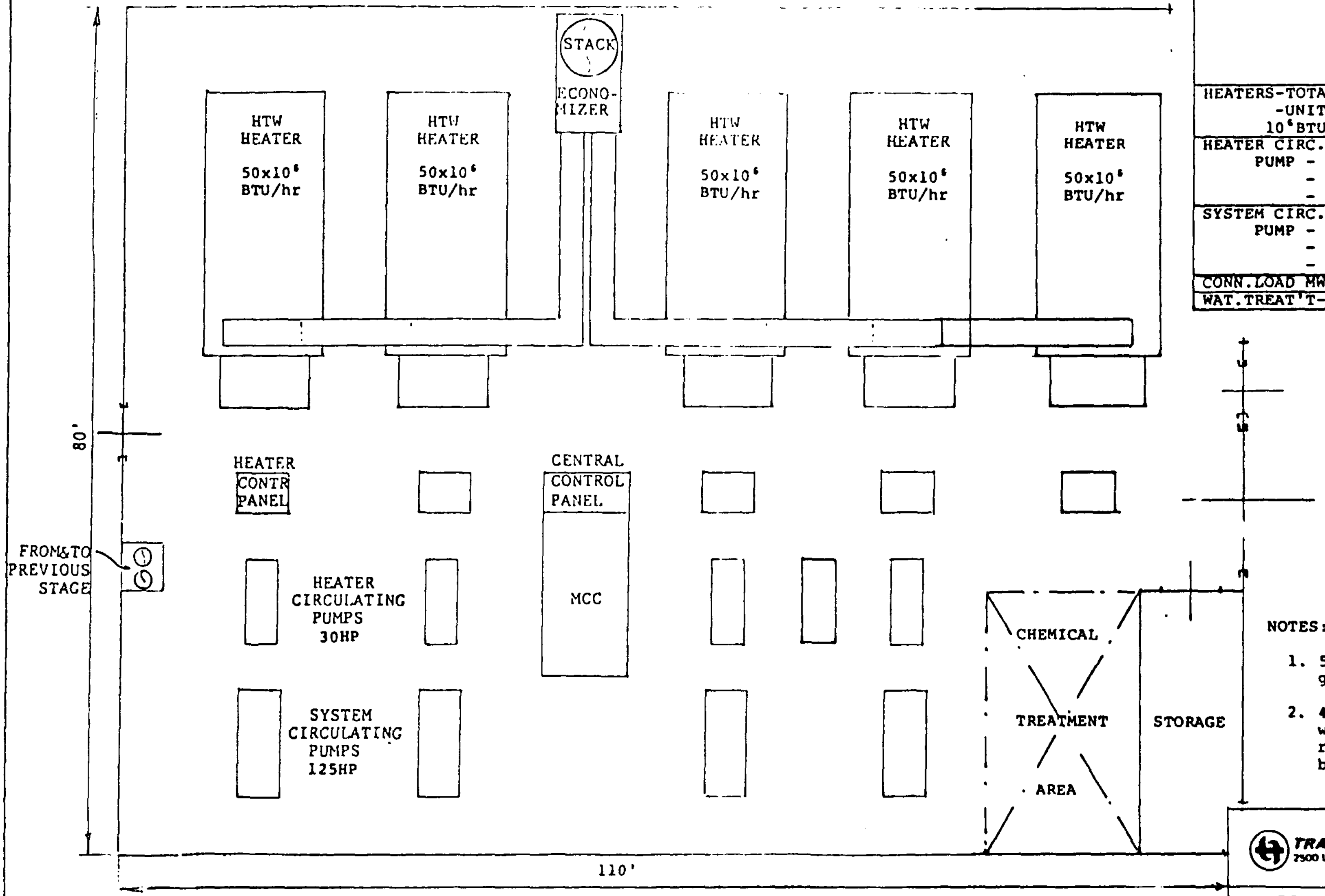
A number of chemical feed tanks and proportioning pumps are also installed here to maintain water quality by feeding amines, hydrozine, etc.

6.4.4 PLANT LAYOUT

Drawing 6.4.2 shows the layout of the plant.

The plant is located in an 80 x 100 ft., approximately 20 ft. high single story building or space.

The tabulation on the referred drawing shows the required equipment sizes in the different potential



	MEADOWLAND	JERSEY CITY	NEWARK
HEATERS-TOTAL	200	200	240
-UNIT	50	50	60
10^6 BTU/HR	50	50	60
HEATER CIRC.	1300	1300	1300
PUMP - GPM	1300	1300	1300
- ΔP	30	30	30
- HP	35	35	35
SYSTEM CIRC.			
PUMP - GPM	1100	1100	1100
- ΔP	150	150	150
- HP	125	125	150
CONN.LOAD MW	.8	.8	.95
WAT.TREAT'T-GPM	50	50	60

NOTES:

1. 5 units for landfill gas operation only.
2. 4 units in conjunction with Hudson G.S. retrofit. Length of bldg. to be 100'.

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DISTRICT HEATING PLANT LAYOUT

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supply areas. The physical size difference does not warrant changing the building design. It is laid out to accommodate the largest pieces of equipment required. The stack is assumed to be a minumum of 6 to 6-1/2 ft. diameter, 50 ft. high prefabricated steel stack with two flues, each for two units.

The plant is assumed to be operated without permanent attendants and therefore no other comfort facilities need to be provided but a washroom.

The facility can be made part of another structure. In this case accessibility and the required stack extension to at least 6 ft. above roof line should be weighed against the savings in building construction and land cost.

6.4.5 OPERATION AND CONTROLS

The units will be supplied with fully automatic local control systems and remote and local supervisory controls. Both operating unit selection and operation will be from a central remote location when the system is fully developed. In the first stage of development, the operation and controls will be local, fully automatic, but with roving supervision only.

If the system serves basically space heating, then the supply temperature will be automatically controlled by ambient temperature. Units will be started up and shut down as required, also automatically. Any heater unit coming on-line will have a pre-purge cycle and any unit coming off the line will have a post-purge cycle also. Due to this arrangement, failure of any of the upstream stages will automatically bring the standby units on-line, trying to maintain the momentarily required send-out temperature. When pumping power fails at the upstream stages, they will open automatically the bypass and the plant will try to maintain service by itself.

The circulating pumps are so controlled that failure of any one will automatically bring in one of the standbys as replacement.

The makeup system will provide water as required by a level controller on the storage receiver and will also regenerate one of the units on a time cycle.

	heaters operating		
	1	2	4
heater circ. pump	35	70	140
F.D. fan	30	60	120
system circ. pump	375	375	375
make-up	10	10	10
contr. & light	20	20	20
	470 HP	535 HP	665 HP
or approx.	350 kW	400 kW	500 kW

Automatic water quality analyzing system will operate the chemical feed pumps to provide proper dosage of chemicals. Replenishing of chemicals will be a manual operation provided by the roving supervisory personnel.

6.4.6 PLANT CONSTRUCTION

It is proposed to build these plants in two or three steps. The first step includes at least two units and the treatment plant. Further units can be added one by one or the other two also in one step. Building construction should be completed in the first step. The prefabricated building cost probably does not warrant a second building phase.

The two-unit plant can be completed within a year. Where speed is necessary, the availability of heaters and pumps will define the shortest possible construction time. In any case, there will be no capital tied down for any long term, before production and thereby revenue start. This is based on the assumption that construction of distribution lines will be carefully coordinated with that of the plant.

6.4.7 OPERATING POWER REQUIREMENTS

The plant as shown on Fig. 6.4.1 has four system circulating pumps (one spare) and as many heater circulating pumps as heaters installed at any stage. At least one heater is normally on stand-by, possibly two.

In addition there are two smaller pumps for make-up feed and some fractional HP ones for chemicals proportioning, and two 100 scfm air compressors for the controls.

Each heater has its own motor-driven forced draft fan of 30-40 HP each.

The required total installed power supply capacity is 800 kW for the smaller and 950 kW for the larger plants plus some 20 kW for utilities and yard lighting.

The electrical load when the heater plant is in operation and when the users have reached the total capacity of the heater is as follows:

6.5 TRANSMISSION AND DISTRIBUTION

6.5.1 GENERAL

The piping for the distribution of heat generated at the various stages of the D-H system is a two-pipe, closed, circulating water system. There are two equal size pipes required to supply and to return the water and therefore all calculations are based on a pair of pipes, generally laid side-by-side. Length of pipe is given as the length of trench and always refers to two pipes. So are heat loss and pump work requirements.

The selection of economically justified pipe sizes is crucial to the economy of the system. Investment in piping is about 70-75% of the total capital outlay. Operating costs, as pumping power and heat loss, also have a major impact on the total operating cost. Approximate cost estimates were made to assist in optimizing these design details. More precise cost estimates were used in the assessment of economic viability and are presented in the Economic Analysis section of this report.

6.5.2 BASIS OF ECONOMICS CALCULATIONS

The investment in piping has to be written off like any other capital outlay. The present PSE&G requirements are as follows:

Return on investment	10.5%
Depreciation	.5%
FIT	1.5%

Total carrying charge	12.5%

This assumes a 33 year booklife for the investment. It is also assumed that the investment will become productive within the year of its installation.

The electrical energy cost is conventionally accounted for at its replacement cost. This is the method all other departments of the company reimburse electric power operations for the power they use. The average annual replacement cost of electric power in 1981 was given as

$69 per MWh

The actual momentary cost varied between 60% and 200% of that average figure. A 50% increase is expected during the coming four years.

The cost of heat for the valuation of heat losses will also be calculated on the basis of incremental power cost. The reason for this is that the heat losses are considered as a base load and will be supplied by the retrofitted powerplant when the system reaches that stage of completion. For the purpose of these calculations, a simplified heat value has been derived from the full heating load conditions of the Hudson No. 2 unit as calculated by Westinghouse.

Output at guarantee point	602734KW
Output at 1653000 lb/hr extract.	453861KW

Loss of output	148873KW
Additional output by back-pressure heating turbines (see Sec. 6.2)	53600KW

Net loss of generation	95273KW

The specific loss is

$$\frac{95273}{804821(1270-148) + 722467(1234-148)} = 56.45\text{KW}/10^6\text{BTU}$$

This at the above replacement cost is

$$56.45 \times 69 \times 10^{-3} = \$3.895/10^6\text{BTU}$$

While this is calculated at the full load conditions, partial load conditions are proportional. Just to allow for minor variations, the figure used was

$$\$4 \text{ per } 10^6\text{BTU}$$

supplied to the district heating system from the Hudson No. 2 unit.

6.5.3 PUMPING COST

The cost of pumping water in the circulating system has been calculated on the following basis:

Pipe:	Carbon steel pipe, seamless or seam welded sch. 40 up to 12", std. 14" and up.
Smoothness:	Hazen factor 120
Joints:	Welded.
Flow:	100% for 5000 hr and 50% for 3760 hr per year.

Cost: @ \$69/MWh:
1 KW installed is
$5000 + (1/4 \times 3760) \times 1 \times 69 \times 10^{-3} =$
\$409.86/KW since at half flow the pressure drop is reduced by 75% and only one of a number of pumps operates during reduced flow conditions.

Resistances: The following individual items have been considered as additional pressure drops.

3/4" to 1-1/2" lines:
- 2 Valves
- 2 Tee's
- 4 Ell's per 100 ft - 200 ft

2" to 4" lines:
- 2 Valves
- 2 Tee's - branch
- 10 Tee's - line
- 8 Ell's per 200 ft

6" to 12" lines:
- 2 Valves
- 2 Tee's - line per 1/3 mile
- 8 Tee's - line
- 2 Tee's - branch
- 8 Ell's per .1 mile

14" and up:
5% additional pressure drop to straight line losses.

The results of these calculations are shown on Fig. 6.5.1. The annual cost figure per million BTU/hr peak use was arrived at by the expression

$$\frac{KW \times 409.86}{gpm \times 500 \times 120} = \$/yr,\ 10^6 BTU/hr\ peak$$

where 8760 is the annual operating hours and 120 is the temperature differential between supply and return at peak load.

6.5.4 PIPING COST

The cost of piping installations is the most significant item of the total investment. It is also the

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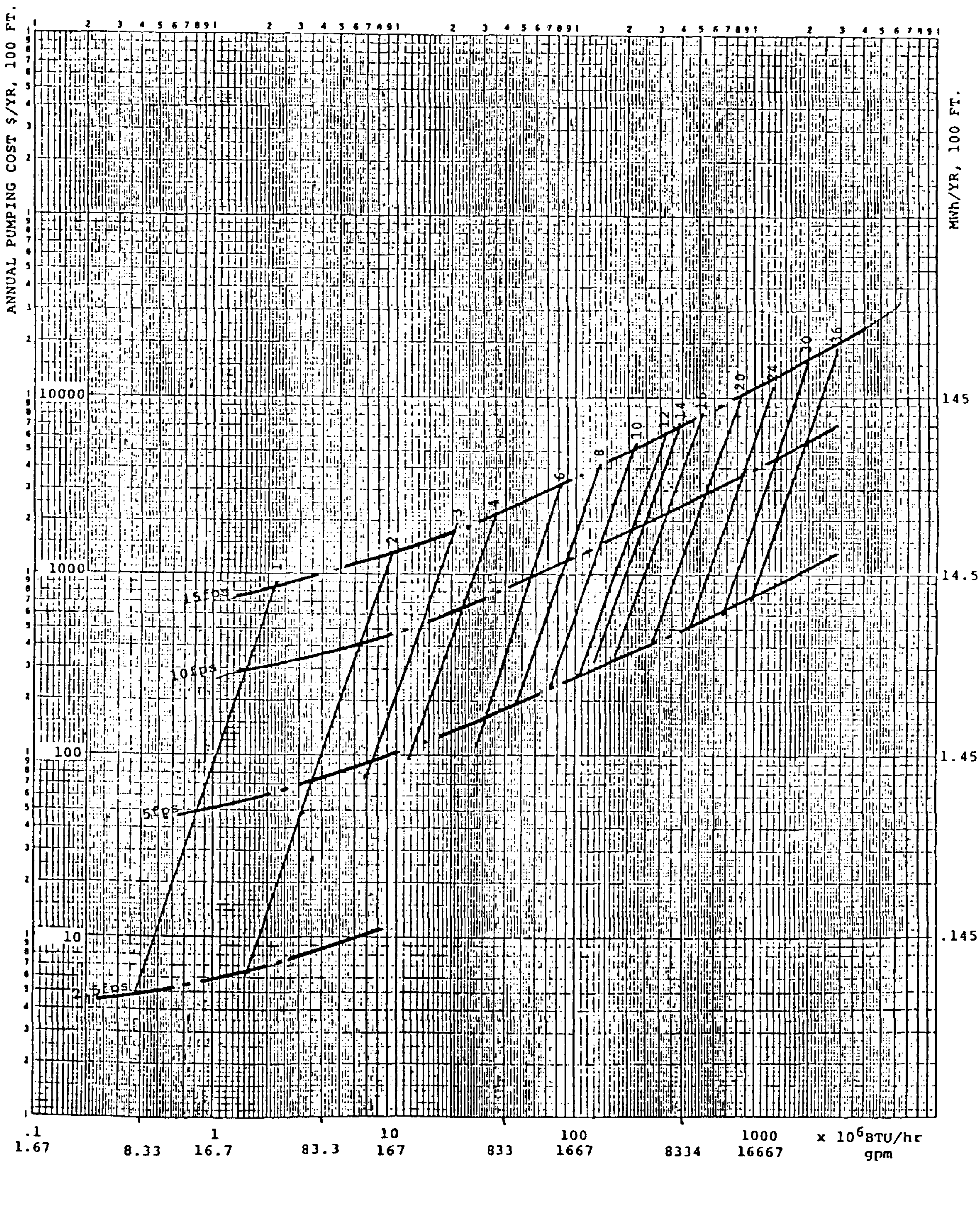

FIG. 6.5.1

ANNUAL PUMPING COST

hardest to estimate correctly since purchased items represent a relatively small fraction of the total cost. Site work is the major element and it varies widely with the congestion of services and traffic, with the soil conditions and with the restoration work necessary. The experience of the Gas Department is very relevant and the figures used are based on their calculations.

Material cost estimates were obtained from a number of prefabricated insulated piping fabricators, and those for steel core pipe with polyurethane insulation and FRP outercoating were used up to 8" diameter and concrete culvert prices above that. The transmission lines between the Hudson G.S. and the three major sites and those between the two sites at the Meadowlands were laid out using existing right-of-ways crossing uninhabited areas. There the lines are laid aboveground on piles and steel supports.

The originally calculated costs have been increased by 15% to account for valves, branching, compensators, manholes, etc. and by another 10% on top for engineering and supervising costs. The resultant figures are shown in graphic form on Fig. 6.5.2. As a comparison, cost figures calculated by Stone and Webster in Phase I and those calculated by Burns and Roe as part of DOE project 79/7672 - I. Oliker, "Assessment of existing and prospective piping technology for district heating applications" are also plotted. It clearly shows that there is reasonable agreement among these sources.

The right-hand ordinate of the plot shows the annual cost of installation based on the % figure shown in para. 6.5.2.

6.5.5 HEAT LOSS

The extensive heat distribution network has considerable heat losses. The system operates at variable temperatures throughout the year, as was shown in Sec. 6.1. The determination of the average supply and return line temperatures was the first step in calculating the losses. These temperatures are as follows:

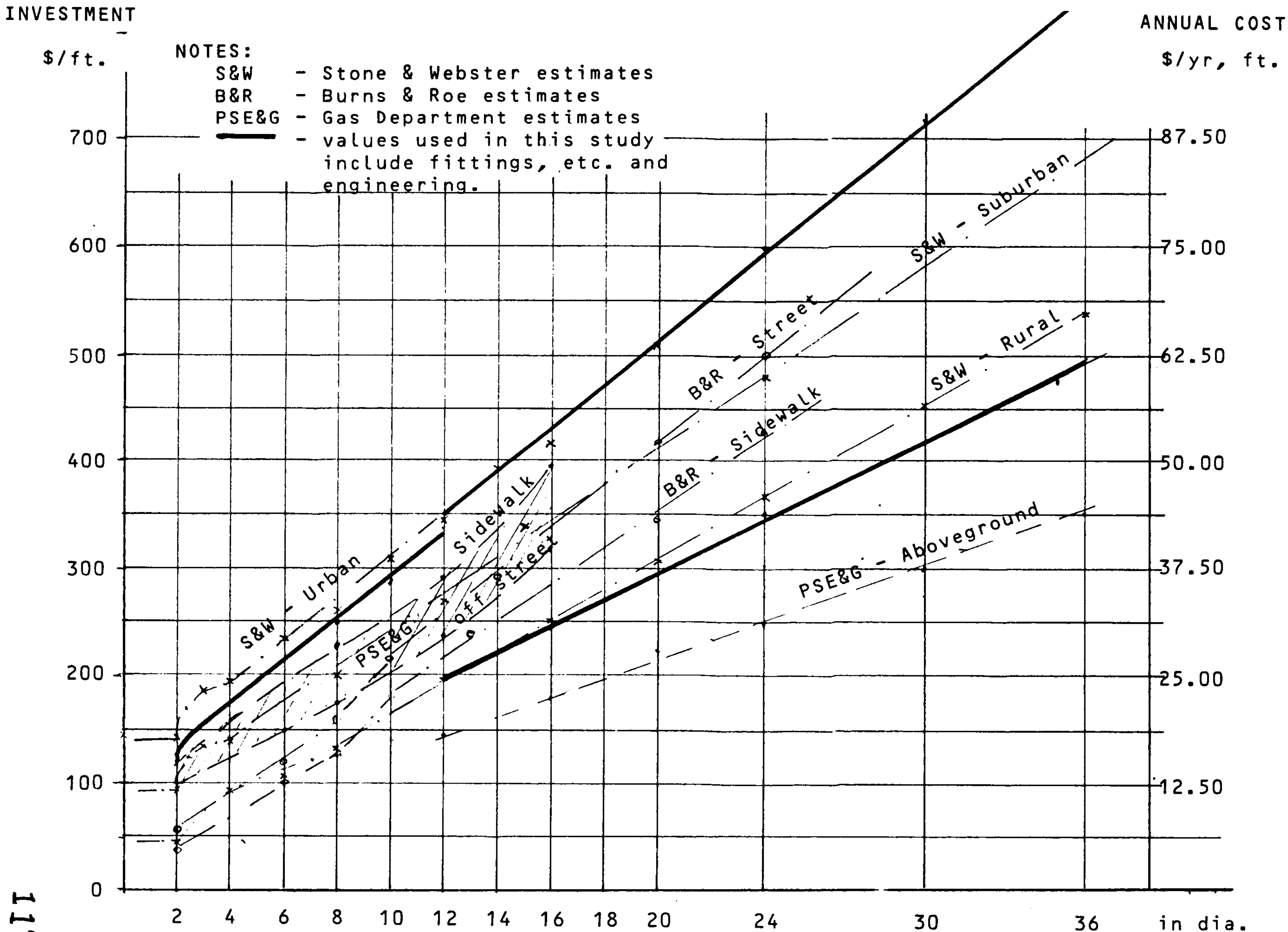

FIG. 6.5.2
INSTALLED PIPING COSTS
AND COMPARISON WITH OTHER ESTIMATES

Final system (all three stages developed)

		av. temp. °F	weighted av. °F
Supply line leaving Hudson	2800 hr/yr	210	
	3000 "	180	
	2200 "	198	
	760 "	210	196.7
Return line to Hudson	1000 "	158	
	3700 "	145	
	4060 "	140	145.9
Supply lines - distribution system	400 hrs	272.5	
	1000 "	235.0	
	1400 "	213.5	
	2200 "	192.5	
	760 "	199.0	
	3000 "	178.0	
	annual		202.2
	winter		213.4
	summer		182.2
Return line - distribution system	400 hrs	163.0	
	1000 "	155.5	
	1400 "	151.0	
	2200 "	145.0	
	760 "	140.0	
	3000 "	140.0	
	annual		147.4
	winter		150.3
	summer		140.0

The average outdoor ambient temperatures for the area are

winter 29.35°F (seven month)

summer 65.00°F (five month)

The heat loss was calculated for the following piping characteristics:

Nom. pipe dia.-in.	Insulation in.	Distance c-to-c supply & ret. nom. in.
1	1-1/2	12
1-1/2	1	12
2	1-1/2	12
3	2	18
4	2	18
6	3	24
8	3	24
10	3	30
12	3	30
14	3-1/2	36
16	3-1/2	36
18	3-1/2	36
20	3-1/2	48
24	4	48
30	4	52
36	4	60

The two pipes laid side-by-side have the effect that the ground temperature increases around the return pipe, reducing its losses beyond that accounted for by its lower temperature. The calculated values are as follows:

Pipe Size in.	Heat loss BTU/hr,ft Winter 5110 hr/yr	Summer 3650 hr/yr	Annual loss BTU/yr,ft	Value of Heat loss $/yr,ft
1	14.6	9.5	109280	.44
1-1/2	16.1	10.5	120590	.48
2	16.9	11.0	126510	.51
3	22.0	14.3	164610	.66
4	25.3	16.5	189500	.76
6	30.3	19.7	226730	.91
8	32.8	21.4	245720	.98
10	39.5	25.7	295640	1.18
12	45.5	29.6	340540	1.36
14	46.8	30.5	350470	1.40
16	52.45	34.1	392480	1.57
18	58.5	38.1	432990	1.73
20	70.35	45.8	526660	2.11
24	79.0	51.4	591310	2.36
30	114.3	74.4	855630	3.42
36	165.8	108.0	1241440	4.96

These values refer to compacted earth with some moisture content. Clay content and/or water saturation can double these values. See also Fig. Fig. 6.5.3 - comparison with computer data of one manufacturer.

6.5.6 PIPE SIZE SELECTION AND OPERATING COST

The proper pipe size for a given load is the one which costs least when all cost components--investment, pumping and heat loss--are considered together. These were compiled as shown on Fig. 6.5.4.

All heat loads under 7 million BTU/hr will have 2" connections. No distribution line in the streets will be less than 3" dia.

As it was mentioned, heat loss values and cost can vary considerably with deteriorating soil conditions. The heat loss cost effect, relative to capital charges and pumping cost is however so small that even doubling it will not materially affect the economical pipe size selection.

6.5.7 DISTRIBUTION PIPING

The distribution piping for the existing city environment has to be estimated on a statistical basis. One can assume, based on previously developed data (sec. 2), that within a square mile 300 x 10^6BTU/hr and 360 x 10^6BTU/hr space heating peak load will be connectable, where the two figures refer to Jersey City and to Newark respectively. This meets the send-out capability of a peaking heater plant assumed to be located in a central location, as for example is shown on Fig. 6.5.5.

The area has approximately 200 city blocks. A city block averages 200' x 400' and about 45% of the total area is public domain, as streets, parks, etc.

