RESEARCH REPORT

Cogeneration Systems in Multi-Unit Residential Structures

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COGENERATION SYSTEMS IN MULTI-UNIT RESIDENTIAL STRUCTURES

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DISCLAIMER

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EXECUTIVE SUMMARY

Cogeneration involves using the waste heat from the production of electricity. Equipment suited to multi-unit residential structures comprises a fossil fuel reciprocating engine and an electrical generator. It has environmental benefits in that approximately 75% of the resource energy is converted to useful output compared to under 30% for traditional methods of generating electricity.

The consultant: reviewed cogeneration products, determined the characteristics of the thermal and electrical loads in multi-unit residential buildings, developed design concepts and cost budgets for four of the buildings, and assessed the financial worth of these "benchmarks".

Equipment is available down to 30kW (suited to a 40 to 60 unit apartment building). Equipment for smaller buildings is currently undergoing field tests. Alternative approaches for an installation are:

- having a consultant design and a contractor install and maintain a system, and
- having an organization finance, design, install and operate the facility.

In the latter case payment to the Energy Service Company (ESCO) would be from the energy savings over a 5 to 7 year period.

Ten (10) buildings were analyzed using a conventional industry "level 1" (screening) assessment. Utility bills provided monthly electrical demand, and electrical and natural gas consumption and cost. The cogeneration unit size was based on the summer domestic water heating load. The industry recommends at least 9 months full load operation. For most Canadian cities, residential space heating lasts 8 months, domestic water 12 months, and pool heating up to 12 months. the average electrical demand ranged from less than 400 watts/unit for condominium apartments, to between 500 and 750 watts/unit for the rental apartments. The methodology described in Part 1 of the report use the blank charts, graphs and tables provided in Appendix A.

A "level 2" (Preliminary Engineering) assessment, described in Part 2 and Appendix B, was performed on buildings selected to provide a range of sizes, namely: 118 units (40kW), 230 units (125kW), 270 units (175kW) and 502 units (275kw).

Appendix C displays the 40% and 100% cogeneration unit thermal outputs on hourly profiles reported by Ontario Hydro in ASHRAE. The profiles indicate that the unit may cycle (typical units operate down to 40% rated capacity before cycling) from midnight till 5:00, and be unable to provide for the peaks between 7:00 to 11:00 and 17:00 to 19:00. An ideal system would have storage tanks to enhance energy exchanges between these intervals. In general, the systems should operate more than the 9 months noted above.

The viability of cogeneration depends on: the ratio of electrical to fossil fuel costs, the system installed cost, the building (system) size and occupancy, and the design of the domestic water heating and electrical power systems. Specifically:

- the ratio of the electrical-to-fuel cost ranges from 1.8 (propane in the Atlantic) through 4.1 (gas in Ottawa) to 6.3 (oil in the NWT), (Appendix D);
- the total installed costs for the four "benchmark" buildings range from $1440 per kW (largest at 275kW) to $2250 per kW (smallest at 40kW);
- it is impractical to connect a cogeneration unit to domestic water heaters in individual units (a central domestic water heating system is required);
- the cogeneration unit output was approximately the same as the average daily domestic water thermal requirements and less than 80% of the average monthly electrical demand for the building.

The cogeneration equipment cost ranged from 40% to 50% of the total installed cost. Based on achieving the system performances noted in Fig. 1, simple payback periods from 7 to 15 years were obtained for Ottawa and Toronto.

Installations in existing buildings may require substantial work to incorporate a cogeneration unit. If the structural, electrical, gas supply, crane, etc, costs are substantial, and the unit size is less than 100kW, there is no financial benefit for such a system.

Cogeneration in residential structures may have potential:

- in new buildings where the items noted previously do not apply, or their incremental cost is small,
- when the installation will result in avoiding the replacement of other equipment (domestic water heater, electrical transformer, etc.),
- if costs are reduced (eg. ESCO's standardize designs, obtain financing, provide warranties, streamline design and installation, improve performance, reduce maintenance requirements, etc.), or
- where the building is not connected to an electrical utility grid.

Additional work is required to:

- perform a "level 3" (Detailed Engineering) design, and monitor the operation of different system sizes. The estimated and actual performance should also be compared to that in Fig. 1; and
- perform a sizing sensitivity analysis and review the cogeneration selection procedure.

INSTALLATIONS DE COGÉNÉRATION POUR LES TOURS D'HABITATION

La cogénération est le fait d'utiliser l'énergie résiduelle de la production d'électricité. L'équipement convenant aux tours d'habitation comprend un moteur alternatif à combustible fossile et un générateur électrique. Du point de vue écologique, cette technique est avantageuse puisque environ 75 p. 100 de l'énergie de la source est transformée en puissance utile comparativement à seulement 30 p. 100 avec les méthodes traditionnelles de production d'électricité.

Le consultant a examiné les produits de cogénération, caractérisé les charges thermiques et électriques des tours d'habitation, établi des principes de conception et des budgets de dépense pour quatre des bâtiments et évalué la valeur financière de ces immeubles de référence.

Les plus petites installations offertes ont une capacité de 30 kW (ce qui convient à un immeuble de 40 à 60 appartements). Des installations destinées à de plus petits immeubles en sont présentement au stade des essais en service. L'aménagement d'une installation peut se réaliser ainsi :

- un consultant conçoit l'installation et un entrepreneur la met en place et l'entretient;
- une entreprise finance, conçoit, met en place et exploite l'installation.

