Energy, Mines and Resources Canada
Earth Physics Branch

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Geothermal Service of Canada

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SURVEY OF GEOTHERMAL ENERGY IN THE MARITIME PROVINCES

Acres Consulting Services Limited
8th Floor - 800 West Pender Street
Vancouver, B.C.
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Earth Physics Branch Open File Number 84-13
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ABSTRACT

Geothermal gradients in the Maritimes are commonly below the world average, indicating the need for either expensive wells to reach deep producing formations or, given the availability of shallower low temperature resources in the 30°C to 50°C range, the need for heat pump assistance to improve utilization.

A number of direct applications using these low supply temperatures but without heat pump assistance are tested. Geothermal unit energy costs are seen to be comparable with oil heating, though not necessarily attractive in terms of savings. The application of large scale heat pumps to improve geothermal heating utilization and thereby to lower unit costs is examined in an evaluation that briefly reviews heat pump experience in France.

Space heating applications (residential, commercial and institutional) involving the use of geothermal heating, typically with heat pump assistance, are examined in detail. Evaluation of before-tax unit costs and comparison with those from oil or gas heating show favourable savings for geothermal based space heating systems. It is concluded that space heating in combination with heat pumps has a significant economic potential in the Maritimes. Much more exploratory field work is required to identify resource conditions. One of the primary constraints is finding or developing a suitable large scale, central space heating operation (such as downtown city core) to utilize the large energy capability of a geothermal supply system in order to justify economically the high geothermal/heat pump system capital investment.

RESUME

Les gradients géothermiques dans les Maritimes sont en général plus basses que la moyenne mondiale. Ceci implique, pour l'utilisation de l'énergie géothermique, soit un besoin de forages coûteux afin d'atteindre des formations productrices profondes ou, si des ressources à basse énergie (30 à 50°C) moins profondes sont disponibles, un besoin de pompe à chaleur pour améliorer l'exploitation.

Plusieurs utilisations directes des ressources à basse énergie, sans pompe à chaleur, sont examinées. Les coûts par unité d'énergie géothermique s'avérent comparables avec le chauffage à l'huile, quoiqu'ils ne sont pas nécessairement attrayants au niveau d'épargne.

On examine l'utilisation de grandes pompes à chaleur pour améliorer le rendement du chauffage géothermique et par conséquent abaisser les coûts par unité d'énergie. Cette évaluation fait une brève révision de la pratique en France.

Le chauffage d'édifices (résidences, commerces, instituts) par des réalisations géothermiques typiquement avec pompes à chaleur adjointes est examiné en détail. L'évaluation du coût par unité avant impôt et la comparaison avec les coûts du chauffage à l'huile ou au gaz indiquent des épargnes favorables pour les systèmes géothermiques. On conclut que le chauffage d'habitats avec le système incluant les pompes à chaleur représente un potentiel économique important pour les Maritimes. Beaucoup de travaux d'exploration sur le terrain sont nécessaires afin d'identifier la qualité des ressources. Une des contraintes principales consiste à trouver ou à développer une opération à grande échelle de chauffage central de logements (tel qu'un centre-ville) pour utiliser la grande capacité d'un système géothermique d'alimentation afin de justifier les grandes dépenses d'investissement pour le système géothermique/pompe à chaleur.

SURVEY OF GEOTHERMAL ENERGY IN THE MARITIME PROVINCES

prepared for:

NATIONAL RESEARCH COUNCIL

ACRES

March, 1984

P7054.00

SURVEY OF GEOTHERMAL ENERGY IN THE MARITIME PROVINCES

Prepared for:
NATIONAL RESEARCH COUNCIL
Division of Energy Research
and Development

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PREFACE

This study was undertaken by Acres Consulting Services Limited as the principal consultant, supported by John A. Leslie and Associates, consulting geologists responsible for the resource assessment overview, and by Alexander Boome Consulting Engineering (1982) Ltd., consulting HVAC engineers who undertook the development of conceptual designs for the various space heating applications.

ABSTRACT

Geothermal gradients in the Maritimes are commonly below the world average, indicating the need for either expensive wells to reach deep producing formations or, given the availability of shallower lower temperature resources in the 30°C to 50°C range, the need for heat pump assistance to improve utilization.

A number of direct applications using these low supply temperatures but without heat pump assistance are tested. Geothermal unit energy costs are seen to be comparable with oil heating, though not necessarily attractive in terms of savings. The application of large scale heat pumps to improve geothermal heating utilization and thereby lower unit costs is examined in an evaluation that briefly reviews heat pump experience in France.

Space heating applications (residential, commercial and institutional) involving the use of geothermal heating, typically with heat pump assistance, are examined in detail. Evaluation of before-tax unit costs and comparison with those from oil heating show favourable savings for geothermal-based space heating systems. Financial and economic discounted cash flow analyses, relevant to the private and public sector geothermal energy user, show very substantial real returns relative to oil priced at both market and marginal levels. Significant returns appear to be realizable also, relative to natural gas priced at 75 percent of oil. It is concluded that a space heating in combination with heat pumps is seen to have a significant economic potential in the Maritimes. Much more exploratory field work is required to identify resource conditions. One of the primary constraints is finding or developing a suitable large scale, central space heating operation (such as downtown city core) to utilize the large energy capability of a geothermal supply system in order to economically justify the high geothermal/heat pump system capital investment.

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LIST OF ABBREVIATIONS & SYMBOLS

ATES - Aquifer thermal energy storage
COP - Coefficient of performance
DCF - Discounted cash flow
f - ratio E_o/E_w
F_{cr} - Heat pump system annual fixed charge rate
HDR - Hot dry rock
I_{hp} - Heat pump system investment (capital cost)
IRR - Internal rate of return
NPV - Net present worth
R_f - Ratio of primary to secondary circuit flows
TDF - Temperature drop factor
UF - Utilization factor
WHR - Waste heat recovery

Thermal Load and Annual Delivered Energy - q (GJ/h) and Q (GJ/yr)

q_p , Q_p - process demand
q_s , Q_s - geothermal/heat pump system supply
q_g , Q_g - geothermal system supply
q_{hp} , Q_{hp} - heat pump system supply
q_1 , Q_1 - primary exchanger heat transfer (geofluid circuit)
q_2 , Q_2 - heat transferred (evaporator on geofluid circuit)
q_i , Q_i - heat transferred (evaporator on secondary circuit)
q_w , Q_w - heat pump work input (to secondary circuit)
q_{wr} , Q_{wr} - heat pump IC engine heat recovery input (to secondary circuit)
q_b , Q_b - peaking boiler supply

Annual Load Factor - LF

LF_p - process demand load factor
LF_g - geothermal delivery system load factor
LF_s - geothermal/heat pump system supply load factor
LF_{hp} - heat pump system load factor
LF_{st} - geothermal/storage system load factor

Heating System Temperatures - T (°C)
Primary Circuit (Geofluid)

T_1 - resource supply temperature
T_2 - resource injection temperature
T_{si} - reference geofluid sink injection temperature (0°C assumed)
T_3 - warm storage extraction temperature
T_4 - hot storage injection temperature
T_H - hot storage temperature
T_5 - secondary HX inlet temperature (storage system)
T_6 - secondary HX outlet temperature
T_7 - evaporator outlet temperature (warm storage injection)
T_d - aquifer formation discovery temperature

Secondary Circuit (Process Heating)

T_s - supply before boiler
T_e - exit from space heating emitters
T_r - return to geofluid exchanger
T_p - supply process after boiler
T_i - process fluid entering
T_o - process fluid leaving

Heating System Flows - F (m^3/h)

F_g - geofluid supply flow (primary circuit)
F_p - secondary circuit flow (hydronic system)
F_p/F_g - ratio R_f

Unit Energy Cost (Levelized) - Ø ($/GJ)

$Ø_s$ - geothermal/heat pump system
$Ø_g$ - geothermal supply system (excluding heat pumps)
$Ø_e$ - heat pump compressor drive energy source (fuel, electricity)
$Ø_{hp}$ - heat pump output
$Ø_{ng}$ - natural gas
$Ø_o$ - heating oil

Efficiency - E (Heat Pump Driver)

E_e - electric motor (0.93 assumed)
E_w - fuel energy utilization (work only); 0.30 assumed
E_o - fuel energy utilization with WHR; range 0.3 to 0.9
E_o/E_w - ratio f; range 1-3

Outdoor Temperatures - t (°C)

t_w - winter design (peak space load)
t_s - summer design (zero space load)
t_1, t_2... - transition temperatures, heat pump sequential operation
t_n - transition temperature, peaking boiler operation

Coefficient of Performance - (COP)

COP_{hp} - heat pumps only
COP - system or effective COP

Annual average COP denoted: - $ACOP_{hp}$; ACOP

1.0 INTRODUCTION

The study examines the technical and economic potential of low temperature geothermal resources in the Maritimes with respect to their use as an energy source for various direct heating applications. The objective and approach are similar to the previous 1983 study by Acres Consulting Services Limited (1) which examined a variety of geothermal direct heating applications based on the 60°C - 100°C hydrothermal resource located in the sedimentary basin region of Western Canada. During the course of the earlier study a methodology was developed for assessing performance potential, investment costs, unit energy costs, and the economics of geothermal direct heating relative to conventional natural gas and oil heating systems. Specific applications examined included:

- residential and commercial building space heating;
- greenhouse and aquaculture heating;
- mine ventilation air heating;
- power plant feedwater heating;
- town water heating; and,
- various industrial process heating applications (breweries, meat packing, plants, dairies, etc.)

Of these, the first three, all involving environment (space) heating, were found to offer the greatest practical and economic potential for development. Of the other applications, each was subject to one or more factors that oppose development. In many cases, the alternative of using available low-cost waste energy was seen to provide a more economic solution. These general findings can be expected to apply equally in the Maritimes and for this reason the effort in this study focuses on space heating applications.

Geothermal energy is again analysed with respect to its potential for direct heating to displace the use of conventional energy sources: electricity, oil and, in the future, natural gas. Geothermal temperature gradients in the Maritimes are generally lower than the 30°C/km average of the Western Basin so that to reach comparable resource supply temperatures will entail deeper wells and higher well costs. On the other hand, the cost of conventional energy in the Maritimes is much higher which, as is shown, helps to offset the high well costs.

Section 2.0 presents an overview of resource data for various sedimentary regions in the Maritimes and also shallow aquifers.

In Section 3.0 the costs of single geothermal doublet supply systems are examined for a 15-30°C/km range of temperature gradients and a 30-50°C range of resource (supply) temperatures. This is followed by geothermal system unit energy costs presented as a function of annual utilization and gradient. Unit costs of various space heating applications are examined corresponding with direct use of the resource (i.e. without heat pump assistance).

In Section 4.0 heat pumps are examined as a means of increasing the supply temperature to the process and/or the geofluid temperature drop. The review of technical and economic aspects of heat pump operation for space heating applications is based mainly on French experience with this equipment.

Aquifer thermal energy storage is briefly reviewed in Section 5.0 as a means of increasing utilization by load factor improvements.

Section 6.0 presents conceptual designs for residential, commercial and institutional space heating applications using heat pumps as necessary. For the residential case, three heating methods (i.e. forced air, baseboard and radiant panel) are developed and analysed and the performance and economic attractiveness of each compared. The economics of geothermal system operation, with and without heat pumps, and from the perspective of both the private and public sector owner/user of geothermal energy is evaluated for each application, and the economic sensitivity to changes in geothermal gradients and other factors assessed for selected cases.

Concepts and methods for performance and cost analysis used herein draw freely on those developed in the Acres (1983) study (1). Some familiarity with the previous study is presumed.

2.0 RESOURCE ASSESSMENT AND DEVELOPMENT

2.1 Deep Geothermal Resources

Low-grade geothermal resources in the Maritime Provinces comprise bedrock warm water aquifers, located in sedimentary basins, and hot dry rock (HDR) formations located within Paleozoic intrusive rock structures. Regional investigations into these resources were initiated in 1981 by the Division of Gravity, Geothermics and Geodynamics; Earth Physics Branch; Energy, Mines and Resources Canada. The early work under the program involved the compiling of available thermal data (2). Later, this was expanded to include acquisition of such data on an opportunity basis (3) from geological investigations, not connected with geothermal energy, being undertaken by others.

Notwithstanding the progress made under the program, comprehensive regional and local analysis and evaluation of the resource is hampered by a general lack of reliable base data. (As a comparison, the demonstration well project of the University of Regina reportedly had access to data from 150 wells drilled for petroleum and potash in the Regina-Moose Jaw district.) In the entire Maritime region, there are perhaps 50 petroleum wells, with detailed well histories available for less than half that number. This, together with limited current geologic activity to generate data on an opportunity basis, supports the need for much more field investigation in order to amass the type of data required to adequately assess the Maritime resource potential.

A diamond drill program sponsored by the Earth Physics Branch, was undertaken in 1982/83 to obtain temperature and rock property data in New Brunswick (4) and Prince Edward Island (5). Groundwater flow studies are also presently being carried out by the Earth Physics Branch in two geologic environments: one in New Brunswick (6) and one in Nova Scotia (7).

Although the above studies have involved both sedimentary and HDR resources, more data is available on the sedimentary resources. This, in part, is attributable to more geologic activities in these areas providing data on an opportunity basis.

Hot Dry Rock

Hot dry rock (HDR) locations in the Maritime Provinces comprise granitoid rocks of Devonian to early Carboniferous age with fairly well distributed intruded areas of older igneous, sedimentary and metamorphic rock. Thermal gradients within these rocks result from heat generated by the radiogenic decay of uranium, thorium and potassium. Permeability necessary for the transport of heat energy from the rock by water is normally lacking in crystalline rock so that artificial fracturing is required. Water, circulated from the surface through the fractured medium, picks up heat and is brought back to the surface for heat exchange. Experiments in this technique are being undertaken by Los Alamos Scientific Laboratories, New Mexico; and in Cornwall, England, which is an area geologically akin to the Maritime Provinces.

Limited investigations indicate thermal gradients in the order of 18°C/km in three New Brunswick HDR intrusives (3, 4). Other potential HDR environments remain to be investigated in the region.

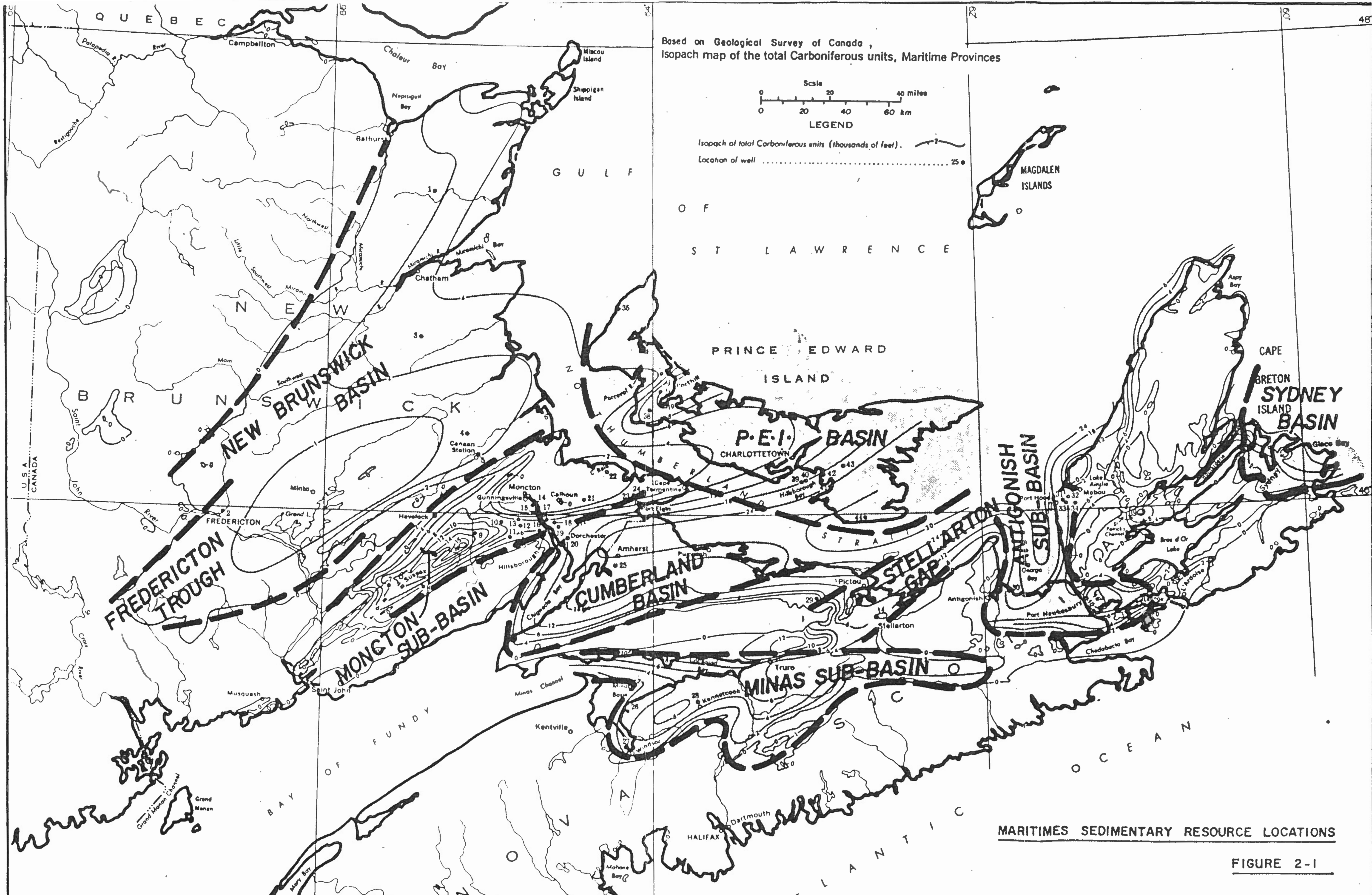
Because of both limited data and the early developmental state of HDR technology this study addresses only the hydrothermal sedimentary resources.

Sedimentary Resources

The sedimentary basins of the Maritime Provinces with the best potential, as indicated by favourable thermal gradient-depth parameters, are those of Carboniferous age. The principal Carboniferous basin in the region has been segregated into several basins and sub-basins (6, 8) as delineated in Figure 2-1. This figure also shows the isopachs in the region. Most of the basins and features in the Maritime region are irregular and somewhat closed and restricted as is evident from the isopachs. For the study area, with perhaps the exception of Prince Edward Island, the depth of potential aquifers may be quite variable over relatively short distances.

Table 2-1 summarizes the pertinent data available for the basins and sub-basins of Figure 2-1. It is emphasized that the data base is extremely limited. In many instances, only one set of data or data point may be available for a particular area and that may be incomplete. Some pertinent information has not been published, and is only available through discussion with scientists working in areas of interest. Data concerning potential aquifer(s), aquifer depths, extraction flow rate potential, water chemistry, natural piezometric levels, and so on, are virtually nonexistent.

The variance of other parameters, such as thermal gradient, porosity, and permeability may be a function of basin size, depth, structure and configuration, and the



MARITIMES SEDIMENTARY RESOURCE LOCATIONS

FIGURE 2-1

TABLE 2-1

SUMMARY OF SEDIMENTARY RESOURCE DATA

Basin/ Sub-basin	Target Formation	Approx. Thickness (m)	Predicted Values of: Porosity (%)	Permeability (millidarcy)	Thermal Gradient °C/km
1. New Brunswick	Boss Point Fm channel sandstone	10	good	good	17
	Pennsylvanian sandstone	10	8	9.8	
2. Fredericton Trough	Mississippian sandstone, shale	8-10	N.A.	(good secondary possible)	25
3. Moncton	Albert Fm deltaic sandstone Boss	12.5	18.2	943	11-13
	Boss Point Fm sandstone	10	good	good	
4. Cumberland	Pictou Group sandstone	up to 70	22.5	193	16
5. Minas	Horton Group sandstone	6-10	12.7	156	N.A.
6. Stellarton Gap	Stellarton Series conglomerate sandstone, siltstone, shale	5-20	N.A.	0.21 (1,030 secondary)	28-32
7. Antigonish	Horton Group sandstone	6-10	21.2	580	15-22
8. Sydney	Lower Morien Group sandstone	10	8.6	0.15	15-18
9. Prince Edward Island	Basal Pictou Group sandstone	10	11.6	300	13-17

physio-chemical properties of the contained rock. Higher thermal gradients show some correlation with shallower basins. Porosities and permeabilities vary with basin depth and structure; predicted values, cited in Table 2-1, are those resulting from primary intergranular relationships of the rock constituents. Imposed secondary processes or features such as rock fracturing could impart higher values.

Assessment

The available data, even considering their limitations, suggest that at least the Fredericton Trough (New Brunswick) and Stellarton Gap (Nova Scotia) have a more favourable resource potential. There, thermal gradients range between 25°C/km and 30°C/km, so that resource temperatures of at least 50°C should be possible at depths of two kilometres or so. Thermal gradients of 11-18°C/km in other basins infer resource temperatures of between 25°C and 40°C at depths of two kilometres.

Before any demonstration project can be contemplated, considerably more exploration is essential. Investigations to date have revealed that little useful reliable data are available, particularly at the depths involved. Therefore, in areas of adequate thermal gradient, consideration must be given to finding aquifers of required resource temperature and flow rate potential, and to delineate and ascertain other properties such as water chemistry and natural piezometric level.

2.2 Shallow Aquifers in the Maritime Provinces

Two types of aquifers, those in bedrock and those in surficial material, occur within the Carboniferous basins of the Maritime Provinces. Although scattered local studies by the groundwater agencies of the various provinces exist, regional coverage of hydro-geologic data for the area is poor. The most readily available regional summaries and compilations of this data are contained in Groundwater in Canada (9), published by the Geological Survey of Canada, and a report (10) of a study that examined opportunities for groundwater source heat pumps, undertaken by MLM Groundwater Engineering for the National Research Council. The latter study provides useful regional maps delineating bedrock and surficial aquifers locations in the Maritimes.

Bedrock Aquifers

Yields of shallow aquifers in rocks of Carboniferous age, summarized from the above-mentioned reports (9, 10), are tabulated below.

	L/s
Horton Group	0.8-7.6
Windsor Group	0-7.6
Riversdale Group	0.4-1.9
Cumberland Group	<0.4
Pictou Group	<0.4
Canso Group	0.5-55
Boss Point formation	5.2-63
Albert formation	0.2-0.7
Permo-Carboniferous (P.E.I.)	0.4-12.3

Because of stratigraphical and structural variations between basins, what constitutes a geothermal resource aquifer at one locality may be a shallow storage aquifer at another. For instance, the Boss Point formation could be the deep resource aquifer in the Moncton basin, but due to depth limitations may only constitute a shallow aquifer suitable for storage, in the Fredericton Trough. It is also important to note that yields within a particular formation can vary with depth, as a result of various geologic processes.

Surficial Aquifers

The thin layer of glacial till in the Maritime Provinces is a poor aquifer. However, Pleistocene sand and gravel deposits, although limited in size and distribution, are good aquifers. Yields in excess of 75 L/s are possible except for Prince Edward Island which has no surface aquifers (9). Municipal wells, 34 to 45 metres deep, at Fredericton, New Brunswick, had initial capacities between 45 and 85 L/s and specific capacities between 8 and 40 L/s per metre of drawdown.

Near-Surface Groundwater Temperatures

Data compiled by MLM Ground-Water Engineering suggests groundwater temperatures between 5.5 and 9.4°C (10). Temperature logs of drill holes by John A. Leslie & Associates Limited indicate an average near-surface groundwater temperature of 7 to 8°C (2, 3, 4, 5, 10). This temperature is important. Combining it with gradient data at any specific site, gives the depth to be expected for a given resource temperature. In this study a conservative value of 5°C has been assigned for the near-surface base temperature condition.

3.0 GEOTHERMAL SYSTEM PERFORMANCE & COSTS

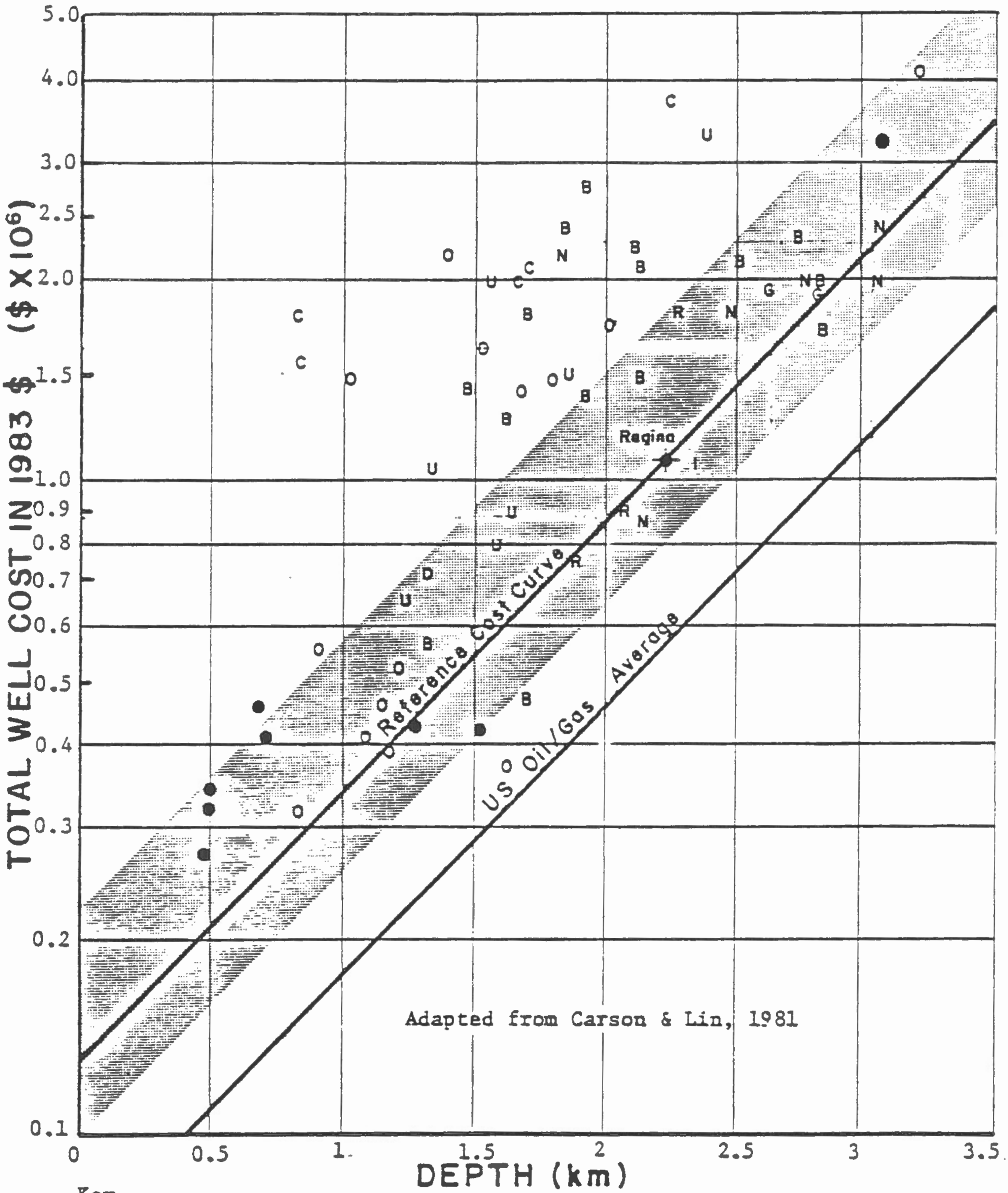
This section presents performance and cost relationships for the single doublet geothermal energy supply system applicable to geothermal gradients of 10°C/km to 30°C/km, and resource geofluid supply temperatures of 20 to 60°C.

All costs are presented in 1984 constant dollars unless stated otherwise. A project start-up date of 1990 is assumed. Comparisons with other energy source costs are based on a 30-year operating life with assumptions made for real escalation in both geothermal and conventional energy sources. For further details on economic criteria and assumptions refer to Appendix A.

3.1 Resource Development Costs

In the Acres, 1983, study (1) historical U.S. oil and geothermal well costs were investigated. The results are reproduced in Figure 3-1. It should be noted that costs are in 1983 dollars. The cost of the University of Regina demonstration well is shown superimposed with the reference cost curve constructed through this point. With appropriate adjustment to 1984 dollars, this reference curve is used to estimate doublet supply and injection well costs.

Regarding well drilling and development in the Maritimes, it is to be expected that costs will be marginally greater there, compared to Western Basin locations, due to possible premium payments for drill rig relocation and operation. However, cost deviations caused by drilling conditions and depth is considered to greatly overshadow any regional cost differences.