A building one can call a major user has an average of 150 apartments and an estimated peak space heating load of 3 x 10^6BTU/hr. The same load is presented by an office building of about 100-120000 sq. ft. Small family row houses of 3-4 units estimated @ 34000BTU/hr per apartment represent 100-136000 BTU/hr peak load each. These are typically 20 ft. wide and 50 ft. deep, so there are 25-30 of these on a typical city block (see Fig. 6.5.6 - development plans for Montgomery St.), adding up to a total load of 3 to 4.5 million BTU/hr.

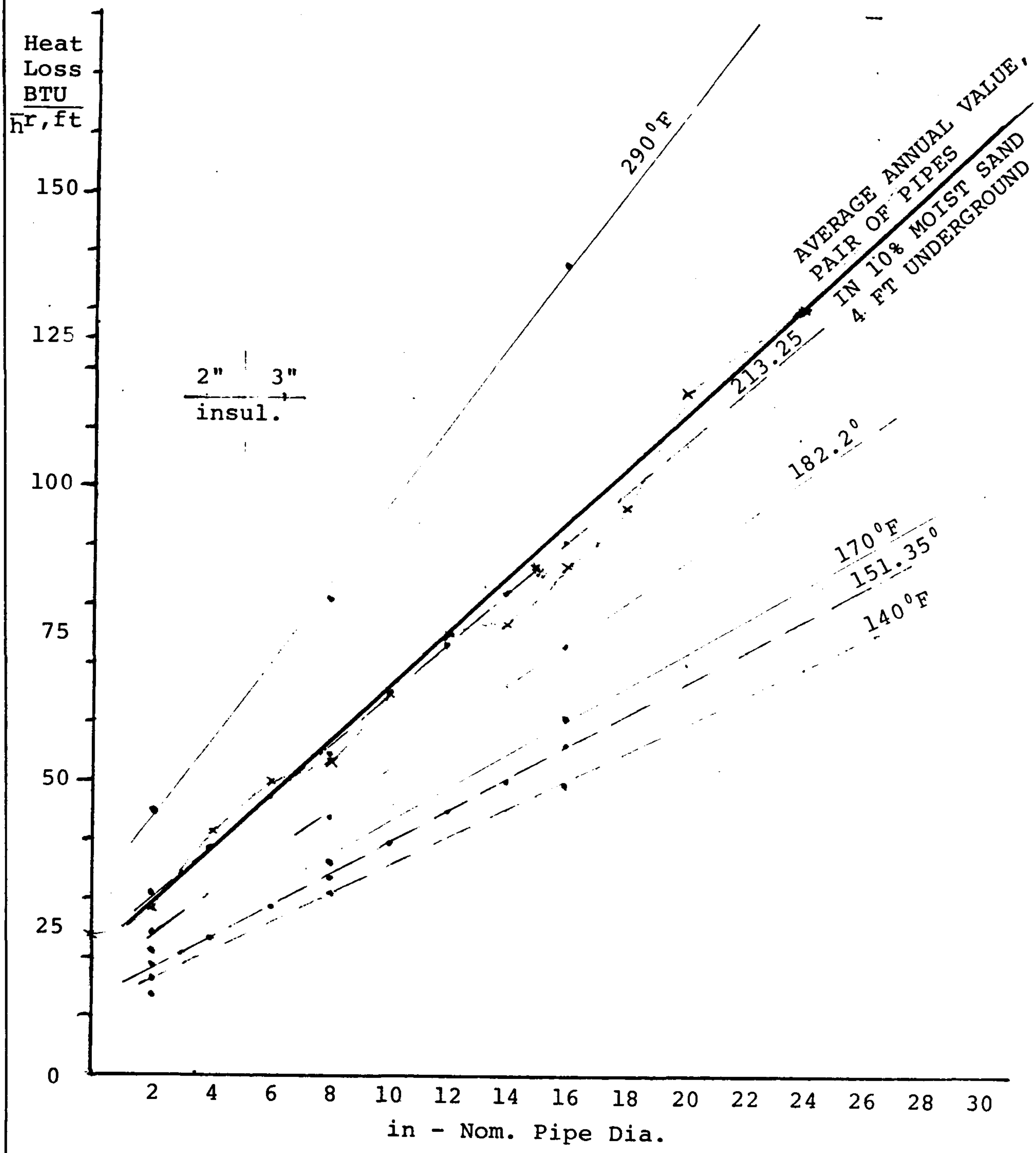

FIG. 6.5.3

SPECIFIC HEAT LOSS OF BURIED PREFAB. PIPE

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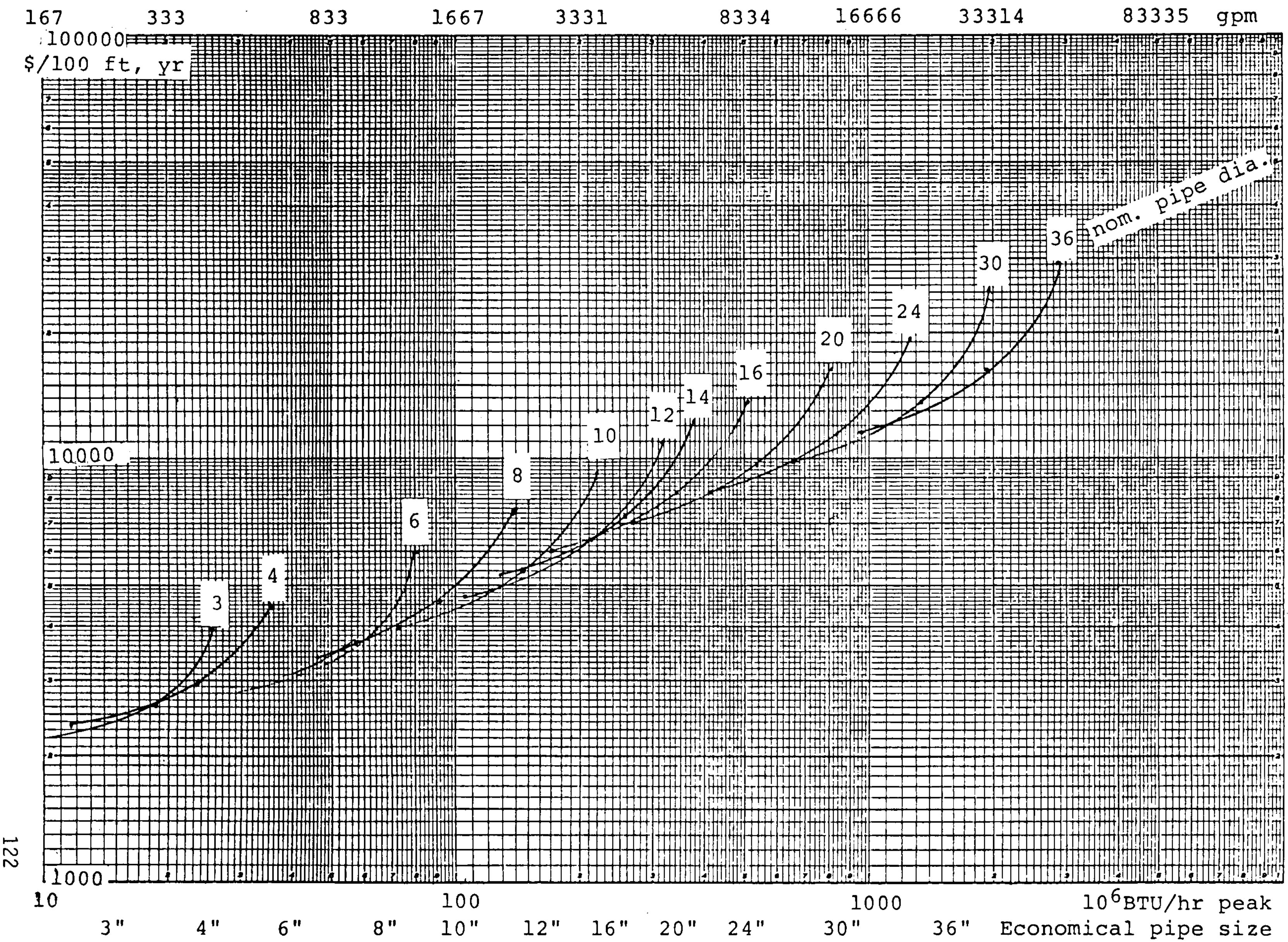
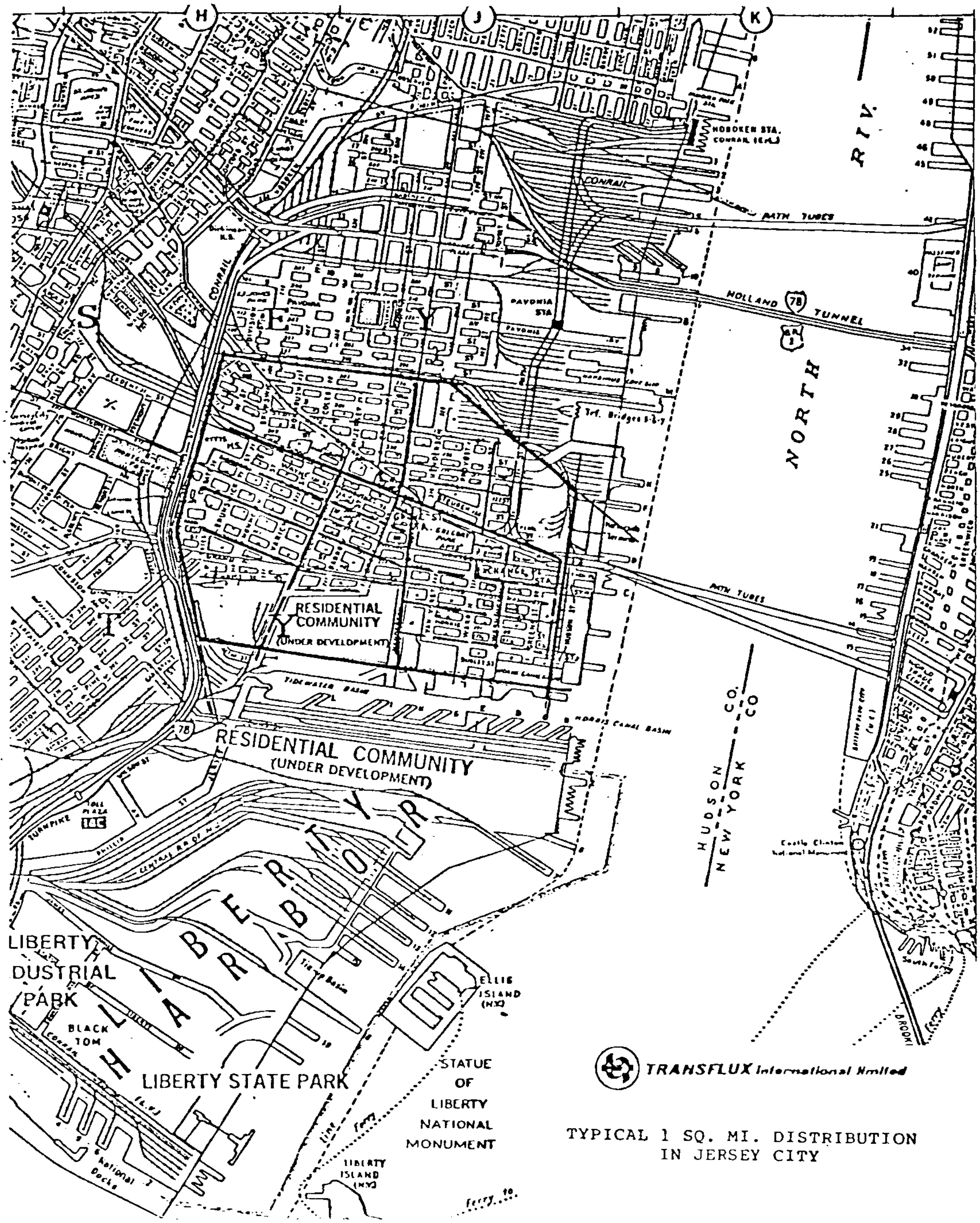
FIG. 6.5.4
ANNUAL COST OF 100 FT OF PIPING
AND ECONOMICAL PIPE SIZE DETERMINATION





TYPICAL 1 SQ. MI. DISTRIBUTION
IN JERSEY CITY

FIG. 6.5.5

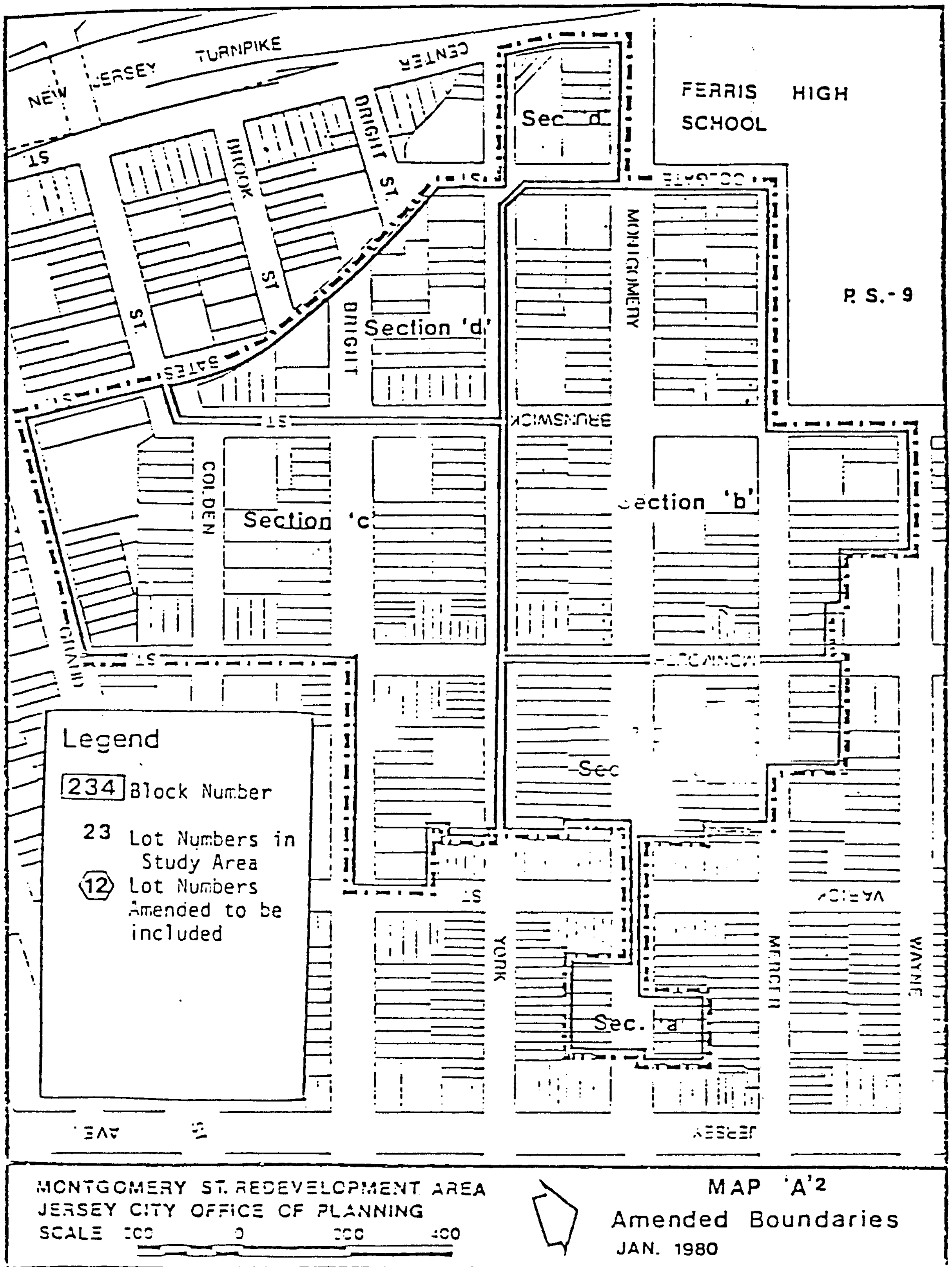
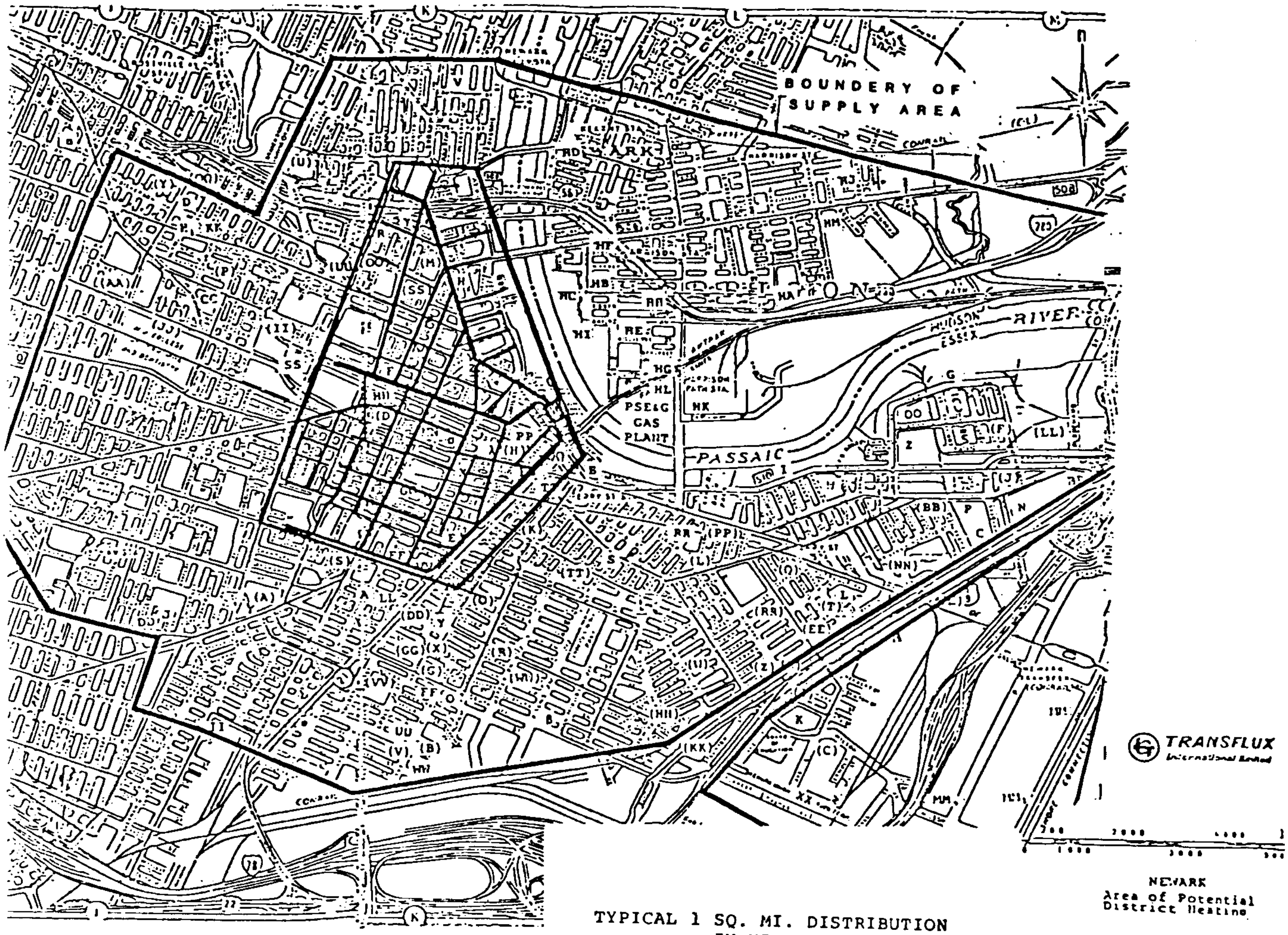

NEW JERSEY TURNPIKE
CENTER
FERRIS HIGH SCHOOL
Sec. 'd'
BROOK ST
BRIGHT ST
ST.
Section 'd'
BRIGHT
MONTGOMERY
P. S.- 9
GATES
BRUNSWICK
COLDEN
Section 'c'
Section 'b'
GRAND
Sec
Legend
234 Block Number
23 Lot Numbers in Study Area
12 Lot Numbers Amended to be included
ST
YORK
MERCER
VARICK
WAYNE
Sec. 'a'
AVE
JERSEY
MONTGOMERY ST. REDEVELOPMENT AREA
JERSEY CITY OFFICE OF PLANNING
SCALE
MAP 'A'2
Amended Boundaries
JAN. 1980

FIG. 6.5.6



TYPICAL 1 SQ. MI. DISTRIBUTION
IN NEWARK

FIG. 6.5.7

It is assumed that by the end of an 8 - 10 year development of district heating in any of these areas there will be connected

80 major users	@ $3x10^6$BTU/hr	$240x10^6$BTU/hr
and 85 blocks of row houses	@ $1.4x10^6$BTU/hr	$119x10^6$BTU/hr
		$359x10^6$BTU/hr

in Newark (Fig. 6.5.7) and 65 major users with 75 blocks in Jersey City (Fig. 6.5.5), for a peak of $300x10^6$BTU/hr. This means providing heating to 160 and 140 blocks of buildings out of over 200 city blocks within a square mile. It also means assumption of providing heat to most large complexes and to about 40% of the row houses.

The distribution mains leave the heaterplant in three or four directions dependent on its position within the supply territory. These lines are 12" or 10" dia. respectively. Each quadrant is looped by 4" distribution lines connecting to the two mains bordering the quadrant. All load centers up to 5 million BTU load will have a house connection of 2" diameter. This same size pipe will also connect to the block supply centers.

A block of multi-family row houses is shown on Fig. 6.5.8. The heatexchanger and pump unit is located in its own housing at the middle of the block. Distribution from here is at the secondary side. Circulating power is also provided by the unit. The lines connecting to a single building are 1" size or 1-1/2" size for two adjoining buildings.

The total average distribution piping system for a square mile of high density city neighborhood then requires the following distribution piping (average):

on-street piping:	10" dia.	5900 ft.
	8" "	5900 ft.
	4" "	79000 ft.
	2" "	26300 ft.
off-street piping:	2" dia.	30000 ft.
	1-1/2"	25500 ft.
	1" dia.	25500 ft.

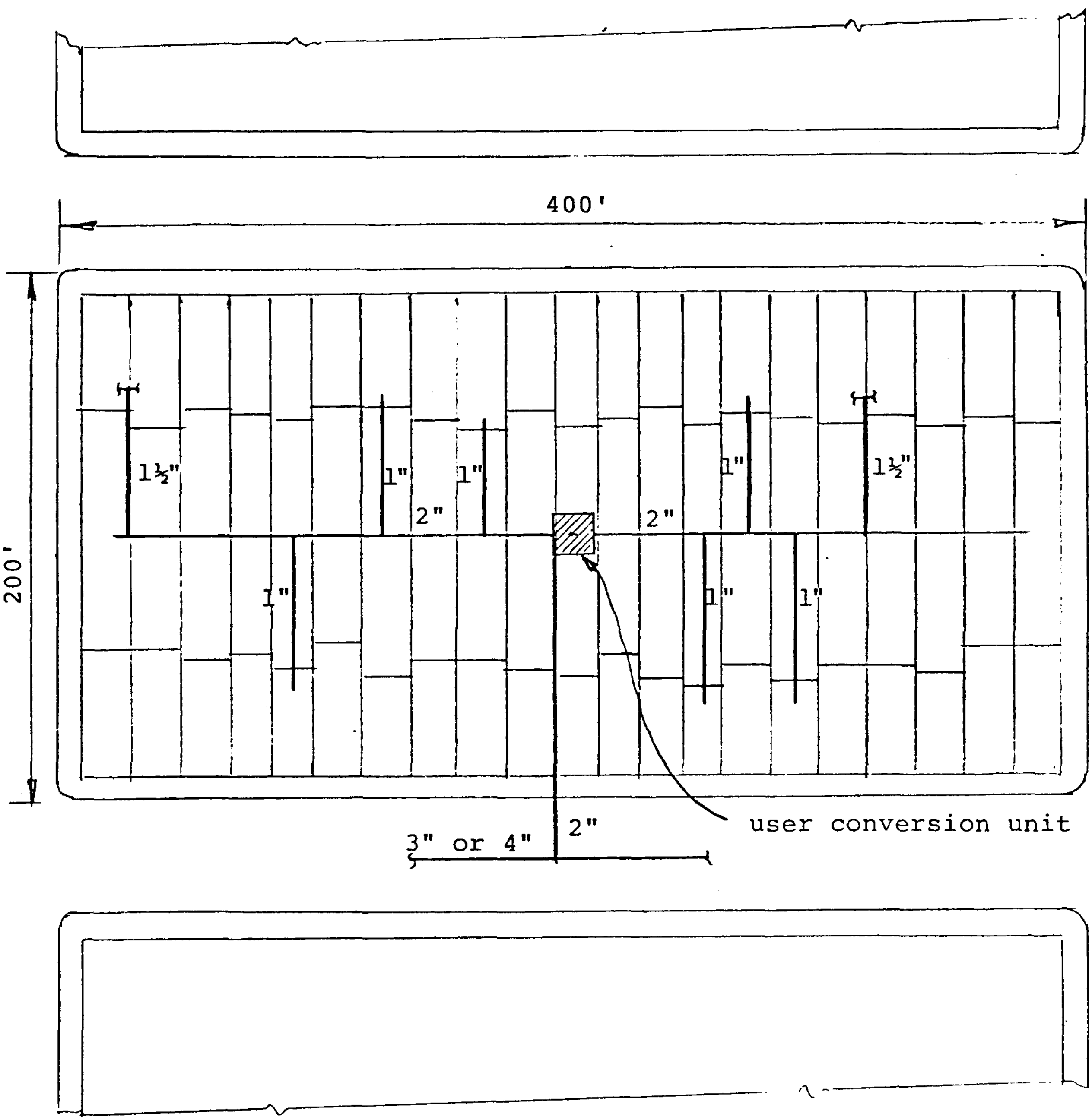


FIG. 6.5.8

TYPICAL BLOCK OF MULTI-FAMILY ROW HOUSES - D-H PIPING

The on-street piping is made of steel, while the low temperature off-street piping is of plastic or copper. The off-street piping can also be run aboveground if conditions permit in concrete or other protective cover.