Dans le dernier cas, le paiement versé à l'entreprise de services éconergétiques serait tiré des économies d'énergie réalisées sur une période de cinq à sept ans.

Dix immeubles ont été analysés au moyen d'un examen courant dans l'industrie visant à déterminer la viabilité d'une installation (phase 1). Les factures des services publics ont servi à déterminer, pour un mois donné, la demande en énergie électrique, la consommation de gaz naturel et d'électricité ainsi que le coût. La capacité de l'installation de cogénération a été établie à partir de la charge de chauffage de l'eau durant l'été. L'industrie recommande un fonctionnement à pleine charge pendant neuf mois. Dans la plupart des villes canadiennes, le chauffage des résidences s'étale sur une période de huit mois, l'eau est chauffée durant douze mois et les piscines sont chauffées jusqu'à 12 mois. La demande moyenne d'électricité varie de moins de 400 watts par logement pour les immeubles en copropriété à entre 500 et 750 watts par logement pour les immeubles locatifs. La méthode décrite dans la première partie du rapport met à contribution des diagrammes, des graphiques et des tableaux vierges figurant à l'annexe B.

Une évaluation technique préliminaire (phase 2), décrite dans la deuxième partie et l'annexe E, a été réalisée pour les immeubles choisis pour illustrer un éventail de capacités, soit 118 logements (40 kW), 230 logements (125 kW), 270 logements (175 kW) et 502 logements (275 kW).

L'annexe G fait état des puissances thermiques à 40 p. 100 et à 100 p. 100 de l'installation de cogénération selon des profils horaires signalés par Ontario Hydro dans une publication de l'ASHRAE. Ces profils indiquent que l'installation peut être soumise à des cycles (habituellement, ce genre d'installation fonctionne à 40 p. 100 de sa capacité nominale avant d'amorcer un nouveau cycle) de minuit à 5 h et ne pas pouvoir satisfaire aux demandes de pointe entre 7 h et 11 h et entre 17 h et 19 h. L'installation idéale disposerait de réservoirs de stockage afin d'accroître l'échange d'énergie thermique entre ces périodes. En général, les installations devraient fonctionner plus que les neuf mois indiqués plus haut.

La viabilité de la cogénération dépend du rapport entre le coût de l'électricité et le coût du combustible fossile, du coût de l'installation en place, de la taille de l'immeuble (capacité de l'installation), du type d'occupation du bâtiment ainsi que du genre d'installation utilisé pour le chauffage de l'eau et l'alimentation électrique. Ainsi :

- le rapport coût de l'électricité coût du combustible varie de 1,8 (propane, région de l'Atlantique) à 6,3 (mazout, T.-N.-O.) en passant par 4,1 (gaz, Ottawa);
- les coûts totaux de l'installation en place pour les quatre immeubles de référence se situent entre 1 440 $ le kW (pour le plus gros bâtiment, capacité de 275 kW) et 2 250 $ le kW (pour le plus petit bâtiment, capacité de 40 kW);
- on ne peut raccorder une installation de cogénération au chauffe-eau de chaque logement (il faut plutôt se doter d'une installation centrale de chauffage de l'eau);
- la puissance de l'installation de cogénération correspond approximativement aux besoins thermiques quotidiens pour le chauffage de l'eau et à moins de 80 p. 100 de la demande mensuelle moyenne en électricité pour l'immeuble.

Le coût de l'équipement de cogénération représente de 40 à 50 p. 100 du coût total de l'installation en place. Lorsque la performance des installations sont conformes aux données de la Figure 1, des délais simples de 7 à 15 ans ont été réalisés à Ottawa et à Toronto pour récupérer les coûts.

L'équipement déjà en place dans les bâtiments existants peut nécessiter d'importants travaux afin de permettre l'intégration d'une installation de cogénération. Si les coûts afférents aux structures, à l'électricité, à l'alimentation en gaz, à l'utilisation d'une grue, etc. sont considérables et que l'installation a une capacité inférieure à 100 kW, ce genre d'aménagement n'offre aucun avantage financier.

La cogénération dans les tours d'habitation peut être prometteuse :

- pour les bâtiments neufs qui n'entraîneront pas les coûts additionnels susmentionnés ou dont les coûts différentiels seront négligeables;
- si l'installation permet d'éviter de remplacer de l'équipement existant (tel qu'un chauffe-eau, un transformateur électrique, etc.);
- si les coûts sont réduits (p. ex. les entreprises de services éconergétiques normalisent la réalisation des installations, obtiennent du financement, offrent des garanties, rationalisent la conception et la mise en place des installations, améliorent leur performance, réduisent les tâches d'entretien, etc.);
- lorsque l'immeuble n'est pas raccordé au réseau public d'électricité.

De plus amples travaux seront nécessaires pour :

- réaliser la «phase 3» de la conception (projet d'exécution) et contrôler le fonctionnement d'installations de capacité différente; les performances prévue et réelle devront être comparées à celles indiquées à la Figure 1;
- effectuer une analyse de sensibilité touchant la capacité des installations et passer en revue le processus de sélection de la cogénération.