Key

G The Geysers
B Baca, New Mexico
C Cove Fort - Sulphurdale, Utah
I Imperial Valley
N Northern Nevada
R Roosevelt Hot Springs, Utah
U Industry Coupled, Utah/Nevada
● Direct Use
O Others

GEOTHERMAL WELL COSTS vs. DEPTH

FIGURE 3-1

3.2 Heat Load and Annual Energy

Figure 3-2 presents geothermal heat load (GJ/h) curves, for resource temperatures ranging from 20°C to 60°C, plotted against temperature drop factor (TDF). With gradients in the Maritimes of 10 to 30°C/km, economic exploitation is expected to be limited to supply temperatures of 25°C to 60°C and depths of 2 to 3 km.

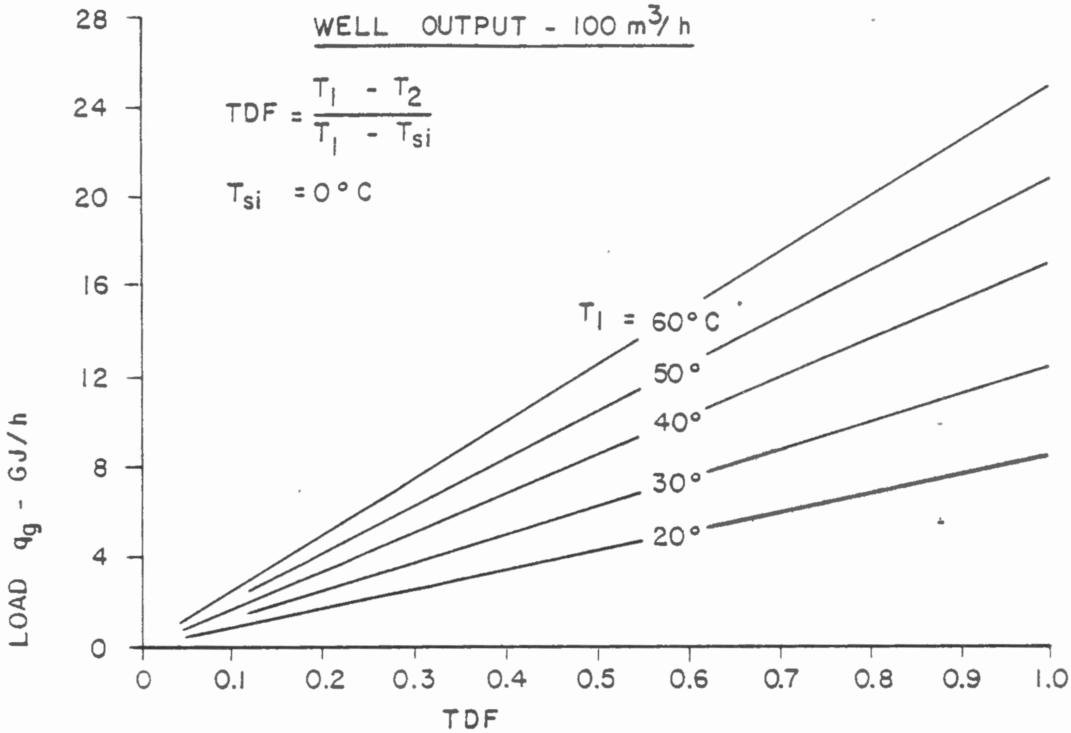
TDF in this study is defined as:

$$\frac{(T_1 - T_2)}{(T_1 - T_{si})},$$

where the sink or reference minimum doublet injection temperature T_{si} is arbitrarily set at 0°C. Because the range of economic resource temperatures is expected to be lower than the 60 to 100°C range applicable for the Western Basin resource, heat pumps will be necessary for many applications, particularly space heating. Heat pumps act to depress the injection temperature T_2 to 10°C and below. Accordingly, 0°C is a more appropriate reference value for T_{si} than the 20°C used previously (1) for non-heat-pump-assisted applications.

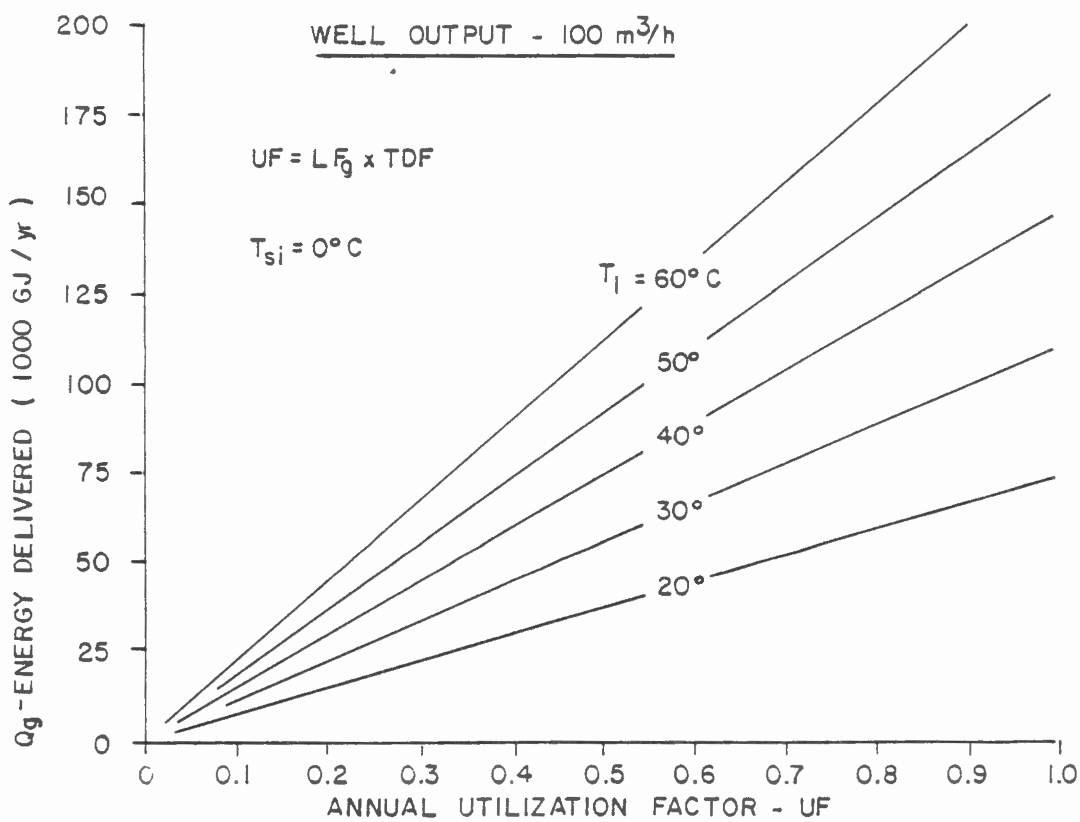
Annual Energy Delivered

Figure 3-3 presents curves showing annual delivered energy for a 20°C to 60°C supply temperature range, plotted against the annual utilization factor, UF. This factor, defined as the product of the geothermal system load factor LF_g and TDF, is also referenced to a T_{si} of 0°C.



LOAD vs. TEMPERATURE DROP FACTOR

FIGURE 3-2



ENERGY DELIVERED vs. UTILIZATION FACTOR

FIGURE 3-3

3.3 Geothermal Doublet System Costs

Capital Costs

Capital costs for the geothermal supply system include the cost of the supply and injection well, above-ground pipework connecting the wells, downhole and booster pumps, and the primary heat exchanger. Various factors influence these costs. For example, angle drilling of the supply and/or injection wells to reduce separation between wells at the surface substantially increases well costs, perhaps by 25 percent, though some compensating savings are obtained from the elimination of much of the inter-well pipework at the surface.

Whereas well costs are essentially independent of flow rate (and resource temperature) in the range of 150 m^3/h and less, the above ground system costs are dependent on flow rate. The size and hence cost of the primary heat exchanger is also affected by the design heat load, approach temperature and metallurgy necessary to suit geofluid chemistry. With resource temperatures in the range of 30-50°C, an approach of 2°C or even 1°C may be justified. For geothermal/heat pump applications the geothermal load will be only partly transferred via the primary exchanger, if the heat pump evaporator is located in the primary circuit (see Section 4.0 for further details).

Table 3-1 presents conceptual level 1984 costs for above-ground equipment, appropriate to a geofluid flow rate F_g of 100 m^3/h. For a flow rate of 150 m^3/h the total will be increased by 30 to 35 percent.

TABLE 3-1

ABOVE-GROUND EQUIPMENT: 1984 INSTALLED COSTS

		$
Surface pipeline		105,000
Downhole and injection pumps		55,000
Primary heat exchanger		100,000
Miscellaneous equipment & services		55,000
	Sub-Total	290,000
Engineering @ 15%		45,000
Contingency @ 20%		65,000
	Total	425,000

TABLE 3-2

ANNUAL OWNING & OPERATING COSTS, 1984

		$/yr.
Fixed	- Annualized Capital Cost	230,000
	- O & M Labour	40,000
	- Overhead Allowance	40,000
	- Equipment Replacement Allowance	30,000
Variable	- Pumping Costs	60,000
	- Chemicals and Supplies	20,000
	Total Annualized Cost	420,000

Figure 3-4 presents geothermal system capital costs versus resource temperature T_1 for various gradients. They are based on the reference well costs of Figure 3-1 and the above-ground equipment costs. A mean surface temperature of 5°C has been used in the determination of T_1 and well depth costs. The effect of gradient on geothermal system capital costs is clearly illustrated.

Annualized Owning and Operating Costs (O & O)

Geothermal system annualized costs include fixed and variable components. Typical values are for a 40°C supply (20°C/km gradient) and 100 m^3/h design flow follow, with costs expressed in 1984 constant dollars, are shown in Table 3-2.

Fixed components:

- Annualized capital cost corresponds with the base project life of 30 years (see Appendix A), private sector financing at a weighted average real cost of money of 11.5 percent. A 5 percent reduction in real costs is assumed for productivity/technology gains through the period to 1990.

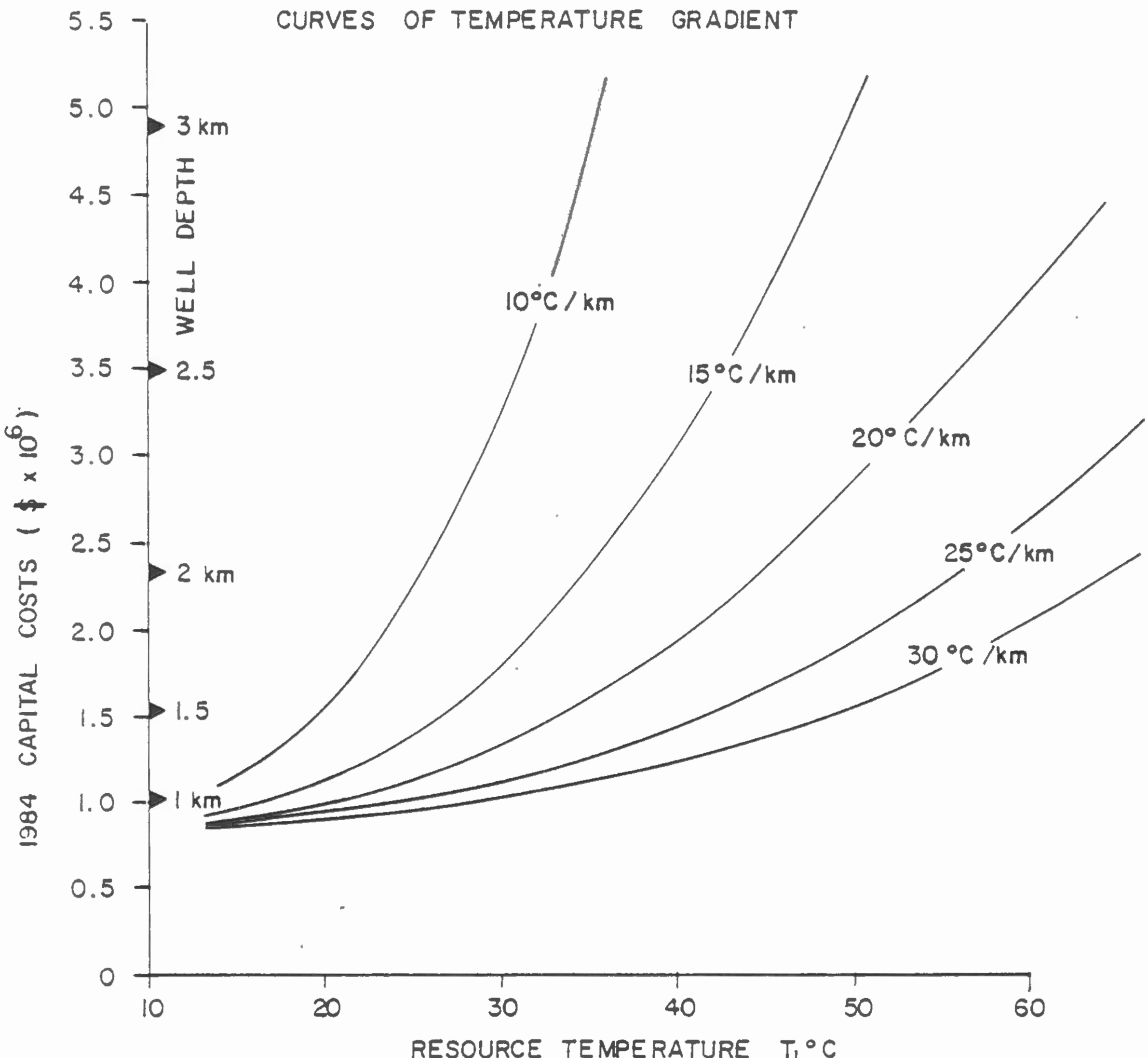
- Operation and maintenance (O&M) labour covers routine and major maintenance.

- Overhead allowance includes insurance, property tax and administration, at a nominal 2 percent of total capital cost.

- Equipment replacement allowance includes for replacement of downhole and injection pumps and production string every four years, and wellheads every 10 years.

Variable components:

- Pumping costs are related to the design flow rate, pumping head and also process energy demand, given the provision of variable speed or partial throttling at part/no load operation. The value is appropriate to



NOTES

1 - MEAN SURFACE TEMPERATURE 5° C

2 - COSTS ARE BROADLY APPLICABLE TO SINGLE DOUBLET OUTPUTS OF 150 m^3/h AND LESS, WITH WELL COSTS BASED ON REFERENCE CURVE OF FIG. 3-1

3 - COSTS INCLUDE TWO WELLS, WELLHEAD EQUIPMENT & PRIMARY HEAT EXCHANGER.

GEOTHERMAL DOUBLET SYSTEM CAPITAL COSTS — FIGURE 3-4 variable speed pumping (100 m^3/h), a system total dynamic head of 350 metres (500 psi), and electricity at 7¢/kWh (1984).

- The chemicals and supplies item is an allowance for consumables mainly used for corrosion and scaling protection and the occasional well stimulation.

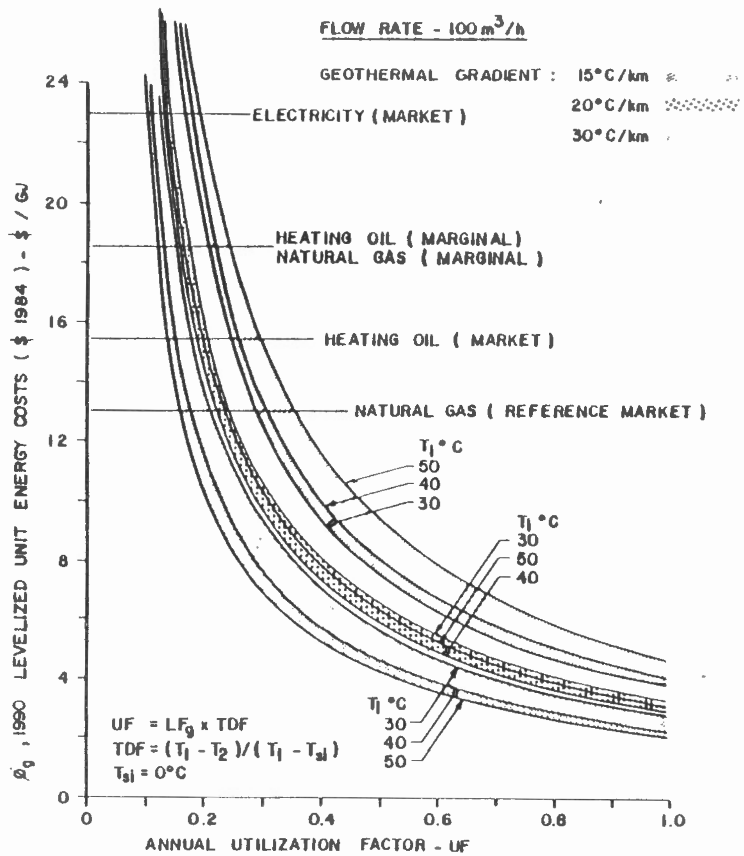
Total annualized costs will be most sensitive to well development cost variations, to injection resistance and pumping power, and also to private or public sector financing. From Appendix A, public sector financing at 5 percent cost of money (100 percent debt) reduces annualized capital cost in Table 3-2 by over $100,000/yr or about 25 percent. Considerable deviation in these two components can occur in practice. The high cost of electricity in P.E.I., estimated at around 13¢/kWh in 1990 (1984 dollars), would contribute a further $50,000, or 12 percent, to the total annualized costs tabulated above.

3.4 Unit Energy Costs

Geothermal Energy

Figures 3-5 and 3-6 present indicative geothermal system unit energy costs for the private and public sectors, respectively, shown plotted against UF for a 15-30°C/km gradient range and resource supply temperatures (T_1) of 30-50°C. For clarity, curves for the 10°C/km gradient are omitted: unit costs are approximately double those for the 15°C/km gradient.

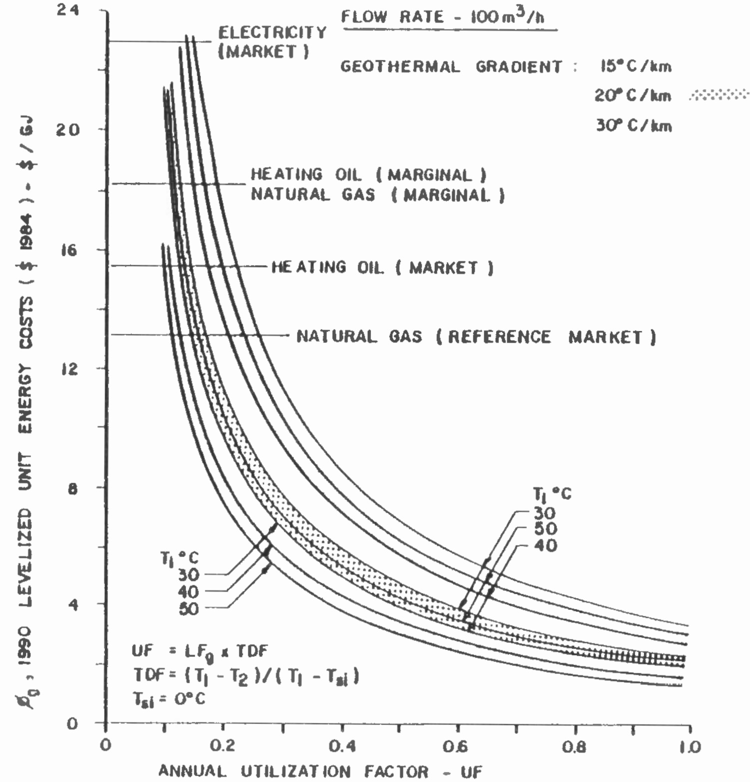
These unit costs correspond with a system flow rate F_g of 100 m^3/h. For higher flow rates up to the limit of a single doublet output, unit energy costs will diminish for a given UF. This is principally due to the high fixed component of well development cost that is independent of



NOTES
1 - BASE UNIT ENERGY COSTS (30 YEAR OPERATIONS LIFE)
2 - REAL COST OF CAPITAL, 11.5% (35/65 DEBT : EQUITY)

GEOTHERMAL SYSTEM UNIT ENERGY COSTS (PRIVATE SECTOR)

FIGURE 3-5



NOTES
1 - BASE UNIT ENERGY COSTS (30 YEAR OPERATIONS LIFE)
2 - REAL COST OF CAPITAL, 5% (100% DEBT)

GEOTHERMAL SYSTEM UNIT ENERGY COSTS (PUBLIC SECTOR)

FIGURE 3-6

well flow rate. There remain a number of items whose size and cost are a function of design flow rate; likewise, for pumping power which is proportional to flow. Unit energy costs at 150 m^3/h can be expected to be 75 to 85 percent of those given in Figures 3-5 and 3-6.

Conventional Energy

Appendix A assesses the more common energy alternatives available in the Maritimes for residential, commercial and industrial process heating purposes. Natural gas is noted as a potential energy source and is included in Figures 3-5 and 3-6 for comparison. Due to present uncertainties regarding future gas availability and its price structure, oil is assumed to present the principal economic challenge for geothermal energy. Conventional energy unit costs for electricity, heating oil and natural gas are shown superimposed on the figures. They reflect:

- predicted growth in energy prices in the Maritimes from 1984 to 1990 at rates outlined in Appendix A;
- levelizing to reflect continued real growth in conventional energy over the 30 years (base) project life; and
- combustion loss allowances (oil and natural gas) to reflect the actual or point-of-use cost of energy delivered to the process.

Geothermal Competitiveness - Unit Cost Equivalence

Geothermal unit cost $\varnothing_g$ is defined as the annual cost of operation divided by annual energy delivered Q_g. It represents for the private sector user/investor a before-tax average cost of energy over the project life that covers capital recovery and operating expenses. As noted in (1), it is not sufficient for geothermal unit costs to be merely equal to or slightly less than conventional energy costs in order for geothermal to displace the conventional energy source; significantly lower unit costs (i.e. savings) must be achieved in order to generate an adequate after-tax return on the large geothermal investment.

The previous study (1) indicated that geothermal unit costs for the private sector might have to be 25 percent less than conventional energy unit costs to achieve attractive levels of after-tax returns. In general, actual conditions for displacement would depend on the financial mandate particular to the geothermal investor/ user and the nature of its operation, whether a public utility, private industry, or government body. Figures 3-5 and 3-6 give a useful but restricted perspective of the competitiveness of geothermal versus conventional energy. Appendix A and Section 7.0 address these issues in further detail.

3.5 Assessment of Temperatures, Gradients and Other Factors

Figures 3-2 and 3-3 demonstrate that with higher resource temperatures T_1, the TDF, geothermal load q_g and the annual energy delivered Q_g will increase for a given application. On the other hand, with diminishing gradients the capital cost of geothermal is also shown to increase as a consequence of increasing well depth. The interactions of these performance and cost factors on the competitiveness of geothermal energy is best examined using a number of examples.

Table 3-3 presents a number of applications previously examined in the Acres study (1). Performance data identified, namely TDF, UF and design load q_g, are determined for a 30 to 50°C range of supply temperatures T_1. Values of temperature T_2 and system load factor LF_g are assigned for each application, which, by careful design, are considered to be achievable. The T_2 values shown are set by the minimum return temperature T_r of the secondary circuit and the primary exchanger approach temperature. It is important to note that lower T_2 values can be achieved by employing heat pumps, an issue that is examined in some detail further on. The purpose of the present comparison is to assess the competitive position for direct unassisted geothermal heat transfer for the low gradient conditions of the Maritimes. In Table 3-3 values of q_g are included to illustrate the trend of application scale magnification as T_1 is increased.

The results for the space heating applications are plotted in Figure 3-7 only for the private sector. Inspection shows the influence of gradient, low resource temperatures and UF on unit energy costs. Compared to conventional (high temperature) energy heating systems, these low resource temperatures can be expected to attract capital cost penalties for exchangers and other heating system components that have to be generally larger in order to make maximum use of the geothermal energy supply. Such costs are not included in Figure 3-7. The results, though understating actual geothermal heating system costs to some degree, do indicate a degree of competitiveness on a before-tax basis (relative to oil) that is reasonably encouraging. In accordance with trends previously determined by economic analysis (1), it is expected that unit energy costs of less than \$12/GJ will produce attractive savings on an after-tax basis, relative to

TABLE 3-3

UTILIZATION FACTOR VS. RESOURCE TEMPERATURE FOR VARIOUS APPLICATOINS WITHOUT HEAT PUMPS

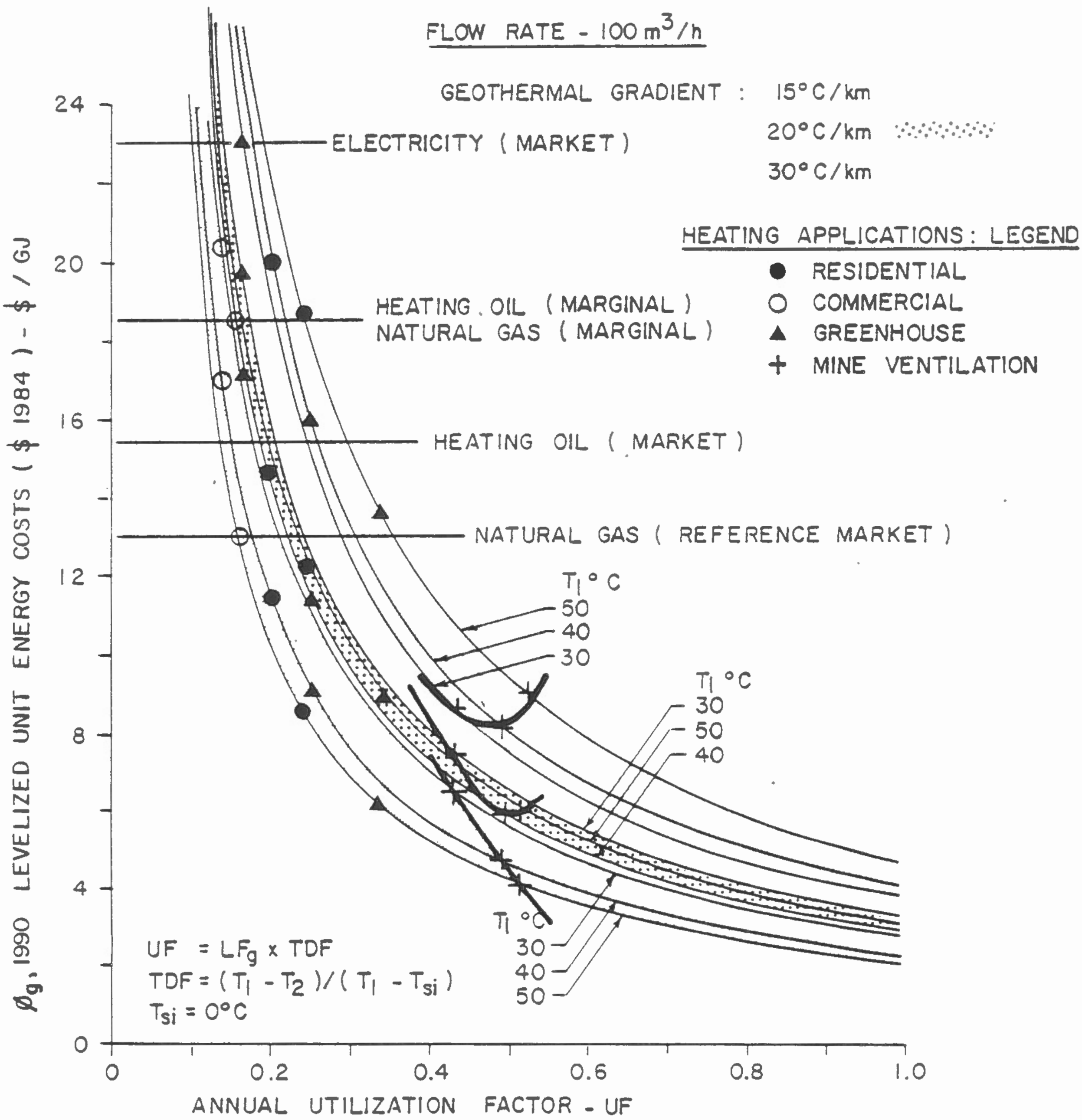
APPLICATION	Assigned Values of: T_2(°C)	LF_g	Utilization Factor for T_1 of: 30°C	40°C	50°C
Space Heating:					
o Residential Buildings	30	0.6*			
TDF			-	0.33	0.4
UF			-	0.2	0.24
q_g (GJ/h)			-	6.0	8.5
o Commercial Buildings	30	0.4*			
TDF			-	0.33	0.4
UF			-	0.13	0.16
q_g (GJ/h)			-	6.0	8.5
o Greenhouse Complex	20	0.5			
TDF			0.33	0.5	0.66
UF			0.17	0.25	0.33
q_g (GJ/h)			4.5	8.8	14.0
o Mine Ventilation	10	0.65			
TDF			0.66	0.75	0.8
UF			0.43	0.49	0.52
q_g (GJ/h)			8.5	13.0	17.0
Aquaculture Heating:	20	0.65			
TDF			0.33	0.5	0.66
UF			0.21	0.33	0.43
q_g (GJ/h)			4.5	8.8	14.0
Town Water Heating:	5	0.4			
TDF			0.83	0.88	0.90
UF			0.33	0.35	0.36
q_g (GJ/h)			10.5	15.0	19.0

* Includes hot water heating

market priced heating oil at \$15.45/GJ.