The off-street piping is secondary distribution. As such it can be made part of the distribution system or it can be considered as part of the conversion package and let its installation and cost be borne by the customer. These possibilities will be dealt with in Section 9.

6.5.8 TRANSMISSION PIPING

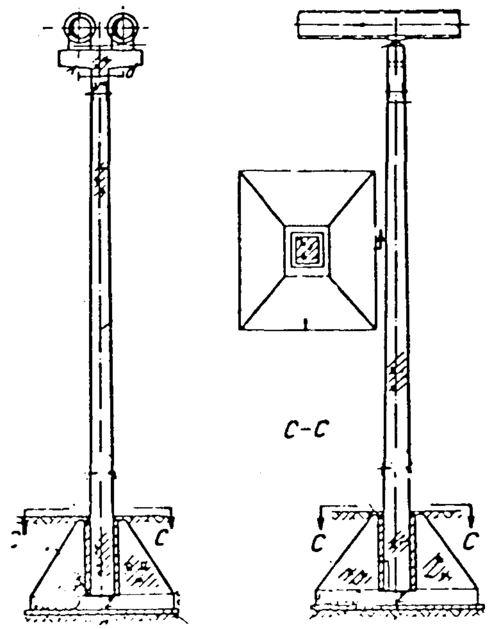
Generally the transmission piping is no different from the distribution piping, except for its larger size and for the environment it may be located in. The size range for the project is 18" to 42" in diameter. Because of their position in the staged system no transmission line will operate over 260^{0}F temperature, while most of the time considerably lower. Their construction will vary dependent upon their location whether underground or aboveground.

The routing of the transmission lines will, where possible, follow existing PSE&G right-of-ways (ROW) owned or leased by the electrical or gas services. On Figs. 6.5.9 and 6.5.10 there are shown typical aboveground pipe support structures used in other systems to carry major piping. Some variants of those will be utilized where required.

River crossings will preferably utilize existing tunnels and road/railroad bridges if permissions can be obtained. Bridges will only be used if other ways prove impractical or unobtainable.

Generally overhead lines will be steel pipes, with fiberglass or rockwool insulation applied at site and covered with a weather resistant finish. Lines located less than 8 ft. aboveground will have also an outside metal cover for mechanical protection.

Remote operated sectionalizing valves for faster repairs will be inserted at every mile on runs with no branches and just downstream of every branch. This way isolation of any pipe failure will assure the minimal effect on the total system. It will also speed the repair work by minimizing line drainage and filling times.



Prefabricated concrete column.
Base poured at site.

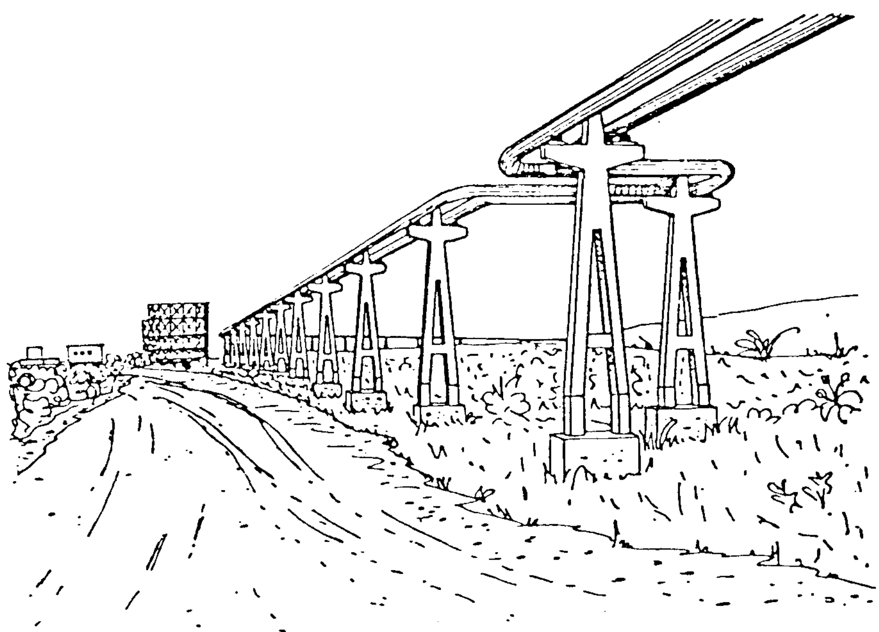
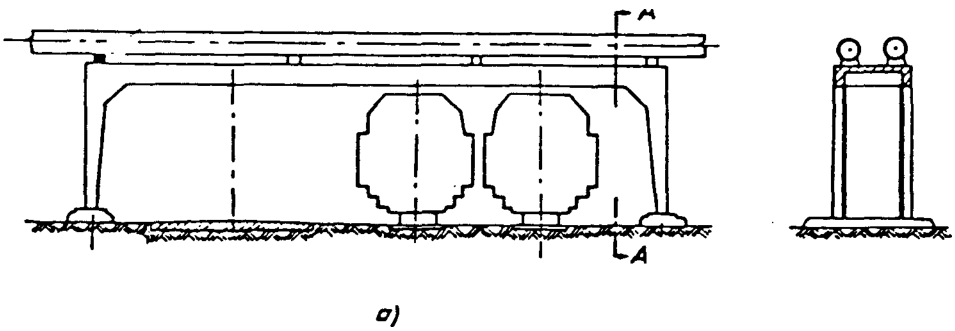
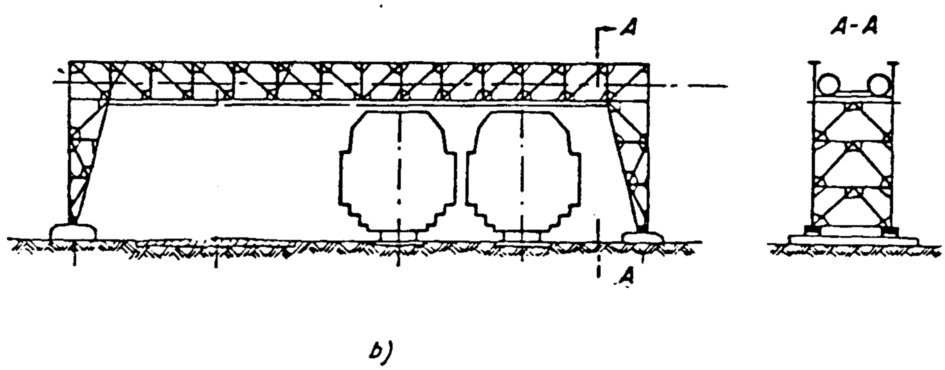
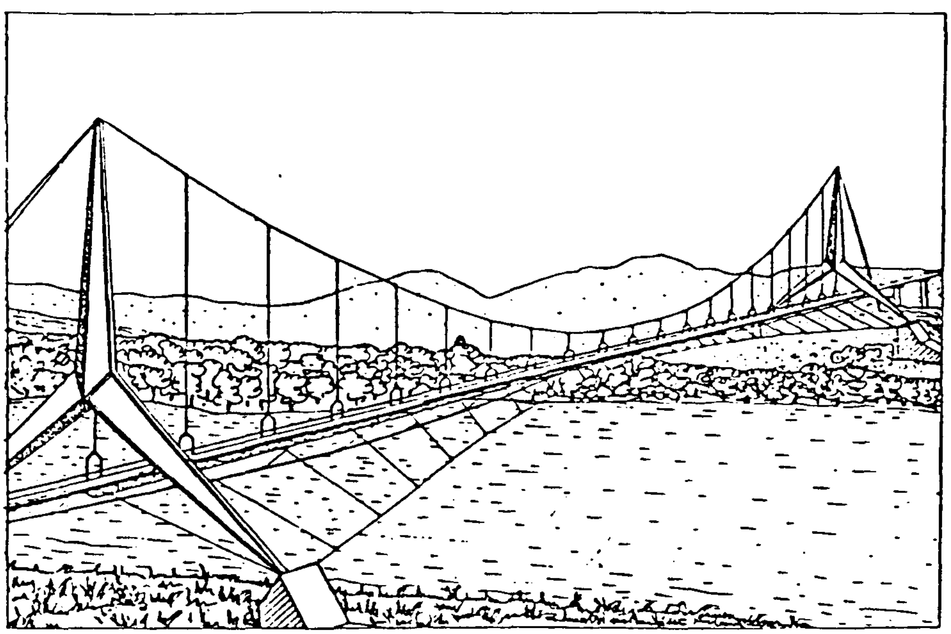


FIG. 6.5.9
TYPICAL ABOVEGROUND PIPE
SUPPORTS





Railroad and road crossings.
a) concrete structure; b) steel structure.



Rope bridge for river crossing.

FIG. 6.5.10
CROSSING OVER OBSTRUCTIONS

6.5.9 SYSTEM PRESSURES & WATER CIRCULATION

The hot water is supplied by a system of closed, circulating transmission and distribution pipes. As the system is developed in stages, so is the pumping capacity needed to move the water around.

A hot water system requires that the pressure at any point will not fall to a value below the saturation pressure corresponding to the maximum temperature generated. This temperature was defined previously as 293°F. The corresponding saturation pressure is 60.5 psia. A cover pressure of 70 psig (84.7 psia) will be maintained to allow ample margin for control fluctuations (-14 psi) and for temperature excursions (up to 316°F). It is to be recognized that this pressure will prevail over the whole system, when no pumps are operating. In order to maintain that static pressure, the make-up capability has to meet the flow requirements due to leakages and volume changes of the fluid due to cooling. Most of the system volume is that of the distribution lines and also the cooling effect of those lines is many times that of the transmission lines. It follows logically that the make-up facility should be as close to the distribution as practical. These close points are the heater plants in the proposed development. Wherever the make-up introduction is, there is the pressurization point for simplicity of control. The means of controlling pressure is feeding water in when the pressure decays and let off water when it increases (e.g. heat-up period). The usual point of pressurization is the suction of a system circulating pump, where a constant pressure can be maintained independent of flow rate.

Based on those premises, Fig. 6.5.11 shows the pressure diagram of the proposed system. Its three intermeshing circulating loops are so developed that each successive loop operates without any change when an upstream loop was lost. Consequently each loop is a fully operational system even before the upstream systems exist.

The right-hand loop with the make-up connection and the heater plant is the first stage to be built and operated. It sends the water through the distribution system to the users and back to the heater plant. The heaters have their own circulating pumps used only when the heaters are actually in use (see Sec. 6.4). Each heater plant supplying an area of about 1 sq. mi., no line is more than a mile long to any user. The hydraulically farthest user defines the

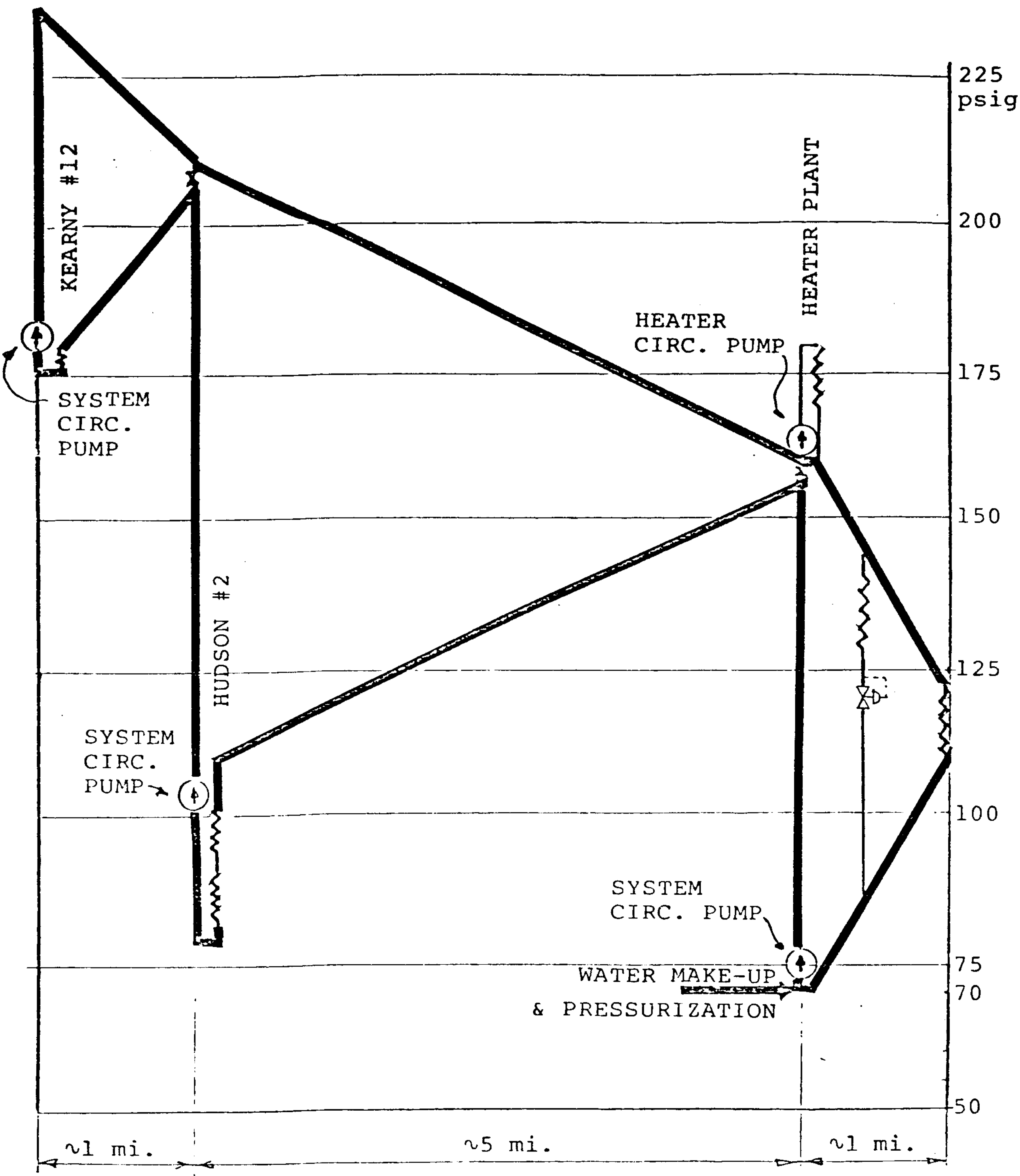


FIG. 6.5.11

SYSTEM PRESSURE DIAGRAM

pressure required to operate the system. Most other users will have excess pressure differential available, which will need throttling to set the proper flow.

The middle loop represents the pressure conditions on the transmission line between Hudson G.S. and a user five miles away (e.g. Berry's Creek). When this stage operates, the valve in the heater plant circulating pump discharge line is closed and that pump now feeds the return water back to the Hudson G.S. It actually drives the water also through the heatexchangers. At this point the Hudson G.S. circulating pumps take over and pump the water back to the heating plant and through the distribution system and user equipment. As before, starting any of the heaters does not change the pressure condition, but only the water temperature.

The last loop at the left shows the condition when Kearny is included and operating. The closing of the valve in the Hudson circulating pump discharge connects this system in series with the other two without affecting the previously prevailing pressure conditions.

It is shown that the maximum pressure within the system is reached at the Kearny circulating pump discharge and it is 230 psig. This is a pressure somewhat higher than allowed for 150 lb. rated flanges (200 psig @ 250°F and 190 psig @ 300°F), but only the discharge side valves of that plant are affected that way. The rest of the system is well within the 150 lb. flange rating requirements.

6.5.10 SYSTEM VOLUME

The hot water transmission and distribution system laid out for the distribution of 3.7 billion BTU/hr as shown in Section 8.3 will have a total estimated volume of 600000 cu. ft. Each individual one sq. mi. system will contain 13-15000 cu. ft. of water in piping, heaters, heatexchangers, etc.

The volumetric variation from cold (50°F) to maximum supply temperature and from cold to maximum return water temperature is 8.3% and 3% respectively. The average change, since supply and return volumes are equal, is 5.65% during initial heat-up. Daily changes in operation are usually limited to 25-30°F variation and the coincident volume change is about 1%.

6.6 USER CONNECTIONS

The interface between the district heating system and the building heating and domestic water preparation systems is the user connection. It is first of all a heatexchanger, which isolates the relatively high-pressure district heating operation from the low-pressure, low temperature in-house systems. The advantage of this method is found in the safety of the user systems and in the integrity of the D-H system.

6.6.1 HOT WATER AND HOT AIR HEATING SYSTEM CONNECTIONS

The variable temperature hot water distribution system is best in supplying warm water or hot air in-house systems. There is no change necessary in their physical plant except the boiler is paralleled or replaced by the heatexchanger. Hot air systems can be connected even without a heatexchanger by replacing the air coils with high-pressure ones and feeding D-H water directly (Fig. 6.6.1). This is particularly desirable where the original coils operated on L.P. steam.

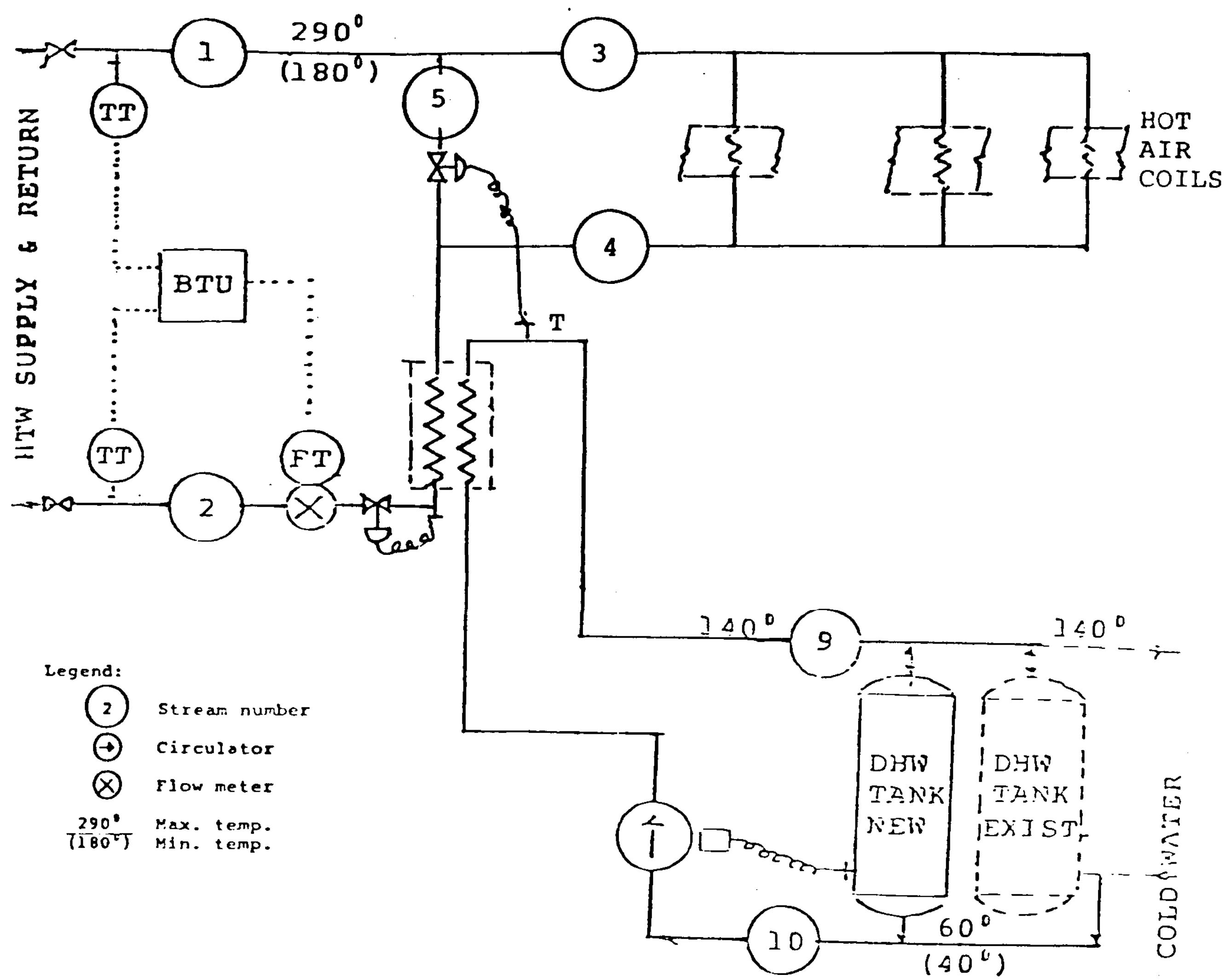
The supply of domestic hot water (DHW) could be accomplished the same way, but safety of the system requires the insertion of an intermediate circuit. This way no tube rupture can cause mixing of high temperature and pressure water into the DHW supply.

Following these requirements, Fig. 6.6.2 shows the typical house connection schematics. It also tabulates the proposed standard capacities and the associated flows and pipe sizes.*

One important addition to usually existing in-house systems is the increased DHW storage. This is a requisite for an effective DH since even distribution over 24 hours of the DHW load can materially affect the total capacity of the system. The average 7-10% DHW load, if not supplied by ample storage, can vary from 0 to 100% of peak heating load. It is also normally concentrated to two 3 hour periods of a day. Large storage and the circulating heating system smoothes out these peaks and lets the DH system, particularly in the off-seasons and during

----

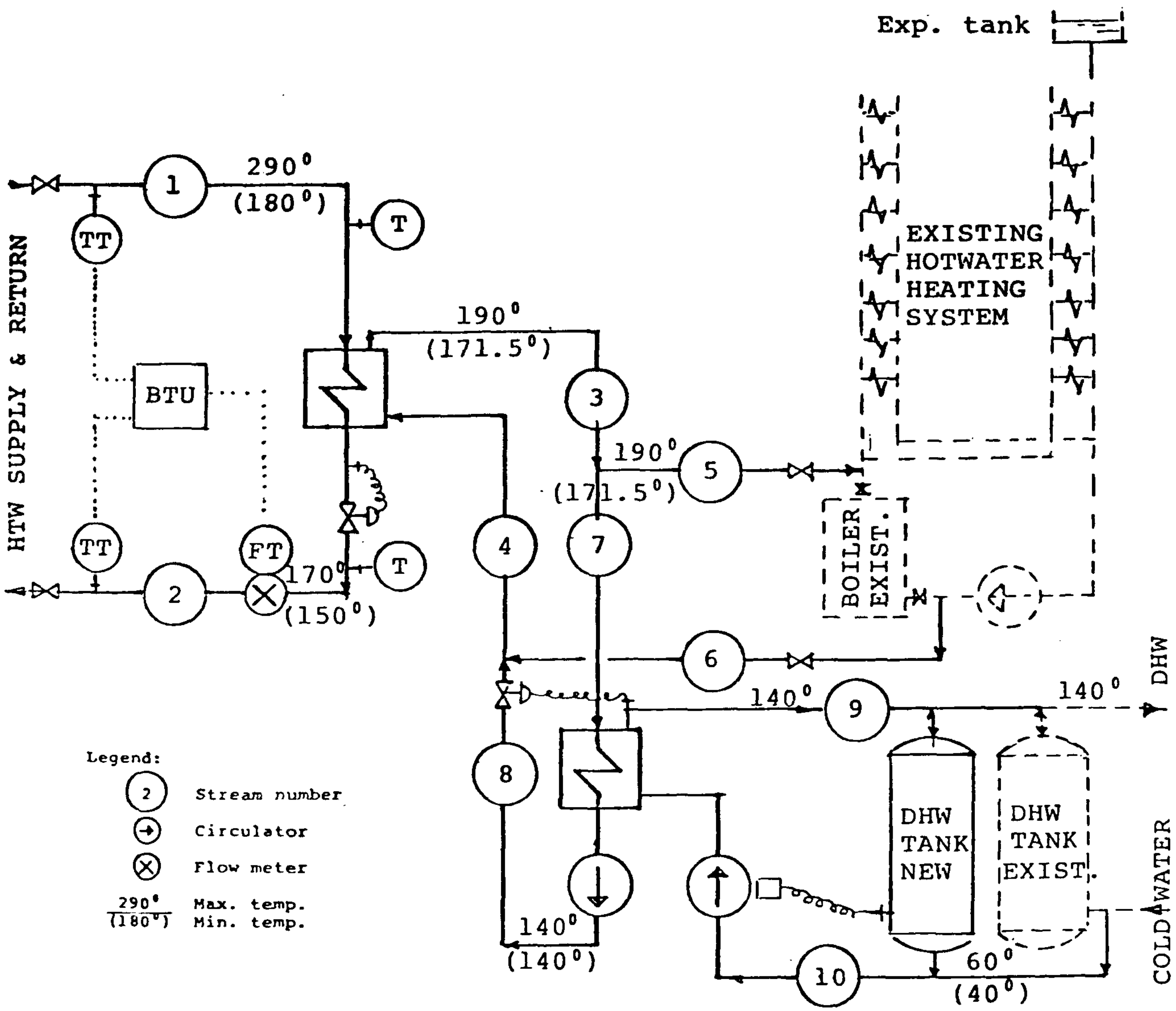
*Figure 6.6.3 shows a simpler, more efficient and less costly schematic using plate type heatexchangers. Since there is no possibility of HP water mixing into the DHW, an intermediate heatexchange step can be safely eliminated.