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Mars 1993

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COGENERATION SYSTEMS IN MULTI-UNIT

RESIDENTIAL STRUCTURES

PREFACE

The purpose of this project is to develop a report suitable for use by a wide range of intended audiences (e.g. property managers, building owners, engineering design professionals) in Canada. This report will provide assistance to determine the viability of a cogeneration application, basic system components, configuration, sizing and preliminary economics applicable to different sized multi-unit residential structures.

Cogeneration systems are usually referred to as "micro" or "macro". Micro-cogeneration units provide up to 600 kW or 1 Megawatt (MW) of peak electrical generation capacity. Macro-cogeneration units provide above 1 MW of peak electrical generation capacity. A group of residential buildings are investigated, and from these, four bench marks are selected which relate to different building sizes and styles.

The industry has accepted a definition, developed by the University of Wisconsin, for three levels of implementation studies, namely:

Level I	- Screening Assessment
Level II	- Preliminary Engineering Analysis
Level III	- Detailed Engineering Analysis (Design Development)

The report provides both a Level I and Level II analysis and is formatted in two segments, whereby Part I (containing Sections 1 and 2 of the document) is directed primarily to property managers and building owners. This segment presents a cursory introduction to cogeneration technology which is covered in Section 1. Section 2 includes the methodology for conducting a Level I ("first screening") assessment and, for illustration purposes, presents an analysis for one of the four benchmark examples. Part II (containing Section 3) is intended for engineering design and other professionals.

A Level II study is performed on each of the four benchmark sizes. This establishes the design criteria, conceptual development, cycle selection, preliminary sizing, capital costs, operating benefits and payback periods for suitable cogeneration units.

COGENERATION SYSTEMS IN MULTI-UNIT RESIDENTIAL STRUCTURES

PART I

This part of the report (containing Sections 1 and 2 of the document) is directed primarily to property managers and building owners and also provides a basis for Part II of the report.

1.0 INTRODUCTION TO COGENERATION TECHNOLOGY

1.1 Rationale for Considering Cogeneration Technology

Two of many items concern those responsible for the operation and maintenance of facilities within Canada:

1. The need for a continuous supply of quality electrical power; and
2. The rising cost of electrical power and thermal energy.

In 1991, some of Canada's power supply utilities advised large commercial power users that, in the future, these utilities may be facing a condition of being a net importer of power, rather than an exporter, with possible voltage reductions if import loads cannot be purchased. This condition has occurred in large U.S. cities such as Boston, and New York, for several years and has been named "brown out", due to the revised colour of electrical lighting. The condition results in serious consequences to facilities which cannot properly function with power reductions, such as hospitals, buildings with refrigeration compressors, data processing facilities, apartment building elevators, circulation pumps, etc.

The shortage condition appears to have been reduced in 1992 by the combination of the recession, conservation programs and the addition of large and small cogeneration systems throughout Canada.

The cost of electrical power in Canada has risen in the order of 10% for the last 3 years and is expected to rise 5% above inflation for the next three or four years. The prospect for tariff increases beyond this period appears even more bleak, as the development of Canada's generating stations has diminished in recent years. Canadians will have to purchase power from outside, potentially unreliable sources who are also short of power. Power costs and expenses are expected to escalate at an even faster rate, as industrial and commercial development grows, placing more demands on the existing supply.

According to Canada Mortgage and Housing Corporation, multi-unit residential high rise buildings tend to be less energy efficient per unit floor area than low rise structures due to larger population density, which leads to greater energy requirements for fans, elevators, pumps, lighting, water heating, etc.

A more critical review of operating costs in residential buildings is taking place. As such, new restrictions and restraints may be enforced where recent developments indicate that the use of electricity for space heating will not be acceptable in social housing. This is due to the high peak demand it places on the hydro utility, and the imposed high operating costs.

The use of cogeneration has experienced considerable growth in Europe and is in wide use in the U.S.A. If properly applied, a cogeneration system can provide excellent power quality and can reduce the total costs of producing heat and purchasing electricity.

1.2 General

A cogeneration system is a Combined Heat and Power (CHP) producer which uses the combustion gases and the heat from the engine water for various on-site services usually produced by a boiler. A cogeneration unit also provides AC power for in-house use or for the local hydro utility on a buy-back arrangement.

However, for micro cogeneration systems it is not usually cost effective to sell excess power from a system back to the utility.

It has been found that properly sized and operating cogeneration units will provide heat and electrical power at a cost of 55% to 80% of that spent if these energies were purchased or produced separately.

The main function of this cogeneration study is to establish if the economic benefits, technical viability, and reliability are acceptable for a candidate facility. As a general rule it is important that a Combined Heat and Power unit satisfy the electrical demand requirements, but it is more important that it satisfy the thermal demand of the application (having a use for the thermal energy produced). In addition, a substantial difference between the average cost of electricity and fuel is required.

The main criteria necessary to establish the technical viability of cogeneration is that a facility must have a centralized thermal load requirement whereby a CHP unit can be sized at maximum capacity to serve this load at a recommended minimum of 6,000 hours (between 8 and 9 months) per year. In this report, monthly billing data is analyzed rather than hourly consumption profiles. Thus, for the remainder of the report, reference will be made to a recommended minimum of 9 months per year of utilization at full capacity for a selected CHP unit size.