In Table 3-3, residential and commercial space heating UF values are seen to be quite low for the T_1 and T_2 values given as a result of relatively low TDF values. With system incremental costs still to be included for potentially larger and more expensive equipment, the economics of unassisted geothermal space heating for buildings is expected to be unfavourable when the gradient is much below 20°C/km or so. Provisionally, economic requirements will dictate a minimum resource temperature of around 50°C or, expressed another way, a minimum design point geofluid temperature drop of about 20°C. These general deductions are applicable to a geo-system flow rate of 100 m^3/h. At a flow rate of 150 m^3/h, $\emptyset_g$ will reduce by 15 to 25 percent to improve competitiveness.

For public sector funding geothermal unit energy costs are lower by about 25 percent, as is seen by comparing Figures 3-5 and 3-6. As a consequence, the economics of geothermal energy under public sector ownership/operation will be somewhat improved.



NOTES

1 - BASE UNIT ENERGY COSTS (30 YEAR OPERATIONS LIFE)

2 - REAL COST OF CAPITAL, 11.5% (35/65 DEBT : EQUITY)

3 - ✕—✕ SHOWS ENERGY COST vs. T_1 TRENDS

GEOTHERMAL GRADIENT vs. UNIT COSTS FOR VARIOUS SPACE HEATING APPLICATIONS (PRIVATE SECTOR)

FIGURE 3-7

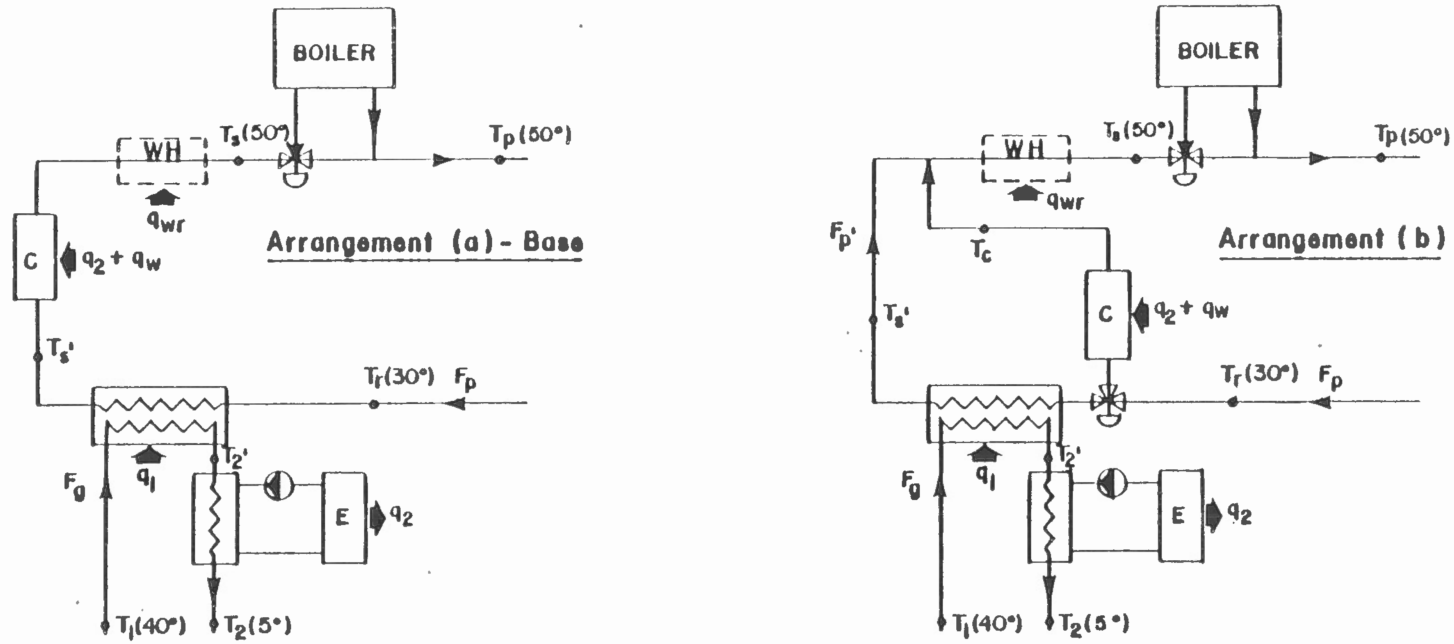
4.0 HEAT PUMPS

4.1 General

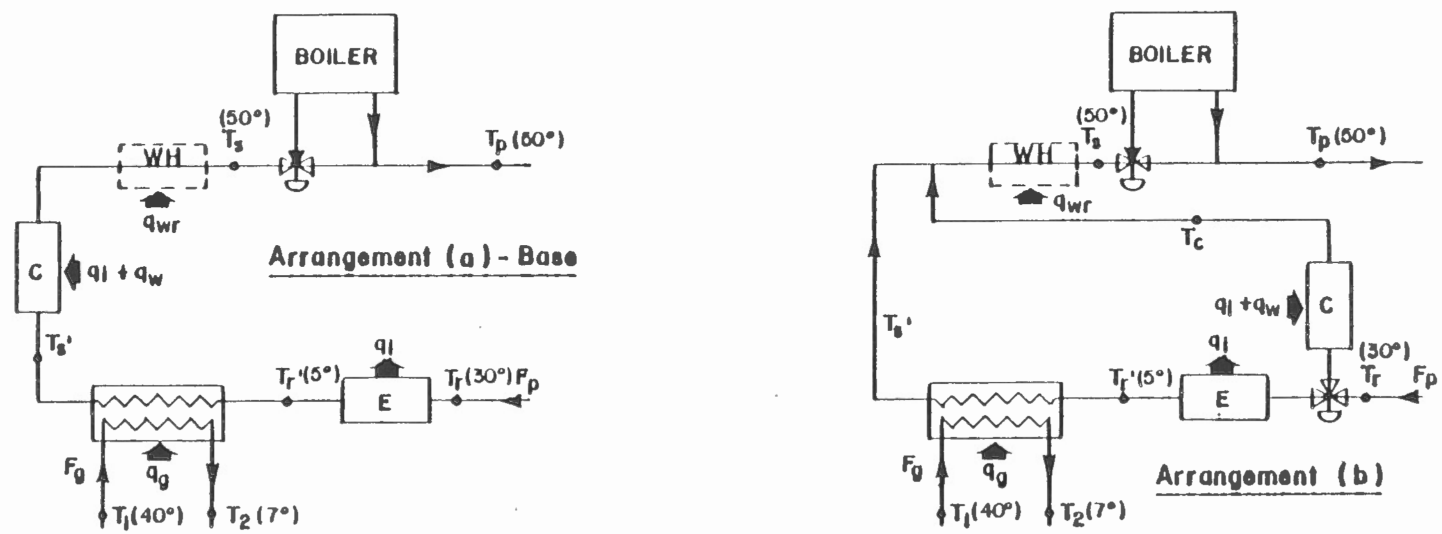
In the previous section, Figure 3-7 indicates that the competitive position of geothermal energy for commercial and residential space heating (T_2 = 30°C) deteriorates quickly with geothermal gradients much below 20°C/km. From the slope of the curves (private sector), energy costs are highly sensitive to UF in this region, which would make the economics very vulnerable to small upsets during operation.

There are current investigations underway in France on the use of lower design temperatures for residential space heating to suit their abundant low temperature resources while avoiding the need for heat pumps. For residential heating applications they are seeking to achieve injection temperatures of less than 20°C (Reference 11) by employing a combination of heating methods, forced air ventilation with make-up and radiant panel (sub-floor) heating systems. (Examples of this are developed and analysed in Section 6.0.) For comfort, this approach requires good building insulation levels and low heat loss from the space in the order of 0.3 $W/m^3/°C$ temperature difference (inside to outside temperature). This heat loss level conforms with the upper limit of residential building insulation and air tightness now being proposed under energy conservation guidelines for use in Canada, and is from two to three times better than the insulation of the average house constructed in the 1970's.

The following examines the use of heat pumps for space heating applications. Figure 4-1 shows the options with



Case 1 - Evaporators on Primary Geofluid Circuit



Case 2 - Evaporators on Secondary Circuit

HEAT PUMP ALTERNATIVE CONFIGURATIONS

FIGURE 4-1

regard to placement of heat pump evaporators and condensers in the heating system. With all arrangements, heat pumps provide the following favourable improvements:

- lower injection temperature T_2, resulting in a higher TDF and UF and a reduced average cost $\emptyset_g$ for energy delivered by the geothermal system;

- increased load q_g extending the load capability of a single doublet and providing flexibility to match a given load demand;

- potential for raising the supply temperature T_s to process when resource temperatures are inadequate.

The penalties include:

- increased capital and operating costs that add an energy cost premium to geothermal system delivery costs; and,

- much greater complexity and maintenance demands.

Figure 4-1 is reviewed in further detail in Section 4-3.

The French have developed considerable expertise in the use of heat pumps for space heating and employ them in operations where resource temperatures range from approximately 45°C to over 70°C, the top end of which is sufficient to meet system design point supply temperature requirements (T_s) without heat pump assistance. The rationale for this case is one of increasing the TDF and heat load q_g by depressing the injection temperature T_2 rather than as a means of increasing T_s.

The heat pump supply of energy to the system, via condensors, is made up of low grade geothermal heat q_2 to the evaporators plus the heat equivalent of the compressor power input. Compressor input energy (work) is expensive, being normally provided by electric motor drives. Compressor work declines with reducing fluid flow through the evaporator, and with lower T_s. The heat pump coefficient of performance (COP_{hp}) is the ratio of total heat supply to the system (from the condenser) and work input. The lower the COP, the greater is the work component of the total heat supply.

The significance of system temperatures on COP is best seen through inspection of the following expression:

$$COP = \frac{K.\ T_s}{(T_s - T_2)}$$

K has a value dependent on a number of factors related primarily to specific heat pump equipment. The temperatures in the above expression must be stated in degrees Kelvin. The term (T_s-T_2) expresses the work input function. COP becomes worse (i.e. lower) with increasing T_s and/or decreasing T_2.

Condenser leaving temperatures (T_s) of up to 70°C can be achieved with Freon R12, or up to 55°C with Freon R22 refrigerant. In both cases it is possible to lower the evaporation temperature to 0°C. This potentially allows T_2 to be lowered to approach 0°C. None of the projects in France have attempted to exploit the heat of geothermal resources so radically, as there is some concern that this could damage the reservoir (12). The range of injection temperatures used by the French, from a cursory review, varies between 10 and 20°C and supply temperatures are normally 65°C or better which allows a significant TDF to be achieved. (The exception noted is at Beauvais, north of Paris, where the heat pump installation uses a resource T_1 of about 47°C. Information on the temperature of injection was not available). For minimized unit energy cost of the geothermal supply, the lower the value of T_2 the better.

4.2 Engine Drives and Waste Heat Recovery

Heat pumps are traditionally equipped with electric motor drives. An alternative, using a technique which has become familiar in Europe, is to use a gas engine or other internal combustion (IC) drive. Heat from the jacket cooling and exhaust systems is then available for recovery and injection into the secondary (heating) circuit. This IC engine-compressor combination has considerable potential for geothermal systems but adds complexity and cost to the overall heating system. An attractive feature is the ability to regulate engine speed to suit part load demand conditions, an important means of minimizing the deterioration in COP at off-design conditions. French researchers are continuing to develop this technique. YORK, a division of BORG-WARNER of France, manufactures packaged, skid mounted IC engine-compressor equipment, each custom designed for heat recovery. For the Maritimes where electricity costs are high, this option could prove to be essential. On P.E.I. the use of electrically-driven heat pumps can probably be dismissed in most instances due to even higher electrical energy costs there.

Waste Heat Recovery and Conversion Efficiencies

Conventional oil fired thermal generating plants contribute to the electrical production mix of the utility system serving the Maritimes. Taking into account conversion and transmission losses, the overall fuel oil to electricity energy conversion efficiency at the end-use point is around 30 percent. On the other hand, IC engines convert approximately 30 percent of fuel energy to work with a further 30 and 35 percent recoverable from the jacket cooling and exhaust systems respectively. Therefore IC engines with such heat recovery features provide the opportunity to use hydrocarbon fuel resources more effectively and economically with benefit to the national interest of conserving oil and reducing imports. The following tabulates typical overall fuel energy utilization efficiencies appropriate to various waste heat recovery (WHR) schemes. The factor f is the ratio of energy utilization with heat recovery (E_o), to energy utilization (E_w) for mechanical work production only.

Heat Recovery Scheme	Utilization Efficiency %	Utilization Ratio (f)
Work only (no WHR)	30	1
Jacket WHR	60	2
Jacket & Partial Exhaust WHR	80	2.7
Jacket + Exhaust (Max) WHR	95	3.2

The fourth scheme above is an extreme case which uses the low temperature of the evaporator to condense the vapor content of the exhaust gas to recover the remaining latent heat. All WHR schemes provide temperatures of

85-90°C and higher which can assist to raise system temperatures if required.

Waste heat recovery usefully increases the effective COP of the heat pump system. Defining COP as the total energy (thermal plus work) delivered by the system divided by the work of compression, then the system COP i.e. COP_s is given by:

$$COP_s = (q_2 + q_w + q_{wr})/q_w$$

$$COP_s = COP_{hp} + (f-1)$$

4.3 Geothermal Heat Pump Design Features

The design to optimize geothermal/heat pump system components is complex and requires a balance of economic, technical, and operating considerations. These include: climate and occupancy-related load demand changes (with impact on T_s, T_r, and circuit flows); maximization of geothermal energy annual usage; heat pump optimization to suit the annual heating demand pattern and also a possible summer air conditioning demand; and others. Computer modeling of a full year's operation of both the heating supply and load demand systems is one approach. The results of such a modeling investigation (13) indicated COP extremes of 5.3 to around 3, resulting in a 4.3 average annual COP. (These figures are based on a district heating system; fixed supply temperature T_s, year round, of 65°C to suit hot water heating demands; and injection temperature, 20°/25°C.)

Heat Pump-System Configurations

Evaporators may be installed on the geofluid injection leg of the primary circuit or on the return side of the secondary circuit. These options are presented as Case 1 and 2 respectively in Figure 4-1 previously. With Case 2 (both arrangements) the heat pump lowers the return temperature T_r sufficiently to allow the full geothermal heat load to cross the primary exchanger. The evaporator load q_i of Case 2 is internal to the system and does not contribute to the energy supply. The magnitude, and the work required to pump q_i, can be high in relation to the additional geothermal energy q_2 made available. With regard to arrangement (a) of Cases 1 and 2, the temperature lift for both is comparable, resulting in similiar COP_{hp}, but if Case 2 (a) evaporator flow F_p is larger than F_g there is a considerable increase in amount of heat pumped q_i and compressor work input compared to Case 1 (a). In both cases an additional q_2 units of geothermal energy are made available to the heating system, but the higher work input for Case 2 (a) will reduce the effective system COP from COP_{hp} to COP_s. The reduction is a function of the ratio of flows (R_f) through the primary exchanger and exchanger effectiveness (EE). The following tabulation [from (13)] illustrates typical system COP reduction ratios (R_c) applicable for Case 2 evaporator arrangements (R_c=COP_s/COP_{hp}).

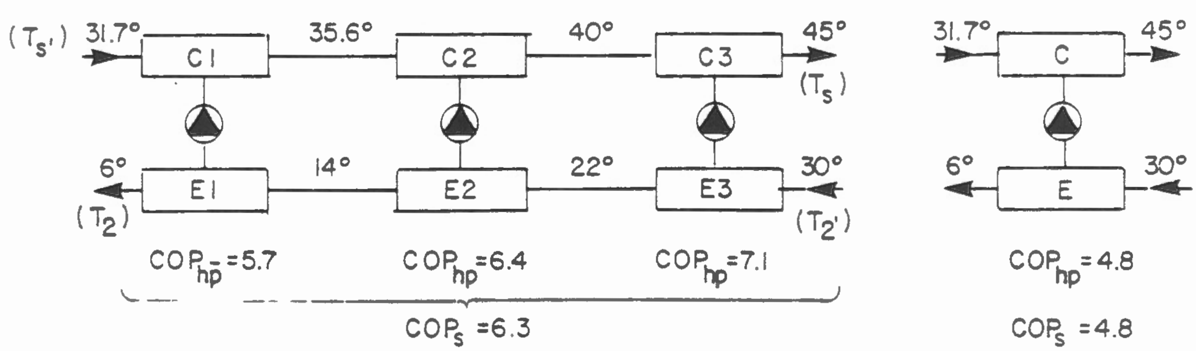
			COP_{hp}						
R_f	EE	R_f x EE	4	5	6	7	8	9	
			COP Reduction Ratio $-R_c$						
1	0.835	0.835	0.881	0.872	0.866	0.862	0.859	0.856	0.854
0.9	0.875	0.708	0.790	0.774	0.763	0.755	0.750	0.745	0.741
0.8	0.875	0.708	0.790	0.774	0.763	0.755	0.750	0.745	0.741
0.7	0.94	0.658	0.754	0.735	0.723	0.714	0.707	0.701	0.697
50.6	0.96	0.576	0.694	0.671	0.656	0.645	0.636	0.630	0.625
50.5	0.975	0.487	0.630	0.603	0.584	0.570	0.560	0.552	0.546

Where the Case 2 configuration of evaporator (Figure 4-1) is to be adopted, arrangement (b) is preferred. This reduces the secondary circuit flow across the primary exchanger to F_p' and R_f tends to unity.

For the Case 1 configuration there is some concern with placing evaporators directly on the geofluid leg. The corrosive nature and fouling potential of the geofluid is a major concern; also the cost of providing exotic metallurgy for the normally large evaporator vessels is high. Even through the geofluid quality is typically high, the approach in France is to employ a separate treated-water recirculation system between the heat exchanger(s) on the geofluid circuit and heat pump evaporator(s) proper, as illustrated in Figure 4-1.

4.4 Heat Pump Staging

A distinguishing feature of heat pump designs for geothermal systems is the large temperature spread between the circuits (T_s-T_2). The negative effects on COP and energy drive costs may be offset by installing several heat pumps in series rather than using a single unit. This is illustrated schematically below.



The results shown are typical and illustrate the considerable improvement in system COP to be derived by employing heat pumps in series to narrow individual condenser and evaporator temperature differences. The need for this kind of improvement becomes all the more significant when heating system design requirements demand greater temperature spreads (T_S-T_2).

Staging of heat pumps is another possibility; here, two or more heat pump circuits, inserted between evaporator and condenser pairs, pump the heat in temperature steps. A two-stage heat pump system requires two independent refrigerant circuits: one circuit conveys heat from the evaporator to an intermediate condenser which forms the evaporator of the second circuit; the second circuit completes the transfer to the main heating system condenser. Staging provides considerable improvement in system COP but involves capital costs more than from simply duplicating the refrigerant circuits; the inter-stage condenser/evaporator is an expensive additional item. This is only partially offset by savings from using smaller motor capacities.

While it is technically feasible to combine heat pumps in an in-series and staged arrangement for maximized COP_S benefits and minimized energy consumption, in practice the high capital costs and extreme complexity are expected to make the economics of such an arrangement unfavourable. Installing several smaller capacity heat pumps in an in-series arrangement offers advantages other than economic ones, including:

- improved system reliability;

- extended period of full capacity operation of individual units at part load demand conditions.

The optimum number of pumps will be specific to a given application and require extensive detailed investigation involving pump performance, costs, and heating system operating factors. The residential heating installation at Creil, France, employs a 3-unit in-series arrangement of heat pumps.

4.5 Geothermal/Heat Pump Load Sharing

In a heat pump assisted geothermal heating application the process receives energy from three sources:

- the geothermal supply system;
- the heat pump system (including heat recovery from IC engine drives where applicable); and,
- the boiler peak heating/backup system.

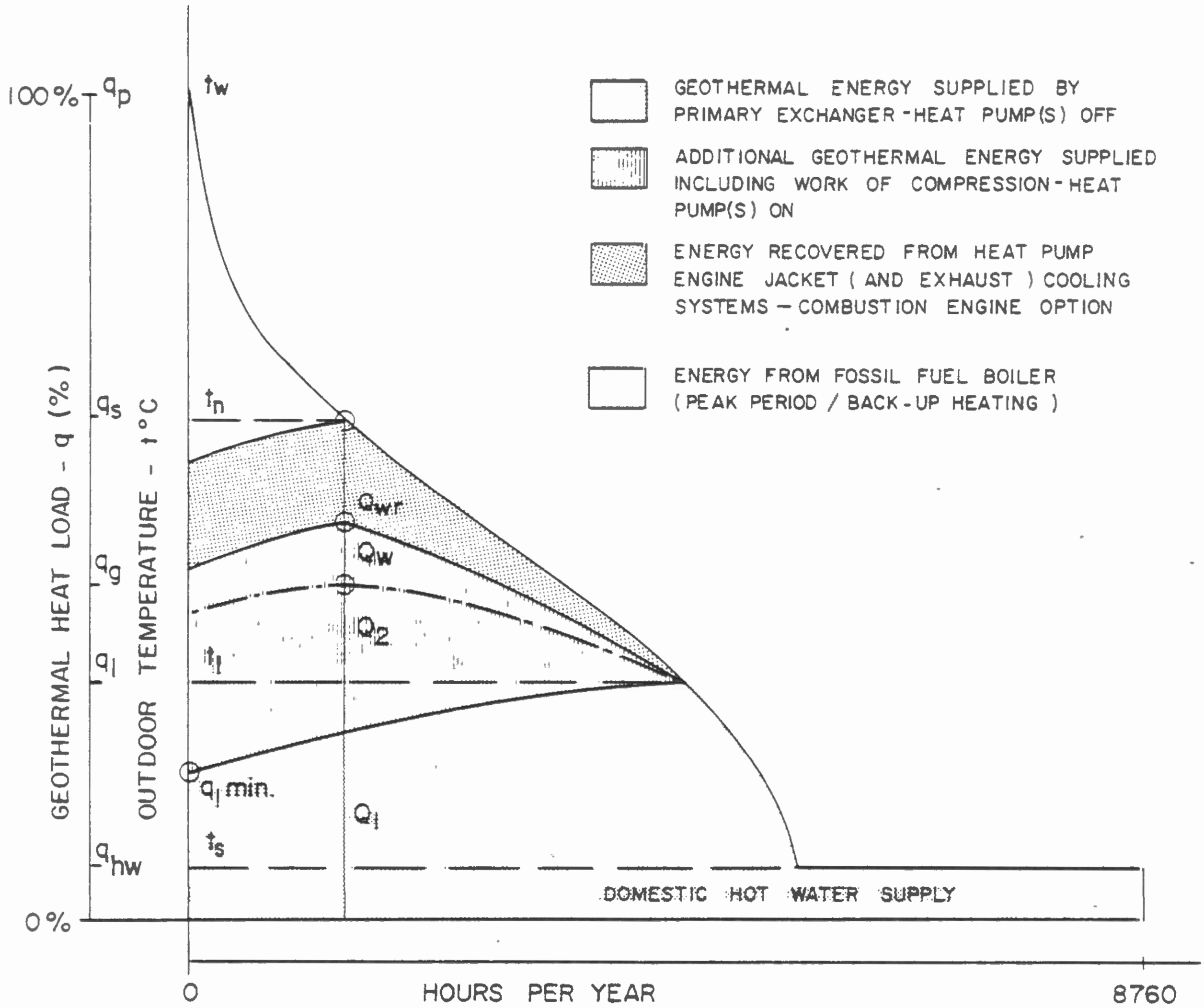
The three sources are called upon in sequence according to the load demand which, in the case of space heating applications, is directly related to the outdoor air The following is a description of the sequence of operation of the system as outdoor air temperature falls and system load increases. It applies where resource temperature T_1 is high enough to justify the transfer of a portion of the geothermal load via the primary heat exchanger. The tabulation below illustrates the principal events for a heating system with a 2 in-series heat pump arrangement.

Outdoor Air, t	Geothermal Primary Exchange	Heat Pump	Boiler Peak
$t_s > t > t_1$	On	All Off	Off
$t_1 > t > t_2$	On	#1 HP On	Off
$t_2 > t > t_n$	On	#2 HP On	Off
$t_n > t > t_w$	On	All On	On

When t is higher than the first transition temperature t_1, the primary heat exchanger alone operates. When t falls below t_1, geothermal direct exchange no longer meets demand and the first heat pump is brought on. As t continues to fall, to below t_2, the second transition point, the second heat pump is brought on and, at t_n and lower, the peaking boiler contributes to meet system demands.

Figure 4-2 is a typical histogram of a geothermal space heating application employing heat pumps with heat recovery from IC engine drives. The annual energy contribution from the three sources is illustrated. The load q_1 is shown to fall off with increasing demand, thus diminishing the area Q_1 representing the annual energy obtained from direct heat exchange. This follows from an assumed upward trend in T_r, a feature that also causes a need for increased heat pump capacity and work input. A heating system design philosophy that emphasizes control of return temperature T_r to minimize such a rising trend is essential. The histogram is basically the same for both Case 1 and Case 2 evaporator arrangements except, for Case 2, the area Q_2 is heat that is transferred by direct heat exchange as a consequence of depressing return temperature T_r.

Q_w in Figure 4-2 represents the annual work input. Under similar conditions the work input Q_w for electrically driven heat pumps would be approximately similar to the sum of Q_w and Q_{wr} (i.e. fQ_w) shown in the figure for the IC engine driven system. That is to say, the IC engine work input is lessened by delivering to a lower temperature (improved COP), with heat recovery contributing the additional energy q_{wr} to raise the



TYPICAL HISTOGRAM OF GEOTHERMAL HEAT PUMP SYSTEM

FIGURE 4-2

hydronic supply temperature to the final T_s value. These features of improved COP and lower cost of fuel, compared to electricity, both favour IC engine operation.

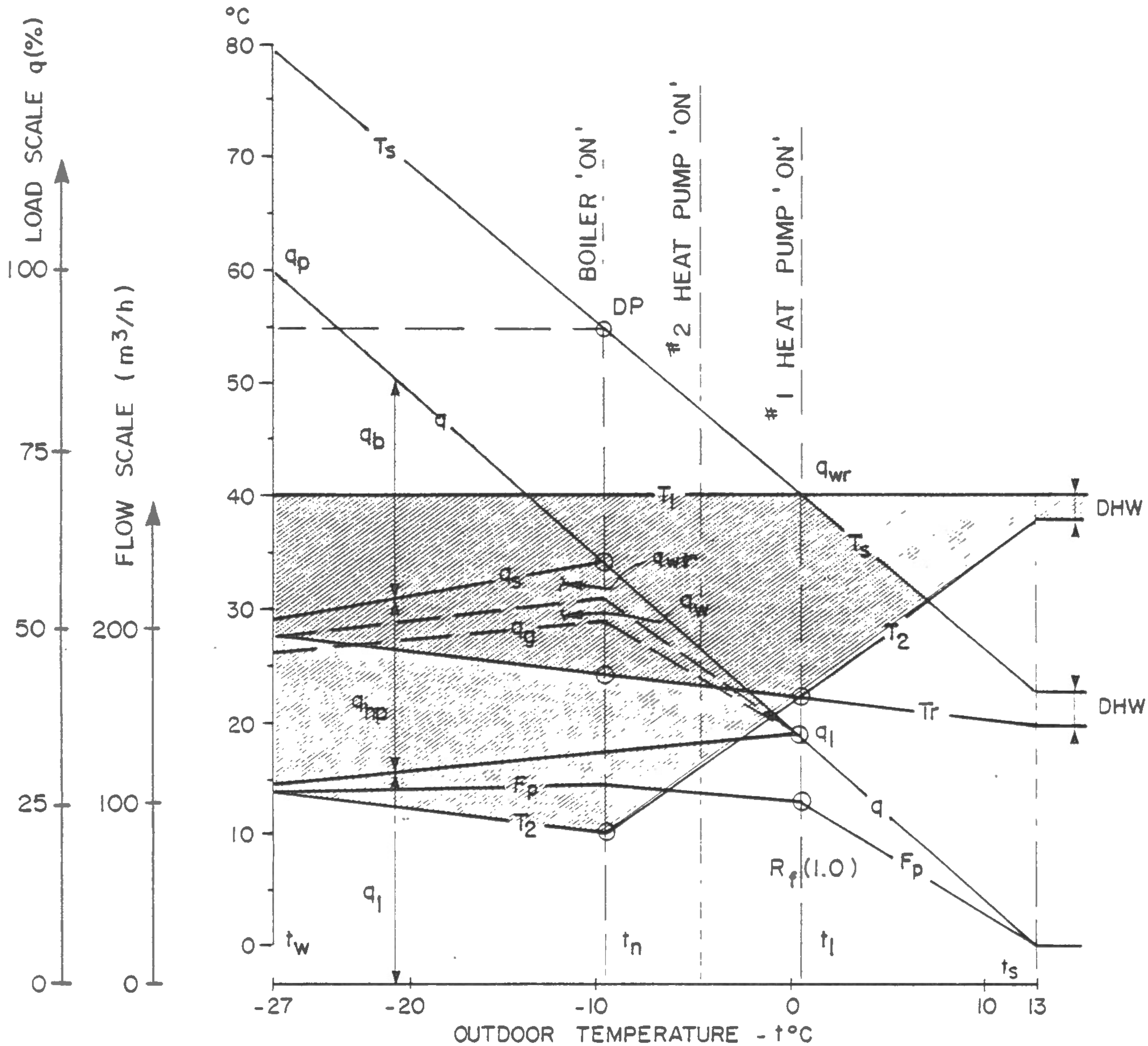
Heat pump and boiler combinations require optimization. French studies have indicated an optimum economic heat pump capacity that is 40 percent of heat pump plus boiler system capacity. The corresponding annual energy supplied by the heat pump system is approximately 80 percent of the total boiler-heat pump contribution. In Canada, differing economic criteria and climatic conditions could modify these results. Modifying factors are reviewed below.