Type of bldg.	Peak load heating d.h.w. 10^6 BTU/hr		① gpm	② dia	③ gpm	④ dia	⑤ gpm	dia	⑦ gpm	⑧ dia	⑨ gpm	⑩ dia	DHW storage gal
small apt. - 25 units	.5	.065	7.1	3/4	6.9	3/4	.2	1/2	X	X	1.3	1	825
med. apt. - 50 units	1.0	.13	14.2	1	13.4	1	.8	1/2			2.6	1	1650
¼ city block - 35 units	1.5	.195	21.3	1¼	20.3	1¼	1.0	1/2			2.7	1	10x130
large apt. - 100 units	2.0	.26	28.4	2	26.8	2	1.6	1/2			5.2	1	3300
hi-rise - 250 units	5.0	.65	71.0	2	67.0	2	4.0	3/4			13.0	1¼	8000

FIG. 6.6.1

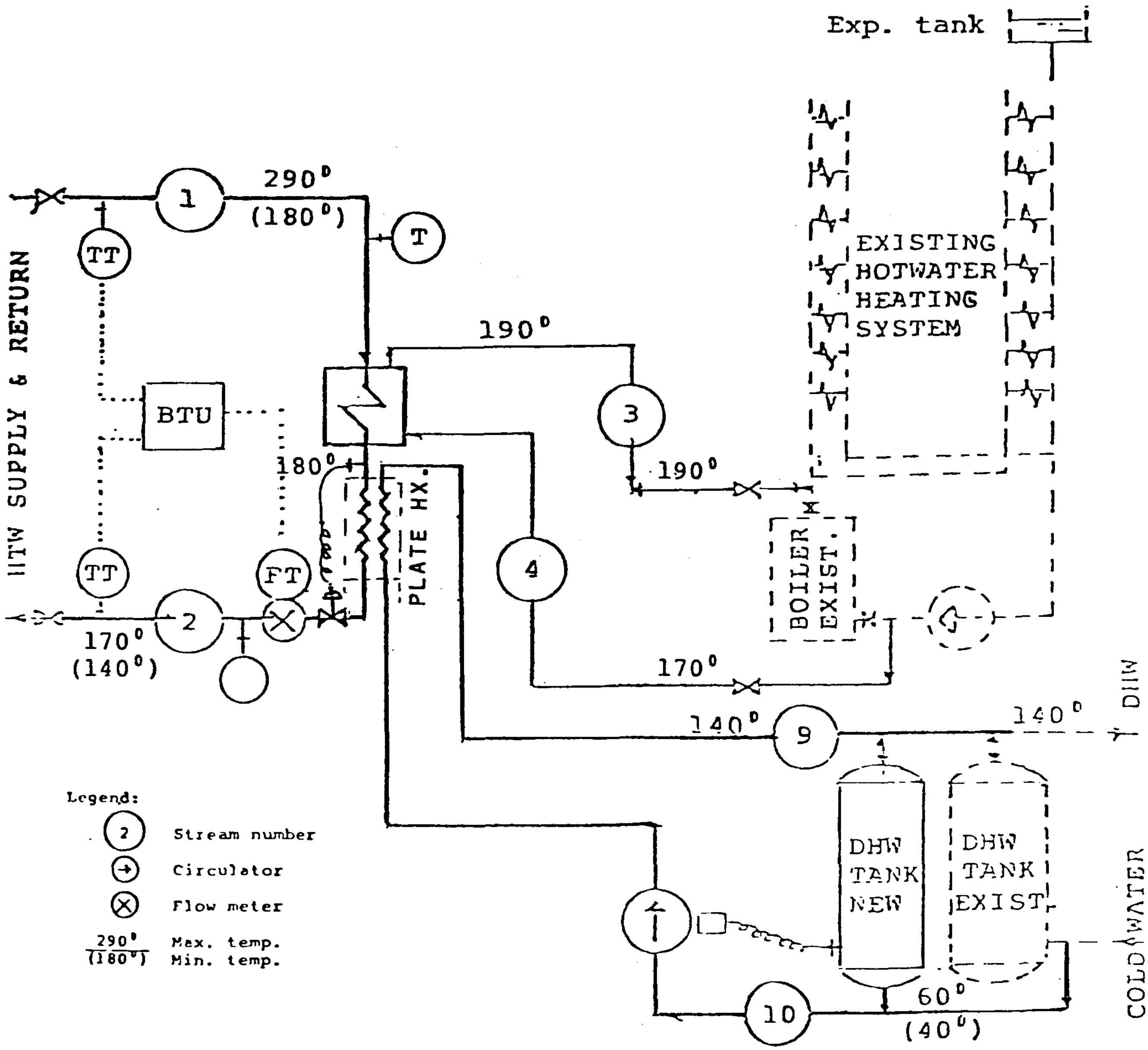
CUSTOMER CONVERSION UNIT SCHEMATICS - HOT AIR HEATING



Type of bldg.	Peak load heating 10⁶BTU/hr	d.h.w.	① gpm	② dia	③ gpm	④ dia	⑤ gpm	⑥ dia	⑦ gpm	⑧ dia	⑨ gpm	⑩ dia	DHW storage gal
small apt. - 25 units	.5	.065	9.4	1	55.2	2	50	2	5.2	1	1.3	1	825
med. apt. - 50 units	1.0	.13	18.8	1½	110.4	3	100	3	10.4	1½	2.6	1	1650
½ city block - 35 units	1.5	.135	28.2	2	160.8	4	150	4	10.8	1½	2.7	1	10x130
large apt. - 100 units	2.0	.26	37.5	2	220.8	4	200	4	20.8	1½	5.2	1	3300
hi-rise - 250 units	5.0	.65	94.0	2	552.0	6	500	6	52.0	2	13.0	1½	8000

FIG. 6.6.2

CUSTOMER CONVERSION UNIT SCHEMATICS - WARM WATER HEATING (A)



Type of bldg.	Peak load heating 10⁶BTU/hr	d.h.w.	① gpm	② dia	③ gpm	④ dia	⑤ gpm	⑥ dia	⑦ gpm	⑧ dia	⑨ gpm	⑩ dia	DHW storage gal
small apt. - 25 units	.5	.065	9.1	1	50	2					1.3	1	825
med. apt. - 50 units	1.0	.13	18.2	1½	100	3					2.6	1	3650
½ city block - 35 units	1.5	.195	27.3	2	150	4					2.7	1	10x130
large apt. - 100 units	2.0	.26	36.4	2	200	4					5.2	1	3300
hi-rise - 250 units	5.0	.65	91.0	2	500	6					13.0	1½	8000

FIG. 6.6.3

CUSTOMER CONVERSION UNIT SCHEMATICS - WARM WATER HEATING (B) the summer, operate at a fairly even load. It also assures the low return water temperature of the DH system, an important requisite of its efficiency.

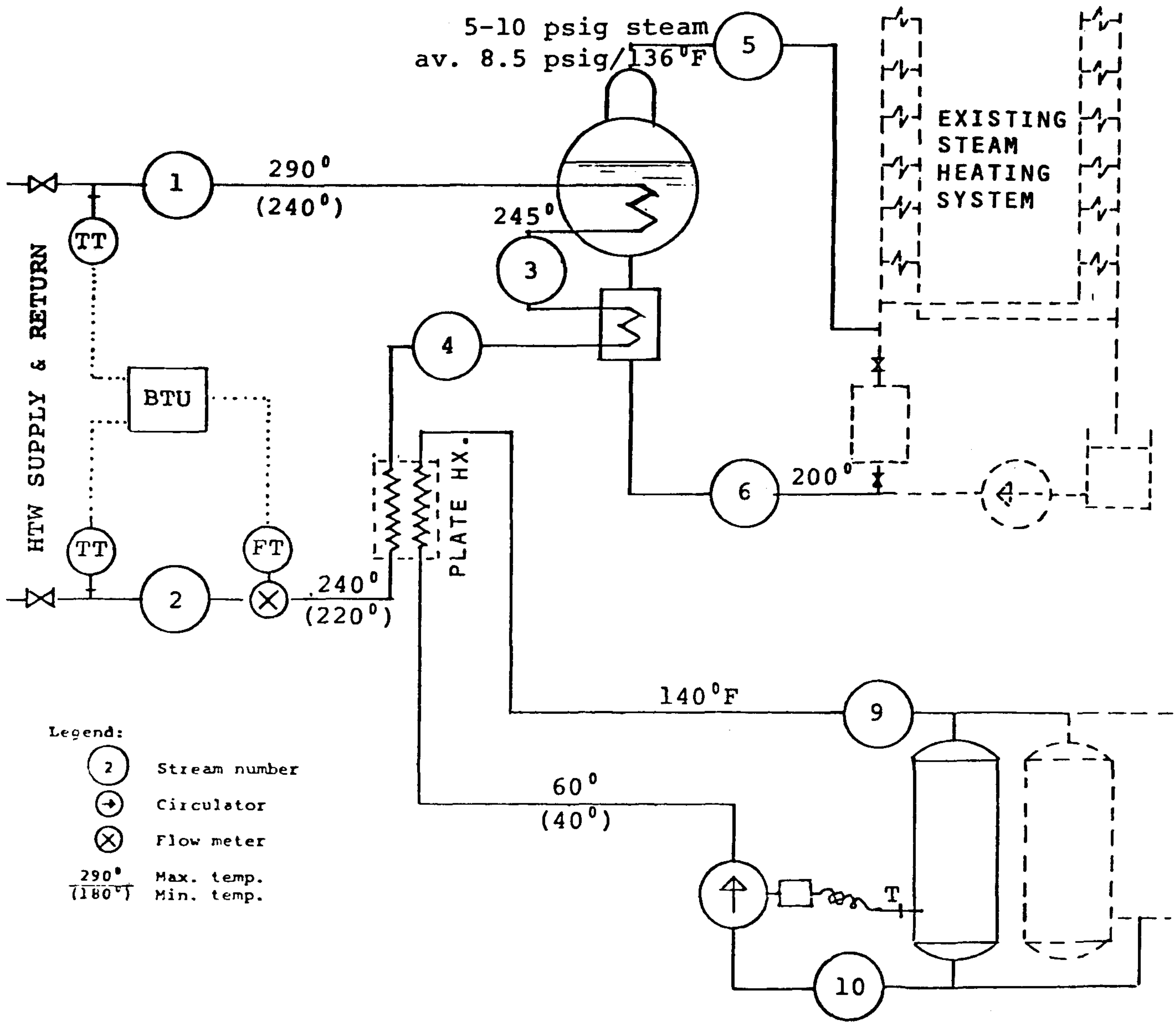
The DHW load and the storage requirements were taken at 8.5 gal/hr peak use in three hours for an apartment in a small house and 4 gal/hr/apt. in a large building. The daily use has been established at 110 gal. and 75 gal. respectively. The hot water heating heat requirements represent 10-11% of the peak space heating load of the same apartments.

The control of the system is simple. Ambient temperature changes are basically compensated for by centrally changing the supply temperature. The control valve in the return line compensates for load reduction on the secondary side in excess of that due to outdoor temperature change. As that load reduces the return temperature increases. Sensing that, the valve closes, reduces the flow and restores return water temperature. Similarly the control valve in the DHW heating circuit reduces flow as the circulating DHW temperature increases above 140^{0}F. That can happen when the tanks are full of hot water.

6.6.2 L.P. STEAM HEATING SYSTEM CONNECTIONS

A significant number of old buildings are steam heated. Most of them are older than 20 years and therefore it is not considered sound to design a system to be completed in another 20-25 years around those. Even so it may be of importance to accommodate such buildings at the early stages of development.

There are two distinct phases in the operation of the staged development. The first stage is when high temperature water fired heaters are operating. At this point it does not make much difference if the send-out temperature is maintained at design value, that is 290^{0}F, or not. As long as the system load does not reach 50% of design capacity the distribution system is capable of operating at half the temperature drop and twice the specific water flow per unit heat delivered. Such a system would then send out 290^{0}F water and return 230^{0}F water if all the users are steam customers. Each user will then have an evaporator capable of producing 5-10 psig steam and a DHW heater as before. This is shown on Fig. 6.6.4. The conversion scheme is simple and only insignificantly more expensive than that of a hot water heated building.



Type of bldg.	Peak load heating	d.h.w. 10^6 BTU/hr	1 gpm	2 dia	3 gpm	dia	5 lb/hr	dia	6 gpm	dia	9 gpm	10 dia	DHW storage gal
small apt. - 25 units	.5	.065	21.3	1½	21.3	1½	505	3	1.1	1½	1.3	1	825
med. apt. - 50 units	1.0	.13	42.6	1½	42.6	1½	1010	4	2.2	3/4	2.6	1	1650
½ city block - 35 units	1.5	.195	63.9	2	63.9	2	1515	5	3.3	3/4	2.7	1	10x130
large apt. - 100 units	2.0	.26	85.2	2½	85.2	2½	2020	6	4.4	1	5.2	1	3300
hi-rise - 250 units	5.0	.65	213.0	4	213.0	4	5050	8	11.0	1	13.0	1½	8000

FIG. 6.6.4

The operating cost addition is in increased (double) pumping and heat loss expenses.

Neither does this system affect the conversion and operation of the hot water or hot air heated building. Those stations will still make full use of the 120°F temperature differential at peak load and return water generally cooled to 170°F or less. Therefore the system can accept much more than 50% of its design capacity without plant and distribution changes. The limitation is determined by the relative shares of steam load to hot water load. For example, the steam heated buildings in an area of Jersey City will amount to 33% of the 300×10^6BTU/hr per sq. mi. design load. Thus the distribution system will be able to carry a load of 200×10^6BTU/hr maximum. If the steam load is only 15%, then the maximum allowable load increases to 245×10^6BTU/hr.

As was said up front, and it has to be restated for emphasis, the above is true only as long as only fired heaters are the heat source. Should gas turbine heat-recovery be the next step of the staged development, the scheme would still hold true. This because the heat recovered is at a high temperature and can make no use of low return water temperatures.

The retrofit of the Hudson unit and its incorporation into the system makes low return water temperatures imperative. The lower the return water temperature, the more back-pressure power can be generated and the less power production is lost. The economy of the entire operation is materially affected.

At this point the steam user and/or the system have the following choices:

- convert to hot water or hot air heating

- add a heatpump

- use the system at the height of the winter only for heating and for DHW heating only the rest of the time

- disconnect

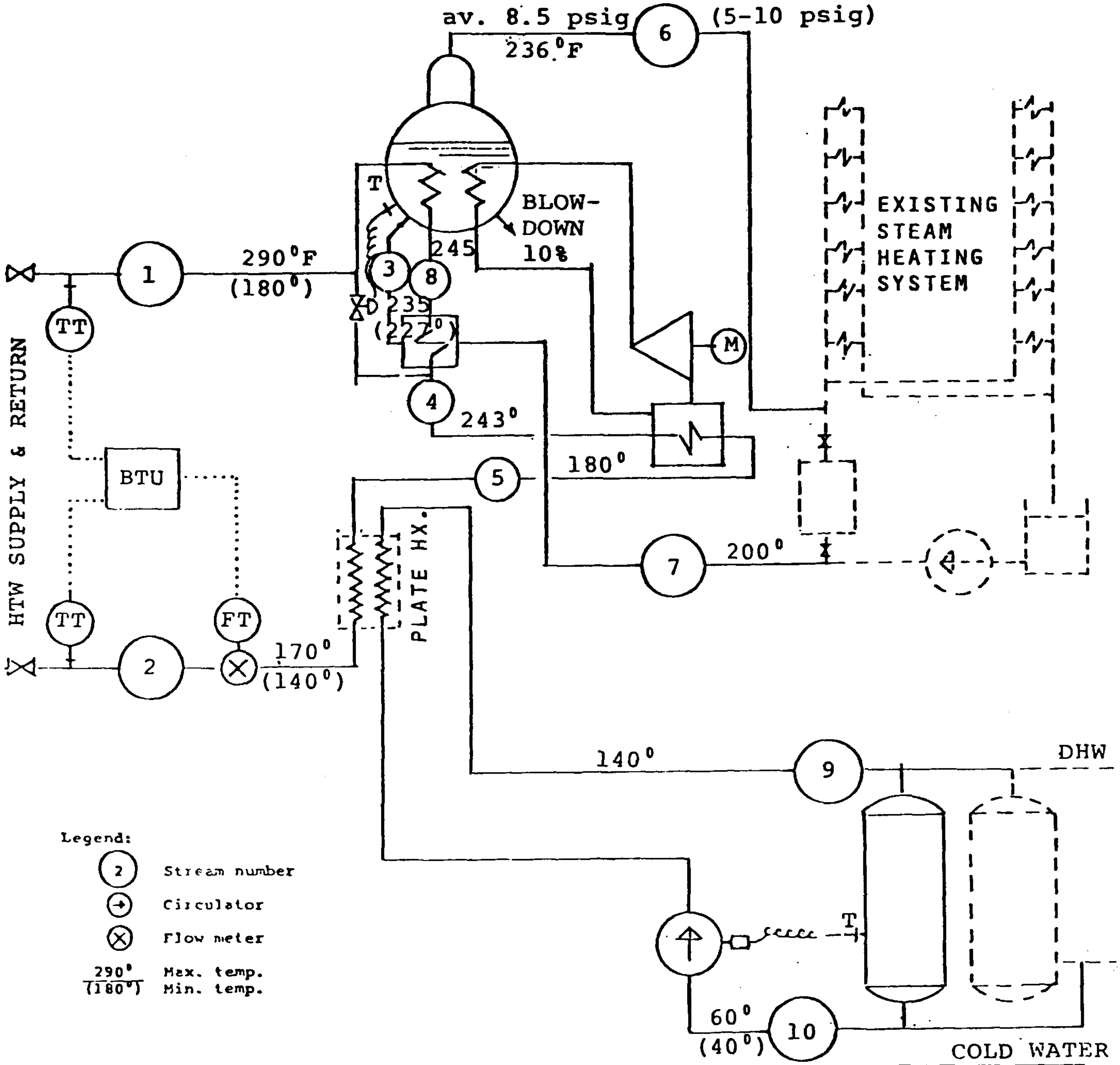
Most buildings at that time (5-10 years from now) will be forced to convert because of the age of the installation on one hand and also because of the inherent inefficiency of a steam heating system. A previous

PSE&G study metered the heat consumption of steam heated buildings. The results showed 15-20% more fuel consumption than that of similar hot water buildings. These conversions are not inexpensive. One completed by the J.C. Housing Authority last year carried a cost of $4400 per apartment including new plant and piping. This cost will be lower if instead of a new plant the D-H system will be the supplier of heat. Twenty percent fuel savings can also significantly help to recoup the expense.

Addition of a heatpump as shown on Fig. 6.6.5 makes the buildings fully compatible with the rest of the system. Considerable heatpump development work is in progress at the present time. There is good reason to assume that by the time the need arises, there will be commercially available, proven small units on the market. Most of the presently available ones are suitable only for the larger buildings and they are marginal at the upper end of the required temperature (235^{0}F commercial limitation v. 240^0-245^{0}F minimum required).

The heatpump in this set-up takes vapor at 160^{0}F and compresses it to the equivalent of 242^{0}F saturation temperature. Taking as an example a low pressure refrigerant as R113, the suction pressure at 160^{0}F would be $\sim$16 psig, while the discharge pressure, at 242^{0}F, 80 psig. The compression ratio is 3. Approximately 1 kWh is needed to produce 12000 BTU heat rejection or 85 kWh per 1 million BTU. The district heating system provides 72% of that heat while the rest is by the electric power input converted into heat.

At peak load conditions the D-H water enters one of the two coils in the evaporator shown on Fig. 6.6.5 and produces 8.5 psig steam while cooling from 290^{0}F to 245^{0}F. In this process, approximately 46 BTU is converted per lb. of water entering. The same 1 lb. of D-H water is then used to preheat the returning condensate from 200^{0}F to 235^{0}F and then it enters the heatpump evaporator, where it is cooled to 180^{0}F. The heat balance is shown on Table 6.6-I.



Type of bldg.	Peak load heating 10⁶BTU/hr	d.h.w.	① gpm	② dia	③④ gpm	⑤ dia	⑥ lb/hr	dia	⑦ gpm	⑧ dia	⑨ gpm	⑩ dia	DHW storage gal
small apt. - 25	.5	.065	7.3	3/4	7.3	3/4	505	3	1.1	½	1.3	1	825
med. apt. - 20 units	1.0	.13	14.6	1	14.6	1	1010	4	2.2	3/4	2.6	1	1650
½ city block - 35 units	1.5	.195	21.9	1½	21.9	1½	1515	5	3.3	3/4	2.7	1	10x130
large apt. - 100 units	2.0	.26	29.2	2	29.2	2	2020	6	4.4	1	5.2	1	3300
hi-rise - 250 units	5.0	.65	73.0	2	73.0	2	5050	8	11.0	1	13.0	1½	8000

FIG. 6.6.5

CUSTOMER CONVERSION UNIT SCHEMATICS - STEAM HEATING W/HEATPUMP

Table 6.6-I

Heat Balance of Heatpump Assisted L.P. Steam User Connection

D-H Evaporation Coil

D-H water entering	259.44BTU;	steam leaving	1160.1		
Leaving evaporator	213.50 " ;	cond. entering	203.8		956.3BTU/lb
Heat rejected	45.94BTU;	steam produced	45.94 / 956.3	=	.048 lb

Cond. preheater

D-H water entering	213.50BTU;	cond. leaving	203.80		
D-H water leaving	211.78 " ;	cond. entering	168.07		35.73BTU/lb
Heat rejected	1.72BTU;	heat utilized	.048x35.73	=	1.72BTU

Heatpump evaporator / **Heatpump condenser coil in evaporator**

D-H water entering	211.78BTU				
D-H water leaving (180°F)	147.99 "				
Heat rejected	63.79BTU				
Electric power added .0073kWh	24.81 "				
Total heat converted	88.60BTU;	steam produced	88.60 / 956.3+35.73	=	.089 lb

Totals

- per 1 lb of D-H water					
D-H heat used	259.44BTU;	steam produced	.048		
	- 147.99 "		+ .089		
	111.45BTU		.137 lb		
Electric power converted .0073kWh	24.81 "				
	136.26BTU;	(956.3+35.73).137	=		135.98BTU
- per 1000 lb of steam per hr					
water - lb/hr	7299.2	steam - lb/hr	1000		
- gpm	14.5				
electric power - kWh/hr	53.3				

It is to be noted that the D-H system has to supply 18.2 gpm of water, or close to 25% more for a hot water/hot air system than to the L.P. steam customer with the above conversion system. This means that some of the conversion cost can be balanced by the reduced share of such conversion in distribution and heat production installations.

The DHW needs of these buildings are satisfied as those of other buildings. The 180°F water leaving the heatpump evaporator enters the DHW heatexchanger and is cooled to approximately 170°F, completing the cycle.

It is significant to note that the share of the heat-pump generated steam in the peak is 66% while the rest is generated directly by the D-H system. The temperature frequency curve of the system shows that the send-out temperature reaches 240°F at just that load point--that is, 66% of peak. So the additional load above that point can be satisfied by the planned temperature run-up of the system.