In general, for the average Canadian climate, space heating of apartment buildings is typically less than 8 months per year. Based on the criteria stated above, it is evident that this thermal load requirement is not normally adequate for sizing a CHP system. On the other hand, the use of domestic hot water is relatively constant throughout the year. As such, on a technical level, virtually any apartment facility with a centralized domestic hot water system can use cogeneration. This is quite common for high rise buildings; however, it is rare for low rise facilities. Low rise apartment buildings tend to be equipped with individual, domestic hot water tanks rather than being supplied from a centralized boiler room; thus, resulting in unfavourable technical and economic conditions for the application of cogeneration. During the study there was one low rise building investigated which has a centralized domestic hot water system, however it is not considered to be a typical or representative building and was not included in Part II of the report for further analysis.

For the reasons stated above, this report concentrates on the application of cogeneration in high rise facilities with centralized domestic hot water heating systems.

Figure 1.1 illustrates the conventional methods of producing energy, as well as that produced from an integrated cogeneration system. The latter is based on a typical energy balance for a reciprocating CHP unit.

Conventionally, thermal and electrical energy are produced separately. To produce electrical energy, fuel is consumed in a power station which generates 25% usable electricity, 5% transmission losses, and the remaining 70% is wasted energy, released to the environment. The traditional fossil heating system has a boiler or furnace which produces 70% to 85% usable energy, while the remaining 15% to 30% is wasted to the environment.

In an integrated cogeneration system, for a typical reciprocating unit, it is shown that fuel is consumed to produce approximately 31% usable electricity, 44% usable thermal heat, and the remaining 25% is wasted to the environment.