With lower gradient conditions prevailing in the Maritimes, economic resource supply temperatures are expected to be lower than in France. The Paris region enjoys gradients of above 30°C/km and resource temperatures are typically above 60°C. As a consequence, geothermal utilization and the TDF potential are inherently higher there, for a given injection temperature. Accordingly the imperative for using heat pumps to improve the geothermal system TDF, and hence the geothermal supply economics, is less. In the Maritimes, heat pump capacity q_{hp} and the annual energy contribution Q_{hp} follow as a consequence of the need to improve the TDF and lower $\emptyset_g$. Accordingly, it is expected that optimization of heat pump capacity q_{hp} is not only a matter of minimizing the combined heat pump and boiler operating costs but must include the geothermal system as well in the optimization process.

System Temperature Trends and Other Parameters

Heating systems (i.e. forced air, radiant panel, baseboard etc., exhibit different temperature-load characteristics affecting the secondary circuit (hydronic) supply and return temperatures, T_s and T_r. In addition to space heating, other heating loads and their position in the hydronic circuit such as the heating of ventilation make-up air and domestic hot water (DHW), also play a part in helping to maintain a low return temperature T_r. With any heating system, when T_s, rising with load, exceeds the resource temperature T_l the geothermal load q_l transmitted by direct exchange can no longer support the system demand alone. If T_r exhibits a rising characteristic then, at the point when T_r equals T_l, direct exchange ceases (q_l = 0). The lower the resource temperature the sooner these direct exchange cut-off points are reached and the lower is the annual energy contribution made by direct exchange (Q_l). In the limit, when T_l is less than T_r at all times, direct exchange is not possible. Examination of Figure 4-3 helps to illustrate the 'squeeze' that is applied to direct exchange (q_l) at lower T_l values.

The flare between the T_s and T_r lines and the slope (indicated by the average of the two) is an important parameter in space heating system design. In fact, this flare for each type of heating system is sufficiently different as to become an identifying characteristic of that system. For example, radiator/baseboard heater system of vintage design typically exhibit a steeply rising, narrow spread flare pattern, one totally unsuited to geothermal energy systems. Radiant floor panels, on the other hand, exhibit a flat based flare where T_r



TYPICAL SYSTEM PARAMETERS
Vs. OUTDOOR AIR TEMPERATURE

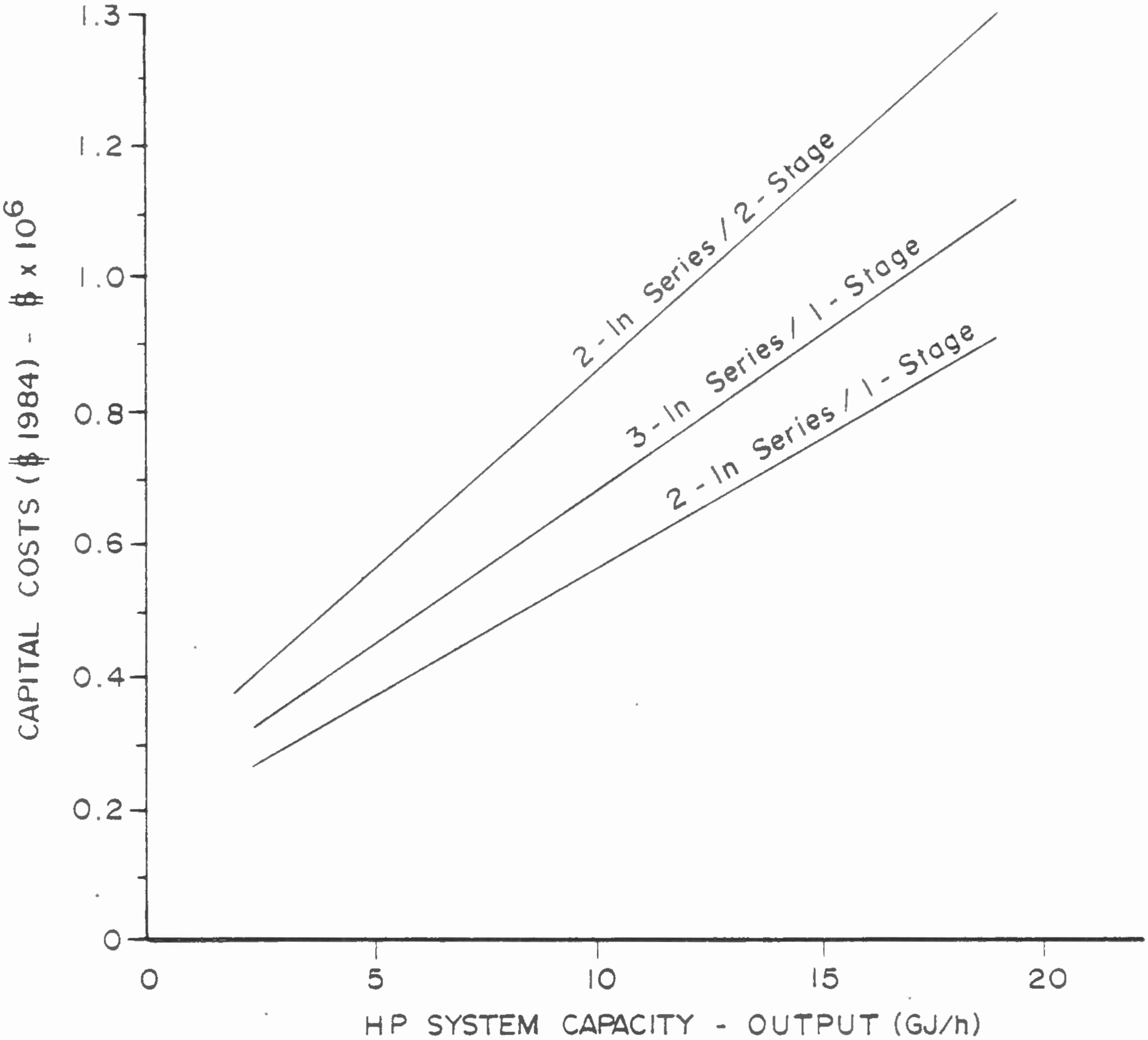
FIGURE 4-3

remains essentially level and only T_s rises with demand. This together with the limited spread makes it ideal for geothermal systems. Note, at the point where T_s equals T_l, load q_l is a maximum: with a rising characteristic, when T_r equals T_l, load q_l ceases. Therefore, the combination of flare and its intersection by resource temperature T_2 indicates visually the opportunities for direct transfer and the point at which heat pump operation takes over.

4.6 Heat Pump System Capital and Unit Energy Costs

Figure 4-4 presents conceptual level estimates of heat pump system capital costs corresponding to 2 and 3 in-series heat pump systems and also, for reference, a combined 2 in-series/2-stage system. As noted, they apply to built up systems and are based on budget information from two heat pump suppliers and also heat exchanger suppliers.

In Section 2.0 of Appendix B, equations incorporating annualized capital and annual operating cost are presented from which can be determined annual average unit energy costs $\emptyset_s$ and $\emptyset_{hp}$ for geothermal/heat pump systems, with and without heat recovery.



NOTE: HEAT PUMP COSTS ESTIMATED FOR BUILT-UP SYSTEMS, VARIABLE SPEED OPERATION, ELECTRIC MOTOR DRIVES AND INCLUDING LOCAL POWER SUPPLIES.

HEAT PUMP SYSTEM COSTS

FIGURE: 4-4

5.0 STORAGE

5.1 General

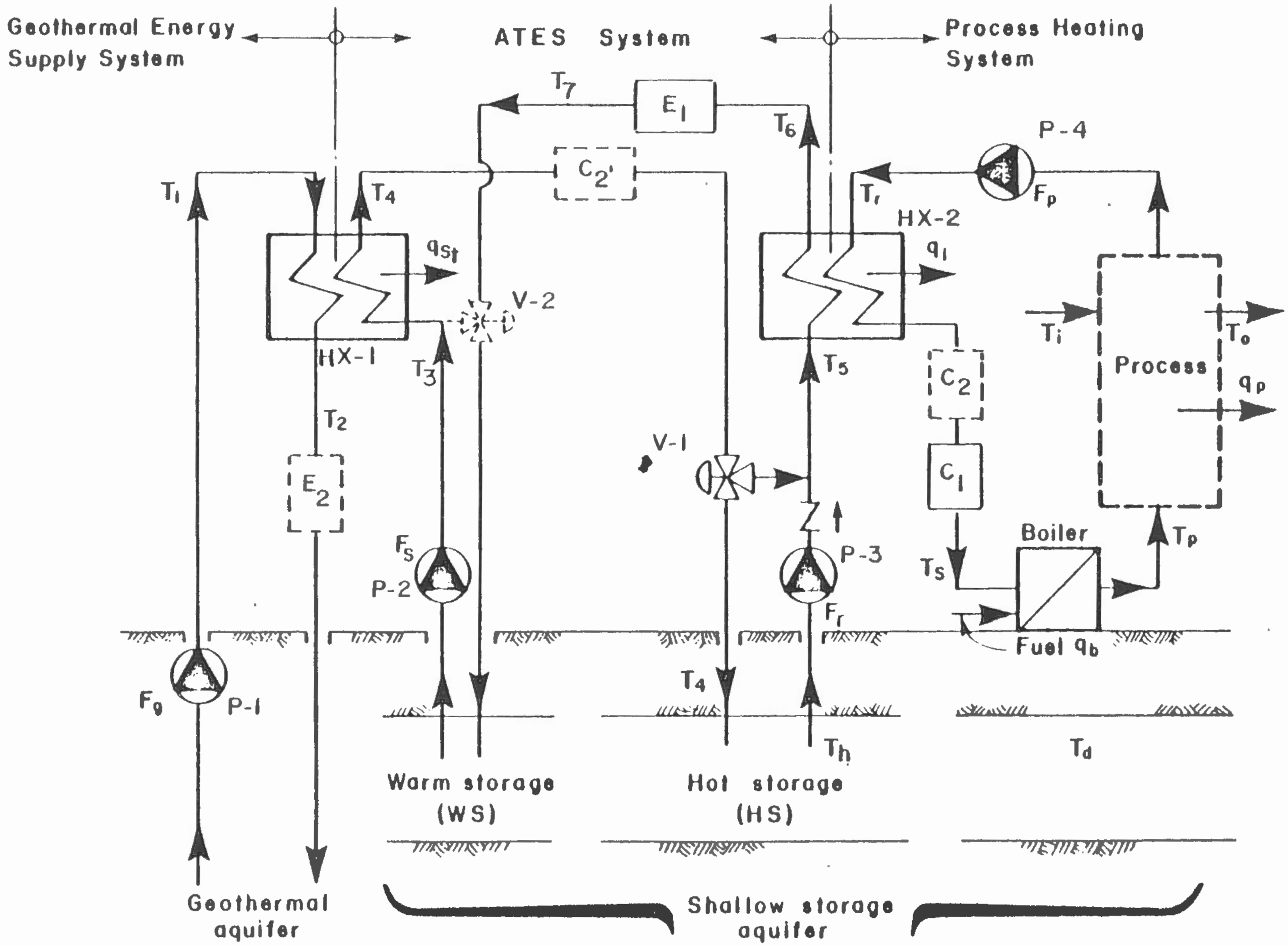
In a previous examination of seasonal storage techniques (1), aquifer thermal energy storage (ATES) was shown to be the preferred and potentially the most economic option for development in conjunction with geothermal energy systems. ATES involves the use of shallow, near-surface aquifers to act as reservoirs of heated water. The schematic of Figure 5-1 shows the basic elements comprising the primary geothermal supply, ATES and process heating systems respectively.

The principal features of storage are as follows.

- Storage improves the load factor of the energy supply system. It is a load levelling device that permits the supply system to operate at a continious output, improving the load factor from LF_g to LF_{st}, the latter approaching unity. Thermal energy not required by the process at times of low or zero demand is sent to storage for reclaim during periods of high demand.

- Installation and operating costs of ATES are a function of the rate of fluid supply and recovery, F_s and F_r respectively, and not of the total volume of fluids or energy stored.

- Storage applied to geothermal energy systems magnifies the scale of the process required for maximized economic utilization of the energy supply. Magnification of the process load q_p is approximately equal to the improvement in load factor ratio LF_{st}/LF_g.



SCHEMATIC OF GEOTHERMAL / HEAT PUMP SYSTEM WITH ATES

FIGURE 5-1

Section 2.2 presents the results of the brief survey of shallow aquifer data for the Maritimes. Shallow aquifers are seen to be extensive in the region and useful data on locations and other conditions are available (10). Some aquifers are shown to provide high recovery rates suitable for geothermal storage purposes.

5.2 Review of System Operating and Design Aspects

With reference to Figure 5-1, system features are described as follows. During times of limited or zero demand, the warm storage extraction pump P-2 delivers water heated by HX-1 to hot storage at temperature T_4. This temperature is maximized by matching flow rates F_s and F_g. With increasing process demand (falling outdoor air temperature), valve V-1 operates to divert part of the flow to HX-2 until, at the first transition point, the flow to hot storage ceases. A further increase in demand causes the hot storage recovery pump P-3 to commence operation, regulating output by speed control to suit load demand. With unavoidable degradation of the hot storage temperature T_h with time, the combined flow mix temperature T_5 at inlet to HX-2 will be less than T_4 and will tend to reduce further with time. The direct exchange load q_1 to the process circuit will be highly dependent on the resource temperature T_1 in the first instance and on the behaviour of the mix temperature T_4 and process return temperature T_r with time, behaviour which will be a function of the process load and the hot storage energy losses. Section 6.0 describes certain space heating applications where T_r decreases with increasing winter demand. This falling characteristic would be particularly desirable on the approach to and during the winter and would be complementary with the similar trend expected for T_5. Accordingly, for this condition load contribution q_1 across HX-2 might conceivably be maintained. Conversely, given opposing temperature-time characteristics of T_r and T_5, q_1 will reduce, perhaps quite rapidly.

A heat pump with its evaporator E_1 installed downstream of HX-2, depresses temperature (T_7) of the combined flows (F_s+F_r), returning to the warm storage, according to increasing process demand. The heat is transferred to process via condenser C_1. Valve V-2 installed to divert some of this cold temperature flow to HX-1 would result in a lowered geothermal injection temperature T_2. While this increases the energy delivered by the geothermal system it is not effective since the amount of this energy (q_1) that is actually conveyed to the process is restricted by the supply temperature T_1. In short, the described storage system improves load factor but lowers the effective or useful TDF relative to the geothermal system without storage. Technically, this can be corrected by installing a heat pump with its evaporator E_2 installed downstream of HX-1 in the geofluid injection leg, with heat discharge to the process circuit, via condenser C_2. Appraisal of the flow, temperature and energy balance conditions indicates that, with this storage scheme and for low resource temperatures (relative to process temperatures), both heat pump systems would be necessary. Comparing geothermal/heat pump systems with and without storage, the benefit from storage of an improved load factor may be negated by lower geothermal/heat utilization (i.e. lower TDF).

There is a further alternative that, from the perspective of reduced complexity and capital cost, is the preferred approach. It involves a heat pump, with evaporator E_2 located as shown but with the condenser C_2' alternatively located on the supply to hot storage. This permits operation of the geothermal/heat pump system independently of the process demand, increases the temperature T_4 to hot storage, and results in improvement to both the geothermal supply system load factor and TDF. The disadvantage is the high operating cost for upgrading the quality of the heat sent to storage, and the partial loss of the value- added energy during storage.

In evaluating any such (deep) geothermal/storage/heat pump scheme, technical and economic comparisons will have to be made with the alternative use of shallow aquifers as energy sources for heat pumps. With aquifer temperatures of about 8°C in the study region (Section 2.2), such aquifers could prove to be more economic sources of very low temperature energy than the expensive, deep geothermal aquifers.

Present study constraints preclude a more thorough examination of the issues, comparable to the earlier study (1). It might be appropriate to pursue the subject further, but preferably in conjunction with specific application conditions. This seems essential since temperatures, and their behaviour with respect to both time and demand, play an important role in the performance (and cost) of the geothermal, storage, heat pump, and process heating elements.

Specifically in the context of lower resource temperatures, it is provisionally concluded that the cost, complexity and scale magnification effects of storage are all factors that will, in general, oppose the economic use of storage where heat pumps are an essential part of the operation.

6.0 SPACE HEATING APPLICATIONS

6.1 Introduction

Primary applications for the direct use of low temperature geothermal energy include space and ventilation air heating, and domestic water heating for residential, commercial and institutional complexes. These applications for geothermal energy are addressed in this section and have been selected based on compatibility of energy demand with the large energy outputs typical of geothermal energy systems. The sizing of each application is set to accord with a direct coupled geothermal supply comprising a single 100 m^3/h geothermal doublet system. The applications selected are:

- a residential apartment complex employing baseboard, forced air, and radiant panel heating systems respectively;
- a commercial office complex employing forced air ventilation and baseboard heating;
- an institutional (university) complex employing forced air ventilation air and baseboard heating.

The design point hydronic water temperature lower limit for radiant panel emitters (in-floor heating) is generally regarded to be around 38°C; for hot water heating emitters of the baseboard or radiator type it is closer to 60° or 65°C; while for forced air systems it is around 55-60°C.

For all applications and heating systems (e.g. baseboard, radiant panel), a reference resource supply temperature T_1 of 40°C has been selected. System schematics are prepared which are reasonably suited to other supply temperatures though the proportions of direct heat exchange to heat pump-assisted exchange will differ. At 30°C the amount of direct heat exchange will be negligable. As resource temperature increases heat pump capacity diminishes.

A minimum injection temperature of 5°C has been selected for heat pump-assisted applications. The value is preliminary and intended to maximize the geothermal supply system TDF, thereby improving UF and lowering unit cost $\emptyset_g$. This directly sets the amount of geothermal heat pumped (q_2) and defines the design heat pump capacity. This heat pump capacity does not necessarily represent the economic balance between direct geothermal energy transfer, and heat pump and boiler capacity. Further reiteration and economic optimization of all geothermal and heat pump/boiler system costs would be necessary. As noted in Section 4.0, it is felt that lower gradients, and hence higher well costs, will tend to justify lower resource temperatures, placing the emphasis on achieving high TDF's.

Heat Pump Systems

Heating system designs are based on the use of electric motor, variable speed, compressor drives rather than IC engines with heat recovery. Further investigation of IC engine-heat recovery system design and cost issues is necessary in order to properly explore the IC engine drive option.

Packaged (i.e. pre-engineered) heat pump systems are available, supplied complete with compressors, condensers, evaporators, controls and drivers, and equipped with standard metallurgy for condensers and evaporators.

Separation from a chemically aggressive geothermal fluid requires an auxiliary loop and an additional heat exchanger. Preliminary prices have been received from MYCOM and others for such systems. Further operating and cost data and other design information must be obtained in order to make proper comparisons with built-up systems.

The built-up or custom designed system comprises a geofluid circuit heat exchanger, acting either as an evaporator or supplying to a separate evaporator, depending on geofluid chemistry; also compressors, condensors, and associated valves, piping and controls. The heat pump systems envisioned in this study are of the built-up type. They offer a potential advantage in overall annual COP and are more flexible, with preliminary cost and performance information indicating them to be potentially superior to the pre-packaged system. Considerable experience has been developed by such organizations as YORK, a division of Borg-Warner in France, that supplies systems 'packaged' and complete but built to specifications appropriate to the application.

Cost and performance estimates for the heat-pump-assisted applications assume two heat pumps in series, bridging the primary and secondary circuits. A single stage of lift from the evaporator (primary) to the condenser (hydronic) circuit is assumed in estimating heat pump system COP. A two-stage system between circuits would improve the single stage COP values estimated for the applications by more than 50 percent. However, economic justification for such additional equipment and system complexity must be determined from a detailed analysis of performance advantages. With IC engine driven heat pump systems, the inherent speed regulation, heat recovery potential, lower fuel (energy) cost, and improved COP potential could limit the benefit of further COP improvement from a combined multi-stage/multi-series heat pump arrangement.

Domestic Hot Water (DHW)

A water supply main temperature of 5°C and hot water supply temperatures of between 49°C and 60°C are assumed to apply. For the 40°C resource temperature selected, only part of the DHW heating load can be met by the geothermal system. A peaking boiler is indicated in the DHW system to make up the difference.

Load and Histogram Development

Histograms for the applications have been calculated with the aid of the CARRIER E20-II computer program developed commercially for the HVAC industry. This program incorporates standardized ASHRAE climatic design input data for major centres in Canada and the United States, and also occupancy/use characteristics of various applications that affect load demand.

The climatic data selected for the study correspond with conditions in Moncton, New Brunswick, the climate there being treated for study purposes as representative of conditions in the Maritimes. Other data, such as hot water heating demand and ventilation air make-up for residential and commercial buildings, are based on average usage values.

Conceptual designs were developed for each application based on ASHRAE practices for the specific application. Typical details affecting heating were recognized in the development of the designs such as glass-to-wall ratios, wall construction and insulation R factors, make-up air requirements, lighting loads, occupancy/non-occupancy periods, and so forth.

Load design points (q_s) are shown superimposed on the histograms of each application. The 100 percent design load q_p corresponds with ASHRAE load exceedance design criteria and also includes the DHW load.

6.2 Residential Complex

6.2.1 Baseboard Heating System Scheme

The residential model consists of a total of 1,680 apartment units contained in seven, six-storey buildings with a total project flor area of 235,200 m^2. The following indicates specifics of building construction and design details that are pertinent to the baseboard heating scheme and also the forced air and radient panel schemes described further on.

Each apartment has 140 m^2 floor area. Building walls and roof have a thermal conductance of 0.28 $w/m^2/°C$ and the windows (glazing ratio, 0.25) are double glazed having a conductance of 3.12 $W/m^2/°C$. Occupancy loads are based on three people per apartment, occupying the space twelve hours per day, seven days per week. The winter indoor design condition is 22°C with a night set back temperature of 18°C. The ventilation rate is 255 m^3/h per apartment unit during occupied hours and 170 m^3/h during unoccupied hours. The electrical energy consumption due to lights and appliances is 10 W/m^2 during the occupied period. Hot water consumption is considered to be constant throughout the year at an average of 0.2 m^3/day per apartment.

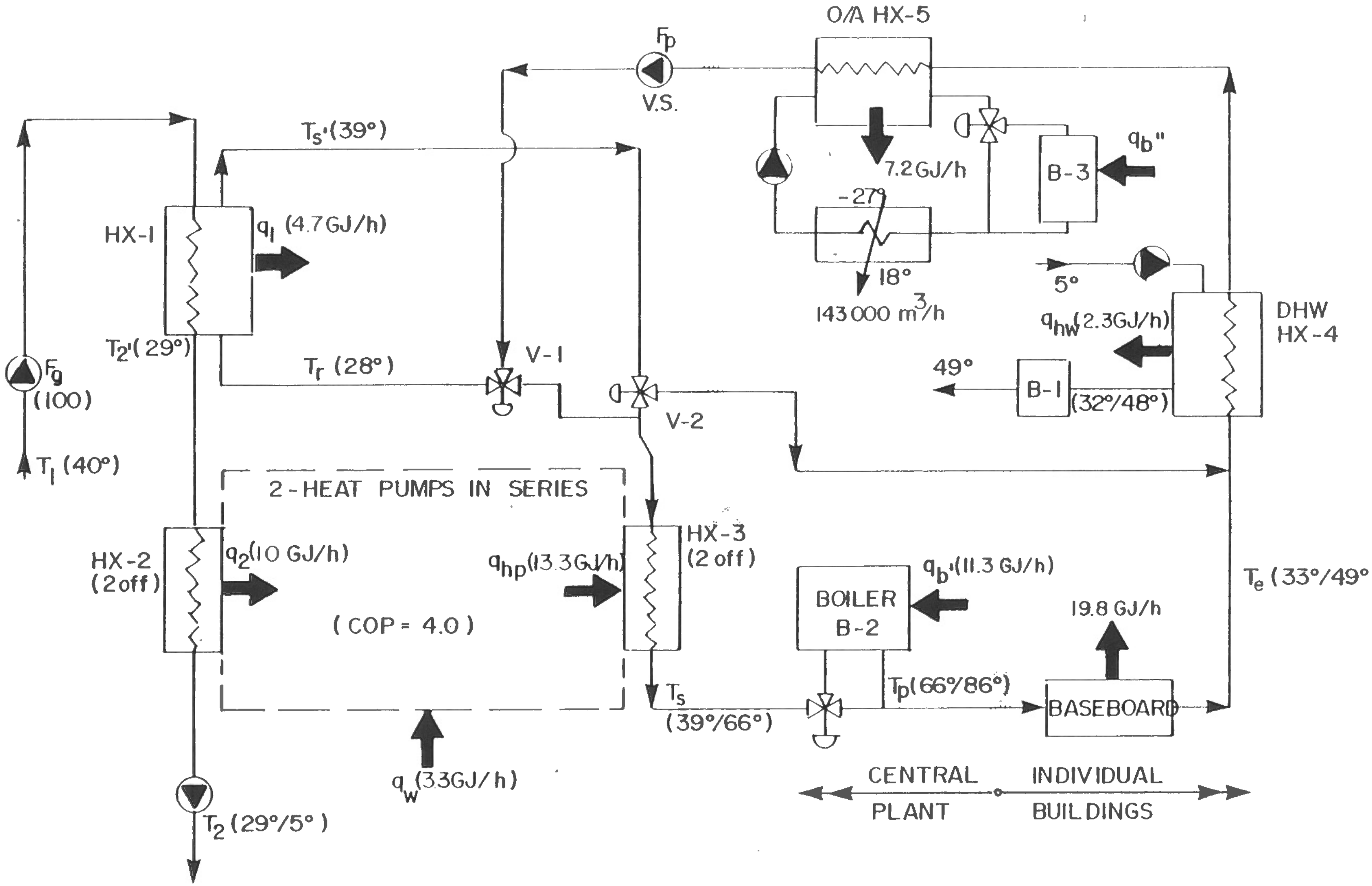
Baseboard Heating Schematic

For the baseboard scheme the ASHRAE winter design space heating load is 27.0 GJ/h, the domestic hot water load is 2.4 GJ/h and the overall combined peak design heating load is 29.4 GJ/h.

Figure 6-1 is a schematic that shows the major components including the geofluid (primary) and hydronic circuits, heat exchangers, and heat pump arrangement with the hydronic circuit supplying to baseboard heaters, DHW, and outside air heat exchangers, in that order. Peak heating boilers (B-1, B-2, B-3) and major diversion valves are also indicated.

Baseboard convector unit costs increase as the design point hydronic supply temperature (T_s) is lowered. Cost is a function of the baseboard unit (emitter) heat transfer surface area which increases rapidly as the design supply temperature is lowered. The following illustrates tentative incremental cost premiums for various values of T_s relative to 88°C, an economic design point for conventional oil fired systems.