The third option, that is to supply peaks and DHW to steam customers after the completion of all the stages, is of a very limited value. It can be done technically since as pointed out in the previous paragraph the send-out temperature is sufficient to generate steam above the 66% load point. Its economic merit is very limited since the duration of that load is about 700 to 750 hours annually. If it is a matter of spanning a couple of years before equipment is replaced or where the old boilers are no longer capable of providing full load, it may have economic merit. As a permanent solution it should not be considered and the building has to be abandoned as a customer.

6.7 ALTERNATIVES TO DISTRICT HEATING

6.7.1 INTRODUCTION

A number of possibly economical alternatives to district heating and additional refinements to district heating have been looked at and a rough economic screening performed. They were found either inferior to the economy of D-H or are considered economically feasible additions, if and where physical circumstances warrant their inclusion. These possibilities are discussed here, but some were not included in the basic evaluation of economic feasibility to avoid overextending the study, even if they were proven practical and economically viable.

The alternatives investigated are as follows:

- Heatpumps for heating and cooling
- Absorption cooling
- Waste heat and/or solid waste recovery
- Coal burning local heater plants
- Landfill gas recovery
- Geothermal storage

The results are compiled in the following sections.

6.7.2 INDIVIDUAL HEATPUMPS FOR HEATING AND COOLING

6.7.2.1 System Selection and Cost

The latest trend in apartment house construction is the use of air to air heatpumps on an apartment-by-apartment basis. It combines low installation cost with individual control of heating and cooling. Payment for the service is outside the rent or the maintenance fee structure so the landlord or the cooperative does not get involved with volatile energy costs. The comparative operating cost of such a unit was calculated on the basis of a widely used make and size unit. The power consumption of that unit versus power consumption of resistance heaters is shown in Table 6.7-I. The 33000 BTU/hr rating of this unit makes it suitable to supply heat heat to one of the housing units in a small multi-family building. It has been assumed in Sect. 6.5 that each of these buildings has four units and D-H will deliver heat to nine of these buildings within one city block. So economic comparison to D-H was made on a 36-unit basis.

TABLE 6.7-I

SINGER Packaged Heatpump
PHP-124-1-10 (208v/1 ph)*

Outdoor temp.	Heating load (100%=33000BTU/hr)		Heat supplied by heatpump			Heat supplied by res. heater		El. energy use	Annual frequency	Total annual el. energy	
°F	%	$kW_{(t)}$	BTU/hr	COP	kWh	BTU/hr	kWh	kWh	hrs	heatpump	res. heaters
0	100.00	9.67	7500	1.05	1.99	25500	7.50	9.49	10	94.90	96.70
2	97.10	9.38	8100	1.10	2.19	23943	7.04	9.23	15	138.45	140.70
7	90.00	8.70	9600	1.20	2.24	20100	5.91	8.15	20	163.00	174.00
12	82.85	8.01	11020	1.40	2.29	16320	4.80	7.09	25	177.25	200.25
17	75.71	7.32	12500	1.50	2.39	12484	3.67	6.01	50	300.50	366.00
22	68.57	6.63	13900	1.70	2.38	8728	2.57	4.95	115	569.25	762.45
27	61.43	5.94	15400	1.80	2.43	4872	1.43	3.86	135	521.10	801.90
32	54.28	5.25	16900	1.90	2.49	1012	.30	2.79	555	1548.45	2913.75
37	47.14	4.56	15556	2.10	2.17	-	-	2.17	695	1508.15	3169.20
42	40.00	3.87	13200	2.30	1.68	-	-	1.68	875	1470.00	3386.25
47	32.86	3.18	10844	2.50	1.28	-	-	1.28	800	1024.00	2544.00
52	25.71	2.49	8484	2.60	.96	-	-	.96	600	576.00	1494.00
57	18.57	1.80	6128	2.70	.67	-	-	.67	600	402.00	1080.00
62	11.43	1.10	3772	2.70	.41	-	-	.41	800	328.00	880.00
67	4.29	.41	1416	2.80	.15	-	-	.15	700	105.00	287.00
										8926.05	18296.20

*cooling capacity @ 95°F; 21600BTU/hr - 1.8T
cop ~2.34, 2.7kW

36 units installed cost

heatpump units	$ 58500
electrical	20000

	$ 76000
if ducting is requ'd, add	14000

	$ 90000
overhead, profit, etc.	27000

	$117000 ($3250 per unit)

In comparison, the D-H system requires the installation of a central heatexchanger and connecting pipelines estimated at

heatexchanger(s)	$ 20000
pipelines (local only)	57000

	$ 77000 ($2200 per unit)

Comparison is however not straightforward since the two provide different services and require a different set of conditions in an existing building:

Hot air heat:	The heatpump provides air conditioning at no extra investment cost, while absorption cooling units have to be installed for this service on D-H. The existing air heating coils may or may not be satisfactory to be connected to the D-H system.
Warm water heat:	The D-H system requires no change in the building. The heatpump can only supply a hot air system.
Steam system:	The D-H system can accommodate it by limiting its minimum supply temperature to not less than 225°F and installing evaporators in each building. The heatpump cannot be used without retrofitting the building heating system.

In all cases separate means have to be provided for domestic hot water production with a heatpump heating/cooling system, while D-H supplies that heat without additional expense. The addition of hotwater heated absorption air conditioners to the D-H system would cost an estimated $65000 for a block of 36 apartments but it would entail major unestimated changes in the concept of supplying these units with all the services combined (as for example centralization of domestic hot water preparation). The issue of absorption cooling is addressed separately in Sect. 6.7.3.

6.7.2.2 Operating Cost of Individual Heatpumps

Table 6.7-I showed that the heatpump consumes 8926kWh/yr or 51.2% of the energy a resistance heating system would require, that is 18296kWh. Comparing these with other modes of heat supply, the following results were obtained:

Net heat delivered (all systems)
· Resistance heat -
18296kWh/yr x 3414BTU/kWh = 62.46 x 10^6BTU/yr

Fuel required to deliver net heat above:

		Fuel 10^6BTU/yr	$/yr
Resistance heat systems 18296kWh/yr x 10000BTU/kWh/.9	=	203.29	1830
Heatpumps (air to air) 8126kWh/yr x 10000BTU/kWh/.9	=	90.28	812
Heating furnaces (oil) 62.46 x 10^6BTU/yr/.7	=	89.23	650
District heating 62.46 x .71	=	44.34	687

where

- the electric power generation is assumed to have a fuel cost of 10000BTU/kWh and $.10 per kWh
- the power distribution losses amount to 10%
- the heating furnaces operate at an average annual efficiency of 70% (high estimate) and $7.30 per million BTU
- the district heating utilizes waste heat at ∿33% of every unit of heat supplied and incurs a distribution loss of 3.5% for an overall COP of 1.4. This is equivalent to using 71% fuel for every unit of heat supplied. Cost is assumed to be $11 per million BTU delivered.

6.7.3 AIR CONDITIONING BY A DISTRICT HEATING SYSTEM

6.7.3.1 Conventional Cooling

6.7.3.1.1 Duration

In the N.Y.-N.J. area the peak air conditioning load occurs at about 78^0 WB temperature and the 2-1/2% peak, the conventional design value, is 76^0 WB. The meaning of the 2-1/2% peak is that 97-1/2% of the time the temperature is at or cooler than the given value, or that for 2-1/2% of the time the installation is not quite capable of maintaining the design conditions. The annual cooling hours in the area are about 1500 hours for residential (hospital, hotel) and 1200 hours for offices and commercial establishments. The core cooling of these latter buildings should not be included here since it is a year-round load not materially affected by outdoor conditions. The equivalent full load hours are 1000 and 800 respectively.

6.7.3.1.2 Specific load and cost

The specific cooling load of different structures, dependent on size, location, shading windows, activities, number of occupants, surroundings, etc. varies between

30-60 BTU/sq ft, hr, or
.0025-.005 TR/sq ft, hr

where TR means tons of refrigeration.

Using these figures, on an annual basis the use amounts to

2.50-5.0 TR/sq ft, season, for residential
and 2.00-4.0 TR/sq ft, season, for office, commercial type buildings.

The machinery to provide that cooling can be several different types and comes in a wide variety of sizes. Accordingly their cost to operate also varies widely. Table 6.7-II shows some examples for office and commercial use.

6.7.3.1.3 Investment

The cost of installing a cooling system also varies considerably with type and size of machinery. Here are some very approximate examples:

Table 6.7-II

Cooling Cost with Conventional Equipment
per sq. ft. of Office or Commercial Space

	kW/TR			Cost power or fuel only $/sq ft,yr
	full load	partial load	Annual kWh	
Window units	2.0	2.0	4.0-8.0	-.32-.80
Recipr. compr. units (small)*	1.3	1.4	2.8-5.6	-.28-.56
Centrif. compr. - medium size*	1.1	1.2	2.4-4.8	-.24-.48
- large size*	1.0	1.1	2.0-4.4	-.20-.44
Absorption - pumping only	.01	.007	.1-.15	-.01-.015
	1000BTU/TR (oil fuel)			
Absorption - steam	18	20	40-80	-.40-.80
- hot water	20	22	44-88	-.44-.88

*incl. pumping

	$/TR	$/TR
	machine only	plant
Window units	500	N/A
Small reciproc.	350	600
Med. centrifugal	300	650
Large centrifugal	250	550
Steam absorption	380-250	av.700
Hot water absorption	450-280	∿800

The absorption system cost does not include the cost of the heat generation plant. It is assumed that it will use the plant erected for the heating of the same building(s), or that it is direct fired.

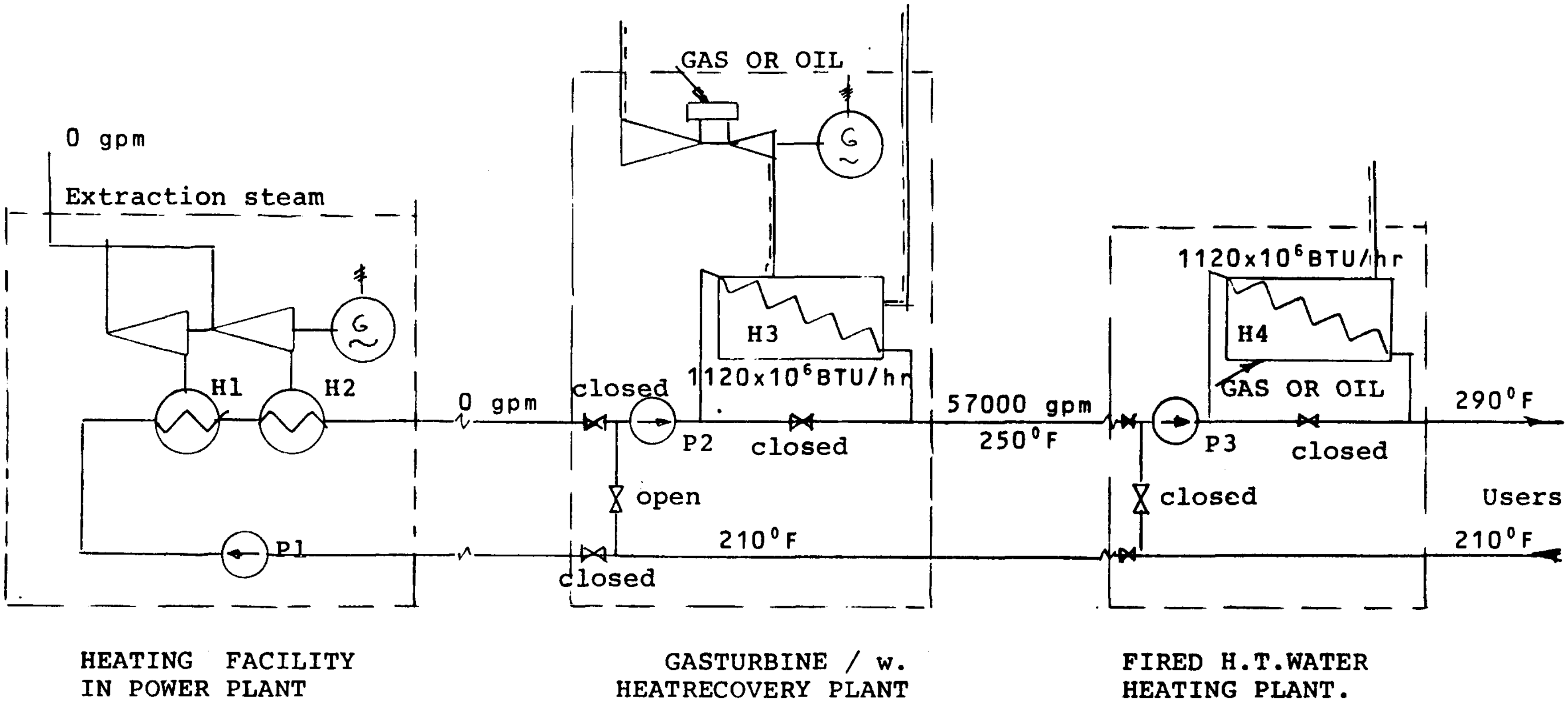
6.7.3.2 Cooling from a District Heating System

6.7.3.2.1 Three stage district heating

A three stage high temperature water heating system lends itself to district cooling by using the gas-turbine/heat recovery and boiler stages as the providers of heat. There are no large economic penalties to be paid for the high temperatures since the heat is available at high temperature (>260^{0}F) even after maximum practical heat recovery. This operation does away with the capacity loss incurred in the powerplant retrofit stage operation. It is also operated at a time when the electric power system peaks and when the penalties for lost operation would be high. Even more important is that the gasturbines produce additional power. It is achieved however by burning an expensive fuel as gas or No. 2 oil.

6.7.3.2.2 System layout and operation

A schematic three-stage system layout is shown on Fig. 6.7.1. Each plant re-pumps the water taking care of the pressure drop of the downstream distribution system. As a consequence each stage can operate and provide its share of the load without the previous stage or stages being in operation. Any upstream stage can cease to operate without affecting the overall operation in any other way, but by lost capacity. The system operating with gasturbine heat recovery and fired heaters only can provide 2/3 of the design peak.



Schematic System Operation
for Absorption Cooling

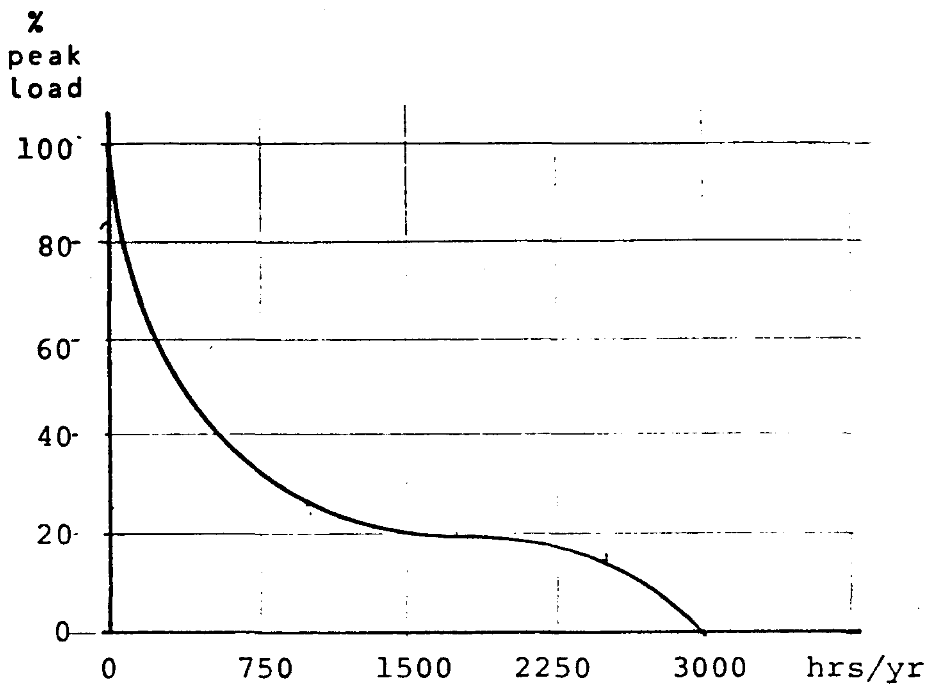
Fig. 6.7.1

When air conditioning load is added to the system, nothing but the operating pattern and the send-out temperatures have to be changed for that season. Absorption cooling machinery can make use of high temperature water, just as a heating system does. The capacity of a given absorption machine depends in this case largely on the temperature of the leaving hot water. At 230^{0}F temperature it has the same capacity as a steam heated unit, at 200^{0}F it is derated by approximately 25%, increasing its cost. The heat supply capability of a high temperature water system designed for a given maximum flow depends on the utilized temperature difference only. The contemplated maximum system temperature is 290^{0}F. The recoverable heat being proportional to the temperature differential, at 230^{0}F return temperature 60^{0}F differential, at 200^{0}F temperature 90^{0}F differential becomes available. Relative to the 120^{0}F differential design value of the heating system respectively 50% or 75% of the heating load can be supplied for air conditioning. Fig. 6.7.1 shows also water temperatures leaving the successive heating stages.

The 2/3 load at full flow gives us an 80^{0}F differential, so the minimum return water temperature at this time shall be 210^{0}F. At this return temperature the absorption machine capacity derating is only approximately 10%, which is probably an economically acceptable alternative.

It is also important to note that for every ton of refrigeration generated by gas turbine waste heat, 3.5kWh electric power is produced simultaneously. This depending on the type of plant (see Table 6.7-II) provides an additional 2.8-3.5TR by compression type machines operating on the system. So altogether the system is capable of providing at least as much air conditioning as heating, given the proper mix of machinery. Conventionally peak heating and peak air conditioning loads relate in a ratio of 1:1.2 or less.

The load frequency of comfort air conditioning is shown approximately on Fig. 6.7.2 along with the load distribution over the cooling season. One can see that the peak to average ratio is even larger than during the heating season. The effect of providing 50% of the peak load by direct fired heaters therefore is not too significant an economic factor. One may consider providing more than 50% of peak by



| 41.2 | 25.2 | 20.2 | 13.4 | % energy

| July | Aug. | June | May/Sep | approx. month

Typical Air Conditioning Load Distribution

Fig. 6.7.2

this means, since the stand-by capacity in these plants is available. This however would reduce the reliability of service.

The cost effectiveness of such a system is questionable. 1 kW of electric power or less can produce a ton of refrigeration by centrifugal machines. It takes 20000BTU and some electric power for pumping to produce it by absorption cooling. So the equivalent rate of D-H heat at 10 cents per kWh electric rate has to be $5.00 per million BTU.

A delivered heat rate of that order seems to make this type of air conditioning economically unfeasible. There are however a number of considerations and circumstances which may justify selective consideration.

- The PSE&G system is summer peaking. Any cogenerative power generated will benefit by high incremental cost and produce heat proportionately cheaper.

- The acquisition of summer loads would increase the load factor from its low 27%-30% level to possibly 32%-35% (50% summer peak). The benefits do not have to be spread equally between heating and cooling. This can also help in making cooling more competitive.

- Large buildings with sizable air conditioning equipment of the centrifugal type may be forced to maintain operators. This would detrimentally affect their decision to join the heating service too. The effective savings in cost and the convenience in many a case justifies the payment of higher than otherwise equitable rates.

In conclusion, the supply of air conditioning by the D-H system is technically feasible during the summer season. It is competitive only where the proper circumstances exist. It will not enter therefore the basic feasibility calculations, but it can serve to enhance the economy and competitiveness of the total system under optimum conditions.

6.7.4 WASTE HEAT AND/OR SOLID WASTE RECOVERY

6.7.4.1 Introduction

A non-dedicated heat source (NDHS) in a district heating system is any heat producer whose operation is controlled by considerations other than the heat requirements of the D-H system. Most of the heat recovery from waste burning processes, industrial heat rejection installations fall into this category.

How a particular installation can be categorized depends not only on its own operating characteristics but also on its operation relative to the total D-H system. An example of that is a heat source which is so small relative to the size of the D-H system in its vicinity that its output can be accepted by the system even during its minimum load period. Such a source can be considered dedicated, no matter what its schedule of operation is.

The general character of an NDHS is that it operates at a variable output, independent of D-H system heat requirements. It also operates without regard to seasons and/or time of day. Since these are characteristics contrary to that of a D-H system, it needs a careful case-by-case analysis of how and if such sources are acceptable in a D-H system.

6.7.4.2 Acceptance Criteria of an NDHS

The following are the general limitations of incorporating an outside source of heat into a D-H system:

A. The total output of the combined NDHS sources is at or below the minimum heat load within the area in which it can be physically distributed.

B. The minimum D-H system is routinely increased by other non-space heating loads connected to the system (industrial heat loads) at the time of the regular operating hours of the source.

C. The source is capable of supplying heat at a temperature level beyond the normal operating range of the HTW D-H system and there are dedicated users of that high level (temp./press.) heat within economical reach of that installation.

Conditions A and B are no different by themselves; the D-H systems involved are different. Industrial/commercial use of heat will diminish the seasonal variations of system load and will increase the daily swings. The latter is mainly because most plants work a single shift only. If the heat source works that same single shift, then the basis for comparison is the minimum load during those hours of a workday.

Case C is a somewhat artificial category. All it says is that if there is a heat source capable of generating, say, 150 psig steam and there are users within the reach of such system operating basically the same hours as the source, a link can be established without any regard to the existence of an HTW D-H system.

In cases A and B the use factor of the power plant retrofit might be greatly influenced. During most of the year, that is at system loads of 44% and less, the power plant generates all the heat at a very good efficiency and at a low fuel cost. Any heat coming from another source has to compete with that cost and carry the proportionate share of the plant installation cost, besides its own. This consideration will limit the acceptable sources to those where recovery can be achieved at a low investment cost and the heat will be sold at a fraction of the power plant fuel cost. These considerations are mitigated by the high cost fuel use of the other two D-H stages during the high load period of the year. In view of that, waste heat at the cost of coal can be classified generally acceptable.

6.7.4.3 Connection of Outside Heat Sources

The physical incorporation of an NDHS into a three-stage series connected heating system needs careful consideration. Most of the NDHS sources operate on an independent schedule and at variable outputs. Their operation has to be coordinated with the overall system and done so without the loss of a central, largely automated control system.

The staged system, without other sources of heat, was shown on Fig. 6.7.1. It is controlled so that outdoor temperature conditions set the send-out temperature. When a maximum, stage send-out temperature has been reached, it triggers the control system of the following stage and starts its operation. At that point the first stage runs at a steady maximum load, while the following stage modulates. Should any stage fail, the other two stages take over the operation automatically. Figure 6.7.3 shows the same system as Fig. 6.7.1, but with the addition of extraneous heat sources. There are three basic ways to connect these sources to the system as shown. The following is a short evaluation of these possibilities.

Fig. 6.7.3a is series connection to the supply side
Fig. 6.7.3b is parallel connection to the system
Fig. 6.7.3c is series connection to the return side

A number of operating parameters are applicable to all three conditions:

- an HTW D-H network is a constant flow system (full flow or half flow)

- in a system carrying basically space heating load, the supply temperature varies with the load as defined by outdoor weather conditions

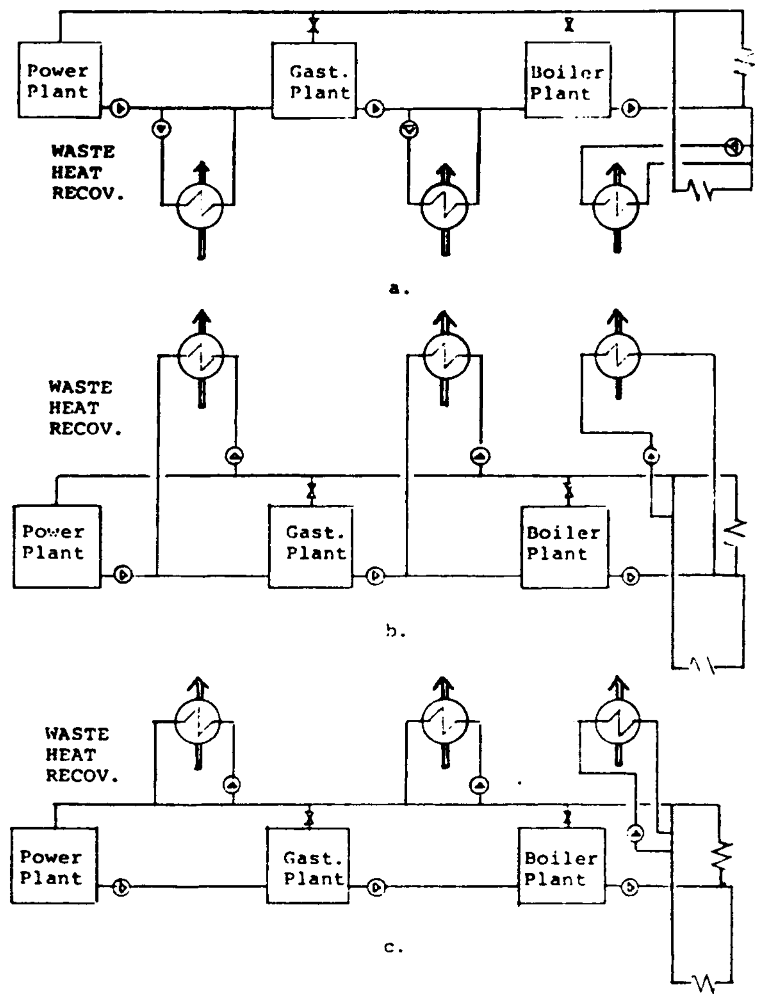
- higher supply temperature than the one defined above would mean overheating at most users and therefore waste of energy

- higher than necessary supply temperature increases the return temperature and reduces the power output of the backpressure turbines

- the acceptable output of an outside heating source connected to the final, local distribution system is limited by the maximum flow transmitting capability and by the maximum allowable temperature of the system at the point of connection

6.7.4.4 Series connected NDHS on the Supply Side

The heat recovery installation is connected to the supply side of the D-H system. Since it is parallel to a piece of pipe, the flow passing through the recovery unit is controlled by the pump in the branch line. In the extreme it can be the total flow normally passing through the main at that point. It should be kept in mind that the off-season flow is only half of the normal flow. This will determine the maximum acceptable size of such systems.