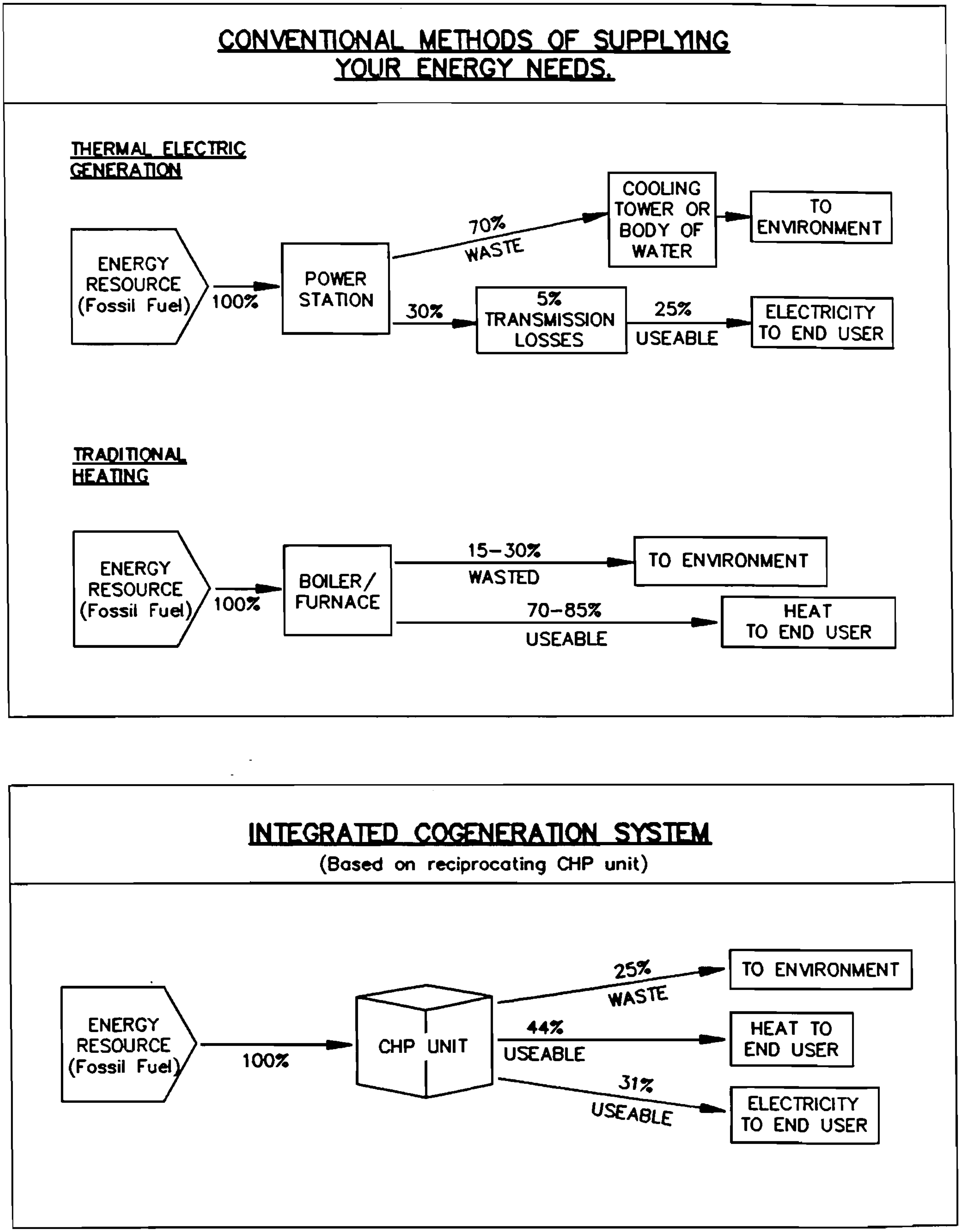
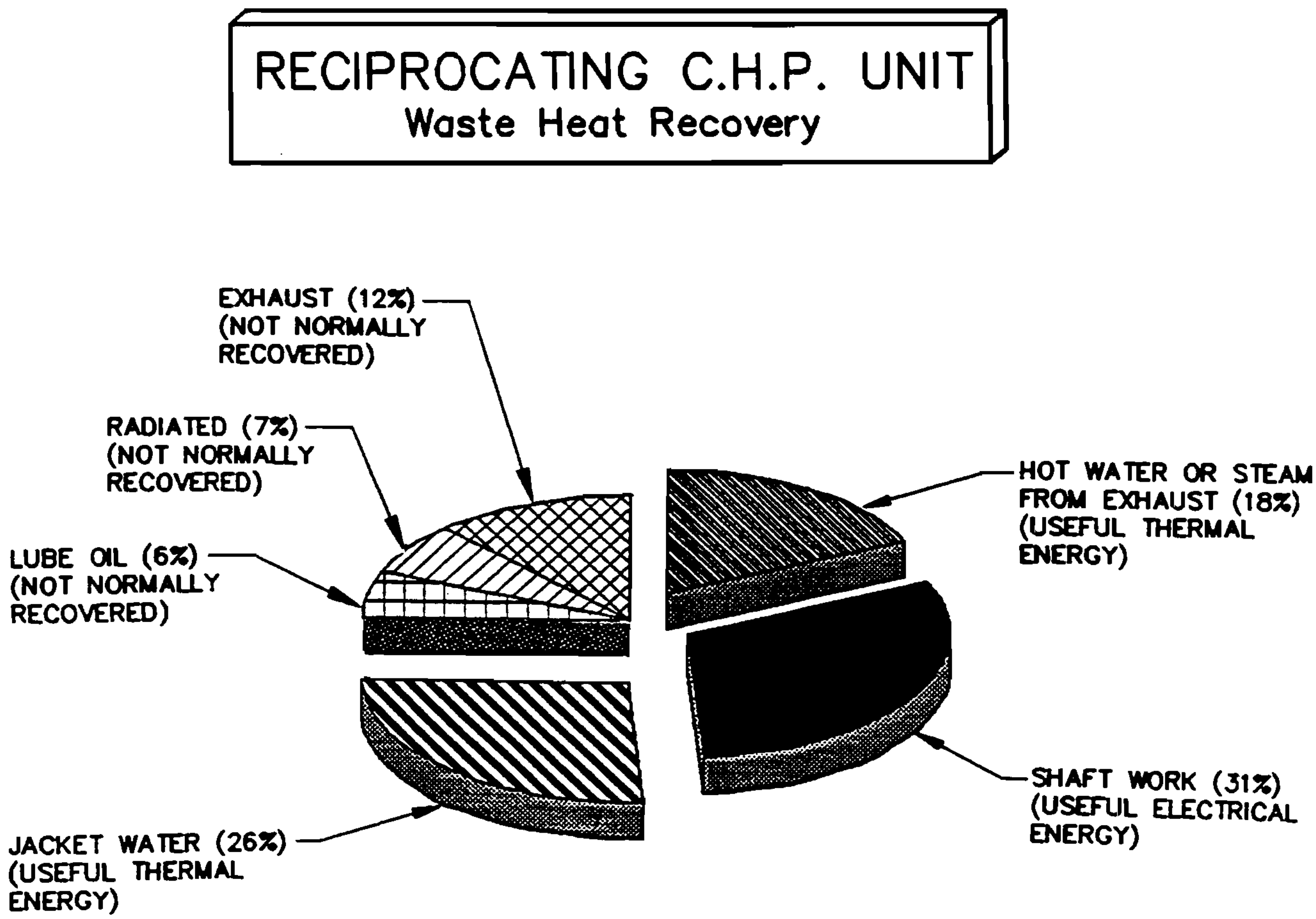

CONVENTIONAL METHODS OF SUPPLYING YOUR ENERGY NEEDS.
THERMAL ELECTRIC GENERATION
ENERGY RESOURCE (Fossil Fuel)
100%
POWER STATION
70% WASTE
COOLING TOWER OR BODY OF WATER
TO ENVIRONMENT
30%
5% TRANSMISSION LOSSES
25% USEABLE
ELECTRICITY TO END USER
TRADITIONAL HEATING
ENERGY RESOURCE (Fossil Fuel)
100%
BOILER/ FURNACE
15–30% WASTED
TO ENVIRONMENT
70–85% USEABLE
HEAT TO END USER
INTEGRATED COGENERATION SYSTEM
(Based on reciprocating CHP unit)
ENERGY RESOURCE (Fossil Fuel)
100%
CHP UNIT
25% WASTE
TO ENVIRONMENT
44% USEABLE
HEAT TO END USER
31% USEABLE
ELECTRICITY TO END USER

Figure 1.1

1.3 Energy Balance of Typical Micro Cogeneration Systems

The basic role of a cogeneration system is to provide electrical power and thermal energy simultaneously. An energy balance of a typical[1] micro system is illustrated as follows:



Actual heat rejection breakdowns will vary in accordance with specified manufacturer's data, as presented in Appendix 'A'.

[1] Typical energy breakdown developed by the University of Wisconsin.