The base design point, T_s of 66°C, has been selected for the baseboard scheme developed for this residential case. At this temperature, the installation cost premium is considered reasonable. Selecting an alternative design



RESIDENTIAL - BASEBOARD HEATING SCHEMATIC

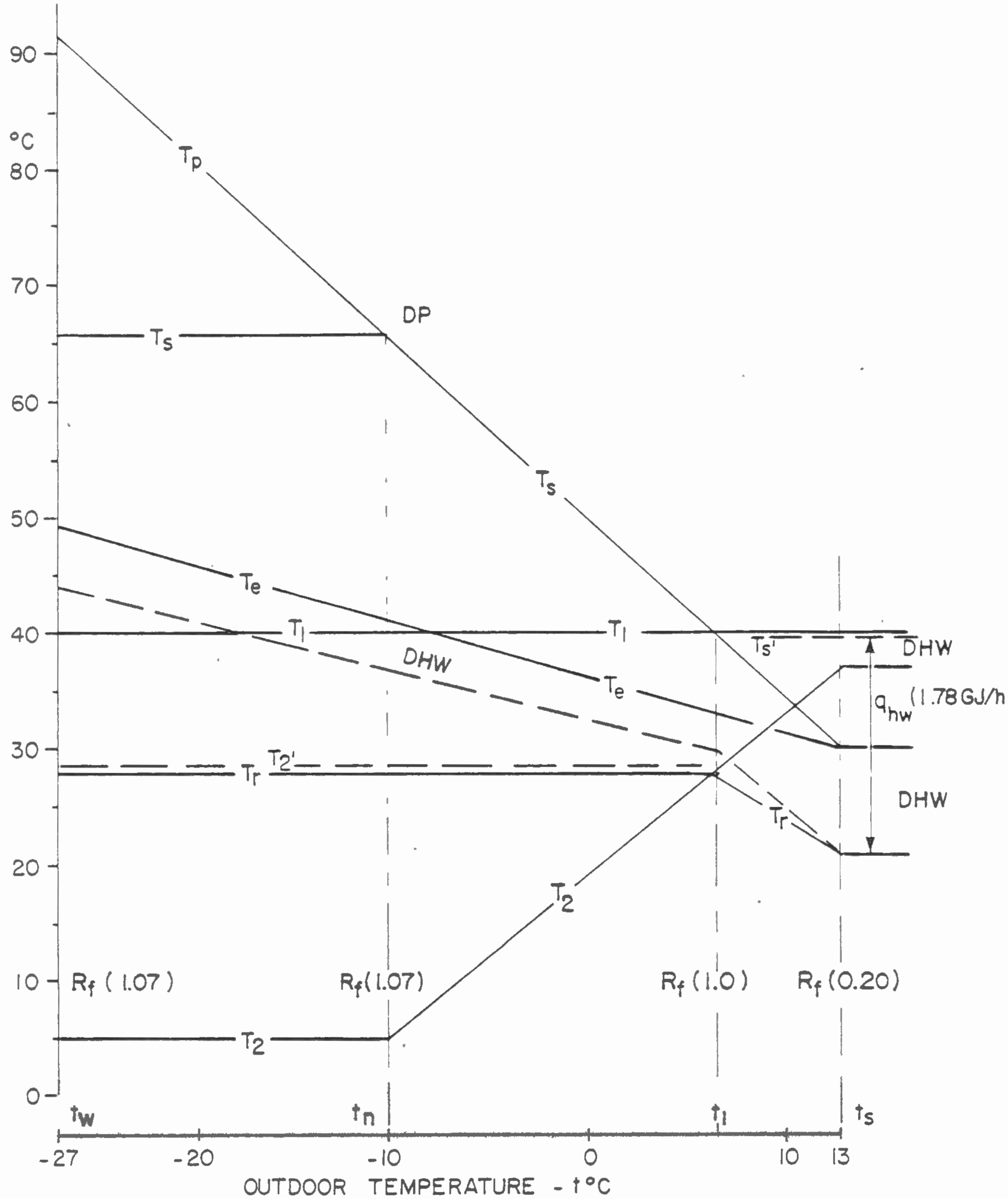
FIGURE 6-1

Incremental Costs ($1984) (relative to oil fired system) Design Point T_S (°C)	Cost Per Unit
88	$ (150)
66	Base
55	$ 200
38	$ 750

T_S of 55°C, though more favourable to the economics of heat pump operation, would incur an incremental cost premium of $200 per unit which, for the complete complex, would exceed $300,000. The merits of increasing capital expenditure to improve COP and reduce lifetime heat pump operating costs would need to be determined. (A superficial examination of the $750 incremental premium ($1,260,000 total) for a 38°C supply might appear to justify elimination of heat pumps on grounds of lifetime cost savings and system simplification. However, taking into account the additional function of heat pumps, which is to improve the geothermal TDF, their presence can be economically justified in most instances, though much depends on the particular conditions.)

Figure 6-2 presents system temperature relationships with varying outdoor air (O/A) temperature, t. This figure, along with Figure 6-1, are used to highlight the principal features of system operation:

$t > t_S$ (13°C): The load is restricted to DHW only. The hydronic circuit flow F_p is controlled by variable speed pump so that T_S' leaving HX-1 closely approaches 40°C, the resource supply temperature. Valve V-2 closes off the flow to the baseboard units, diverting it directly to HX-4 to heat DHW to about 36°C, a load of 1.78 GJ/h.



RESIDENTIAL - BASEBOARD HEATING

SYSTEM TEMPERATURE Vs. OUTDOOR AIR

FIGURE 6-2

$t_s>t>t_l$ (7°C): The small space heating load and a portion of the DHW load are met by direct exchange HX-1 as q increases linearly with falling outdoor air temperature t. As t decreases from t_s to t_l the baseboard leaving temperature T_e increases linearly from approximately 32°C. The hydronic circuit flow F_p is controlled by means of pump and valve V-1 to meet the increasing load requirements up to transition point t_l. Valve V-2 modulates the flow to bypass. At t_l, V-2 closes the bypass flow to the DHW heating exchanger which is now entirely supplied by the hydronic water leaving the baseboard system at temperature T_e.

$t_l>t>t_n$ (-12°C): The heat pump system begins operation at t_l and continues with increasing output to t_n. Over this outdoor temperature range the hydronic supply temperature increases linearly from 39°C to 66°C. The baseboard leaving temperature increases with falling t in order to improve heat transfer between the baseboard element and room air.

$t_n>t>t_w$ (-27°C): The peaking boiler B-2 is operated and increases load input q_b. At winter design t_w, the temperature to the baseboard heaters (T_p) from the boiler is a maximum at approximately 86°C.

Figure 6-2 shows T_2 reducing linearly from the zero space load (t_s) to 5°C at transition temperature t_n of approximately -10°C corresponding to heat pumps at full load; from t_n to t_w, T_2 is constant at 5°C. Also, the rising T_e characteristic enables more of the DHW load to be supplied by the hydronic circuit which also contributes to reducing the temperature to HX-5 and ultimately T_r.

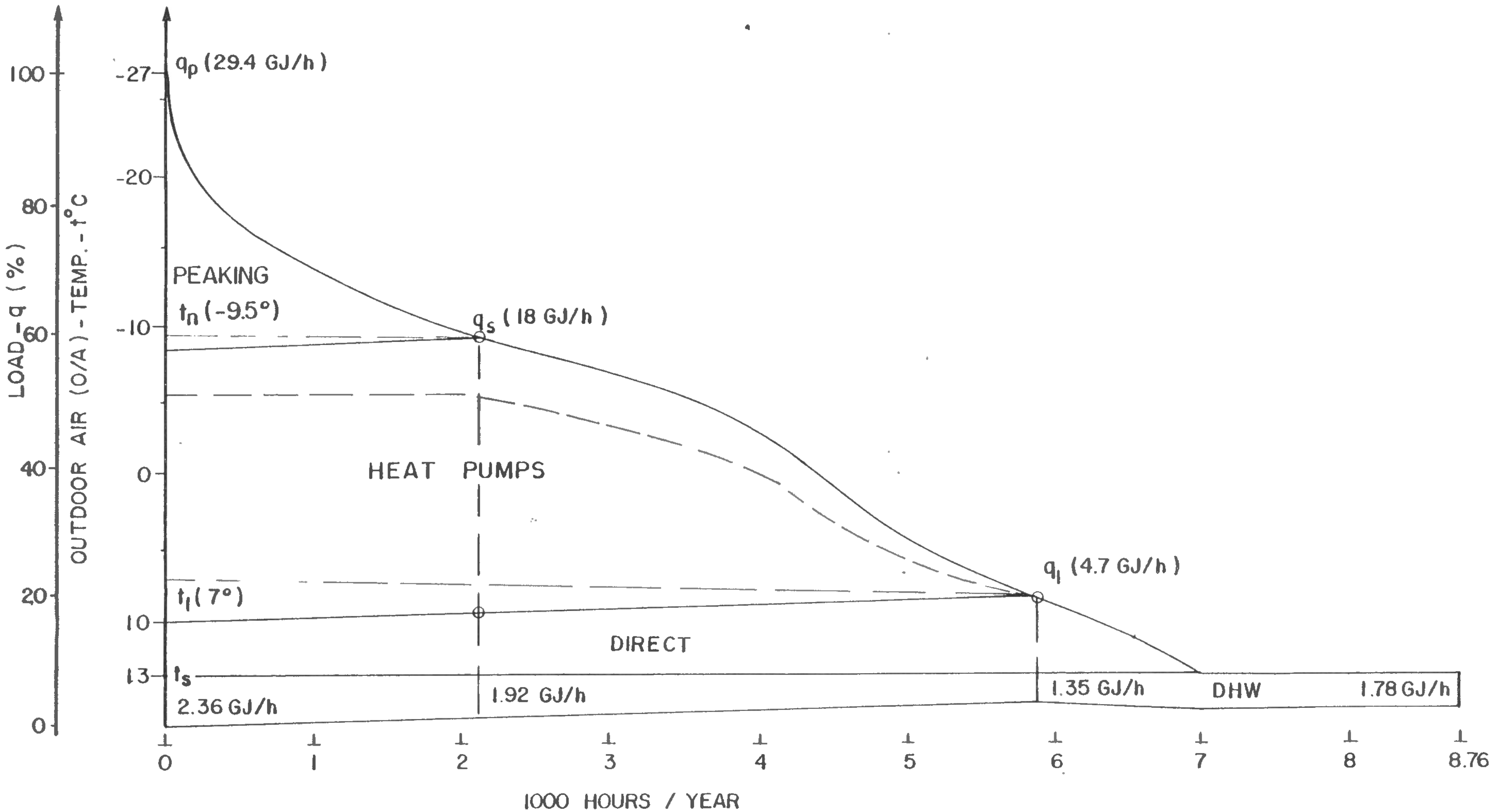
The histogram for the system is shown in Figure 6-3. The increasing DHW load with rising T_e is clearly evident but since T_r is constant (and hence T_2') the total direct load q_1, is constant. At q_s the geothermal/heat pump system design load, heat pump design capacity is represented by the difference in direct load q_1 and q_s.

6.2.2 Forced Air Heating System

The residential forced air system schematic is basically the same as the baseboard system (see schematic Figure 6-2) except for the replacement of baseboard elements with hot water air heating coils. System operation is also similar. Because of the general similarity in performance and other aspects, figures showing hydronic and geothermal system temperatures and histogram load profile are not included. The design point T_s value for the forced air system is 55°C; transition temperatures t_1 and t_n are 8°C and -11°C, respectively.

6.2.3 Radiant Panel System

Radiant panel floor heating systems are suitable for hydronic supply temperatures T_s as low as 38°C and at this level can supply 60 percent of the space heating load without heat pump support so that only a peaking boiler is required. At these low temperatures the in-floor pipe spacing must be reduced from the normal of 350 mm to 300 mm. This increases material costs by about 15 percent or so, with about a 3 percent increase in the overall radiant panel system costs. There is a limit to reducing pipe spacing; this is imposed by comfort considerations which restrict maximum temperatures underfoot to



HISTOGRAM - RESIDENTIAL BASEBOARD HEATING SYSTEM

FIGURE 6-3

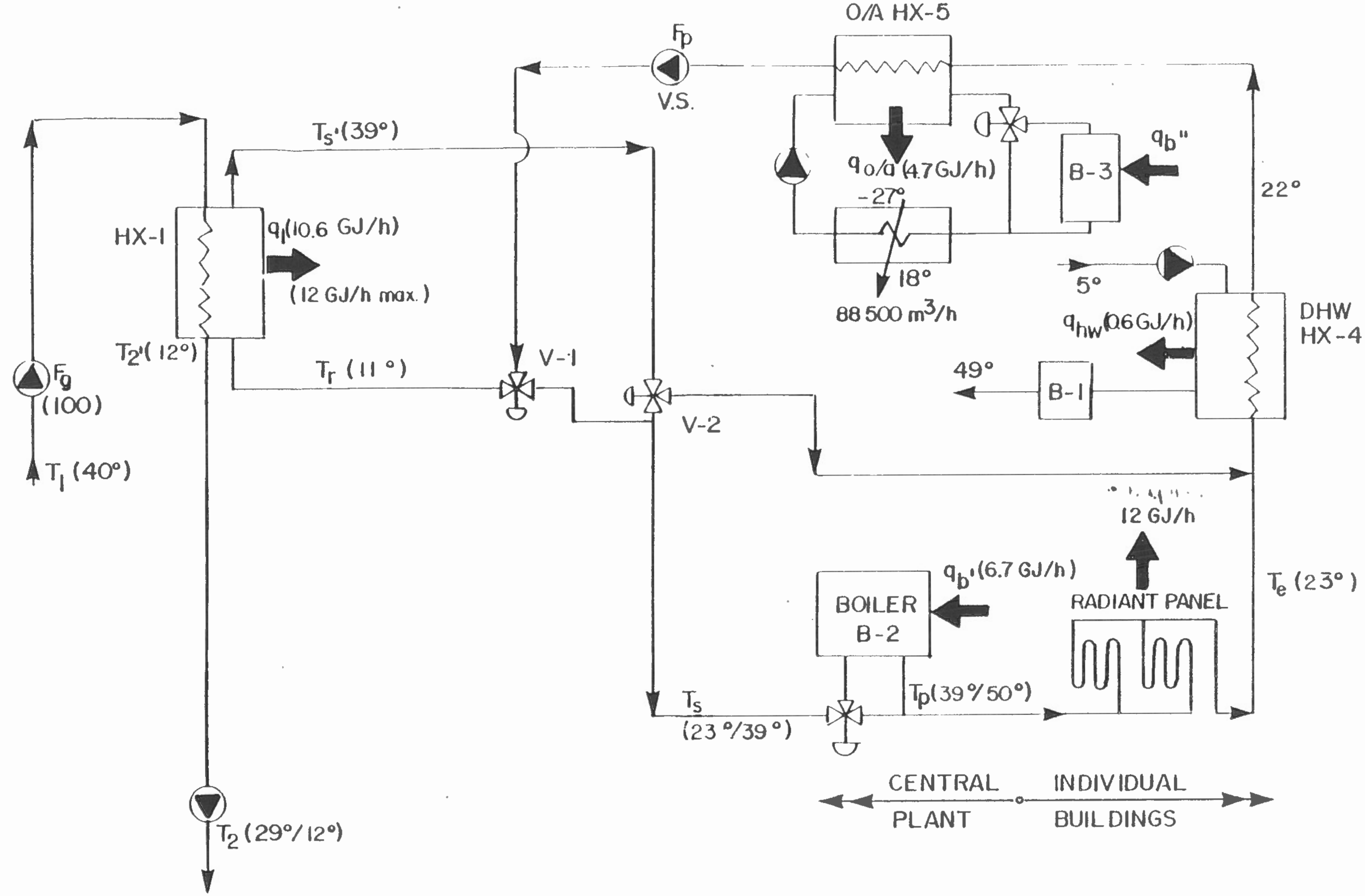
approximately 30°C. Since water temperatures above 38°C are required at peak times an excessive spacing reduction can produce uncomfortable conditions and has to be avoided.

The hydronic system supplies radiant panels, DHW heating and outside air heating systems. A feature of the radiant panel emitters, important to geothermal operations, concerns the hydronic exit temperature T_e from the panels which is essentialy constant with load. Superposition of outdoor air and DHW heating lowers the final hydronic temperature T_r further with beneficial results to the direct energy exchange q_1 via HX-1. This is illustrated more fully in the following which examines radiant panel systems, with and without heat pumps.

Radiant Panel (Without Heat Pumps)

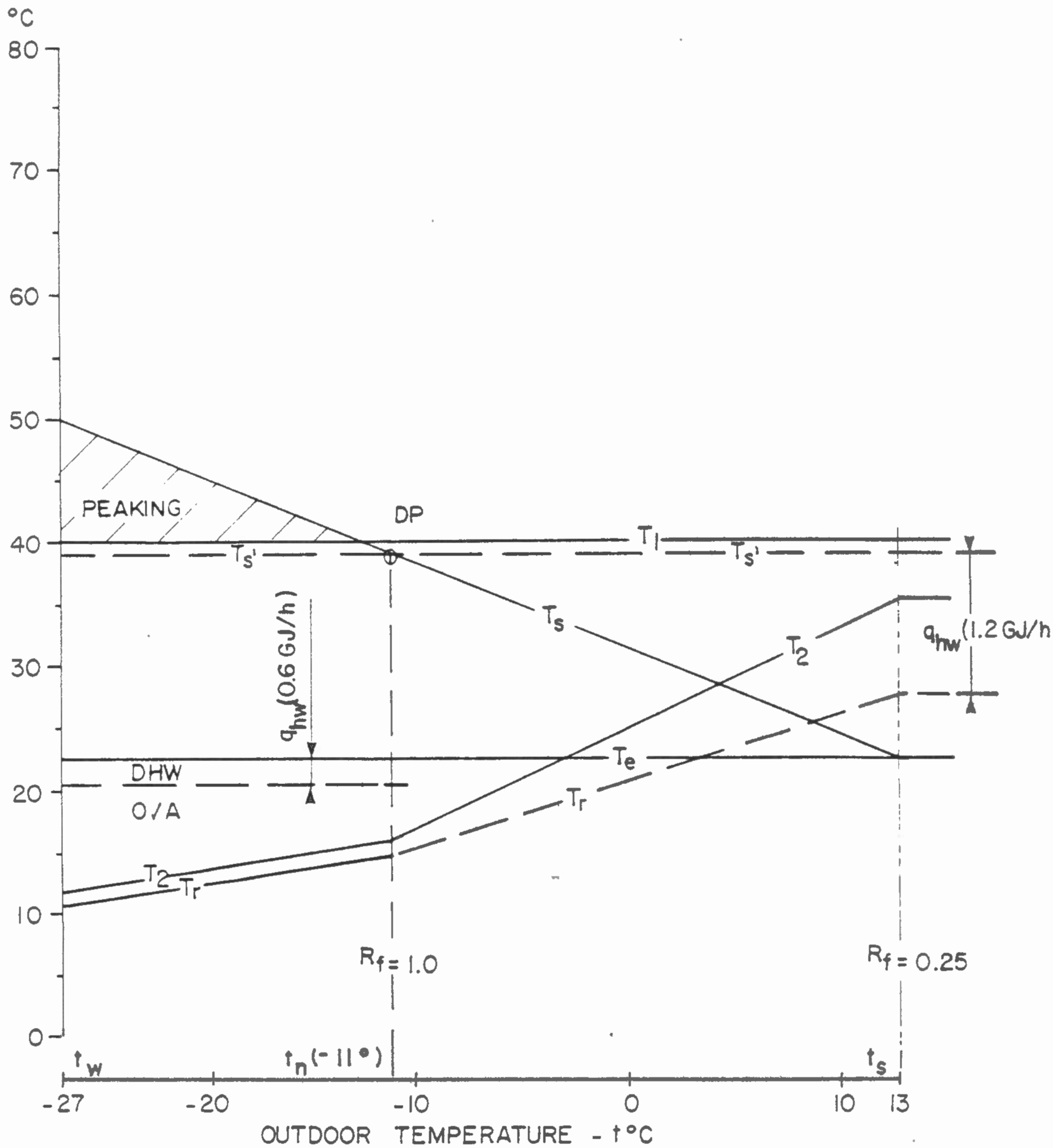
Without heat pumps, the geothermal system load is capable of meeting the needs of approximately 1,040 apartment units, the number determined by a process of re-iteration to achieve an acceptable load factor LF_g. The system schematic Figure 6-4 is essentially similar to the baseboard system except for the omission of heat pumps.

Hydronic system temperature vs. outdoor air temperature curves presented in Figure 6-5 show exit temperature T_e of 23°C, which is lower than that of the previous systems. Placing the DHW heater HX-4 downstream from the radiant panels reduces the DHW load that can be met from the hydronic circuit. During the summer and at low space conditions the load to the DHW contributed by the geothermal system is improved by bypassing supply water upstream of the radiant panels via valve V-2 at a temperature close



RESIDENTIAL - RADIANT PANEL (WITHOUT HEAT PUMPS) HEATING SCHEMATIC

FIGURE 6-4



RESIDENTIAL - RADIANT PANEL (WITHOUT HEAT PUMPS)

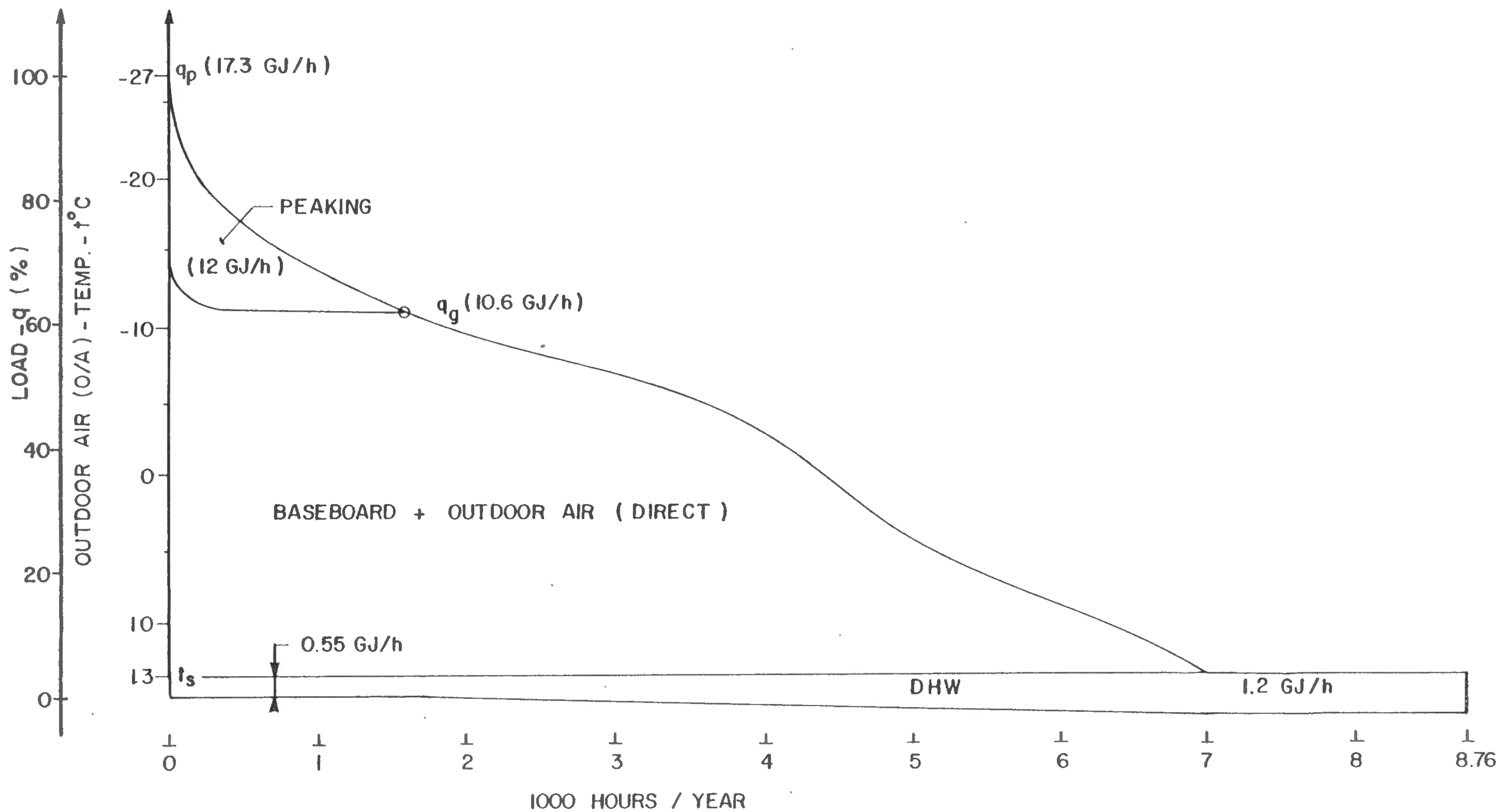
SYSTEM TEMPERATURES Vs. OUTDOOR AIR FIGURE 6-5 to the resource temperature of 40°C.

Figure 6-5 shows the combined effect of the constant exit temperature T_e, and the downstream DHW and outdoor air heating loads, on return temperature T_r which falls continuously with decreasing O/A temperature. To the left of design point (DP) (see Figure 6-5) T_r falls a further 3-4°C which aids the TDF. However, as can be seen on the histogram, Figure 6-6, this contributes little to the direct annual energy due to the limited period of operation at conditions of low T_r and high load. (This further supports the validity of the analytical determination of geothermal system performance, using a TDF based on design point conditions. An increase or decrease in T_r (and hence T_2) to the left of this design point results in only a modest change in load and an even more modest effect on annual energy.)

The histogram, Figure 6-6, is straightforward and based on similar considerations reviewed for earlier histograms. Between t_s and t_n (Figure 6-5) the DHW load is shown to fall steadily as the hydronic bypass flow reduces and more is directed to the radiant panels to meet space load needs.

Radiant Panel (With Heat Pumps)

With heat pumps, the combined geothermal/heat pump/radiant panel system is capable of meeting the needs of approximately 1,475 apartment units (minimum T_2 of 5°C). This is 200 units less than the baseboard system for similar minimum T_2 value. The reasons are that the lower hydronic temperature T_s feature of radiant panel systems permits more of the geothermal load q_1 to be transmitted



HISTOGRAM - RESIDENTIAL RADIANT PANEL (WITHOUT HEAT PUMPS)

FIGURE 6-6

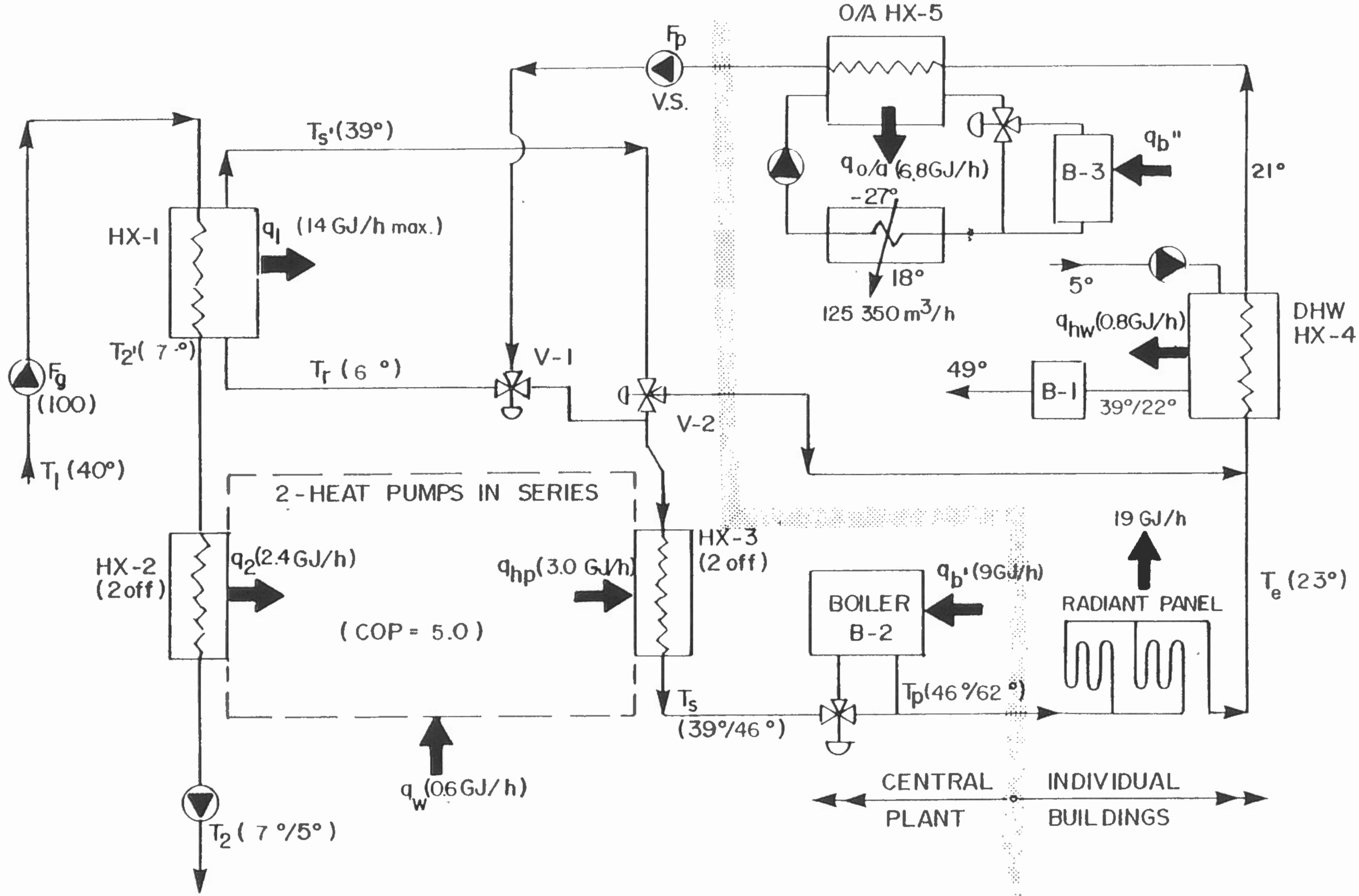
directly, lowering q_2 accordingly; and the lower T_s regime also improves heat pump COP. In combination these factors reduce the compressor work input q_w (Q_w). The net effect is that with less load (and energy) input, fewer apartment units can be heated. This is beneficial in that the electrical energy input is reduced, reducing also the unit energy costs $\emptyset_s$ and $\emptyset_{hp}$. Of course, if more than 1,475 units were required to be heated, a larger peak oil firing load would be necessary to make up the difference.