Alternative Methods of Connecting
Waste Heat Recovery Plants
to an HTW District Heating System

Fig. 6.7.3

The heat rejection level would normally be determined by the maximum leaving design temperature of the stage immediately upstream of the unit. This would be, for example, 225°F leaving the power plant. This in turn defines the minimum temperature of recoverable waste heat streams at 240°F. Similarly, it would be 275°F when connected downstream of the gasturbine plant.

There is a different set of conditions where the connection is made to the final distribution system. Here the normal leaving water temperature of the last stage, the boiler plant, is also the maximum allowable temperature at peak load. It is not allowed to pass that without setting different design conditions for the total system. So to compensate for the additional heat received from the outside source, the temperature at the boiler plant has to be cut back. This on the other hand would not be practical when the source is connected to a branch in the system, as shown. Users on the particular branch will get the proper supply temperature, while all the others will not. So it can be set as a rule that NDHS installations cannot be connected to branches of the final heat distribution network.

6.7.4.5 Parallel Connected NDHS

The heat recovery installation is connected across the return and supply lines. Each would be operating parallel to the other stages of the D-H system. The major problem with this arrangement is the control of the hydraulics in the total system. These plants will reject heat dependent on their design and also on their own momentary operating requirements. The D-H system operates on a different set of parameters, as outdoor temperature, constant flow, variable return and supply temperatures. A given heat rejection would require a different flow through the recovery heatexchanger at every different Δt of the D-H system. This in turn will change the flow to the plant or plants downstream of the NDHS installation on the return line side.

The design and operating conditions being so varied, the control of the system hydraulics will become much more complicated and it will require the introduction of telemetering and remote controls.

6.7.4.6 Series Connected NDHS on the Return Side

It is a similar arrangement to 6.7.4.4, but the connection is to the return lines.

The advantages are manyfold. Heating the return water has no direct effect on the control of the supply water temperature. Heating the return water at any point in the system assures the preferential treatment of the waste heat rejection over any other heat source. This is important from the viewpoint of the NDHS plant operator, since their operation and economy might be predicated on the sale of the reject heat. The relatively low temperature (170°F max.) of the return allows the utilization of low (>190°F) temperature heat sources and/or less expensive heat recovery equipment due to the increased LMTD.

The plants can be connected to any point on the system. There is no limitation as to size other than the heat carrying capability of the lines from the point of connection back to the transmission mains. The hydraulics of the system is simple and has no effect on that of the D-H system mains. The temperature limitations are the same as on the total system, or lower if so desired.

The system controls stay basically unchanged. The NDHS installations could heat up the return water to a temperature momentarily demanded by the system as supply temperature. This temperature would be sensed by the power plant temperature controller and it would signal the backpressure turbines to close down. Any time the return temperature drops below the desired send-out temperature, it would let steam down the turbines to make up for the deficiency.

The limitation of total NDHS capacity connected not exceeding the minimum momentary load of the system is still valid.

6.7.4.7 Incorporation in System Studied

No NDHS were incorporated in the calculation of economic feasibility of the D-H system. The foregoing clearly shows that only a source-by-source evaluation and known system parameters at the location of the source allow a determination of acceptability. Having no firmly identified source to consider and no firm system development pattern to compare with, the effect of such sources will be considered as part of the sensitivity analysis. Obviously only sources which can reduce the cost of heat are acceptable in any case. So fuel cost sensitivity will include the effect of those potential sources.

6.7.5 SMALL COGENERATION AND/OR SOLID FUEL BURNING PLANTS

Rough cost estimates were developed for six options to compare with the base case of a gas-fired heat-only hot water heating plant. The options examined are:

1. Mass-burning, MSW (Municipal Solid Waste)-to-hot water plant, based on a 1981 IDHA Conference paper by Mr. G. Kjaer.

2. Atmospheric Fluidized Bed AFBC cogeneration plant, burning coal or MSW, based on an AFBC plant quote by Johnston Boiler Co. and other estimates developed by Mr. Kurz.

3. Gas-fired steam cogeneration plant.

4. Gas-fired, heat-only hot water heater plant, based on Transflux/SWEC estimates, as revised by the PSE&G Engineering Dept.

5. and 6. Two hybrid designs using AFBC cogenerating concept for base thermal load and gas-fired heat-only boilers for thermal peaking.

Figures 6.7.4 and 6.7.5 give simplified descriptions of the options examined. Table 6.7-III gives the results of an approximate economic analysis of the cost of heat from each option.

It should be noted that

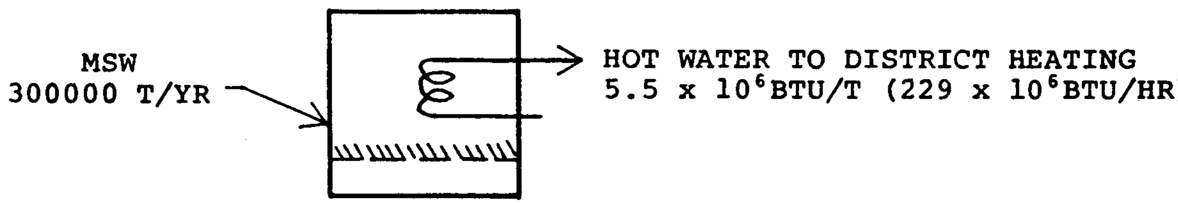
1. Some of the plants considered are of differing capabilities.

2. Certain capital and operating expenses are omitted because not readily available. These should be included in subsequent more accurate analysis.

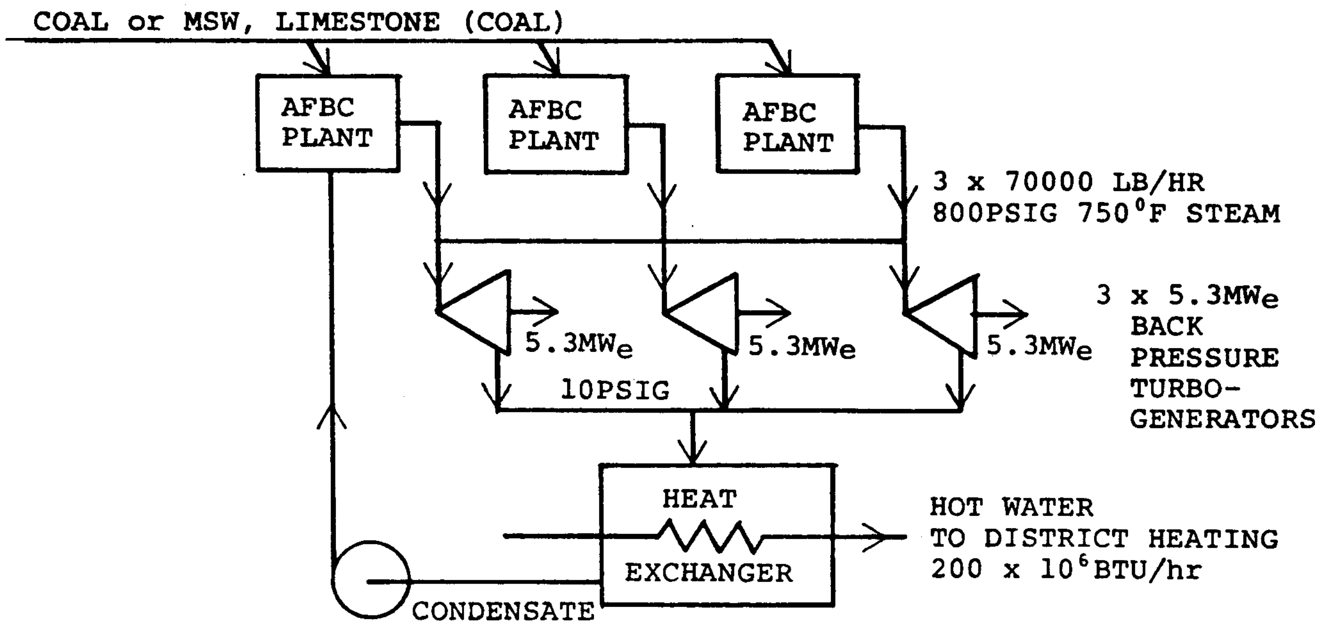
3. A library search has been initiated to verify the assumption that MSW can be burned in an AFBC and to quantify more precisely the O&M costs.

Other assumptions made are listed in Table 6.7-IV.

(1) MSW MASS-BURNING PLANT:



(2) AFBC BOILER PLANT:



(3) GAS-FIRED STEAM COGENERATION: Similar to (2) except 4x50 million BTU/hr gas-fired package steam boilers replace 3 AFBC's. There are still 3 turbines. 200×10^6BTU/hr and 15.9 MW_e.

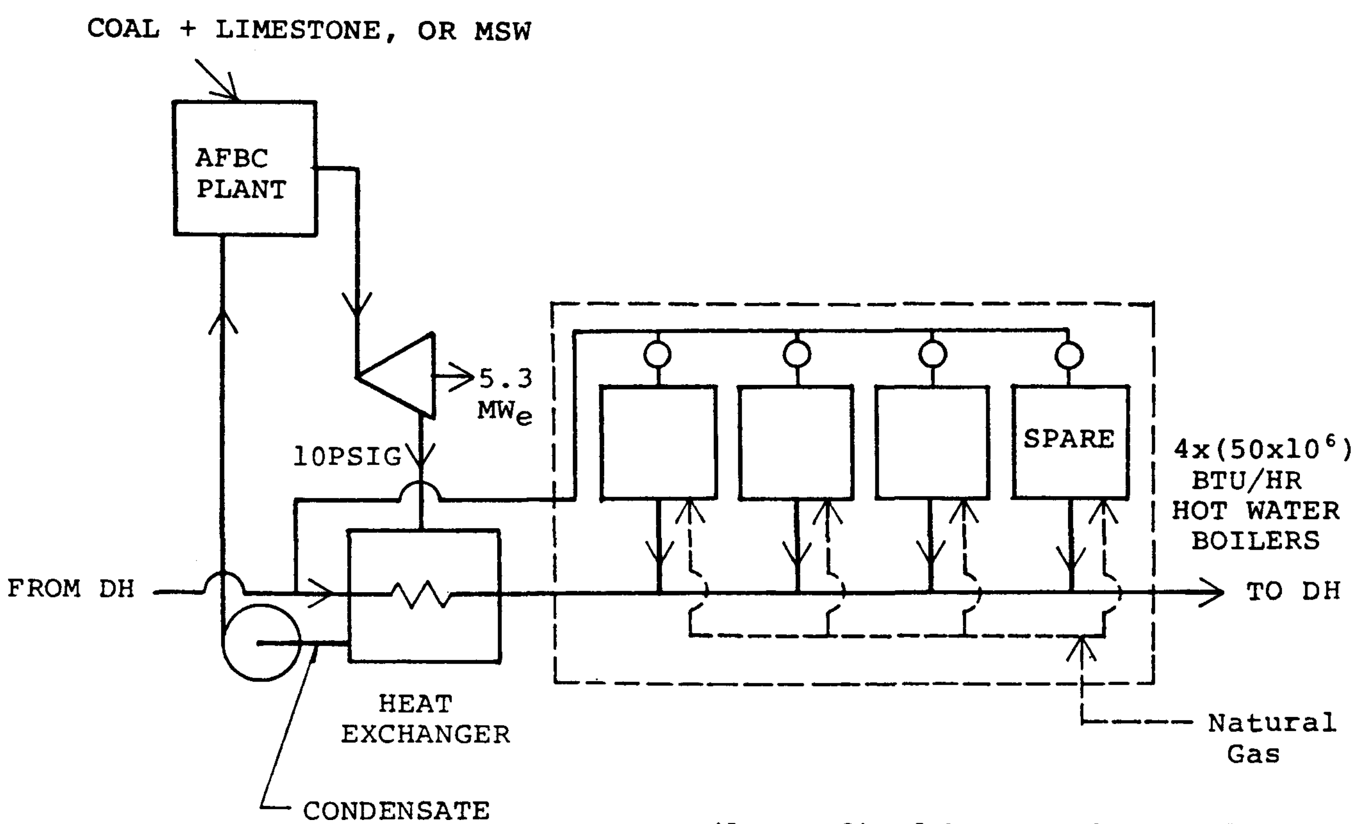
(4) Gas-fired heat only boiler plant: Per SWEC/Transflux design. 4x50 million BTU/hr gas-fired package hot water boilers and auxiliaries 200×10^6BTU/hr.

HEATING PLANT OPTIONS

FIG. 6.7.4

(5) Hybrid System: 1 AFBC plant per (2) (containing 3x70,000 lb/hr AFBC plants and 3x5.3MW_e back pressure turbines and 2 gas-fired heat only boiler plants per (4). Output: 600 million BTU/hr peak and 15.9 MW_e.

(6) Scaled-Down Hybrid System: 1 70,000 lb/hr AFBC plant and 1 gas-fired heat only boiler plant per (4). One of 4x50 million BTU/hr package boilers held as backup.



(1 Gas-fired heater, heat only boiler plant as in Case (4))

HEATING PLANT OPTIONS

FIG. 6.7.5

TABLE 6.7-III

Assumptions

1. Capital cost, O&M and heat recovery for mass-burning MSW-to-hot water plant per G. Kjaer, Proc. 72nd IDHA Conf. (1981).

2. Capital cost for AFBC boiler plant per Johnston Boiler Co. quote obtained by Mr. M. Kurz.

3. Gas-fired heat-only plant capital cost per SWEC as increased by PSE&G Engineering Dept.

4. O&M for MSW-burning AFBC same as mass-burning MSW plant
   O&M for coal-burning AFBC = ½ that of mass-burning MSW plant
   O&M for gas-fired steam cogeneration plant = ¼ that of mass-burning MSW plant
   O&M for gas-fired heat-only plant = 1/8 that of mass burning MSW plant

5. O&M cost for mass burning MSW plant is 50% fixed and 50% variable.

6. 1985 electricity replacement costs ($69/MWh) and fuel costs (high S coal = $2.73/MMBtu, natural gas = $5.29/MMBtu, obtained from PSE&G Fuel Supply Dept.) were used.

7. AFBC and gas-fired boiler thermal efficiencies were taken as 85%.

8. District heating system thermal load factor was taken as 27%.

9. Capital costs are for dates in the range mid-1981 to mid-1982.

10. Limestone costs, outside limestone, coal and MSW-handling capital costs were not included in AFBC costs.

11. A heat source providing bottom 1/3 of peak thermal load provides 2/3 of anuual energy (per Mr. M. Kurz)

12. Landfill gas was not considered. However, substitution of landfill gas for natural gas in Cases (3), (4) and (5) might improve the economics, especially at high load factor.

13. Cost of heat is given at plant boundary. T&D not included.

14. It has been assumed that MSW can be successfully burned in an AFBC. A library search to verify this is in progress.

TABLE 6.7-IV

SMALL COGENERATION AND/OR SOLID FUEL BURNING PLANTS
EVALUATION

	Case	Cost of Heat* $/10⁶ BTU @ Load Factor 27%	54%	100%	Capital Cost ¢/Btu/hr Peak	Capital Cost 10^6 $	Peak Thermal output 10^6 Btu/hr	Electric Generator Capacity, MWe
(1)	- Mass Burning MSW, heat only (229 MMBtu/hr)	20.45	9.73	4.80	26.2	60.0	229	-
(2)	AFBC (cogenerating)(200 MMBtu/hr)							
	- Coal	6.40	2.79	1.13	9.6	19.1	200	15.9
	- MSW	2.97	(1.73)	(3.88)	9.6	19.1	200	15.9
(3)	Gas-Fired, (200 MMBtu/hr steam cogeneration	5.89	3.71	2.71	6.2	12.4	200	15.9
(4)	Gas-Fired (200 MMBtu/hr) peak Heat only heater plant	8.08	7.20	6.83	2.2	4.4	200	-
(5)	Hybrid (600 MMBtu peak) AFBC = 1/3 peak (54% L.F.) Gas-fired heat - only = 2/3 peak (13.5% L. F.)							
	- AFBC on coal	5.12	NA	NA	4.7	27.9	600	15.9
	- AFBC on MSW	2.12	NA	NA	4.7	27.9	600	15.9
(6)	Hybrid (220 MMBtu Peak) AFBC = 1/3 peak, gas fired boilers 2/3 peak							
	- AFBC on coal	5.56	NA	NA	4.9	10.8	220	5.3
	- AFBC on MSW	2.76	NA	NA	4.9	10.8	220	5.3

( ) = Negative cost of heat

NA = Not applicable

* At plant boundary.

It should be noted that decreased fuel cost due to burning MSW can be offset by increased O&M cost. It was assumed that O&M costs for an AFBC burning MSW were the same as those for a mass-burning plant of the same capacity, but they could be higher (or lower).

This analysis has not examined a landfill-gas fired hot water heating plant. This has previously been done for Berry's Creek, and found more economical than natural gas - for locations where landfill gas is available. Landfill gas, at a given location, is a limited-lifetime resource. It can be suitable as a stopgap prior to connection to a central district heating system, but not for an independent installation.

Refuse disposal facilities are regulated public utilities, and "tipping fees" are set by the BPU to provide a 15-18% rate of return to the facility, based on its specific costs, and not on the basis of alternate disposal costs. For purpose of analysis, a published value, such as the $12.25/ton quoted by Mr. Kjaer in his IDHA paper was used. However, if an actual facility were to be built, negotiations to acquire rights to the MSW and to set rates ("tipping fee") would be needed. It is surmised that rules and regulations might preclude use of MSW for district heating. If this should prove true, there are still attractive coal-fired and other options shown in Table 6.7-IV.

Conclusions

1. The mass-burning MSW plant (Option 1) has the highest capital cost and capital cost per unit thermal capacity. It also has the highest cost of heat of all options, except when operated at near 100% load factor.

2. Natural gas-fired heat-only boilers (Option 4) provide the lowest capital cost and capital cost per unit thermal capacity, but a high cost of heat.

3. Cogenerating AFBC plants burning coal or MSW (Option 2) or hybrids combining a base-loaded cogenerating AFBC with gas-fired peaking boilers (Options 5 and 6) provide the lowest cost of heat.

   (a) Option 2 is most economic when connected into a large DH system and operated at high load factor.

   (b) The MSW-fired AFBC could actually produce a negative cost of heat. This means that electricity could be produced at less than the assumed $69/MWh, even if the heat were discarded.

(c) Cases 5 and 6 can operate in an isolated model, without connection to a central DH system or generating station. They are suitable for "heat islands" far from generating stations.

4. Gas-fired steam cogeneration (Option 3) is a close contender with all options except those involving MSW-fired AFBC's and is far cheaper, at all load factors, than a mass-burning MSW plant.

There is no way to make firm conclusions on any of the options beyond stating that some of them may turn out viable additions and/or alternatives to the large system investigated. All of them have several hurdles to pass, as environmental acceptability and community acceptability in front. Both of these are site-specific and therefore no generalized evaluation carries sufficient significance to deal with them in detail and include them in this study. At a site-specific studay of a small system, the best options warrant detail evaluation, including EPA permit applications.

6.7.6 SOLAR ALTERNATIVE(S) TO DISTRICT HEATING

A simplified analysis of solar alternatives to district heating was undertaken to determine the cost per million BTU of these alternatives.

Table 6.7-V summarizes the results of this effort. Costs for solar thermal, wind, and photovoltaic system alternatives are shown to range from $30-165 million BTU for three types of housing configurations. The solar thermal alternative is the lowest cost solar alternative with a range of $30-35 per million BTU.

In order to complete this analysis, it was necessary to make assumptions concerning the loads of the three types of housing, as well as the load serving capability of each solar alternative. Table 6.7-VI illustrates key load assumptions that went into this analysis. Having defined the loads to be served, assumptions were made as to the load serving capabilities of each solar alternative, such as:

- Each solar system type would be designed to provide on the average, 50% of the total annual space and water heating load. For the solar-electric alternatives it was assumed that their output would be thermally dissipated and used in a similar fashion as the solar-thermal system.

TABLE 6.7-V

COST PER MILLION BTU
SOLAR ALTERNATIVES

	Solar Thermal	Wind	Photovoltaic
• Single Family Detached (1 unit)	$35	$ 55	$165
• Townhouse (15 units)	$30	$125	$165
• Multifamily/ Apartment (50-200 units)	$30	$125	$165

Note: Does not include capital charges, interface costs, O&M escalation, permit/insurance/contractor-consultant fees and land costs.

All costs in 1981 dollars.

TABLE 6.7-VI

HEATING AND HOT WATER LOADS
OF TYPES OF HOUSING

	Total Annual Load (Btu)	Total Annual Load kWh(6)
• Single Family(1)(4) Detached (1 unit)	139×10^6	40,727
• Townhouse(2)(5) (15 units)	1490×10^6	436,566
• Multifamily/(3)(5) Apartment (50-200 units)	2484 - 9935×10^6	727,805 - 2,910,919

(1) load - 60,000 Btu/hr/unit ⎫ heating load
(2) load - 40,000 Btu/hr/unit ⎬ 1783 full load hours
(3) load - 20,000 Btu/hr/unit ⎭ (5200 D.D.x24)/70
(4) hot water load - typical family of 4 (20 gals./person/day)
(5) hot water load - constant 8% of heating load
(6) kWh load is assumed to be a straight conversion of
Btu ⟶ kWh (3413 Btu/kWh).

- Sufficient roof and/or land areas exists or is available for the placement of collectors, turbines and arrays.

- A conventional full sized back-up system is still required.

- Storage sizing is optimal for load.

- All solar options are capable of being correctly and directly interfaced to the existing heating and water heating systems already existing in the types of housing considered.

Integral to the sizing of each solar system alternative was a realistic estimate as to its annual production capability. This key figure was derived from actual information developed by PSE&G in its various solar studies, tests and analyses, and modified by discussions with knowledgeable solar suppliers/contractors and other sources of solar information. Table 6.7-VII describes the annual energy production figures used in the analysis. These figures were then applied against 50% of the annual loads in Table 6.7-VI to arrive at the size of the system required. Table 6.7-VIII shows the size of solar systems required based on the "modular" (equivalent) units described in Table 6.7-VII. Table 6.7-VIII also presents cost data for these systems based on industry available information.

The cost data presented in Table 6.7-VIII is optimistic and may not fully represent the true retrofit cost. The site specific costs of retrofit situations could add as much as 15-25% to cost estimates. The reader is also reminded, as mentioned earlier, that all system interfacing is assumed to be available and hence implied as minimal cost. Also, there are no land costs assumed--as in the case for siting wind turbines.

The reader's attention is directed to the wind energy alternative--note the penalty paid in the need to oversize turbine capacity to achieve the necessary 50% of load condition, especially in the single family detached case. This is due to poor wind speed conditions in New Jersey. Typical wind speeds are 7 mph or less.

Also, the reader will notice that the cost and ultimate cost per million BTU of energy from the larger 200 kW turbines are significantly greather than that from the 10 kW unit. One would expect this not to be true. This occurs because a severe performance penalty is exacted for operating such a large turbine at small wind speeds. One could postulate using a large number of small turbines; however this is not prudent because excessive interconnection and space requirements would

TABLE 6.7-VII

ANNUAL ENERGY PRODUCTION FIGURES
SOLAR ALTERNATIVES

- Solar Thermal:

  Flat plate panel technology capable of producing approximately 112,000 Btu/ft^2/yr(1).

- Wind Energy:

  Horizontal axis machines -

  - 10 kWe machine for residential applications; 3300 kWh annual production(2)

  - 200 kWe machine for commercial applications; 44,000 kWh annual production(2).