1.4 Typical Reciprocating Cogenerator (CHP) Sizes

Table 1.1 was developed in accordance with the energy balance presented in Section 1.3. Nominal CHP (Combined Heat and Power) sizes are displayed with corresponding electrical and thermal output. The sizes are typical of what is commercially available; however, an actual site selection would be very manufacturer-specific.

TABLE 1.1

Generic Reciprocating Cogenerator Sizes

Nominal CHP Size (kW)	Prime Electrical Output (kW)	Thermal Output (kW_{th}) [1]	Thermal Output (kWh_{th}/month) [1]	Equivalent Boiler Input [2] (kWh_{th}/month)[1]
Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
5	4.5	6	4,665	5,830
10	9	13	9,325	11,655
20	18	25	18,650	23,315
25	23	33	23,830	29,790
30	27	40	27,975	34,970
40	35	50	36,265	45,330
50	45	65	46,625	58,280
60	55	75	55,950	69,940
75	70	95	70,455	88,070
100	90	130	93,250	116,565
125	115	160	117,085	146,355
150	135	190	139,880	174,845
175	160	225	165,780	207,225
200	180	255	186,505	233,130
225	205	290	212,405	265,510
250	225	320	233,130	291,410
275	250	355	259,030	323,790
300	275	390	284,935	356,170
350	320	455	331,560	414,450
400	365	520	378,185	472,735
475	425	605	440,355	550,445
500	455	645	471,440	589,300

[1] Note: Subscript "*th*" denotes thermal demand and energy consumption. Data in this column factors in round offs from a series of calculations.

[2] Based on an assumed boiler efficiency of 80% where, Equivalent Boiler

$$\text{Input} = \frac{\text{Thermal Output}}{0.8}$$

1.5 Relationship Between Nominal Cogenerator (CHP) Size and Number of Apartment Units

Table 1.2 provides a summary of recommended CHP sizes and general information for buildings examined under this study. The ratio of the CHP size (kW) to the number of apartment units, varies between 339 Watts/Unit and 750 Watts/Unit. The weighted average for this ratio is 563 Watts/Unit.

TABLE 1.2

Summary of Recommended CHP Sizes and General Information for Buildings Examined Under This Study

Primary Occupancy	Nominal CHP Size (kW)	No. Apartment Units	Watts/Unit	Building No.
(A)	175	270	650	7(2)
(A)	275	502	550	6(a)&(b)(2)
(B)	300	400	750	9
(C)	75	161	470	5
(C)	75	118	640	8
(C)	100	206	490	3
(C)	125	230	540	4
(C)	500	720	690	10
(D)	40	118	340	2(2)
(D)	75	206	360	1
	1,740 (Total)	3,092 (Total)	560(1) (Average)	

(1) weighted average (=1,740,000 ÷ 3,092)
(2) pool
(A) family - medium income rental - high rise
(B) family - medium income rental - low rise
(C) family - low income rental - high rise
(D) family - condominium apartment

The above data is based on the 10 building sites which were analyzed, and is not to be considered representative for all apartment buildings. As can be seen from

Column 5, the ratio of Watts per unit varies considerably between facilities which is based on a variety of site specific conditions such as actual electrical demand and consumption, as well as gas used for thermal loads (i.e. domestic hot water and space heating). Many cogeneration projects (primarily in the USA) have been incorrectly sized, based on incomplete analyses of all costs and implementation methods. Such projects have resulted in wide differentials on the projected and actual return on investment, percent of availability, (i.e. relating to down time due to failed equipment or maintenance), etc.

1.6 Cogeneration System Methods of Development

(a) Traditional Design/Build

The conventional method of adding a cogeneration unit to a building is to purchase and own the system, similar to any other mechanical device. The system is normally designed by a consultant and installed by a mechanical/electrical contractor. There may be a tax advantage available to the "Purchaser" of cogeneration systems if the costs can be treated as an operating expense rather than as a capital expense. Revenue Canada has implemented a Class 34 accelerated method to allow rapid depreciation of the investment for a Prime Mover such as a cogeneration system.

Further information may be obtained from:

Class 34 Secretariat
Efficiency & Alternative Energy Technology Branch
Energy, Mines and Resources
580 Booth Street
Ottawa, Ontario
K1A 0E4
(613) 996-6004

(b) Third Party Financiers

Third Party Financing through an ESCO (Energy Service Company) offers an option to the traditional design/build method of implementation. This option should preferably be exercised in conjunction with retaining a consultant to provide review assistance.

Third party financiers will finance and/or build the facility and/or manage the system on behalf of the Owner. Under the current utility regulations in place in most provinces, the "ownership" of the power processing system cannot be the third party since no one can sell power except a utility. However, lease agreements are becoming more popular where a third party installs the plant and charges a fee for recovering their investment. In some areas of Canada, innovative financing is available through energy service companies (ESCO's) which will provide a method of reducing thermal and/or electrical energy, at their cost. These companies will share the benefit from the reduction in energy costs on a predetermined agreement basis. When a cogeneration system is included in an ESCO type arrangement, it can essentially be paid for out of the actual savings.