The figures for the system, Figures 6-7, 6-8 and 6-9, present the system schematic, temperature variations with outdoor air, and histograms, respectively. A similar upward curve in direct load occurs with reducing T_r to the left of the design point.

6.3 Commercial Complex

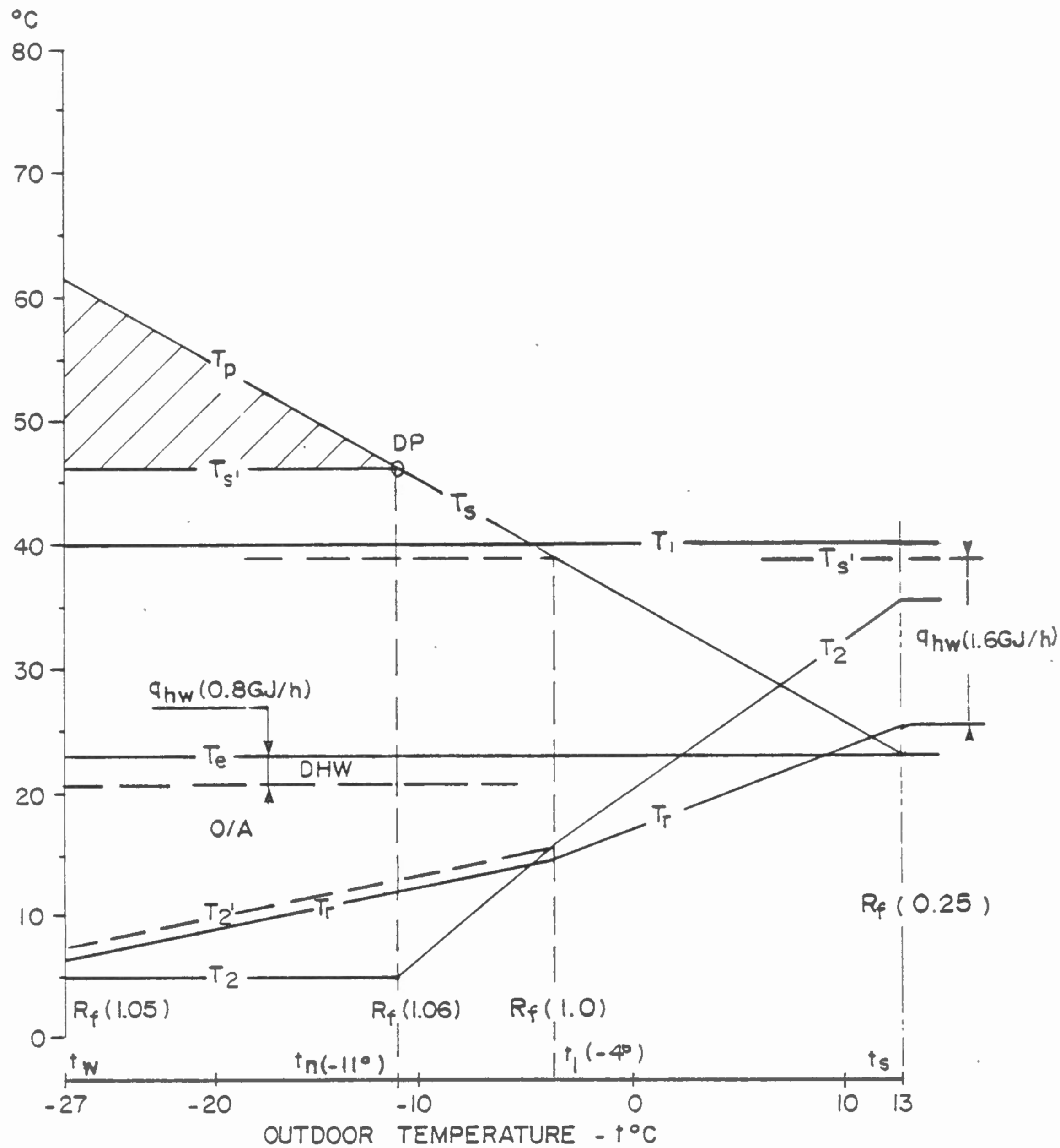
6.3.1 - Description of Commercial Model

The commercial model consists of eight, twenty-storey office buildings. Each floor contains 2,000 m^2 of gross floor area including 140 m^2 of core area. A typical office building floor plan and exterior elevation module were developed for the model resulting in a glazing to gross wall area ratio of 0.46. A wall and roof thermal conductance of 0.28 W/m^2/°C and double-glazed window conductance of 3.12 W/m^2°/C were assumed. Occupancy is based on 9.3 m^2 net floor area per person, equivalent to 200 people per floor, with the offices occupied 12 hours per day, 5 days per week. The winter indoor design condition is 22°C with a night set back to 18°C. The ventilation rate is 25 m^3/h per person during occupied



RESIDENTIAL - RADIANT PANEL (WITH HEAT PUMP) SCHEMATIC

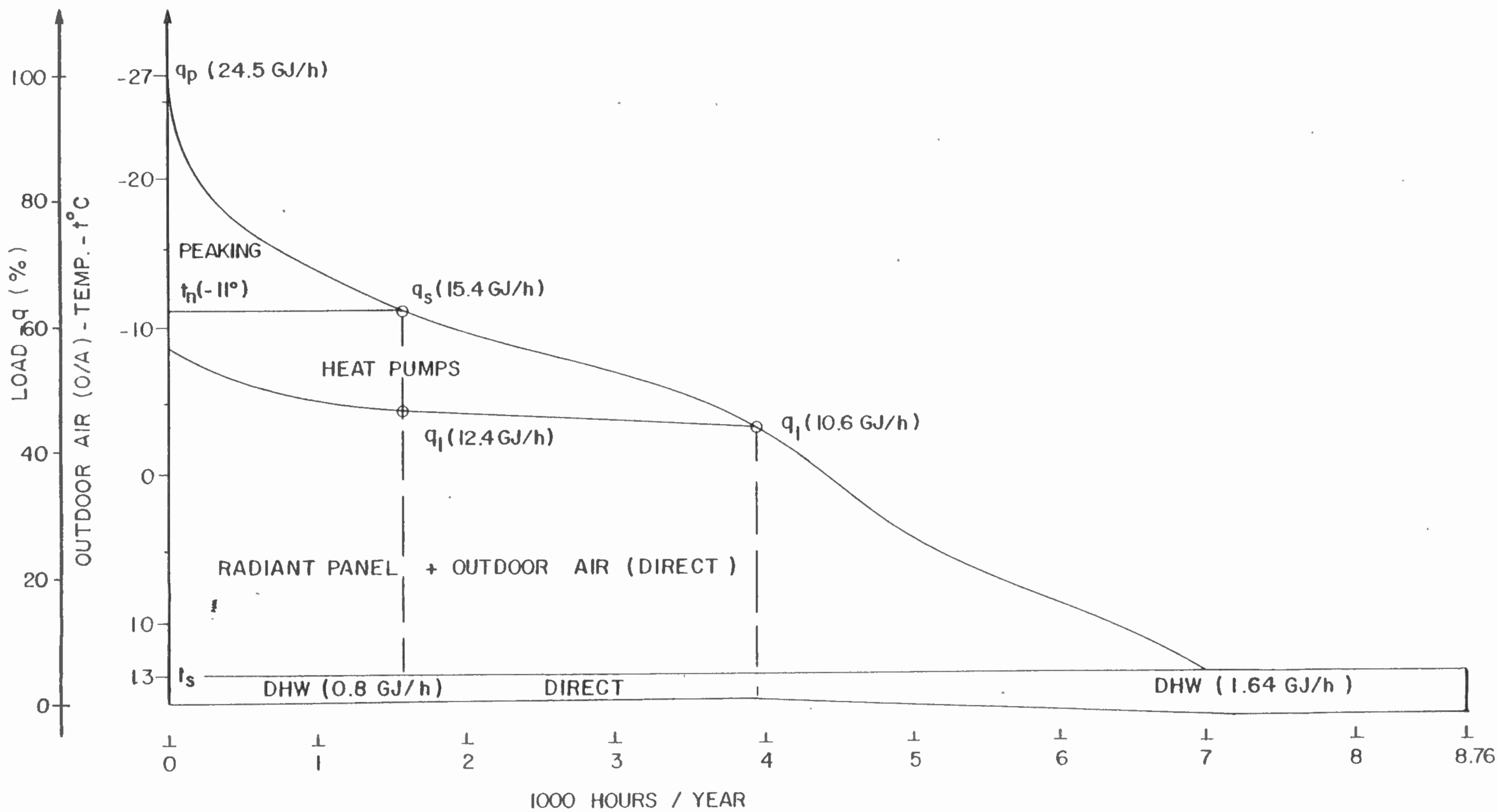
FIGURE 6-7



RESIDENTIAL- RADIANT PANEL (WITH HEAT PUMPS)

SYSTEM TEMPERATURES Vs. OUTDOOR AIR

FIGURE 6-8



HISTOGRAM - RESIDENTIAL RADIANT PANEL (WITH HEAT PUMPS)

FIGURE 6 - 9

ventilation rate is 25 m^3/h per person during occupied hours reducing to 10 percent of this value during unoccupied hours. The estimated electrical energy consumption due to lights and appliances is 27 W/m^2 during the occupied period. Hot water consumption, considered constant throughout the year, averages 0.0076 m^3 per person per day.

The ASHRAE peak design space heating load is 27.5 GJ/h, the domestic hot water load is 1.88 GJ/h and the overall combined peak design heating load is 29.3 GJ/h.

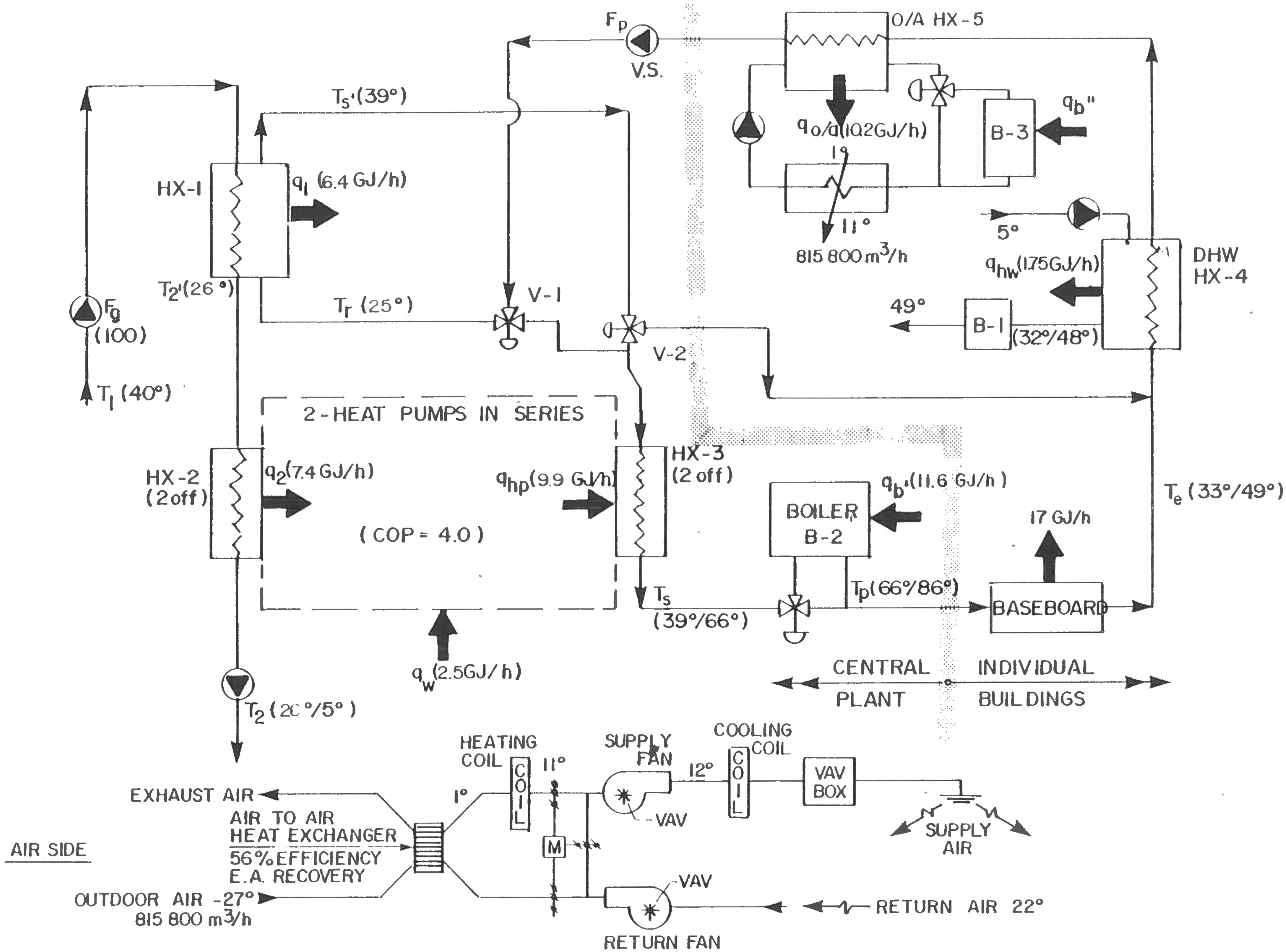
The commercial office building has a cooling load requirement for approximately 28 percent of the year. The cooling load demand fluctuates greatly between the occupied and unoccupied periods due to the variation in people, lighting, ventilation and solar load conditions. For an actual case, the economics of introducing daily storage would be investigated in conjunction with a cooling load analysis.

The cooling requirement necessitates the provision of refrigeration equipment for air conditioning purposes. A portion of this plant including the compressors, motors, drives, and condenser heat exchangers can serve a dual function, operating in the refrigeration circuit during the cooling season and in the heat pump circuit during the heating season by appropriate use of diverting valves. Crediting the cost of these components to air conditioning reduces the heating system capital cost component for heat pumps by approximately $280,000.

Heating System Schematic

Figure 6-10 illustrates the configuration of major components for the commercial building system; the system provides heating of outdoor ventilation air, space heating and domestic water. As shown in the figure, the space heating system comprises a variable air volume (VAV) supply air system and a hot water baseboard system for perimeter heating. In the VAV system, outdoor air passes through an air-to-air heat exchanger (A/A HX) and is preheated by the building exhaust air. The outdoor air load is zero with falling outdoor temperature to -2.5°C and increases linearly to -27°C. At outdoor design conditions of -27°C (t_w) the air-to-air heat exchanger preheats outdoor air to 1°C based on an air-to-air heat exchanger efficiency of 56 percent. The outdoor air then passes through the hot water heating coil, is heated to 11°C and enters the air distribution system at 12°C. The air is then ducted to VAV boxes in each zone and distributed through ceiling diffusers. The interior spaces of the commercial building generally require heat removal throughout the year due to high internal loads from lights and people and limited conductive losses. The supply air is thus heated in the space. On its return it passes through the air-to-air heat exchanger, preheating the incoming outdoor air, and is then exhausted from the building. The perimeter zones of the building are also provided with hot water baseboard heating to offset transmission heating loads.

During unoccupied periods throughout the heating season there is a net heating load. The outdoor air is reduced to 10 percent of the occupied flow rate to pressurize the



COMMERCIAL - BASEBOARD / VAV SYSTEM SCHEMATIC

FIGURE 6-10

building against infiltration during which there is no air-to-air heat exchange. Accordingly, the outdoor air has to be heated from t to 18°C entirely by the coil during unoccupied periods.

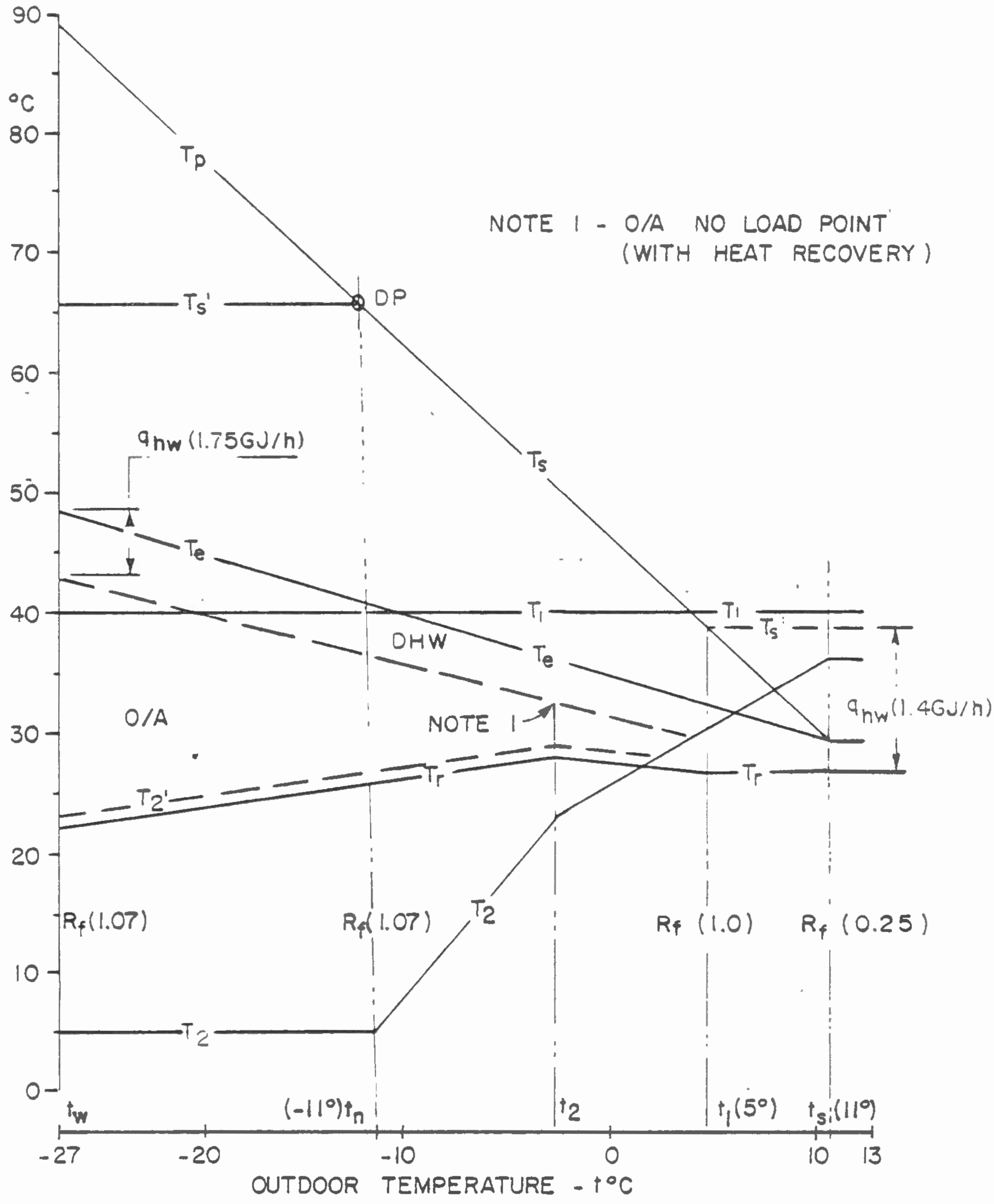
The hydronic system is schematically similar to the residential system and requires no specific explanation with the exception of the outdoor air heating system, as follows. The O/A heat exchanger HX-5 transmits heat to a glycol recirculation system serving the hot water heating coil of the outdoor air system. Between t_s and t_w the entire O/A heating load can be supplied via HX-5.

Figure 6-11 is a plot of heating system temperature vs. outdoor air temperature. The zero space load outdoor temperature (t_s) is 11°C, above which the only load is from the DHW system. Of this 1.40 GJ/h can be supplied by the geothermal system directly, approximately 75 percent of the total. Again, there is a beneficial fall-off in T_r with decreasing outdoor air temperature that assists to reduce heat pump capacity requirements. This is seen in the histogram, Figure 6-12.

6.4 Institutional Complex

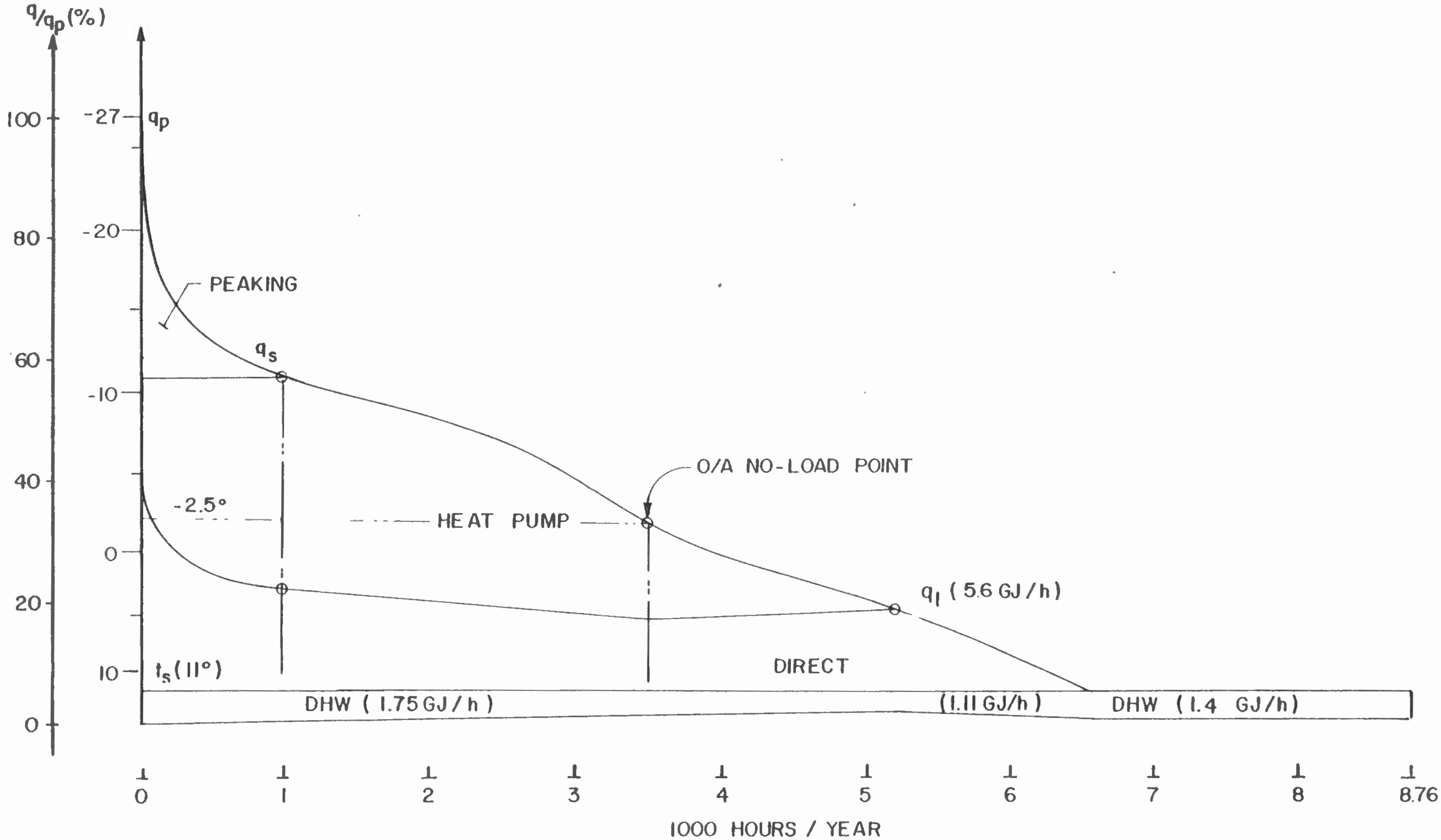
6.4.1 Description of System Model

The institutional application investigated is that of a university. A university complex consists of classroom buildings, administrative office buildings, student housing buildings, laboratories, libraries, cafeterias, activity centers, sports facilities etc. The student housing and administration buildings would have similar load profiles to the residential apartment application and



COMMERCIAL - BASEBOARD / VAV HEATING
SYSTEM TEMPERATURES Vs. OUTDOOR AIR

FIGURE 6-11



HISTOGRAM - COMMERCIAL BASEBOARD / VAV HEATING SYSTEM

FIGURE 6-12

commercial office buildng application looked at previously. This section of the study investigates specifically the load profile for the third major classification, classroom buildings. The institutional model, matched to the single doublet supply, comprise nineteen (19) university classroom buildings, each four stories in height. Each floor constains 2,300 m^2 of gross floor area and contains ten (10) lecture rooms. This number of classroom buildings substantially exceeds a university's demands for such classroom space. Therefore, the heating needs of laboratories, cafeterias, activity centers, sports facilities and other ancillary spaces would be intergrated with classroom needs in an actual university application. The detailed analysis of such an applicaton is outside the scope of this study. Heating demands of a university would also include residential and commercial elements with characteristics similar to those of Section 6.1 and 6.2.

A typical classroom building floor plan and exterior elevation module were developed for the model resulting in a glazing to gross wall area ratio of 0.31. The building walls and roof have a thermal conductance of 0.28 $W/m^2{}^\circ C$ and the windows are double glazed having a conductance of $3.12W/m^2{}^\circ C$. The occupancy is based on 1.8 m^2 per person which is equivalent to 100 people per lecture room. The building is considered occupied 12 hours per day five days per week with a 75 day shut down period in the summer. The winter indoor design condition is 22°C with a night set back temperature of 18°C. The ventilation rate is 25 m^3/h per person during the occupied periods set back to 10 percent of this value during unoccupied periods. The lighting load is $23W/m^2$ during the occupied periods and is shut off during unoccupied periods. The domestic hot water consumption is considered constant throughout the year, averages 0.0076 m^3 per person per day. The ASHRAE peak design space heating load is 22.6 GJ/h, the domestic hot water load is 4.4 GJ/h and the overall combined peak design heating load is 27.0 GJ/h.