- Photovoltaic:

  Flat plate single crystal silicon technology - a 5 kWp module (540 ft^2)(3)

(1) This is a figure derived for N.J. conditions and based on data collected during PSE&G's Solar Demonstration Program. It is the average production rate between domestic water heating (144,000 Btu/ft^2/yr) and space/water heating (80,000 Btu/ft^2/yr) systems. Data reviewed in a recent DOE publication: <u>DOE Regional Solar Updates</u> (Conf-790758-Vol I, July-August 1979, pp. 159-284) indicates national production rates ranging from 30,000-145,000 Btu/ft^2 for commercial sized water and/or space heating demonstration systems.

(2) These figures are based on information developed by PSE&G N.J. weather data as input.

(3) Based on information gained from MIT Lincoln Labs in telephone discussions:

- 10m^2 of panel area are required for each 1 kWp of capacity (5kWp - 540 ft^2).

- Each 1 kWp of capacity results in 3 kWh/day of gross production (3 kWh x 5 kWp x 365 days = 5475 kWh).

These rules of thumb are valid for the northeast region according to MIT. 1000-2000 kWh/rated kWp is typical across the U.S. with 1500 kWh/rated kWp as typical.

TABLE 6.7-VIII

SIZE AND COST OF SOLAR
SYSTEM ALTERNATIVES

	Solar Thermal		Wind Turbines		Photovoltaic Array	
	Size (x 10^3 ft^2)	Cost(1) (x 10^3\$)	Size (Units)	Cost(2) (x 10^3\$)	Size (x 10^3 ft^2)	Cost(3) (x 10^3\$)
. Single family (1 unit)	.620	\$ 37.2	6(10kW)	\$ 60	2.0	\$ 186
. Townhouse (15 units)	6.66	\$333	5(200 kW)	\$1,500	21.5	\$ 1,993
. Multi/Apt (50-200 units)	11.1 - 44.4	\$ 555- 2,218	8 - 33 (200 kW)	\$2,400- 9,900	35.9- 143.5	\$ 3,223- 13,291

(1) Cost figures for solar thermal based on \$60/ft^2 for residential and \$50/ft^2 for commercial size (4 units or more) systems. Figures based on discussions with N.J. solar system manufacturers/installers.

(2) These cost figures are based on PSE&G obtained data which indicates; 10kW unit-\$10,000; 200 kW unit - \$300,000.

(3) Cost based on average system cost of \$10,000/kWp - a 5 kWp equivalent module would be \$50,000. Economies of scale were not included for larger size array(s) because it was assumed that support structures would increase in size to negate any cost benefits. Also associated wiring and connection costs would also correspondingly increase.

be needed. The larger turbine is the correct choice, but low wind speeds in New Jersey greatly diminish rated capacity and disproportionately increase costs for large turbine systems.

One other assumption is worth some additional discussion. It was assumed that the energy output of the solar-electric options was equivalent directly to the solar-thermal system energy output. It is recognized that this may not be the optimum way to utilize the electric energy developed. A system employing a heat pump/temperature amplification device would be a more appropriate way of evaluating/sizing a solar system. However, this combined solar-heat pump system concept is just now receiving attention. Most of the literature deals with solar-thermal storage directly and for this reason, so did this analysis.

To arrive at the cost per million BTU figures shown in Table 6.7-V, it was necessary to again make some important assumptions:

- Assumed equipment lifetime - 20 years.

- Solar tax credits:

  - residential; 40% of first \$10000 - maximum of \$4000 (only applied to solar thermal option). Wind and photovoltaic were given a straight 15% credit (optimistic assumption).
  - townhouse and multi/apt; all solar options given a straight 15% credit.

- O&M assumed at 2% of capital cost per year (no escalation)

- A sample cost per million BTU calculation is shown for the reader for the case of a solar thermal option for the townhouse type of housing:

  - Installed cost = \$333,000

  - Savings = $(1490\times10^6 \text{BTU})(.5 \text{ solar contribution})(20 \text{ yrs}) = 14{,}900\times10^6 \text{BTU}$

  - O&M = $(\$333{,}000)(0.02)(20 \text{ yrs}) = \$133{,}200$

$$\$/10\ \text{BTU} = \frac{(\$333{,}000)-(\$333{,}000)(.15 \text{ tax credit})+\$133{,}200}{14{,}900}$$

$$\approx \$30/10^6\text{BTU}$$

This is obviously not a rigorous analysis; however, it does realistically place in perspective the relative costs of three solar options as well as their relationship to district heating costs. A detailed analysis which accounted for factors such as cost of money to finance the systems, site specific modifications, parasitic power consumption, O&M escalation, interface costs, permit/insurance/contractor-consultant fees and land would all tend to significantly increase installed costs. Such an increase might probably overwhelm any benefits gained in a detailed analysis which accounted for fuel price escalation, 10% investment tax credits available for solar system owners and other possible tax advantages.

It is being felt that within the scope of the work and charge of this alternate study the facts presented herein are realistic and representative of New Jersey conditions.

6.7.7 NUCLEAR DISTRICT HEATING SYSTEM SUPPLY TO CAMDEN RESIDENTIAL AREAS FROM SALEM NUCLEAR GENERATING STATION

6.7.7.1 Introduction

This paper reviews the concept of providing space heating in an urban residential area utilizing an existing nuclear plant as the heat source. The objective is to take a brief look at the application of the district heating concept to New Jersey areas where PSE&G fossil plants are not available. Specifically, the paper explores the technical, economical, and institutional issues in connection with the production and transportation of hot water from the Salem Nuclear Generating Station to the city of Camden. These issues are examined on a conceptual basis and, where possible, comparisons are made with the proposed Hudson-Meadows district heating system for illustrative purposes. No attempts have been made to perform a detailed analysis of the concept.

In order to prepare the paper, discussions were held with H. B. Baranek, Engineering and Construction; G. W.Bowdren, Production Support; R. P. Douglas, Licensing and Environmental; P. A. Moeller, Nuclear Production; and T. M. Piascik, System Planning. Published articles on the subject of district heating from LWR power plants were also reviewed. (See reference section)

6.7.7.2 Results and Conclusions

1. The concept of nuclear district heating is technically feasible, and the relatively low operating cost of a nuclear heat source is a positive economic factor. In the case of

Salem-Camden system, however, other economic factors appear to be negative.

2. The potential for lower cost heat from a nuclear source, as compared to a fossil (coal) source, is uncertain for the following reasons:

   a) The power plant heat exchange equipment for district heating would have to be larger, and therefore more expensive, for a nuclear plant retrofit than for a fossil plant retrofit. This conclusion is based on a comparison of the steam conditions for the Salem nuclear plant versus the Hudson 2 fossil plant.

   b) The power plant heat exchange equipment for district heating may have to be constructed of higher quality, and therefore more expensive, materials for a nuclear plant than for a fossil plant. The power plant side steam purity requirements, are much more stringent in a nuclear power plant than in a fossil power plant, principally for the protection of steam generator equipment.

   c) The net cost penalty per KWhr for the replacement of electrical output losses from a retrofitted power plant will be greater for a nuclear plant than for a fossil plant. This is because the incremental production costs associated with nuclear generated electricity are lower than those for fossil generated electricity, while the replacement costs are the same.

3. The capital and operating costs for a district heating transmission system from Salem to Camden could be excessive. The 40-45 mile distance to the nearest customer is significantly greater than the 30-35 mile distance which is commonly accepted as the economic limit to the furthest customer (3). The Hudson-Meadows transmission system covers a distance of only 5 miles (7).

4. Obtaining licenses and permits for a Salem-Camden district heating system would be more difficult and more costly than for a Hudson-Meadows system.

   a. While the addition of district heating equipment to Salem is not expected to adversely affect the units' operating licenses, a time consuming and expensive change to the station's Technical Specifications would be required.

   b. It is quite likely that a Coastal Area Facility Review Act (CAFRA) review of a Salem-Camdem transmission pipeline would be required.

6.7.7.3 <u>Discussion</u>

A nuclear power plant operates with poorer steam conditions and greater steam flows than a fossil plant. This is illustrated in Table 6.7-IX, which compares turbine inlet steam conditions for Hudson No. 2 and a generic Westinghouse 1200 MWe PWR (comparable to Salem Nos. 1 and 2). As can be seen from this table, the fossil plant cycle operates at higher steam temperatures and enthalpies (heat content) than the nuclear plant cycle.

TABLE 6.7-IX

TURBINE INLET STEAM CONDITIONS

NUCLEAR VS. FOSSIL

Plant:	Nuclear (Generic Westinghouse PWR)						Fossil (Hudson 2)					
Gross Generation:	1200 MW						652 MW					
Turbine Element	Temperature (°F)	Pressure (Psia)	Enthalpy (Btu/lb)	Enthalpy Drop (Btu/lb)	Mass Flow(1) (lb/hr/MW)	Turbine Output (MWe)	Temperature (°F)	Pressure (Psia)	Enthalpy (Btu/lb)	Enthalpy Drop (Btu/lb)	Mass(1) Flow (lb/hr/MW)	Turbine Output (MWe)
VHP	-	-	-	-	-	-	1000	3690	1415	113	30,770	130
HP	541	975	1191	102	34,240	410	1025	1017	1519	124	28,170	124
IP	-	-	-	-	-	-	1050	338	1552	175	19,950	151
LP(2)	515	160	1281	279	12,660	790	695	81	1377	332	10,500	247

Notes: 1) Adjusted for turbine extractions
2) Extraction point for district heating

There are a number of possible modifications which can be made to the steam cycle of an electric power plant to retrofit it for district heating. The simplest and most appropriate is usually considered to be the extraction of steam from the low pressure (LP) turbine cross-over piping[2]. This extraction point was selected for the retrofit of both the Salem and the Hudson generating units. In general, this approach allows for maximum operating flexibility with regard to both electrical and district heating output. It also minimizes the changes which must be made to the existing plant/turbine design. However there are a number of interrelated considerations which affect the design and capital costs of the retrofit scheme and the operating costs of the modified power plant. Table 6.7-X shows the steam conditions at the proposed extraction points. It will be helpful to refer to this table when considering the following points.

- In the case of a nuclear plant, there is a moisture separator/reheater in the HP/LP cross-over. Steam extraction from the cold side of the cross-over would minimize the district heating impact on power plant efficiency, and could provide hot water temperatures as high as 350°F for the district heating system. However, the cold cross-over steam is saturated, and has a relatively low heat content as compared to the hot cross-over steam. This would require relatively larger and more costly heat exchangers.

TABLE 6.7-X

DISTRICT HEATING EXTRACTION STEAM CONDITIONS

NUCLEAR VS. FOSSIL

Location	Steam Parameter	Nuclear (Generic Westinghouse PWR)	Fossil (Hudson 2)
Cold LP Cross-over	T - °F	370	695
	P - psia	176	81
	H - Btu/lb	1,089	1,377
Hot LP Cross-over	T - °F	515	-
	P - psia	160	-
	H - Btu/lb	1,281	-
After Auxilliary Back-Pressure Turbines	T - °F	-	510 / 405
	P - psia	-	29 / 14
	H - Btu/lb	-	1292 / 1242

T = Temperature

P = Pressure

H = Enthalpy

- The Hudson 2 cross-over steam has a higher temperature and heat content than either the cold or the hot nuclear plant cross-over steam. If the extraction steam is introduced directly into the heat exchangers, nuclear plant equipment would have to be larger than equivalent fossil plant equipment due to the lower quality nuclear steam. Nuclear plant heat exchangers would therefore be more costly than fossil plant heat exchangers.

- In the Hudson/Meadows district heating study, it is proposed that the extraction steam be partially expanded through auxilliary back-pressure turbines prior to entering the heat exchangers(7). In this way, some of the electric generating capacity which is lost due to the steam extraction can be recovered. Table 6.7-X shows that the heat content temperature of the fossil plant steam entering the heat exchangers in this scheme is comparable to the heat content of the hot cross-over nuclear plant steam. The heat exchangers would therefore be of comparable size and cost. The nuclear system would not have the additional capital cost of the back-pressure turbine/generators, but it would incur an operating cost penalty due to a greater loss of net unit electrical output as compared to the fossil system.

- It would be possible to add back-pressure turbine/generators to a nuclear district heating system, as is proposed for the fossil system, providing that hot cross-over steam is used.(6) However, this would reduce the heat content of the nuclear steam, again requiring larger heat exchangers for the nuclear system, Also, because of the lower quality steam, the nuclear back-pressure turbines would be larger and more costly, or would provide less electrical output, than their fossil counterparts.[4]

A quantitative cost evaluation of the trade-offs discussed above is beyond the scope of this paper, and it is not the intent have to evaluate nuclear vs. fossil district heating. However, it does appear that the thermodynamics of the nuclear steam cycle may introduce capital and/or operating costs penalties which can to some extent offset the advantages of low nuclear fuel costs in district heating applications.

Water (steam) purity is more critical in a nuclear power plant than in a fossil power plant. The saturated steam conditions in a nuclear plant increases the susceptibility of equipment to damage from water impurities, and the costs resulting from any equipment deterioration (maintenance, loss of production, and loss of efficiency) can be greater for a nuclear plant than for a fossil plant. Industry experience has shown that PWR steam generators in particular are very sensitive to steam purity. It is therefore more essential in a nuclear plant to prevent any leakage of lower quality water from the district heating side of the heat exchangers to the power plant side. It is quite likely that higher quality, and consequently higher cost, heat exchangers would be required in a nuclear district heating system as compared to a fossil district heating system.

It would also be necessary in a nuclear district heating system to prevent leakage from the power plant side of the heat exchanger to the district heating side, to provide radioactivity monitoring on the district heating side. Although the equipment would probably not have to meet nuclear QA and seismic requirements, it would be necessary to submit changes to the plant's Technical Specifications to the NRC. This is a burdensome, time consuming, and therefore costly procedure. The net result is that the engineering effort required to retrofit a nuclear plant for district heating would be significantly more expensive than that required to retrofit a fossil plant.

In terms of operation, a nuclear plant is less adaptable to district heating than a fossil plant. Nuclear units are less likely to be subject to economic load reductions than fossil units, particularly on the PSE&G system. Such load reductions make otherwise unneeded energy available for district heating. Further, while a fossil unit may or may not have some amount of reserve capacity, which could be utilized in times of need by over-firing the boiler, nuclear unit heat production is strictly limited by the licensed thermal output of the reactor. It is not permissible to increase the reactor output to help offset heat extracted for district heating. An additional consideration is the impact of the one to two month coast-down period at the end of the fuel cycle on the electrical and district heating outputs of a nuclear unit. The net result of all these factors is that more frequent electrical deratings can be expected from a nuclear plant as compared to a fossil plant.

The net cost of replacing any electrical output losses is greater for a nuclear plant than for a fossil plant. Although the system replacement energy cost would be the same in either case, the cost of energy produced by a nuclear plant is less than the cost of energy produced by a fossil plant. Therefore the differential between plant production cost and system replacement cost is greater for nuclear. This differential electric energy cost should be charged to the production cost of the district heating energy, and will reduce, if not eliminate, the cost benefit of the nuclear energy heat source for district heating.

In terms of reliability, a nuclear plant can be forced out of service for conditions under which a fossil plant could remain in service. Once out of service, a nuclear plant can take longer to return to service than a fossil plant. Also, planned outages of nuclear units are dictated by the fuel cycle and, to some extent, by regulatory decree. There is very limited flexibility to schedule outages around the demands of a district heating system. To the extent that the fuel cycle can be adjusted to accommodate the district heating loads, the resulting electric system inefficiencies would be subject to the same cost penalties as the loss of capacity during operation. In any event, the possibility exists that a nuclear power plant may be less reliable than a fossil power plant for supplying district heating energy. Although back-up facilities would be required for either a fossil or a nuclear district heating system, the back-up may be used more often in the case of the nuclear system. And, as has been seen on some electric systems, the impact of replacement energy costs on rates resulting from extensive outages of nuclear capacity can create public relations problems with consumers.

The use of heat extracted from a nuclear plant for residential space heating may tend to aggravate licensing issues. Knowledgeable PSE&G personnel do not foresee any significant problems at this time, other than the previously mentioned requirement to modify the plant's Technical Specifications. However, no large nuclear power plant with district heating capability has been approved by authorities in the United States. Therefore licensing problems may be very difficult to predict, and future licensing decisions may have an important impact on the economic feasibility of the nuclear district heating concept.[3]

The transmission and distribution of heat is a significant economic issue in district heating, particularly in the Salem-Camden application. With respect to the heat transport medium, the advantage is strongly on the side of hot water as opposed to steam because it produces lower losses in electricity production per unit of extracted heat.[3] Most studies indicate that nuclear district heating can be competitive with on-site fossil fuel boilers for loads distributed up to 30-35 miles from the nuclear plant.[3] In the case of Camden, the location of the closest heat loads at 40-45 miles away from Salem nuclear plant alone could make the concept economically unfeasible. Rough calculations show that 20-40 MW of pumping facilities would be required for the transportation of hot water from Salem to Camden.

It is interesting to note that the district heating transmission pipeline acts as a buffer between supply and demand. The heat load characteristics at the customer is followed at the power station with a delay of about 13 minutes per mile of transport distance.[2] In the case of Salem and Camden, this delay time would be on the order of 9-10 hours. This would require a forecasting capability for district heating dispatch, and could present operating problems if the forecast turned out to be in error.

The cost of piping used to transport the hot water can be expected to be very significant for a Salem-Camden district heating system. This high cost is due to the extremely good piping insulation required due to the distance involved, and to the special coatings and materials required to assure the corrosion protection of the pipes in a marshy, brackish area such as exists between Salem and Camden. Obtaining permits for pipeline construction in this area could also be a problem. A CAFRA review may be required. Because it is a pristine area, this is certain to present more problems than a district heaitng system is the Meadowlands area.

In summary, the feasibility of the nuclear district heating concept depends on a number of uncertainties such as the environmental acceptability and cost of the transmission and distribution systems, the amount and replacement cost of lost electric production, licensability, and the cost of retrofitting the nuclear power plant.

One thing is certain - all of these items will be more difficult and more costly for a Salem-Camden nuclear district heating system than for a fossil district heating system such as we are now studying for the Meadowlands area. Therefore, the overall economic feasibility of the system cannot be determined without more detailed study. As it appears right now, the transmission cost penalty resulting from the location of the load at distances in excess of 40 miles from the Salem plant is the main limiting factor in implementing the concept. The production cost trade-off between the low cost of nuclear energy and the capital and operating costs of retrofitting an existing nuclear power plant are secondary factors.

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6.8 LANDFILL GAS

6.8.1 BACKGROUND

Dumping of refuse at the edge of a town and burning it was a popular method of solid waste disposal in the early 1900's. As the population increased so did its refuse, and this haphazard method of disposal became a matter of great concern to public health officials. In the late 1940's sanitary landfilling techniques were developed. This technique involved the reducing of solid waste to the smallest volume possible and covering it with a layer of soil at the end of each day. However, by covering or "capping" these landfills, various environmental conditions such as refuse composition, moisture content, and temperature existed within the landfill may be very well suited to methane generation.

In recent years, it has become widely recognized that landfill methane gas can become something more than just a nuisance and a hazardous problem. It can become a greatly needed source of energy for our nation. Previous study had indicated that between 1,000 to 10,000 landfills in the United States are eligible for gas recovery and utilization. These landfills represent about 200 billion cubic feet of methane gas or about 1 percent of the Nation's total energy needs.

Presently, New Jersey produces approximately 15 million tons of solid waste each year. If all of these wastes could be converted to methane, then the result would be an energy equivalent of 20 million barrels of oil per year or 3-5% of PSE&G's gas supply needs. Therefore, methane from landfills can play a significant role in alternative fuel sources particularly in New Jersey which has no indigenous energy resources.

6.8.2 METHANE GENERATION

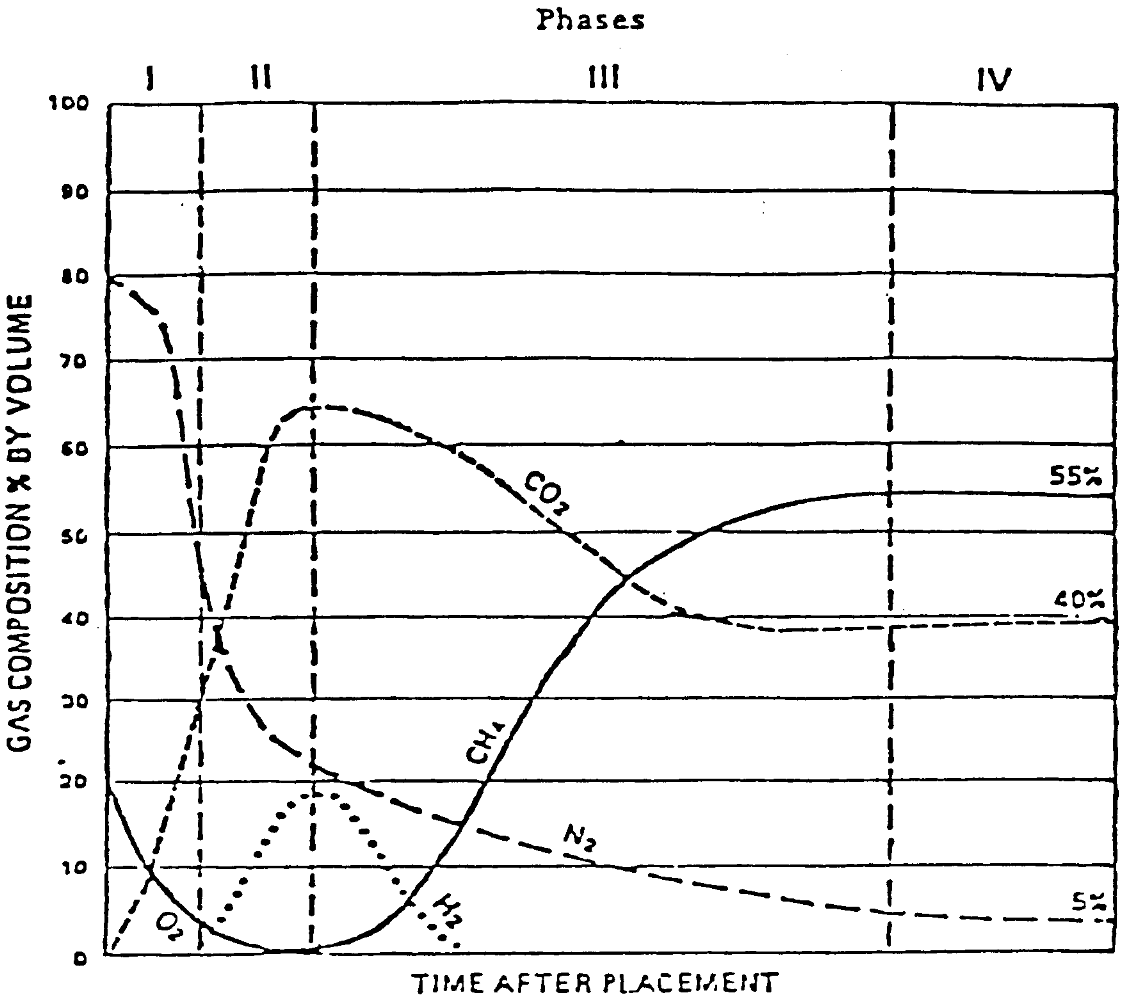
As the organic biodegrable components in solid wastes decompose, they undergo a microbiological fermentation process to a variety of simple organic materials and by-product gases. The primary gases generated are carbon dioxide and methane, with lesser amounts of oxygen, nitrogen, ammonia, and hydrogen sulfide. The composition of landfill generated gas changes as the gas undergoes first aerobic, then anaerobic conditions. The landfill gas generation process develops in four phases. A typical landfill's gas composition and its evolution are illustrated in Fig. 6.8.1.

The first phase, the aerobic phase of gas composition and evolution, lasts several days to several weeks. Oxygen (O_2), which is present at the time of refuse placement, aids in the decomposition process. The principal by-products of this phase are carbon dioxide (CO_2) and water (H_2O).

The second phase, the anerobic non-methanogenic phase, prevails until all the free O_2 has been depleted. During this phase, significant amounts of CO_2, as well as some nitrogen (N_2) and hydrogen (H_2) are produced.

The third phase of gas composition and evolution, the anaerobic methanogenic unsteady phase, lasts between 2-12 years and is characterized by the first evidence of methane (CH_4) a reduction in CO_2 and N_2 concentrations, and a depletion of all H_2 molecules.

The fourth phase, the anaerobic methanogenic steady phase, illustrates pseudo steady-state conditions for the production of the landfill gas. The steady-state composition of the landfill gas is about 55% CH_4, 40% CO_2 and 5% N_2.



I. AEROBIC

II. ANAEROBIC. NON-METHANOGENIC

III. ANAEROBIC. METHANOGENIC. UNSTEADY

IV. ANAEROBIC. METHANOGENIC. STEADY

GAS COMPOSITION AND EVOLUTION
IN A TYPICAL LANDFILL[1]

FIG. 6.8.1

1. Emcon Associates "Methane Generation and Recovery from Landfills", Ann Arbor Science Pub., 1980.

Methane generation, which may last from a few years to a century, is dependent on the specific conditions of the sanitary landfill. The overall rate of gas production at any time is a function of numerous factors, including the levels of oxygen present, quality and quantity of nutrients, refuse moisture content, pH, age of refuse, temperature, size and composition of refuse.