1.7 Assistance from Power Utilities and Provincial Ministries

A cogeneration encouragement program may be available under some of Canada's utility or provincial ministry incentive programs, to partially fund Consultant costs for related system design and engineering. Other eligible activities may include detailed financial analysis and preparation of financial and legal documents required for project development. The respective officials should be contacted to receive current updates on program incentives. Most power utilities have conservation officers or advisors and offer the most appropriate contacts for information or direction on local programs relating to possible incentives.

2.0 "FIRST SCREENING" ANALYSIS

The procedure for determining the viability of cogeneration, using a Level I ("first screening") analysis, is presented below.

It should be noted that a concerted effort and an adequate allotment of time (1-2 days) are required from the property manager and/or building owner to properly perform a Level I analysis for a given building.

Copies of blank worksheets, used in the following sections for sizing a CHP (Combined Heat and Power) unit and determining it's economic viability, are included in Appendix 'A'.

2.1 General

The analysis included in this section of the report is a variation of a procedure developed by Texas A & M University, which offers a concise method to establish a cogeneration project as a "Go", "Maybe" or "No go" scenario. This procedure has been used in the USA for many years and is considered the standard of the industry for facility managers and operators of similar facilities. For the purposes of this report, the procedure has been modified and simplified for Canadian conditions. Obviously, the preliminary analysis does not include enough parameters to proceed with the procurement of a CHP unit. The analysis establishes only the viability of proceeding ahead to a Level II or III study to be performed by a consulting engineering firm with experience in this domain.

For a given project, some general rules of thumb (developed from experience), are used to account for a CHP unit's viability. A facility must have a centralized thermal load requirement and a thermal energy consumption profile whereby a suitable baseload can be utilized at a recommended minimum of 6,000 hours (between 8 and 9 months) a year. Since monthly billing data is analyzed in this report, reference will be made to 9 months. For apartment buildings to satisfy this requirement, the cogeneration unit would typically have to be sized to primarily serve the domestic hot water loads, rather than space heating loads since space heating of apartment units in Canada is usually less than 8 months of the year. Thus, when sizing a CHP Unit (See Section 2.2) it should be done such that the thermal output capacity at full load (identified in Section 1.4) would closely match the requirements for the heating of domestic hot water in the building. However, during the winter months, excess heat from the CHP unit can be relieved to the space heating system to improve system utilization.

The thermal properties analyzed in this report relate to average monthly thermal consumption profiles for a base loaded system. In practice, for a given building, the boiler systems are usually cycled to provide heat on demand where the output fluctuates in accordance with the building's heating requirements. However, the use of a CHP system is optimized when load fluctuations are kept to a minimum, and it is run at it's maximum rated capacity for as many hours during the year as possible. This is often accomplished by incorporating a thermal storage vessel to "load level" the system. Thermal energy (heat) is supplied continuously to the vessel during periods of low demand. This stored energy is subsequently supplied to the thermal loads on demand. Somewhat constant thermal demand conditions would then tend to occur. These would provide a fairly uniform utilization of the CHP System over the medium (daily or weekly) term.

If it is not practical to incorporate a thermal storage vessel as a load levelling device, (e.g. due to a large tank size requirement) the CHP system output would not likely satisfy peak thermal load requirements on the domestic hot water system and the output level would have to be reduced ("turned-down") during low load periods in the summer. Cogeneration units normally have turn-down capabilities to 40% of peak capacity; however, if the load requirements were less than this, the system would have to be turned off.

For cogeneration to be economically feasible, it is necessary to have a substantial difference between the average electrical and fossil fuel energy rates. The economics of cogeneration can be further enhanced if based on premium cost for modifications which would have to be carried out in any event, such as the need to replace failing or inefficient boilers, or the requirement to upgrade the electrical service to the building.

For the "first screening" analysis, costs for cogeneration units are estimated at \$1,200/kW, including full turnkey service. Costs estimated on this basis are representative for new construction projects or projects involving minor retrofit work. However, in the current Canadian market, CHP units less than 100 kW are very rare, which means the \$1,200/kW may be a low number due to the availability and competition of suppliers. As the technology develops in Canada, the cost of smaller units should approach the \$1,200/kW range. Furthermore, this Level I study must be viewed in the context of the abbreviated data. For retrofit projects, if unusual site conditions exist, such as major rebuilding of the Mechanical Room to accommodate the unit, etc., the base cost would not be representative. Often projects can range from \$1,500/kW to \$2,500/kW total unit cost depending on the complexity of the project and site conditions.

Although exact pricing criteria cannot be forecasted for each project from generic techniques, the complexity of a specific installation will have a substantial impact on the actual cost. A stated above, if a project appears to be substantially more complex than a "clean" installation, an installed cost based on \$2,000/kW will be more representative, primarily for units smaller than 100 kW.

Economic assessment sheets based on \$1,200/kW and \$2,000/kW are provided in Appendix 'A', in order to suit different project conditions.

2.2 Sizing the Combined Heat and Power (CHP) Unit

The methodology to be used for sizing a CHP unit for a given facility is as follows:

1) Gather details on electrical and thermal billing data for a recent 12 month period. Pertinent information would include monthly electrical energy consumption, demand and costs, as well as monthly fuel consumption and costs.

2) Organize the gathered data in a format as illustrated in Table 1.3.

TABLE 1.3

Electrical and Thermal Billing Details for a Recent 12 Month Period

MONTH	ELECTRICITY			THERMAL	
	Energy[1] (kWh)	Peak Demand (kW)	Total Cost ($)	Consumption [2] (kWh*th*) [3]	Cost ($)
	Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
TOTALS					

(1) An approximation of average demand can be found by dividing column (1) by the number of system operating hours per month.