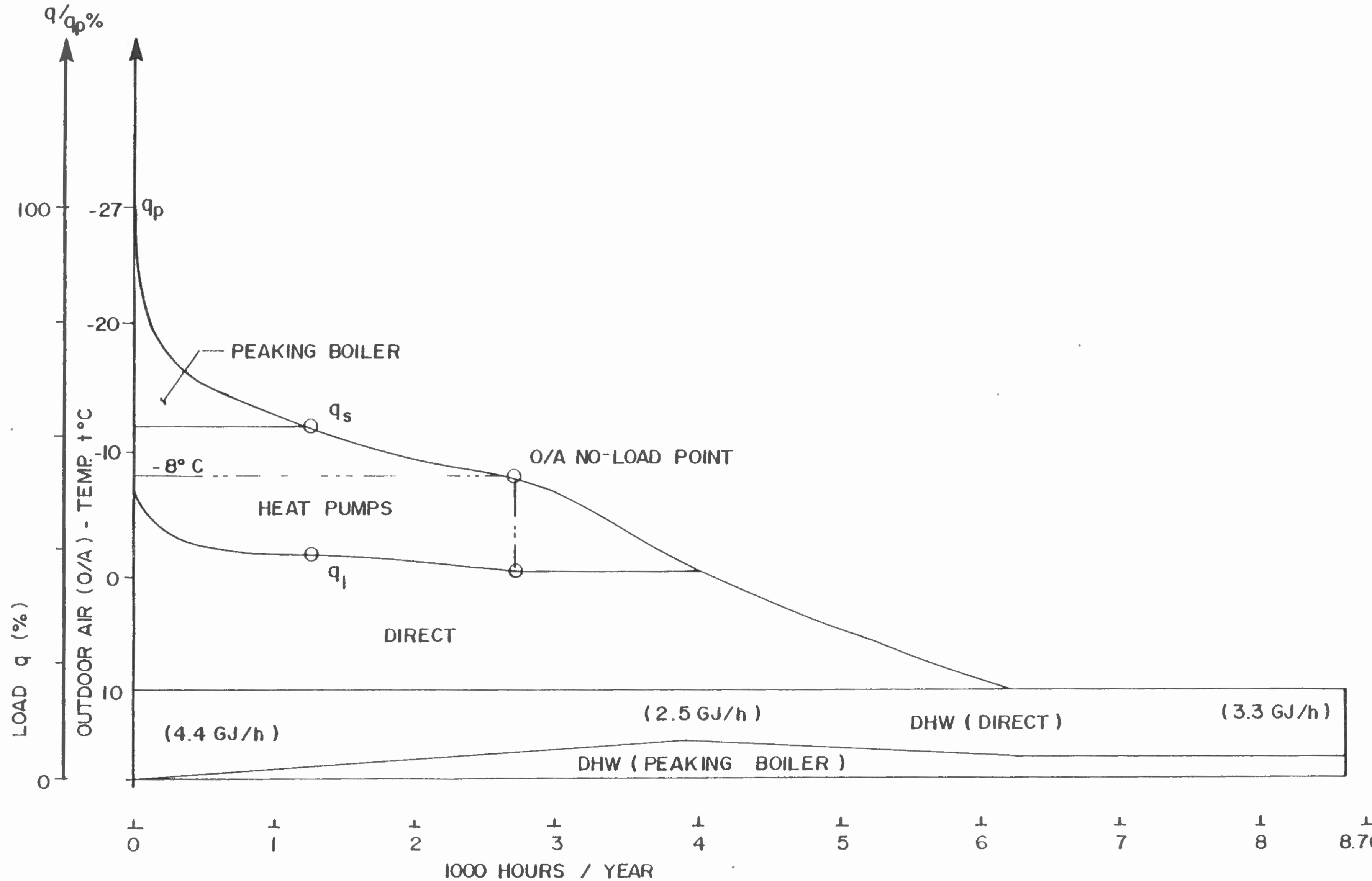
6.4.2 Heating System

The system provides heating of outdoor air, space heating and domestic water heating. The system in terms of its components and operation, is similar to that for the commercial office building described earlier, with a VAV supply air system and perimeter hot water baseboard supplying space heating needs. The system schemetic arrangement is similar to that of Figure 6-10. System temperature variations with outdoor air temperature are also basically similar to that of the commercial application (Figure 6-11) except for specific transition point temperatures.

The histogram load profile is illustrated in Figure 6-13. The high DHW heating load is evident.

6.5 Performance and Cost Evaluations

Performance and cost data from analysis of the various residential, commercial and institutional schemes are presented in Table 6-1. To determine well system costs an arbitrary gradient of 20°C/km was selected as the base condition. From this the depth of formation and geothermal system costs were obtained from Figure 3-4 for the 40°C resource temperature selected for all applications.



HISTOGRAM - INSTITUTIONAL (UNIVERSITY) BASEBOARD / VAV HEATING SYSTEM

FIGURE 6-13

TABLE 6-1

SPACE HEATING APPLICATIONS: PERFORMANCE AND ENERGY COST EVALUATIONS

APPLICATION	RESIDENTIAL			COMMERCIAL	INSTITUTIONAL
HEATING SYSTEM	Baseboard Heat Pumps	Radiant Panel w/o Heat Pumps	Radiant Panel Heat Pumps	Variable Air/ Baseboard/ Heat Pumps	Variable Air/ Baseboard/ Heat Pumps
SIZE	1680 Units	1040 Units	1475 Units	300,000 m^2	175,000 m^2
TECHNICAL DATA					
Gradient °C/km	20	20	20	20	20
Resource Temperature T_1 °C	40	40	40	40	40
Min. Inject Temperature T_2 °C	5		5	5	5
Geothermal TDF	0.875	0.62	0.875	0.875	0.875
Component Design Loads* GJ/h					
q_p demand (incl. DHW)	29.4	17.3	24.5	29.4	27.0
q_b peaking boiler	11.3	6.7	9.3	11.6	9.1
q_1 geothermal direct	4.7	10.6	12.4	6.4	6.2
q_{hp} heat pump capacity	13.3	-	3.0	9.9	6.3
q_g geothermal total	14.85	10.6	14.85	14.85	14.85
q_w work	3.1	-	0.55	2.5	1.6
q_s system supply	18.0	10.6	15.4	16.3	16.45
Annual Energy 1000 GJ/yr					
Q_p process demand	77.43	46.56	65.87	60.45	50.80
Q_b peaking boiler	6.35	2.22	3.21	2.13	1.5
Q_1 geothermal direct	28.98	44.34	54.02	31.5	37.13
Q_{hp} heat pump supply	42.09	-	8.65	26.8	12.16
Q_w work energy	10.52	-	1.73	6.7	3.05
Q_2 geothermal (HP induced)	31.57	-	6.92	20.1	9.10
Q_g geothermal supply	60.55	44.34	60.94	51.6	46.23
Q_s system supply	71.07	44.34	62.67	58.3	49.3
Load Factor					
LF_p process	0.30	0.31	0.31	0.23	0.21
LF_s supply system	0.45	0.48	0.465	0.40	0.34
LF_g geothermal system	0.47	0.48	0.47	0.41	0.36
LF_{hp} heat pump system	0.36	-	0.33	0.31	0.22
CAPITAL & UNIT ENERGY COSTS					
Capital ($1984 Costs) $1000					
Geothermal System*	1,900	1,900	1,900	1,900	1,900
System Incremental Cost	375	300	375	95**	375
Heat Pump System*	650	-	300	560	420
Total	$ 2,925	$ 2,200	$ 2,575	$ 2,555	$ 2,695

Unit Energy Costs (Levelized) $/GJ

Financing Basis	Private	Public	Private	Public	Private	Public	Private	Public	Private	Public
¢$_g$ geothermal (inc. increment)	7.50	5.56	10.05	7.40	7.45	5.46	8.10	6.10	9.83	7.24
¢$_{hp}$ heat pump	14.45	12.00	-	-	16.85	13.60	15.85	13.40	19.10	15.60
¢$_s$ system	11.60	9.40	10.05	7.40	8.75	6.60	11.65	9.45	12.05	9.25
¢$_o$ oil (market)	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45
Geothermal Savings (market)	3.85	6.05	5.40	8.05	6.70	8.85	3.80	6.00	3.40	6.20
¢$_o$ oil (marginal)	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40
Geothermal Savings (marginal)	6.80	9.00	8.35	11.00	9.65	11.80	6.75	8.95	6.35	9.15

Note *Summation of Component design loads does not necessarily equal total demand.

**Credit of $280,000 savings in air conditioning costs assigned.

Annual energy values Q_p, Q_s and Q_1 were obtained by planimeter measurement of the histograms. Values Q_w, Q_2 and Q_g were derived by calculation, using the relationships of Section 2.0, Appendix B. Though an over simplification, annual COP values were assumed to equal heat pump COP values, an assumption which is partially justified considering the use of variable speed drives which greatly assist to minimize the fall-off in COP at low part load conditions. Also, assigned COP_{hp} values are believed to be conservative and probably can be improved upon, depending on the specific equipment selected. A detailed evaluation of heat pump and system performance would be required in order to properly determine part load performance conditions, cost penalties, and design and annual COP values.

<u>System Incremental Costs:</u> The values entered in Table 6-1 are based on a budget estimate of hydronic system costs for equipment over and above that required for conventional oil-fired heating. The schematic baseboard system, Figure 6-1, was used as a model. As indicated in that figure, the primary circuit heat exchangers, HX-1 and HX-2, the heat pump system, peaking boiler B-2 and hydronic circuit pumps are assumed to be located in a central plant with distribution piping running from the central plant to each building in which the individual space heating terminals, DHW system and the ventilation air system are located. It is similarly assumed that the conventional oil fired system alternative would also be located in a central plant with distribution piping to each building. Therefore equipment, common to both the geothermal and oil fired plant is excluded from the incremental costs (i.e. boiler B-2, hydronic pumps, distribution piping to each building, in-building

distribution system, the DHW system, and the ventilation air circulating water system.) These cost specifically include for: geothermal evaporator heat exchangers HX-2; hydronic circuit piping between the geothermal heat exchangers, the heat pump condensers and the peaking boiler; a number of 3-way diverter bypass valves not all of which are shown in the schematics, and an allowance for differences in heating terminal (emitter) equipment. Costs of approximately $20,000 are also included for the provision of local electrical power supply and distribution systems serving heat pumps equipped with electric motor drives.

In Table 6-1 the system cost increment of $375,000 is treated as an appropriate amount suitable, at this conceptual level of investigation, for all applications except for the commercial office building where the amount is reduced by $280,000 to reflect a credit to the heat pump system for avoided air conditioning system costs.

6.5.1 - Unit Energy Costs and Commentary

Table 6-1 unit energy costs were calculated, using the equations of Section 2.0, Appendix B. For the 30 year life base case conditions of Table 6-1, the unit energy cost savings relative to oil are generally encouraging for all applications, even for the residential-baseboard heating application which involves a large heat pump capacity and energy input. As is to be expected, public sector financial criteria, lowering the cost of capital, result in uniformly lower system unit energy costs, ϕ_s compared to those for the private sector. The unit cost ϕ_{hp} of energy (Q_{hp}) delivered by the heat pumps is high and in some cases exceeds the unit cost of oil heating. As the proportion of Q_{hp} to Q_s increases, so will the average cost of energy ϕ_s. The proportions will increase with a lower gradient/lower resource temperature and/or higher hydronic system supply temperature regime (T_s). The improvement in unit cost ϕ_s to be gained from using radiant panel heating, (with its lower hydronic temperature regime) as opposed to baseboard heating, is evident. The ability of the radiant panel system to use the 40°C low temperature resource for direct transfer of up to 60 percent of the maximum load results in attractive cost savings relative to oil even without heat pumps. With heat pump angmentation of the radiant panel heating scheme, the small capacity heat pump system (though expensive in terms of ϕ_{hp}) is effective in lowering the system unit cost ϕ_s and enhances the oil savings potential of a single doublet geothermal supply system by almost 40 percent i.e. from 44,000 to 61,000 GJ/yr.

For the residential-baseboard heating application, the contribution of the three cost components (reference equation 9, Appendix B) - namely geothermal energy, compressor electrical energy, and capital - to heat pump unit energy cost, ϕ_{hp}, is 39, 43, and 18 percent respectively and, for the residential - radiant panel system (with heat pumps) is 35, 29 and 36 percent respectively. The alternative use of IC engine heat pump drives (with an assumed heat recovery utilization value of E_o = 0.75; f = 2.67) would reduce the cost of compressor energy by 30 percentage points and result in a reduction in ϕ_{hp} of 13 and 11 percent respectively for the two applications. Obviously, these potential savings will be reduced if the IC engine drive/heat recovery system capital cost is significantly greater than that of the variable speed electric drive heat pump system.

Unit costs $\emptyset_s$ give an indication of the competitive position relative to oil but do not reflect important tax effects for the private sector nor the position relative to natural gas. Similarly they do not, as presented, allow for such factors as load connection delays which, practically, is an important item reducing savings in the early years. These and other aspects are more appropriately examined through computer aided after-tax discounted cash flow analyses discussed in Section 7.0.

7.0 ECONOMIC EVALUATION OF SPACE HEATING APPLICATIONS

Economic considerations will play a large role in determining whether geothermal developments are implemented in Canada, either by the private sector or the public sector. As noted in Section 6.0, the geothermal projects analyzed in this study are technically capable of providing large quantities of energy and the costs on a per-unit basis for this energy can be competitive with conventional energy forms. These circumstances, however, do not necessarily indicate that entrepreneurs are willing to invest in such systems, that consumers are willing to buy geothermal energy, or even that governments are willing to support such projects.

Appendix A of this report outlines the principal investment criteria and economic assumptions employed in evaluating the economic and financial attractiveness of the five large scale space-heating schemes described in the previous section. Within the scope of this study, it is necessary to make simplifying assumptions to limit the number of variations to be evaluated. However, to provide further indication of the relative importance of key factors in the economic results, several alternative assumptions are tested and comments on the implications of these factors are provided in the following discussion.

7.1 Private Sector Financial Feasibility

Discounted cash flow models are utilized to examine the relative attractiveness of investments in geothermal projects by the private sector. Such analysis assumes that private capital would be forthcoming for such enterprises, provided the after-tax cash flows generated by the project yield a positive net present value (NPV) after discounting these cash flows. The discount factor, or rate, explicitly incorporates the time value of money, the cost of capital to the investor, the investor's assessment of the relative riskiness of the stream of cash flows and the expected returns on alternative investment opportunities.

If an investor, after taking account of these factors, deems that a minimum return of 10 percent is required on a particular type of project, then the after tax cash flows discounted at 10 percent must yield a positive net present value. When such is the case, the interpretation is that the stream of cash flows provides sufficient return to replenish the original invested capital, provide for the cost of this capital (i.e. interest), and supply surplus economic returns in the amount of the NPV.

When the NPV is positive, it can also be said that the internal rate of return (IRR) exceeds the discount rate, or the minimum rate of return required by the investor. As noted in Appendix A, the after-tax "real" discount rate used in this study is 10.8 percent and thus the hurdle rate, or minimum IRR, is 10.8 percent. This rate applies where the investor is a taxable private corporation, as outlined in the Appendix A.

As with any financial analysis, the most critical estimate is the magnitude and timing of the revenues or cash in-flows. Typically, a much greater degree of certainty is available with respect to out-flows, or costs, but the revenue estimate relies on a number of assessments and projections of market conditions in the future.

For this analysis, the revenue stream is assumed to equal the end-use energy value of heating oil displaced by the geothermal system. Since it is expected that natural gas will eventually be available in the Maritimes, the annual savings from displacing this fuel are also examined.

The assumption that revenues will be equivalent to fossil fuel savings is most relevant where the developer and the user of the geothermal energy are the same. Under these circumstances, it is clear that the benefit of the geothermal supply is a direct cash savings to the owner in terms of fuel purchases. Where the developer intends to sell the energy to another party, valuation of the revenue stream is more complex. Certainly such revenues would still be related to the value of the displaced fuel but other factors would also have some impact. Questions such as: should there be a differential value between base load and peak load energy, or are discounts necessary to induce customer hook-ups, or will long-term supply contracts influence prices; and many other market considerations would have to be addressed. Such questions are beyond the scope of this study, however, and the revenue stream used in the analysis herein is simply the value of the displaced fossil fuel.

7.1.1 Cash Flow Analysis

While it has been noted earlier that front end capital costs of geothermal projects are high when compared to conventional heating systems, it is also true that subsequent annual operating costs are lower. It is not surprising then that large negative cash flows occur in the two year drilling and construction period at the beginning of the project but that the cash flows quickly turn positive once the system is operating.

The baseboard heating scheme (Residential 1 case) is a good example (See Table 7-1). Capital and drilling expenditures in the first two years amount to over $2.6 million. However, in the third year, the value of the energy savings is over $950,000 and this level of savings is then available in each of the remaining years of the project. The operating costs off-setting this cash inflow are only about $420,000. Therefore, for less than a $3 million investment, net returns of over half a million are provided annually over the life of the project.

The attractiveness of this situation is indicated by the fact that the hurdle rate NPV for this project is calculated to be over $1.0 million with an IRR of 18 percent. Since temperature gradients will affect the capital costs for the project, computer runs at 15°C/km and 30°C/km were also performed. Even at the lower gradient, the hurdle rate NPV remains positive at $394,000 and the IRR is 13 percent. At the 30°C/km gradient, the IRR improves to 23 percent. Under the circumstances assumed in this analysis, this project is financially viable at even the lowest gradient and at gradients of between 20 and 30°C/km, the potential returns are exceedingly attractive.

Analysis of the other residential, commercial and institutional cases also indicates returns well in excess of the assumed minimum hurdle rate of 10.8 percent. Table 7-2 summarizes the results for all five projects. Only in the Institutional case when gradients are only 15°C/km do returns become less than the minimum requirements. Even so, the same case turns positive with higher

TABLE 7-1

RESIDENTIAL BASEBOARD HEATING CASE: CASH FLOW ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40	
GRADIENT: (DEG. C./KM)	20	
SURFACE TEMP.: (DEG. C.)	5	
HOLE DEPTH: (KM)	1.75	RESIDENTIAL 1
SYSTEM SUPPLY (TJ/YR):	71.07	NO. OF UNITS: 1680
HEAT PUMP CAPACITY: (GJ/H)	13.3	EMITTERS: BASEBOARD
HP WORK ENERGY (TJ/YR)	10.52	

C A S H F L O W S	Y E A R 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		725												
Above-Ground Equipment		425												
Low Temp System Increment		375												
Heat Pump System		325			325									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	1849	0	0	325	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	953.0	962.6	962.6	972.2	981.9	991.7	1001.7	1011.7	1021.8	1032.0	1042.3	1063.2
OPERATING COSTS														
Exploration Drilling Costs	570	81												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			36.0	35.8	35.6	35.5	35.3	35.1	34.9	34.8	34.6	34.4	34.2	34.2
Heat Pump Energy			226.2	228.5	230.8	233.1	235.4	237.8	240.2	242.6	245.0	247.4	249.9	254.9
TOTAL OPERATING COSTS	570.0	80.5	420.2	423.0	425.9	428.8	431.7	434.6	437.6	440.6	443.7	446.8	449.9	456.5
NET OPERATING INCOME	-570.0	-80.5	532.8	539.5	536.7	543.4	550.2	557.1	564.1	571.0	578.1	585.2	592.4	606.7
CAPITAL COST ALLOWANCES														
Class 34 @ 50%	25.0	512.4	949.7	462.4	81.2	162.5	81.2	12.5	25.0	12.5	0.0	0.0	22.5	45.0
LOSSES CARRIED FORWARD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAXABLE INCOME	-595.0	-593	-417	77	455	381	469	545	539	559	578	585	570	562
TAXES @ 40%	-238	-237	-167	31	182	152	188	218	216	223	231	234	228	225
NET INCOME	-357	-355.7	-250.2	46.297	273.27	228.57	281.4	326.77	323.43	335.13	346.86	351.13	341.95	337.01
NET CASH FLOW (NOI-T-C)	-432	-1693	700	509	30	391	363	289	348	348	347	351	274	382

NET PRESENT VALUE @ 3%	5426
NET PRESENT VALUE @ 6%	2902
NET PRESENT VALUE @ 9%	1540
NET PRESENT VALUE @ 10.8%	1022
NET PRESENT VALUE @ 12%	757
NET PRESENT VALUE @ 15%	282
NET PRESENT VALUE @ 18%	-20

TABLE 7-1, Continued

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
			50					740					50					90
0	0	0	50	0	0	0	0	740	0	0	0	0	50	0	0	0	0	90
1084.4	1106.1	1128.3	1150.8	1173.8	1197.3	1221.3	1245.7	1270.6	1296.0	1321.9	1348.4	1375.3	1402.8	1430.9	1459.5	1488.7	1518.5	1548.9
70.1	71.5	72.9	74.4	75.9	77.4	78.9	80.5	82.1	83.8	85.5	87.2	88.9	90.7	92.5	94.4	96.2	98.2	100.1
44.6	44.9	45.1	45.3	45.5	45.8	46.0	46.2	46.4	46.7	46.9	47.1	47.4	47.6	47.9	48.1	48.3	48.6	48.8
36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1
18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2
260.0	265.2	270.5	275.9	281.4	287.1	292.8	298.7	304.6	310.7	316.9	323.3	329.7	336.3	343.1	349.9	356.9	364.1	371.3
463.2	470.0	477.0	484.1	491.3	498.7	506.2	513.9	521.7	529.6	537.8	546.0	554.5	563.1	571.9	580.8	590.0	599.3	608.7
621.3	636.1	651.3	666.8	682.5	698.6	715.1	731.8	748.9	766.4	784.2	802.3	820.9	839.7	859.0	878.7	898.8	919.2	940.1
22.5	0.0	0.0	12.5	25.0	12.5	0.0	0.0	185.0	370.0	185.0	0.0	0.0	12.5	25.0	12.5	0.0	0.0	22.5
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
599	636	651	654	658	686	715	732	564	396	599	802	821	827	834	866	899	919	918
240	254	261	262	263	274	286	293	226	159	240	321	328	331	334	346	360	368	367
359.25	381.67	390.77	392.55	394.52	411.69	429.04	439.1	338.36	237.83	359.5	481.4	492.51	496.35	500.42	519.72	539.25	551.54	550.57
382	382	391	355	420	424	429	439	-217	608	545	481	493	459	525	532	539	552	483

TABLE 7-2

FINANCIAL RETURNS - RESIDENTIAL PROJECTS

Case	Gradient (°C/km)	Hurdle Rate NPV @ 10.8% ($1000)	IRR (%)
Residential 1	15	394	13
(Baseboard)	20	1022	18
	30	1363	23
Residential 2	15	945	16
(Radiant Panel	20	1574	22
with heat pump)	30	1915	28
Residential 3	15	90	11
(Radiant Panel	20	719	17
w/o heat pump)	30	1060	22
Commercial	15	29	11
	20	658	16
	30	999	20
Institutional	15	-107	10
	20	522	15
	30	863	19

Note: Assumes displacement of oil, immediate hook-up and ability to use tax losses against other income.

gradients. At the other end of the range, with the Residential 2 case (radiant panels and heat pump) and a 30°C/km gradient, the hurdle rate NPV is an extremely healthy $1.9 million and the IRR is 28 percent.

Few alternative investments would be expected to provide returns of this order. Resource Planning Associates (1977) conducted a study (15) of the potential for cogeneration development in the U.S. which indicated that 60-70 percent of the possible projects would be undertaken if returns of 20 percent (nominal) could be achieved, and 100 percent of the projects would be accepted if the returns were between 30 and 40 percent. This study was conducted at a time when inflation was running close to 10 percent. Therefore, these findings indicate that most geothermal projects with expected "real" returns of between 10 percent and 30 percent would be accepted. All of the cases summarized in Table 7-2 fall in this range.

7.1.2 Tax Effects on Private Developers

The cash flows indicated in Table 7-1 are influenced in two major ways by taxation measures. Firstly, it has been assumed that geothermal projects would be eligible for the preferential capital cost allowance deductions currently available to other energy conservation projects. Specifically, the Tax Act provides that the capital costs of such investments may be deducted from income at a rate of 25 percent in the year of purchase, 50 percent in the second year and the remainder in the following year. Thus, the company can write off its capital costs in three years, thereby shielding income from taxation and retaining cash in the amount of the capital cost times the tax rate. In the example in Table 7-1, the investment of $2.6 million in the first two years provides a cash benefit, in the form of avoided taxes, to the corporation of $1.0 million. With this tax benefit, the net capital investment is actually reduced by 40 percent.

While not incorporated in the cash flow analysis performed for this study, it should be noted that various investment tax credits would increase even further, and make more immediate, the tax shielding cash flow benefits for geothermal projects.

The second item of note with respect to taxation is the use of losses on one operation as deductions against income of another. As indicated in Table 7-1, the taxable income for the project is negative for the first 3 years. Provided a company has positive taxable income from other of its operations, this negative taxable income from a geothermal project effectively gives rise to negative income tax. This negative tax also represents a positive cash flow to the firm in the year of the loss.

To get the maximum benefit from this factor, however, the company obviously must be large enough and established enough to have existing profitable operations. If a major oil company for example developed a geothermal project, it would therefore be able to reduce its current corporate income taxes by deducting the losses in the early years of the project.

The situation is somewhat less favorable for a small company that may not have sufficient "other income" to take full advantage of the tax losses or which may have been formed specifically to develop the geothermal project, in which case there is no other income at all.

In these circumstances, the losses would have to be carried forward until the company becomes profitable. The amount of the tax benefit would be the same but it would be delayed for several years, thereby making the discounted value of the benefit less.

For the Residential 1 case for example, the hurdle rate NVP at 10.8 percent drops to $834,000 when losses must be carried over, as opposed to $1.02 million in the immediate write-off situation (Table 7-1). Similary, the IRR drops to 16 percent from 18 percent. The same order of magnitude effects can be anticipated for the other cases.

It is clear that large, integrated companies enjoy some advantage as future geothermal developers, at least from a taxation point of view.

7.1.3 Hook-Up Timing Effects

Thus far, the financial analysis of the geothermal developments under consideration has assumed that the full amount of the revenues related to the displaced heating oil are available to the developer in the first year of operation. This assumption is appropriate in cases where the geothermal system is developed for an existing load. Certainly many potential geothermal projects will not face such fortuitous circumstances.

Since the cash flows involved are quite large and the required rates of return are also significant, the timing of the project benefits will be critical to its financial viability. To determine the impact of a prolonged period of consumer hook-up, several computer runs were performed assuming the connected load grew to full capacity over a 5 year period. Thus, for the Residential 1 case, the revenues in the first year are only $190,000 as opposed to $950,000.

The effect of this assumption is much more significant than the loss carry-overs discussed above. Table 7-3 summarizes the financial results for the immediate hook-up versus a 5-year hook-up schedule. In all cases, there is a significant drop in the project net present values and rates of return. If the hook-up period were slower than 5-years, the attractiveness of the projects would decline accordingly. Nevertheless, at the 5 year level, all remain viable but the institutional case is on the borderline. Market penetration will be critical to future geothermal projects and will require more in-depth analysis.

7.1.4 Displacement of Natural Gas

From the foregoing discussion, it is clear that geothermal developments can be attractive private sector investments when heating oil is the displaced fuel. In the analysis described above, it was assumed that the near term increases in oil prices are relatively modest (0 percent to 1985, 0.5 percent to 1990). If actual price escalations are greater than these, the financial viability of geothermal systems will be even more assured.

A question remains, however, as to whether geothermal can compete with natural gas once production from Sable Island is available. Assuming that the end use cost of gas is 75 percent of that for heating oil on an energy parity basis, geothermal still represents an attractive invest-

TABLE 7-3

IMPACT OF HOOK-UP SCHEDULE

Case	Immediate Hook-Up (From Table 7-2) NPV ($1000)	Immediate Hook-Up (From Table 7-2) IRR (%)	5-Year Hook-Up NPV ($1000)	5-Year Hook-Up IRR (%)
Residential 1	1022	18	431	13
Residential 2	1574	22	920	16
Residential 3	719	17	235	12
Commercial	658	16	139	12
Institutional	522	15	37	11

Note: 20°C/km gradient assumed for all cases.

ment with immediate consumer hook-up. In the 5-year hook-up situation, however, financial viability becomes less certain. Since no distribution system for natural gas is in place at the present time in the Maritimes, there is a reasonable expectation that the final delivered cost would exceed 75 percent of the oil equivalent cost barring government subsidization.

In the Residential 2 case for example, with immediate hook-up and a 20°C/km gradient, the hurdle rate NPV is $932,000 and the IRR is 20 percent. This compares with $1.6 million and 22 percent when the displaced fuel is oil. However, if it takes 5 years to reach capacity when displacing gas, the rate of return drops down to 12 percent. As would be expected, if gas is the competing fuel, a rapid rate of customer connections becomes even more critical. Constraints on this study did not allow a fuller investigation of geothermal's competitiveness with natural gas, the likely pricing policies with respect to gas, or the influence of protracted customer hook-up periods. Nevertheless, this preliminary assessment indicates that geothermal could well be a more profitable investment than natural gas installation.

Based on the parameters examined in the foregoing assessment, geothermal system development represents a viable economic opportunity in all but the most pessimistic cases. In many of the cases examined here, such investments offer sufficiently attractive returns that virtually all such projects would be implemented.

Still, despite these positive findings, there has been very little private sector interest in geothermal development. Three related complications are the probable causes of this apparent contradiction. Firstly, many people are simply unaware of the possibilities with geothermal energy. Secondly, not enough is understood about the abundance, quality, locations and reliability of geothermal resources in the Maritimes. Finally, the necessary load demand, or market, to justify geothermal projects is is difficult to find or develop. The uncertainties resulting from these problems cannot be fully captured in any financial analysis and are beyond the scope of this study. The federal government has been examining these issues, however, and it will likely be a government demonstration project which will be required to set aside some of the private sector's doubts. The following section reviews the social benefit/cost considerations relevant to government support of such projects.