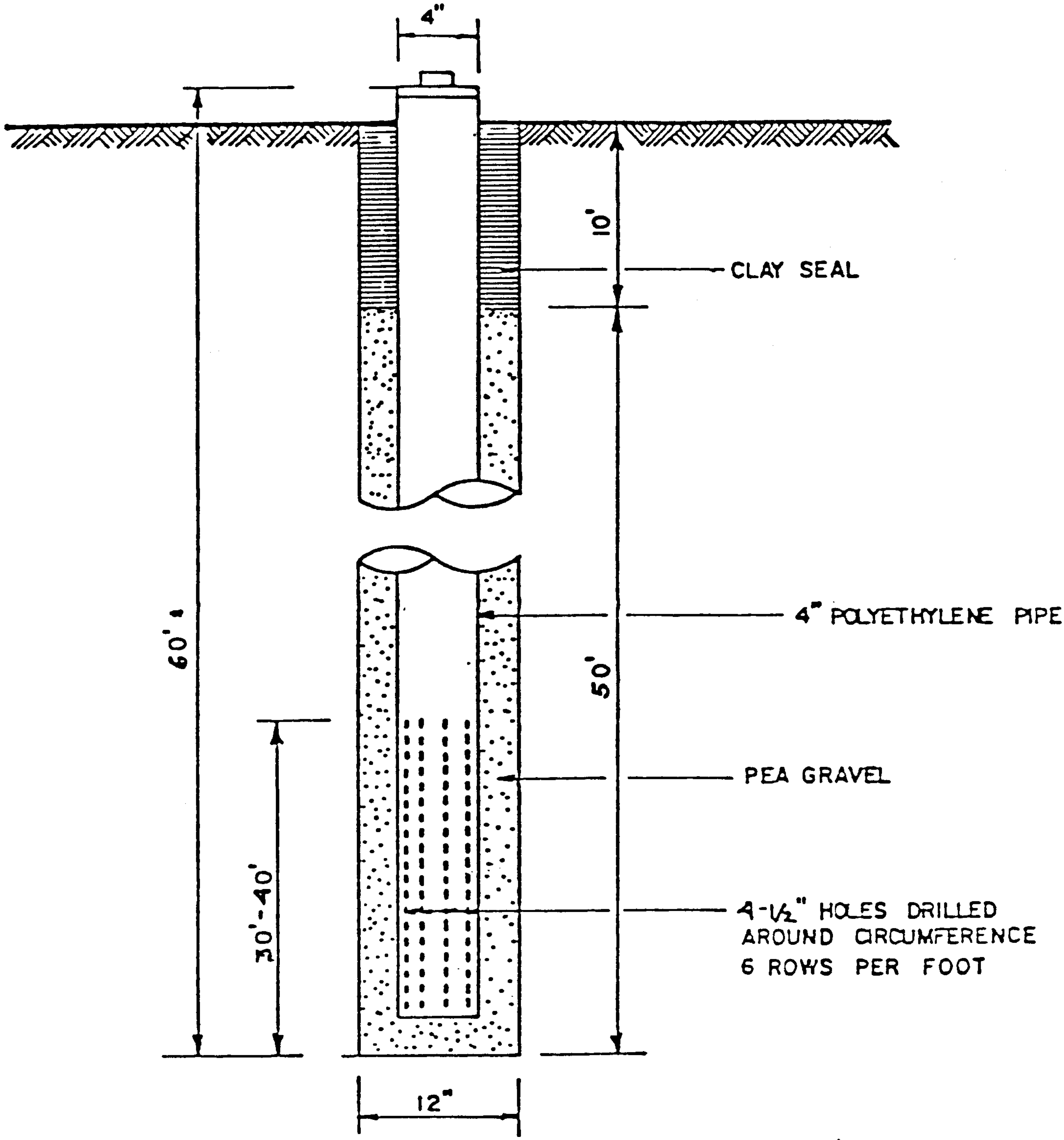
6.8.3 METHANE MIGRATION

Landfill generated methane gas has been known for its potential hazard because it becomes explosive when mixed with air in concentrations between 5 and 15 percent. Normally, approximately 80 to 90 percent of the landfill gas produced by a landfill will exit through the landfill cover. But when the methane is blocked from its normal vertical escape by an imperious cover such as road pavement, frost, rain-saturated cover soil, or impermeable clay, it begins to migrate laterally until an opening is reached for a natural vent to the atmosphere. In general, a landfill constructed in a porous environment with an imperious cover would experience greater lateral methane migration than the one built in imperious environment with an imperious cover.

6.8.4 LANDFILL GAS EXTRACTION AND UTILIZATION

During the last ten years, the extraction and utilization of a landfill methane gas has become a reality. There are presently at least a dozen commercial ventures in the U.S. recovering and utilizing landfill gas for its methane content. These projects use the landfill gas as fuel for boilers, process heat or electricity generation, or the gas is processed to remove undesirable constituents and then inject into utility gas pipelines as practically pure methane.

The recovery of landfill gas from landfills requires available technology. Holes are drilled into the refuse and perforated polyethylene or PVC pipe, (see Fig.6.8.2), are inserted to serve as the wells; the wells are connected together by piping installed on the landfill, and the gas is drawn through the wells and



TYPICAL TEST WELL

FIG. 6.8.2

collection piping by the slight vacuum produced by a connected gas compressor.

Some type of water separation equipment is usually added, and sulphide removal equipment may be necessary depending on the end use of the gas. In cases where pipeline quality gas is the desired end product, an elaborate purification plant is required. The gas collection system will vary in complexity with the surface size and depth of the landfill.

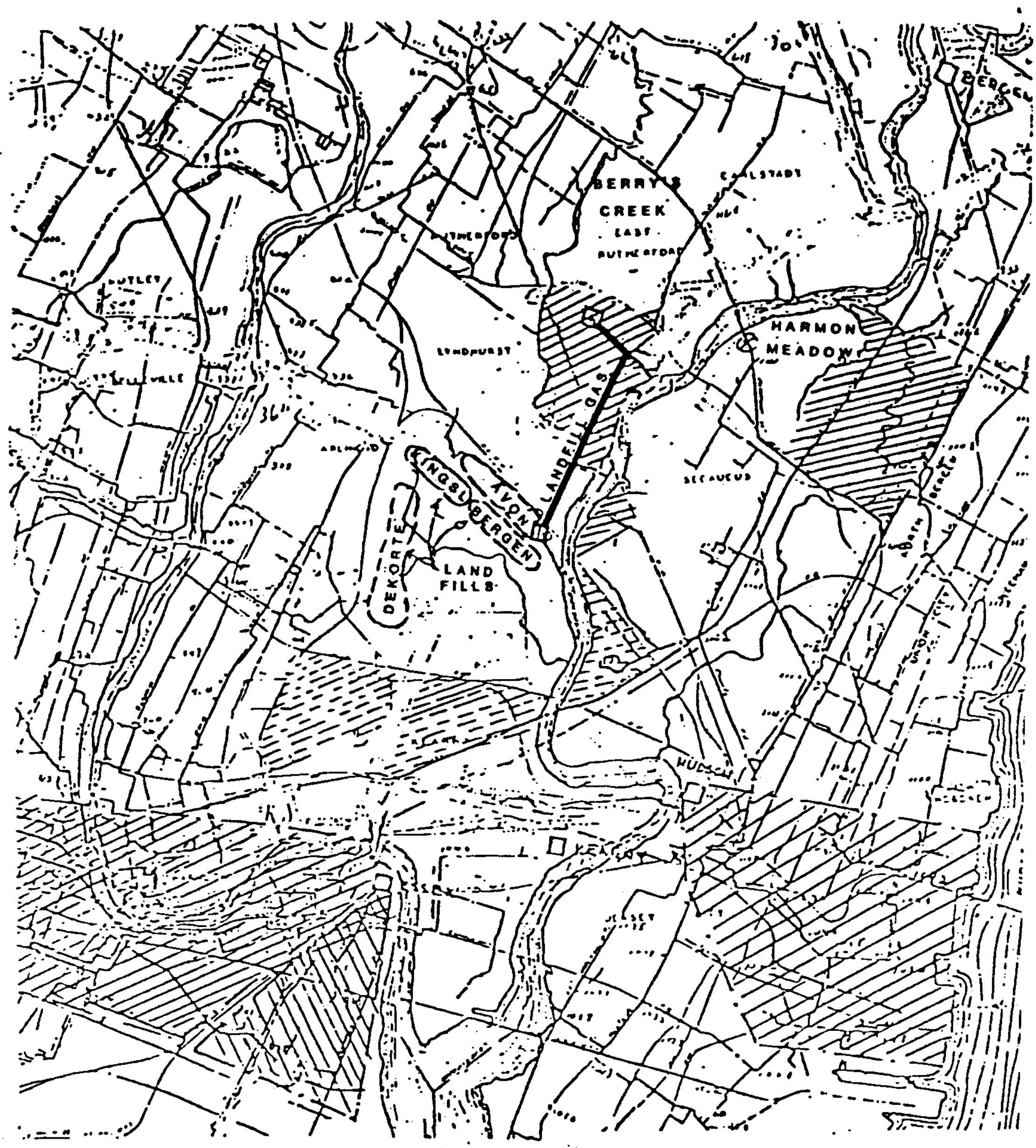
6.8.5 LANDFILL GAS PRODUCTION

In 1979, PSE&G initiated its first methane extraction project from a landfill in Cinamminson, N.J. to provide a source of fuel for a nearby industrial customer. After a cleaning process to remove some of the impurities comprised mainly of carbon dioxide and water vapor, the methane gas extracted in this manner has a heating value of approximately 500BTU/ft^3, about half that of natural gas. The Company is also pursuing several other potentially viable landfill gas projects in its service territory. See article in Appendix C.

To utilize the landfill gas, separate transmission piping to deliver the gas to the utilization points and modifications of customers' boilers are needed to burn the lower BTU gas. For district heating applications, the adoption of a concept of installing several large boilers at centralized locations with the capability of burning either landfill or natural gas could more effectively use landfill gas.

Landfill gas is expected to reduce the overall fuel cost of supplying thermal energy in comparison with natural gas. However, the dependability and expected life of a landfill gas source may be less certain.

Figure 6.8.3 shows the location of several major landfills in relation to the Berry's Creek and Harmon Meadows district heating regions under consideration.



BERRY'S
CREEK
HARMON
MEADOW
LANDFILL GAS
AVON
BERGEN
DEKORTE
LAND
FILLS

FIG. 6.8.3

Complete development of all the existing major landfills in the area were assumed for the full system. Even with this extensive development, landfill gas can only supply a small percentage of the peak load of a system as large as this.

6.9 System Operations

The complexity of the system and the time span of 25 years for its completion create differing operating scenarios at differing stages. While most of the aspects had been covered in the previous paragraphs, an overview may clarify some of the aspects not shown before.

6.9.1 Heater Plants Alone

Gas fired hot water generators located at the perceived load center of an area will operate on automatic controls and with remote supervision. So will the circulating pumps of the units and of the system. Day-to-day and scheduled maintenance will be performed by roving crews of craftsmen.

The firing of landfill gas, where made available, will always be in preference of the stand-by natural gas. The same burner train will be able to handle both as long as the supply pressures are adjusted for the difference in heating values, so as to compensate for it by varying flow rates.

The distribution, in the form of hot water, will operate at this stage at a basically constant temperature, variable flow rate system. Sliding temperature does not, while sliding flow rate does provide operating savings, when the heat supply is not cogenerative. The flow rate reduction is limited by distribution system balance. When that point is reached then the supply temperature starts to reduce also to meet very low load requirements.

One side effect of the constant temperature send-out is that the system can readily accept old low pressure steam users at the early stages of development. An understanding has to be established however that the steam system needs to be replaced by a hot-water system in a few years' time, as the system grows and/or as it becomes cogenerative. System growth is limited by a steam user, because the utilizable temperature differential is reduced to 60^{0}F at the minimum return temperature of 230^{0}F to be expected from those users. The limitation in the cogenerative model becomes that of economics. High return temperatures prevent the use of a low pressure steam exhaust and reduce the power produced, if not entirely eliminate power production because of the physical limitations of a given turbine. Those limitations do not apply to a combustion turbine driven cogenerative machine, and only partially so to a diesel driven one.

The plant operations are completed by the treatment of the make-up water and by the pressurization of the system. The make-up water, provided by the city water supply system, is planned to enter a resin treatment facility and is stored in a tank. A level controlled pressurization tank dumps water in the same tank on the heat-up cycle. The pressurization pump feeds water in from the tank on the cool-down cycle and to replace leakage losses. It also maintains a set cover pressure on the system to prevent the flashing of hot water.

There is always at least one stand-by heater unit in any one of the plants. These relatively small heaters are capble of coming on-line in less than half an hour without undue strain. Consequently the stand-by unit will not be fired normally and the fly-wheel effect of the considerable heat stored in the distribution system will be called upon to gap the time span created by the stand-by unit start-up. This philosphy is maintained over the later stages of development, since with the increase of transmission systems the fly-wheel effect increases also.

6.9.2 Heater Plants Plus Partial Retrofit of Hudson #2 Unit

It was conceived that a situation may develop when one of the heater plants is called upon to supply a larger load at an early stage of overall system development than its future share in the total load demands. At that point in time two possible actions are feasible. A temporary heater can be installed to bridge the time until other parts of the system grow sufficiently to justify retrofitting either the Kearny or the Hudson G.S. for D-H. This would perpetuate the relatively expensive central heater plant operation.

The other, much more fuel efficient, approach is the partial retrofit of the Hudson #2 unit. This retrofit, which is a relatively simple bleed at the two crossover lines, can supply approximately $200x10^6$BTU/hr without controls other than pressure reducing stations to maintain HTW temperasture. The installation of heat-exchanger(s), circulating pumps and transmission line to the affected heater plant are the needed installations. The operation of these elements is totally automatic and self contained.

Start-up of a circulator makes the supply temperature controller call for steam. This opens the control valve in the bleed line and maintains a steam flow which may or may not satisfy the set temperature. It will not meet the control value, if the called-for flow is above the set limits of the bleed line. In this case the heater plant comes on automatically because its supply temperature controller is not satisfied either. Should the turbine shut down momentarily, it does not change this control sequence. It only brings more heaters on as the deviation from controlled temperature increases. Should the turbine outage be sustained, an operator will have to shut off the Hudson plant circulators and remotely open the by-pass valve at the heater plant(s) to direct the return water back at this point instead of circulating it through the transmission line.

There is no pressurization and make-up system required at the Hudson plant. These systems at the heater plants are to be made sufficient to cover the additional small leakage losses due to the transmission line and heaters added. The treatment facility included with the design of the Hudson G.S. retrofit is applicable only if a non-staged system construction scheme was adopted.

The study run by the manufacturer of the turbine, the Westinghouse Corp., established the maximum allowable bleed flow at full throttle flow and also the power generation lost due to that bleed (approx. 18 MW). The paper written by Messrs. Kan and Silvestri on the retrofit (see Appendix B) states that the steam generator can take 5% more flow at 5% higher throttle pressure. It has never been operated at those conditions. Actually, environmental restraints on the steam generator kept the unit operation below rated conditions. It seems possible that the losses encountered by the partial retrofit may be compensated by increased throttle flow, if the environmental restraint can be lifted. That involves a full investigation and impact presentation, beyond the boundaries of this study.

An additional feature of this retrofit is that Hudson Unit #1 has a tie-line of similar capacity to No. 2 unit which can be used as the back-up to this service. So no stand-by heaters are needed in the heater plant for this capacity.

6.9.3 Heater Plants and Combustion Turbine Plant

The operation of these two elements combined is no different from the one described in the previous paragraph. There are only a few exceptions to this statement.

First of all the Kearny #12 unit is made up of of four pairs of combustion turbines. Each pair is going to feed a heatrecovery heatexchanger of about 300×10^6 BTU/hr capacity. The gas stream enters at about 900^0F at full load and it is cooled to $250-300^0$F. Consequently there are no limitations on the supply side water temperature within the selected $295-170^0$F operating range of the HTW system. This in turn means that this unit combined with heater plants, can supply high temperatures year-round at varying flows without thermodynamic penalty. In practice this allows a time extension of supplying steam systems at no other operating losses, but an increase in heat losses on the system and higher pumping power use.

Each of the up to four heatrecovery HX's have their own circulators. They work parallel with the system circulators. This way a constant flow is maintained across the heatexchangers. The temperature leaving is a function of turbine load. At full load it is of a value higher than 295^0F. The required leaving water temperature in the HTW system is maintained by mixing the system return water with varying amounts of water leaving the heatexchangers. At peak load all the return water may be flowing through the heatexchanger before leaving as supply water. This will occur only when this stage alone is called upon by the controls to supply 295^{o}F water to the distribution system, without any heaters operating. Any other time the leaving water temperature is less. The fired heaters at the local plant(s) work in series with the heatexchangers.

Electric power production is independent of heating load in one direction only. More power can always be generated than that required by the heating system dictated momentary heatrecovery requirements. Conversely the turbines cannot be on electrical dispatch when the system incremental rate would dictate less output (or no output) from these units. To satisfy the heat requirements will necessitate its operation in lieu of a more cost efficient unit. An incremental cost penalty is incurred at these times and it is carried as a cost component of supplying heat. The installation of heat recovery also reduces the full load output of the units. This reduction amounts to approximately 5% of rated capacity or 3–4 MW, but due to the peaking nature of the plant no penalty was considered as a heating cost. In the winter, at the peak of the heating system, these units operate at a higher than ISO rated output anyway.

Low heating load conditions are also controlled by dampers. All or part of the flue gas flow can by-pass the heatexchangers and exhaust directly to atmosphere. Also any number of the four exchangers can be selected to operate at any given time. This alone provides a step control in 25% of full load increments.

All the operations are controlled by temperature and are automatic. The gas turbines are remote operated and supervised as they are. The only additions needed are the damper controls. Pump controllers and temperature controllers are the only devices needed to operate the HTW side.

6.9.4 Heater Plants and Hudson No. 2 Unit Phase II & III Retrofit

The 600 MW, supercritical, double reheat, coal fired No. 2 steam turbine-generator unit can provide 1600x10^{6}BTU/hr heat, at full load, extracted from the two 64" dia. crossover lines between the IP and LP cylinders. This was established by the manufacturer. Extracting this flow reduces the output of the unit by close to 150 MW. The full load pressure at the crossovers is considerably higher than the HTW system leaving temperatures dictate. It was concluded that the insertion of back pressure turbine–generators for the utilization of the available pressure differential is an economically justified proposition. The same justification was found for two–stage heating. So two turbines, each handling half the flow, expand the steam to two different and sliding pressures feeding the two heaters connected in series on the HTW side. The turbine back pressure is controlled by the temperature set of the water leaving the heatexchanger (condenser). Outdoor temperature, with some system related modifications, controls the set point. Should the set point be satisfied by the lower stage unit (low load), the other unit stays idle. The two turbine–generators, at full load, recapture ca. 65 MW of the generation lost for a residual loss of approximately 85 MW.

The two stage approach also allows the graduation of construction. One unit with its heatexchanger and pumps can be erected when more than 200 million BTU/hr load is imposed on the plant. It will operate alone up to the time the plant load reaches 800 million BTU/hr. This corresponds roughly to a connected system peak of 1500 million BTU/hr. The difference is supplied by the heater plants in series with the heatexchangers.

Water from the users returns directly to the heatexchangers at about 167°F maximum. It is heated to a maximum of 237°F before leaving the plant and finally to 290°F+ by the heater plants, when the load so requires. At design peak load the system utilizes a 120°F temperature differential and provides for the system heat losses by actually operating at an approx. 128°F differential (5°F loss on the supply and 3°F loss on the return line at full load). At lower than peak loads the supply temperature is considerably lower than the design value, while the return temperature is also diminishing, but at a lesser rate. The temperature differential is however always proportional to the load as long as constant circulating flow is maintained. At very low loads that is not cost efficient, so the operation in the summer reverts to halving the flow and raising the temperature differential.

The constant flow, sliding temperature operation is the major advantage of a water system compared to a steam distribution system. What is sacrificed is the ability to provide heat at the required temperature level for steam users. There is a possibility to do so by installing heat pumps at these locations, but it is technically marginal with the equipment commercially available. Therefore its economy had not been established either.

The capability of the Hudson #2 unit to provide the design extraction flow is tied to the operation of the unit at not less than 85% load. This means that at times, as during a winter night, the unit will be forced to operate at higher loads than electric power incremental cost rates would dictate. This cost penalty will have to be absorbed by the D–H system. At times when electric power dispatch would call for the full output of the unit and heat is to be provided at the same time, the up to 85 MW lost capacity will have to be made up by some other plant on the system. If there is an incremental cost to do so, it also will be debited to the heat supply side of the ledger.

There are historically considerable intervals each year when the Hudson #2 unit is not available. For eight weeks each year there is a planned maintenance outage, which doubles to 16 weeks every five years for the regular major overhaul of the turbines. Several weeks of unplanned outages need to be added and catered to. The planned outage work will be normally performed during the low heating load periods of March and ALpril. The major planned outage however needs to encroach on the heating season—February to May—because the PSE&G power system peaks in the summer. During these times the heating system would revert to the heater plants including the stand–by heater units in these plants, with the exception of a 190000 lb/hr capacity crossover from Unit #1 at Hudson. This line can be utilized as a stand–by source during those outages of Unit #2.

6.9.5 Heater Plants, Combustion Turbine Plant Plus Hudson No. 2 Unit Retrofit

This combination of plants represents the full development of the 3700 million BTU/hr peak capacity heating system. The three types of plants operate in series on the HTW side, the Hudson #2 unit carrying the base load including the system losses. The peak loads and the entering and leaving water temperatures at each step are as follows.

Plant	Peak output	entering	leaving
		peak water temp.	
	10^6BTU/hr	°F	
Hudson #2	1600	167	223
Kearny #12	1100	223	259
Total of 11			
heater plants	1000	259	295
(installed)	(2300)		

It is a repetition of the foregoing to say that each plant has its circulators, spared, to move the water to the next plant and the heater plant circulators move the water through the distribution system. Water returning from the users by–passes the upper stages in the chain and enters the plant carrying the base load at that point in time.

The operation and control of the three stage system is no different from the one described for the two stage one, with one stage added to the series chain in the heating and pumping process.

A detailed analysis has been made comparing the quantity and type of fuel burned annually at each of the three stages of the system assuming an eight week planned shut–down of the Hudson #2 unit (Table 6.9–I) and also in the case of a 16 week planned shut–down (Table 6.9–II). In both cases unplanned shut–downs of Unit No. 2 amounting to 25% of the rest of the time were evenly distributed over each month. These figures do not show however the additional fuel used by another unit to generate making up an equivalent of the kWh's lost due to high pressure extraction for heating.

TABLE 6.9-I

Summary of Fuel Burned by Months for the
Three Types of Supplies to the Fully Developed
District Heating System - Hudson #2 out for Maintenance
For 8 weeks Between April and May
Fuel Burned - 10^9 Btu

	Hudson #2			Kearny #12			Boilers
Month	Base Case	Dist. Heat Case	Delta	Base	Dist. Heat Case	Delta	Total
January	2750	2859	109	134	874	740	632
February	2503	2598	95	76	450	374	340
March	2690	2841	151	34	351	317	197
April	0	0	0	65	823	758	383
May	0	0	0	147	316	169	74
June	2156	2182	26	44	44	0	14
July	2372	2394	22	17	43	26	14
August	2375	2422	47	32	88	56	18
September	2468	2520	52	97	130	33	26
October	2817	2930	113	353	357	4	286
November	2720	2817	97	276	433	157	303
December	2806	2904	98	264	715	451	523
TOTAL	25,657	26,467	810	1,539	4,624	3,085	2,810

TABLE 6.9-II

**Summary of Fuel Burned by Months for the
Three Types of Supplies to the Fully Developed
District Heating System - Hudson #2 out for Maintenance
For 18 weeks Between February and May
Fuel Burned - 10^9 Btu**

	Hudson #2			Kearny #12			Boilers
Month	Base Case	Dist. Heat Case	Delta	Base	Dist. Heat Case	Delta	Total
January	2750	2859	109	134	874	740	632
February	0	0	0	76	982	906	1174
March	0	0	0	34	1010	976	681
April	0	0	0	65	823	758	383
May	0	0	0	147	316	169	74
June	2156	2182	26	44	44	0	14
July	2372	2394	22	17	43	26	14
August	2375	2422	47	32	88	56	18
September	2468	2520	52	97	130	33	26
October	2817	2930	113	353	357	4	286
November	2720	2817	97	276	433	157	303
December	2806	2904	98	264	715	451	523
TOTAL	20,464	21,028	564	1,539	5,815	4,276	4,128

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