7.2 Public Sector Benefits and Costs

In the previous discussion of the financial viability of geothermal projects for private investors, the revenues were assumed to be the equivalent of the market prices of the fossil fuel purchases which would be displaced. Also, the required rates of return (and the discount factor) were predicated on after-tax cash flows and an assumed cost of capital to corporations. However, these considerations are not relevant to the assessment of a government-sponsored project.

The most obvious distinction between government assessment and private is that taxes and other transfer payments do not apply to the government and crown corporations. Therefore, income taxes, capital cost allowances and the deduction of losses play no role in the analysis.

7.2.1 Social Returns

Required rates of return are also at variance when considering government investments. Governments can typically borrow at lower rates than private investors and certain business risks are lessened because the government faces no uncertainty about taxes or other government measures that would affect the private investor's returns. In addition, it is generally assumed that it is appropriate for the government to require lower returns than the private sector in recognition of the social goods derived by the project. Basically, it is argued that society as a whole is more patient than private investors (i.e., lower time value of money) and takes a broader perspective (includes benefits other than direct cash flows, such as employment increases, trade balance impacts, pollution costs, etc.) when evaluating a project. For all of these reasons, then, it is appropriate that the required "social" rate of return be lower than the hurdle rate of the private sector. While there is general agreement on this point, it is difficult in practice to establish the appropriate rate. Treasury Board has suggested that since there is ambiguity regarding the exact rate, all projects should be evaluted at real rates of 5 percent, 10 percent and 15 percent. As noted in Appendix A, the expected hurdle rate for a utility-type crown corporation would be about 6 percent based on its cost of capital. The NPV's provided in this analysis are based on the 6 percent rate.

7.2.2 Marginal Prices

Market prices for energy in Canada reflect a wide range of production costs and sources. Electric power supplied to a provincial grid for example, may be generated by a number of stations, including vintage hydro plants which are virtually paid for, oil-fired thermal plants with high operating costs, and relatively new nuclear plants that were very costly to build. The price of the electricity sold from this grid is based on a blend of these various costs.

Petroleum products in Canada also reflect a blend of costs. Some of Canada's supply is imported, some is from high cost enhanced recovery and tar sands projects, while some is from conventional "old" wells. As a matter of federal government policy, prices are roughly equivalent all across the country such that heating oil in the Maritimes, where virtually all of the supply is from offshore, costs almost the same as in Alberta. Aside from this blending effect, market prices incorporate a number of taxes, subsidies and other transfer payments which further distort the real economic value of the commodity.

When evaluating a new project to provide energy from the public perspective, it should be assumed that the most expensive source of conventional energy is that which would be displaced first. In the case of oil, the cost avoided is that of imported oil because this represents the greatest drain on the Canadian economy both in terms of cash outlays as well as permanent leakages of economic wealth from Canada. This "most expensive alternative" indicates the marginal price which should be used in evaluating the project.

Marginal prices are always greater than market prices since the more economical and less scarce sources of supply are always utilized first. Each increment to the supply is thus more costly than the previous one. For example, an oil company would first exploit its easily accessible, conventionally produced reserves before pushing out to produce from frontier lands or from the continental shelf. The latter will only be brought into production once cheaper sources are no longer adequate. Naturally, the new oil will be more costly than the old.

For this analysis, marginal prices reflecting the economic cost of the next unit of energy supply avoided are used in evaluating the social benefits accruing to geothermal projects. Appendix A provides further rationale for the use of marginal prices and supports the 1990 real price assumption of $16/GJ for oil and gas used in this analysis.

7.2.3 <u>Economic Analysis</u>

Table 7-4 provides the analysis for the Residential 1 case. Note that taxes, loss carry overs and capital cost allowances have no effect on the cash flows. The net cash flows are merely the value of energy cost savings less operating costs and less capital expenditures in each period. Note that by incorporating marginal prices, the savings in the first year of operation become greater than $1.1 million. Also, since marginal prices of electrical energy are used for valuing the consumption of the heat pump system, this cost is $271,000 in the public case, as opposed to $210,000 in the private sector case. Because of the difference in the magnitude of the volumes, however, the increment in the fuel savings value is far more significant. With the hurdle rate NPV at 6 percent of over $6.8 million, this project far exceeds the criteria for government support. The internal rate of

TABLE 7-4

RESIDENTIAL BASEBOARD HEATING CASE: MARGINAL PRICE ANALYSIS

RUN ASSUMPTIONS:

RESOURCE TEMP.: (DEG. C.)	40	
GRADIENT: (DEG. C./KM)	20	
SURFACE TEMP.: (DEG. C.)	5	
HOLE DEPTH: (KM)	1.75	MULTI-UNIT RESIDENTIA
SYSTEM SUPPLY (TJ/YR):	71.07	NO. OF UNITS: 1680
HEAT PUMP CAPACITY: (GJ/H)	13.3	EMITTERS: BASEBOARD
HP WORK ENERGY (TJ/YR)	10.52	

CASH FLOWS	YEAR 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
CAPITAL COSTS														
Land	100													
Exploration and Drilling		725												
Above-Ground Equipment		425												
Low Temp System Increment		375												
Heat Pump System		650			0									
Capital Replacements								50					90	
TOTAL CAPITAL COSTS	100	2174	0	0	0	0	0	50	0	0	0	0	90	0
ANNUAL FUEL COST SAVINGS ($)	0	0	1137.1	1148.5	1148.5	1160.0	1171.6	1183.3	1195.1	1207.1	1219.1	1231.3	1243.7	1268.5
OPERATING COSTS														
Exploration Drilling Costs	570	81												
Geofluid Pumping			61.0	61.6	62.2	62.8	63.5	64.1	64.8	65.4	66.1	66.7	67.4	68.7
O & M Labour			40.0	40.4	40.8	41.2	41.6	42.0	42.5	42.9	43.3	43.7	44.2	44.4
Overhead Allowance			38.0	37.8	37.6	37.4	37.2	37.1	36.9	36.7	36.5	36.3	36.1	36.1
Chemicals and Supplies			19.0	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.3	18.2	18.1	18.1
Heat Pump O & M			36.0	35.8	35.6	35.5	35.3	35.1	34.9	34.8	34.6	34.4	34.2	34.2
Heat Pump Energy			271.5	274.2	276.9	279.7	282.5	285.3	288.2	291.1	294.0	296.9	299.9	305.9
TOTAL OPERATING COSTS	570.0	80.5	465.5	468.7	472.0	475.4	478.8	482.2	485.6	489.1	492.7	496.3	499.9	507.5
NET OPERATING INCOME	-570.0	-80.5	671.6	679.7	676.4	684.6	692.8	701.1	709.5	717.9	726.5	735.1	743.7	761.1
NET CASH FLOW (NOI-T-C)	-670	-2255	672	680	676	685	693	651	709	718	726	735	654	761

NET PRESENT VALUE @ 3%	12205
NET PRESENT VALUE @ 6%	6861
NET PRESENT VALUE @ 9%	3966
NET PRESENT VALUE @ 12%	2293
NET PRESENT VALUE @ 15%	1271
NET PRESENT VALUE @ 18%	615

TABLE 7-4, Continued

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
			50					740					50					90
0	0	0	50	0	0	0	0	740	0	0	0	0	50	0	0	0	0	90
1293.9	1319.8	1346.2	1373.1	1400.6	1428.6	1457.1	1486.3	1516.0	1546.3	1577.3	1608.8	1641.0	1673.8	1707.3	1741.4	1776.2	1811.8	1848.0
70.1	71.5	72.9	74.4	75.9	77.4	78.9	80.5	82.1	83.8	85.5	87.2	88.9	90.7	92.5	94.4	96.2	98.2	100.1
44.6	44.9	45.1	45.3	45.5	45.8	46.0	46.2	46.4	46.7	46.9	47.1	47.4	47.6	47.9	48.1	48.3	48.6	48.8
36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1	36.1
18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2
312.0	318.2	324.6	331.1	337.7	344.5	351.4	358.4	365.6	372.9	380.3	387.9	395.7	403.6	411.7	419.9	428.3	436.9	445.6
515.2	523.1	531.1	539.2	547.6	556.1	564.8	573.6	582.6	591.8	601.1	610.7	620.4	630.4	640.5	650.8	661.3	672.1	683.0
778.7	796.7	815.1	833.8	853.0	872.5	892.4	912.7	933.4	954.5	976.1	998.1	1020.5	1043.4	1066.8	1090.6	1114.9	1139.7	1165.0
779	797	815	784	853	872	892	913	193	955	976	998	1021	993	1067	1091	1115	1140	1075

return is similarly very attractive at 22 percent.

All of the other projects examined here also easily surpass the minimum requirements for project viability.

As with the private sector analysis, economic results will be quite sensitive to the timing of the savings benefits. If a 5-year market penetration schedule is assumed, the Residential 1 case provides an NPV of $5.9 million and an IRR of 18 percent. Clearly, all projects remain attractive even with this qualifier.

Finally, a further test of the viability of a public sector project was performed by using market prices for the energy savings and a 5-year hook-up schedule. Again, the economic returns are well within the acceptable range for public projects. Table 7-5 provides the economic results for the three residential projects under these circumstances.

On the basis of the analysis presented here, public sector investment in geothermal projects is well justified provided a suitable load demand can be established. Public building complexes would be attractive candidates for demonstration projects for a variety of reasons. Generally, such buildings have high visibility in the community and there is support for cost-savings improvements in publicly-funded facilities. Given the potential for social benefits from geothermal development, governments at all levels should have an interest in promoting and supporting feasibility studies and actual projects.

TABLE 7-5

ECONOMIC RETURNS - RESIDENTIAL PROJECTS

Case	Gradient (°C/km)	NPV @ 6% ($1000)	IRR (%)
Residential 1 (Baseboard, heat pump)	15 20	2660 3747	11 14
Residential 2 (Radiant panels, heat pump)	15 20	4029 5116	13 17
Residential 3 (Radiant panels, w/o heat pump)	15 20	1853 2749	11 13

8.0 CONCLUSIONS AND RECOMMENDATIONS

8.1 Conclusions

There is a clear economic potential for direct-use geothermal energy development in the Maritimes. The below-average geothermal gradients in the region will necessitate the use of deep wells to obtain appropriate supply temperatures, or the use of heat pumps. For low temperature resource conditions, heat pumps may be used to raise the supply temperature or to increase the economic utilization of the geothermal system by depressing the geofluid injection temperature, or both.

Economic analyses of geothermal energy relative to commercial and marginal pricing structures for conventional energy indicates that geothermal will become decidedly competitive, for large scale central system space heating applications, with respect to oil and to natural gas (when the latter becomes available) in the Maritimes. The economics of space heating projects with earlier in-service dates than 1990 have not been rigorously examined. However, a provisional inspection of the analysis results indicates that geothermal would probably be competitive if implemented at any time in the future, given the presence of a suitable candidate with a large load demand.

The high level of annual savings that is produced from the displacement of oil (and natural gas) is such that the results are not overly sensitive to reasonable cost variations, either capital or operating. A faster rate of connection to load users (i.e. hook up rate) than the 5 years assumed would improve early revenue (i.e. savings), significantly offsetting greater capital expenditures incurred in the process. Accordingly, a retrofit installation of an enlarged geothermal central heating distribution system (such as a downtown core) with an early connection to a full capacity demand might be economically justifiable depending on the specific situation.

Much investigation is still required to prove up the Maritime resource. Given satisfactory resource conditions, one of the primary constraints to development is the large scale nature of candidate applications required to fully utilize the energy potential from even a single doublet.

Technically, a number of geothermal heating opportunities exist for using very low temperature (VLT) resources of less than 30°C, principally in processes that involve the heating of cold water (e.g. aquaculture heating or the melting of ice or snow). Economically, however, these and similar geothermal applications will frequently face competition from abundant low grade, low cost waste heat from such sources as thermal power plants (cooling water effluents), near-surface aquifers (ground water) or surface water (lakes, rivers), all of which can provide a source of heat suited to heat pump operations. In any feasibility appraisal of energy sources, the alternatives mentioned above should be examined along with VLT and LT geothermal energy options. The most economic of these for a given application will depend primarily on proximity and cost of getting the heat from its source to the application.

Space heating combined with domestic hot water heating is expected to provide the greatest opportunity for using the low temperature geothermal resources. For residential space heating applications and resource temperatures of 40°C or so, the favourable hydronic temperature-load characteristics of radiant panel in-floor heating assist to improve system economics relative to either baseboard or forced air heating. At 40°C, radiant heating combined with some fresh air and DHW heating is competitive without assistance from heat pumps. However, this position is further improved with the use of heat pumps.

For commercial and institutional complexes, the ventilation make-up air load is the more significant since large air flows are required to convey heat build-up from occupied spaces. Low injection temperatures can be achieved with these systems as a consequence of heating outdoor air, though some heat pump assistance is required to improve viability.

8.2 Recommendations

The following recommendations are made.

1. An in-depth analysis should be undertaken to examine costs and technical parameters affecting geothermal economics for space heating applications. The analysis should examine further specific economic sensitivities of such factors as: additional costs for extending system to central heating, varying load hook-up schedules, particular operating cost impacts (e.g. potential re-injection pressure variations with effect on pumping power), and others.

2. Further work should be done with regard to proving up the resource, geofluid quality and assessment of

resource boundaries, particularly to confirm the presence of the resource in the vicinity of major communities and the depth of producing formations.

3. Specific opportunities for geothermal heating at various localities in the Maritimes should be studied, not necessarily only space heating applications. This work would include visits and an examination, at an overview level, of central and district heating opportunities in the larger communities, and examination of the requirements necessary to achieve economic viability with respect to both marginal and commercial energy pricing conditions.

4. A technical and economic evaluation of heat pump space heating applications should be performed where the heat source is a low temperature shallow aquifer. This would include identification of the conditions, technical and economic, at which the use of shallow aquifers would defer to the use of deep geothermal resources.

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APPENDIX A
ECONOMIC PARAMETERS AND ASSUMPTIONS

The following economic and financial assumptions have been employed in the financial analysis discussed in Section 7.0.

1.0 General

- All costs are expressed in constant January 1984 Canadian dollars.

- Capital Expenditure Schedule:
  - 1987: land, exploration drilling and testing (30 percent of total)

  - 1989: production drilling and above ground system (70 percent of total)

  - 1990: in-service date

  - every 5 years after 1990: replacement of down-hole pumps

  - every 10 years, replacement of wellhead equipment

  - every 20 years after 1990: replacement of heat pump systems

  (Note: 1990 in-service date is selected as the expected earliest time for significant geothermal development)

- Capital Cost Allowances:

- Class 34 - Energy Conservation Equipment: Class 34 provides accelerated write-offs for energy systems certified by the Minister of Energy, Mines and Resources to be qualified. However, the tax regulation specifying Class 34 applies to qualifying assets acquired before 1985. The provision is currently under review by the federal government and it is likely that this or some other tax benefit would be extended to energy conservation projects beyond 1985. For the purposes of the analysis, Class 34 CCA's at a rate of 50 percent have been assumed.

o Exploration and Development Expenses:

- Exploration Expense: prospecting, exploring, sampling, testing and drilling the first production well. (Expensed in year incurred or carried over to offset income of other years).

- Development Expense: production well completion, injection wells, above-ground well equipment costs are capitalized.

o Project Life: 30 years

2.0 Price Level Changes

Since all amounts used in the financial analysis are in 1984 constant dollars, only real changes in relative price levels are relevant. Similarly, interest or discount rates are stated in real rather than nominal terms to exclude the effects of general inflation.

Predicted real annual growth rates for project components are based on a consensus of opinion from the Economic Council of Canada, the Conference Board of Canada, Energy Mines and Resources Canada, the Atlantic Provinces Economic Council, Dept. of Energy and Forestry (P.E.I.), Energy Secretariat (New Brunswick), Ministry of Energy (Nova Scotia), and Data Resources Inc. Predictions for the period beyond 2000 were not available and the values used are based on extrapolations assumed for this study.

Period	Maintenance	Labour	Capital	Energy*
1984-85	-0.8	-1.0	-0.8	0.0
1986-90	-0.5	0.5	-0.5	0.5
1991-2000	-0.5	1.0	0.0	1.0
2001-2030	0.0	0.5	0.0	2.0

*Based on estimates of world oil prices (WOP).

Of the above growth rates, the economics of future geothermal developments will be most sensitive to changes in relative prices of conventional energy. As is discussed below, it is assumed that the prices of natural gas, coal and electricity move parallel to petroleum prices. As such, the growth rates shown here are basically those forecast for world oil prices.

The near-term reductions in the prices of maintenance, labour and capital reflect general expectations of improving productivity in the economy as a whole, as well as gains resulting from further experience with geothermal development and technology, in particular.

3.0 Value of Displaced Energy

Since it is assumed in this study that possible geothermal developments would, at the earliest, be in service in 1990, it is necessary to estimate the value of conventional energy which would be displaced (at that time). Several considerations influence such an estimate, but the relationship of domestic market prices to world prices and the notion of marginal prices are key factors.

The forecast growth rates described in the previous section apply to world oil prices. However, in Canada, domestic petroleum product prices are a blend of lower priced domestic conventional oil, higher priced new and enhanced recovery domestic oil, and imports. Due to recent reductions in world oil prices, the Canadian blended price and the import price are quite close (e.g. Montreal blended price of about $34 per barrel and world prices of between $36 and $39). Over the remainder of this decade, it is expected that "new" oil will represent more and more of the Canadian blend such that domestic prices will increase faster than world prices. By 1990, domestic prices will have substantially closed the gap with world prices. Such increases represent a real escalation rate of about 1.6 percent per year for domestic market prices through this period or a total increase of 10.5 percent in 1984 dollars. This price jump is assumed in the economic analysis with respect to crude oil costs. Beyond 1990, it is assumed domestic oil costs will move with the general price increase expected for world prices provided in the previous section.

The actual fuel of interest in this analysis is heating oil rather than crude oil. For the purposes of this study, it is assumed that current heating oil prices of about 1.27 times the crude oil prices will remain constant.

Natural gas is not currently available in the Maritimes but offshore reservoirs have been discovered on the Scotian Shelf. Mobil Oil, one of the major developers of the field, has projected an in-service date of 1988 for natural gas distribution in Nova Scotia and New Brunswick.

Delineation wells are being drilled now and the probability of commercial development is considered fairly high. Therefore, it is assumed that gas will be available in this study. For the purposes of this analysis, it is assumed that natural gas will be priced at about 75 percent of oil on an energy parity basis.

Given the foregoing assumptions, the 1990 market prices of energy are developed in Table A-1 following. The unit energy costs indicated in the table represent the gross value of energy savings that could be realized by a developer of geothermal energy. If the developer plans to sell the energy, the unit costs represent the maximum revenue that could be expected, assuming geothermal must at least match the cost of heating oil to successfully compete.

From a social benefit/cost and economic efficiency viewpoint, however, these market prices may not necessarily represent a true indication of the value of displaced conventional energy. For this type of analysis, the appropriate value is the economic cost of

TABLE A-1

1984 ACTUAL AND 1990 ESTIMATED ENERGY COSTS

(1984 DOLLARS)

Energy Type	Market Price	Energy Content	Conversion Efficiency	1984 Energy Unit Cost	1990 Energy Unit Cost (non-levelized)
Heating Oil	35.5¢/L	39 MJ/L	.75	$12.14/GJ	$13.41/GJ
Electricity: (General Service Accounts)					
o New Brunswick	6.0¢/kWh	3.6 MJ/kWh	1.0	16.67/GJ	18.42/GJ*
o Prince Edward Is.	11.5¢/kWh	3.6 MJ/kWh	1.0	31.94/GJ	35.29/GJ*
o Nova Scotia	6.7¢/kWh	3.6 MJ/kWh	1.0	18.61/GJ	20.56/GJ*
Natural Gas	N.A.	1.073 GJ/mcf	.75	N.A.	10.05/GJ

* For study purposes, a base value of $20/GJ is used for electricity costs. However, it is recognized that electric costs are significantly higher in Prince Edward Island.

the next unit of energy supply avoided, or the "marginal price." As with any scarce resource, the marginal price of energy would be expected to be higher than the market price. Marginal prices are used in analyzing the economic benefits associated with geothermal development in the context of the Canadian economy.

EMR recommendations on the implementation of oil reduction measures by the federal government suggest that it is appropriate to evaluate oil savings after applying a "crown premium". This premium is designed to reflect the true economic benefits to Canadian society of avoiding the outlay for incremental imported oil. The premium explicitly recognizes the fact that imported oil represents an increasingly scarce, non-renewable commodity, the supply of which is not controlled by Canada and the purchase of which results in a direct reduction in the balance of trade.

Marginal prices are used in the analysis of social benefits and costs ascribed to geothermal development from the perspective of the Government of Canada. For the purposes of this study, an average premium of 20 percent is assumed. After adjusting for conversion efficiency, the marginal end-use energy costs applied in this analysis are as follows:

Energy Type	1990 End-Use Marginal Cost ($ GJ)
Heating Oil	16.00
Electricity	
New Brunswick	22.10
Prince Edward Is.	42.35
Nova Scotia	24.65
Natural Gas	16.00

Note that at the margin and assuming an average conversion efficiency of 75 percent for both gas and oil, natural gas would be expected to be roughly the same price as oil since the only economic differences between the two would be those arising from differences in the cost of distribution.

4.0 Investment Criteria

To judge the financial and economic viability of geothermal development, a standard discounted cash flow model is utilized in the analysis. In the financial analysis, where the project is evaluated from the perspective of a private investor, the following investment criteria and assumptions are applied to the after tax cash flows generated by the project:

Tax rate (average):	40%
Revenue:	market prices (as in Table A-1)
Debt/Equity Ratio:	35/65
Cost of Debt (before tax):	5% (real)
(after tax) :	5% (1-.4) = 3%
Cost of Equity:	15% (real)

Weighted Average Cost of Capital:

.35(5%)+.65(15%) = 11.5% (before tax)

or

.35(3%)+.65(15%) = 10.8% (after tax)

Therefore, the discount rate used in the cash flow analysis is 10.8 percent and the hurdle rate which the internal rate of return (IRR) must exceed is 10.8 percent to indicate a viable project.

It should be noted that the foregoing investment criteria would apply to a completely private developer of geothermal energy such as would be the case if an industrial company were to analyze such a project for supplying heat to its own processes. It must be recognized that the development of geothermal energy represents a relatively risky investment for a private developer given the uncertain returns. Exploration and drilling risks, along with uncertainties regarding the resource's useful life, would cause the investor to demand a relatively high rate of return. Under these circumstances, 15 percent is considered a reasonable minimum hurdle rate.

An alternative which would also be appropriate for analysis would be a scenario in which the developer is a regulated utility/crown corporation type of organization. Under these circumstances, the debt/equity ratio could be more like 90/10 and the corporate income taxes would be nil. Thus, the hurdle rate for such an entity would be lower (e.g. 5-6 percent). This type of arrangement would basically be a hybrid of private and government sponsorship of geothermal development.

For the social benefit/cost analysis where the perspective is that of the government of Canada, taxes obviously are merely transfer payments and not relevent to the cash flows. Marginal prices are the appropriate value for the revenues or cash inflows. The appropriate discount rate or hurdle rate should theoretically be the social rate of return. While difficult to establish precisely, the social discount rate should be lower than the private discount rate. For the purposes of this study, the Treasury Board's recommendation that projects be evaluated at 5, 10 and 15 percent is followed.

The base case application of levelization factors to calculate energy unit costs over the assumed project life of 30 years is 1.15. This factor reflects the cost of capital to the proponent and the increasing real cost of energy over time.

APPENDIX B

GEOTHERMAL/HEAT PUMP SYSTEM RELATIONSHIPS

1.0 Basic Relationships

Loads (GJ/hr)

With reference to Figure 4-1 of the main report:

Process demand $q_p = q_s + q_b$

Supply system $q_s = q_g + q_w + q_{wr} + q_b$

$= q_g + f.q_w + q_b$ -- eq. 1

Geothermal $q_g = q_1 + q_2$ -- eq. 2

where q_g is a function of TDF

Heat Pump $q_{hp} = q_2 + f.q_w$ (Case 1) -- eq. 3

and $q_{hp} = q_i + q_w$ (Case 2) -- eq. 4

Annual Energy (GJ/yr)

$$\begin{aligned} Q_s &= Q_1 + Q_2 + Q_w + Q_{wr} \\ &= Q_1 + Q_2 + f.Q_w \\ &= Q_g + f.Q_w \\ & \quad Q_g + \frac{f.Q_2}{(ACOP_{hp} - 1)} \end{aligned}$$

where Q_2 is portion of geothermal energy supply Q_g made available by heat pumps.

Let $Q_2/Q_g = r$

Then $Q_s = Q_g \left\{ 1 + \frac{f.r}{(ACOP_{hp} - 1)} \right\}$ -- eq. 5

and Q_g, a function of UF, is determined from Figure 3-3.

2.0 Heat Pump and System Energy Costs

The cost of energy delivered by heat pumps is a function of geothermal supply system energy costs, heat pump COP_{hp} (and COP_s), fuel (or electricity) prices, and capital (investment) cost of the heat pump (and WHR) system.

The unit cost $\not{0}g$ of geothermal supply system energy is a function of UF which is, influenced by the heat pump's effect on the geothermal system TDF. Annual costs of the geothermal/heat pump system operation, with waste heat recovery accounted for, are as follows:

Annual Cost of System Energy Q_s (levelized):

$$\not{0}_s \cdot Q_s = \not{0}_g \cdot Q_g + \not{0}_e \cdot \frac{f}{E_o} \cdot Q_w + I_{hp} \cdot F_{cr} \qquad \text{-- eq. 6}$$

where $f/E_o = 1/E_w$ (or $1/E_e$ for electric drive)

Levelized Unit Energy Cost $\not{0}_s$:

$$\not{0}_s = \not{0}_g \cdot \frac{Q_g}{Q_s} + \not{0}_e \cdot \frac{1}{E_w} \cdot \frac{Q_w}{Q_s} + \frac{I_{hp} \cdot F_{cr}}{Q_s}$$

$$= \frac{Q_g}{Q_s} \left\{ \not{0}_g + \frac{\not{0}_e \cdot r}{E_w\,(ACOP_{hp}-1)} \right\} + \frac{I_{hp} \cdot F_{cr}}{Q_s}$$

Substituting Q_s from eq. 5 gives:

$$\not{0}_s = \frac{1}{1 + \dfrac{f.r}{(ACOP_{hp}-1)}} \cdot \left\{ \not{0}_g + \frac{\not{0}_e \cdot r}{E_w(ACOP_{hp}-1)} + \frac{I_{hp} \cdot F_{cr}}{Q_g} \right\} \text{- eq. 7}$$

The annual cost of heat pump energy, Q_{hp} is derived as follows for Case 1 (Figure 4-1):

Annual Cost of Heat Pump Operation (Levelized)

$$\text{Ø}_{hp} \cdot Q_{hp} = \text{Ø}_g \cdot Q_2 + \text{Ø}_e \cdot \frac{Q_w}{E_w} + I_{hp} \cdot F_{cr} \qquad \text{-- eq. 8}$$

Levelized Unit Energy Cost Ø_{hp}:

From eq. 8 and substituting for Q_{hp}, gives:

$$\text{Ø}_{hp} = \frac{1}{1 + \frac{f}{(ACOP_{hp}-1)}} \left\{ \text{Ø}_g + \frac{\text{Ø}_e}{E_w} \cdot \frac{1}{(ACOP_{hp}-1)} + \frac{I_{hp}F_{cr}}{Q_2} \right\} \qquad \text{-- eq. 9}$$

Assumptions for specific terms in the above equations 6 through 9 are as follows:

Ø_e, energy price (levelized):

	$/GJ
diesel fuel (1.1 x heat oil)	$12.75
ref. nat. gas (75% of heat oil)	$ 8.70
electricity - average (excluding PEI)	$23.00
- PEI	$38.35

$I_{hp} \cdot F_{cr}$, is annualized cost of total heat pump and WHR system investment, I_{hp}

$ACOP_{hp}$ is calculated or assigned

F_{cr}, real annual fixed charge rate on heat pump/WHR system (20 year life) as percentage of I:

typ. private sector (i = 11.5%)	0.18
typ. public sector (i = 5%)	0.13

r, ratio of geothermal energy made available (Q_2) to total geothermal energy (Q_g)

For electric motor drivers, r, in the above equations, will equal unity and E_w will be replaced by E_e. The annual average $ACOP_{hp}$, is defined as:

$$ACOP_{hp} = \frac{Q_2 + Q_w}{Q_w}$$