(2) For natural gas, 1 m^3 = 10.33 kWh*th*.

(3) subscript "*th*" denotes thermal energy.

3) Use the data from columns (2) and (4) of Table 1.3 to develop electrical demand and thermal energy consumption curves for the facility as per the format illustrated in Figures 1.2(a) and 1.2(b).

4) From Figure 1.2(b), identify a thermal consumption level which is exceeded 9 months of the year.

5) From Table 1.1, select a CHP unit size. Generally, for the simplicity of a Level I Study, it is recommended that the CHP unit size be selected such that the equivalent boiler input of the unit (identified in column (5), of Table 1.1) be one size down from the consumption level defined in step (4) above. However, if the unit one size up is a very close match, then it is recommended that it be selected. The corresponding nominal CHP unit size is identified in column (1) of Table 1.1.

6) Confirm that the prime electrical output (column (2) of Table 1.1) of the CHP unit size selected in step (5) does not exceed the average demand baseload (see footnote at bottom of Table 1.3) of the building, which is plotted in Figure 1.2(a).

7) If the prime electrical output determined in steps (5) and (6) exceeds the building's average electrical demand, then reduce the CHP unit size until this condition no longer occurs.

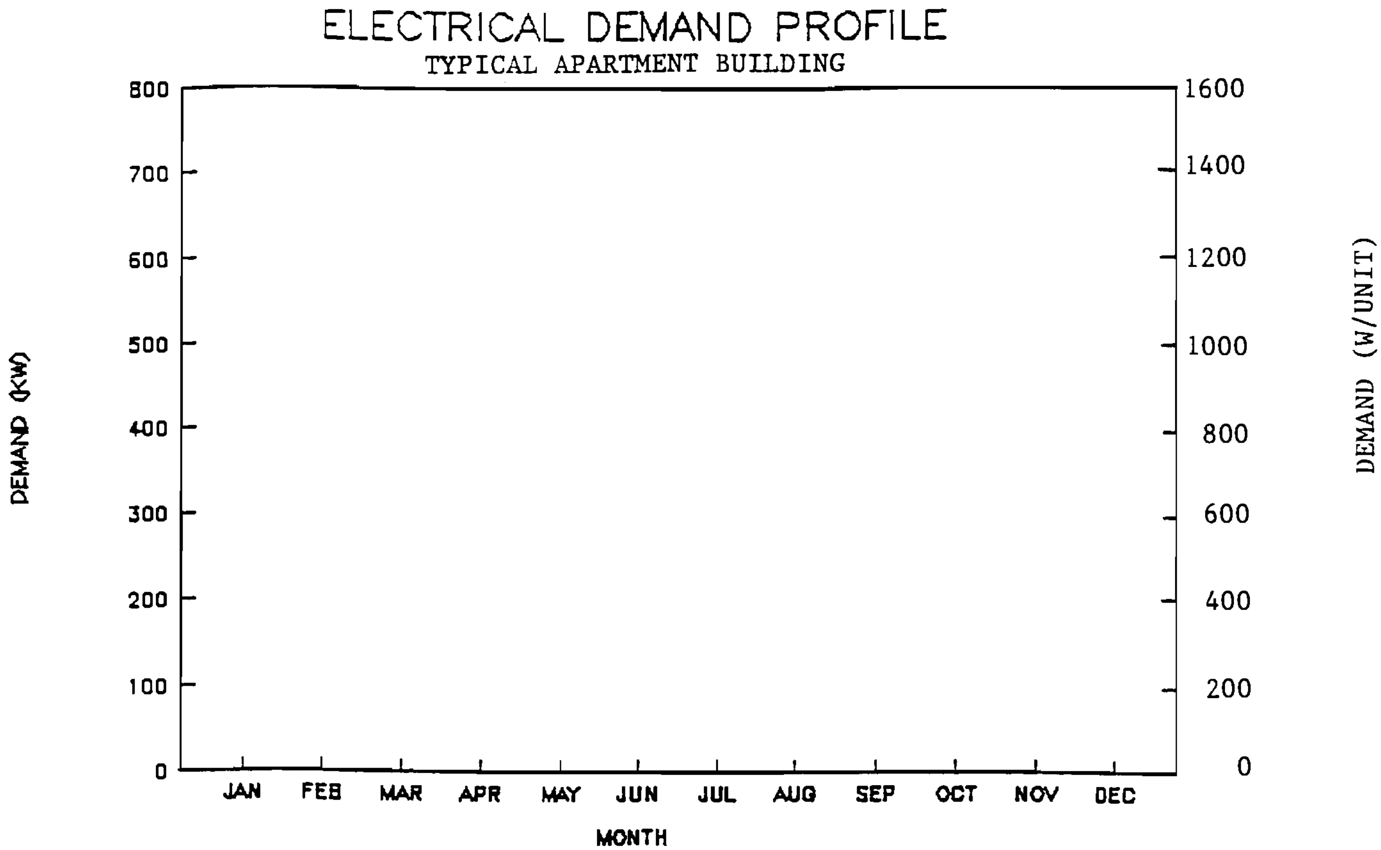


FIGURE 1.2(a)

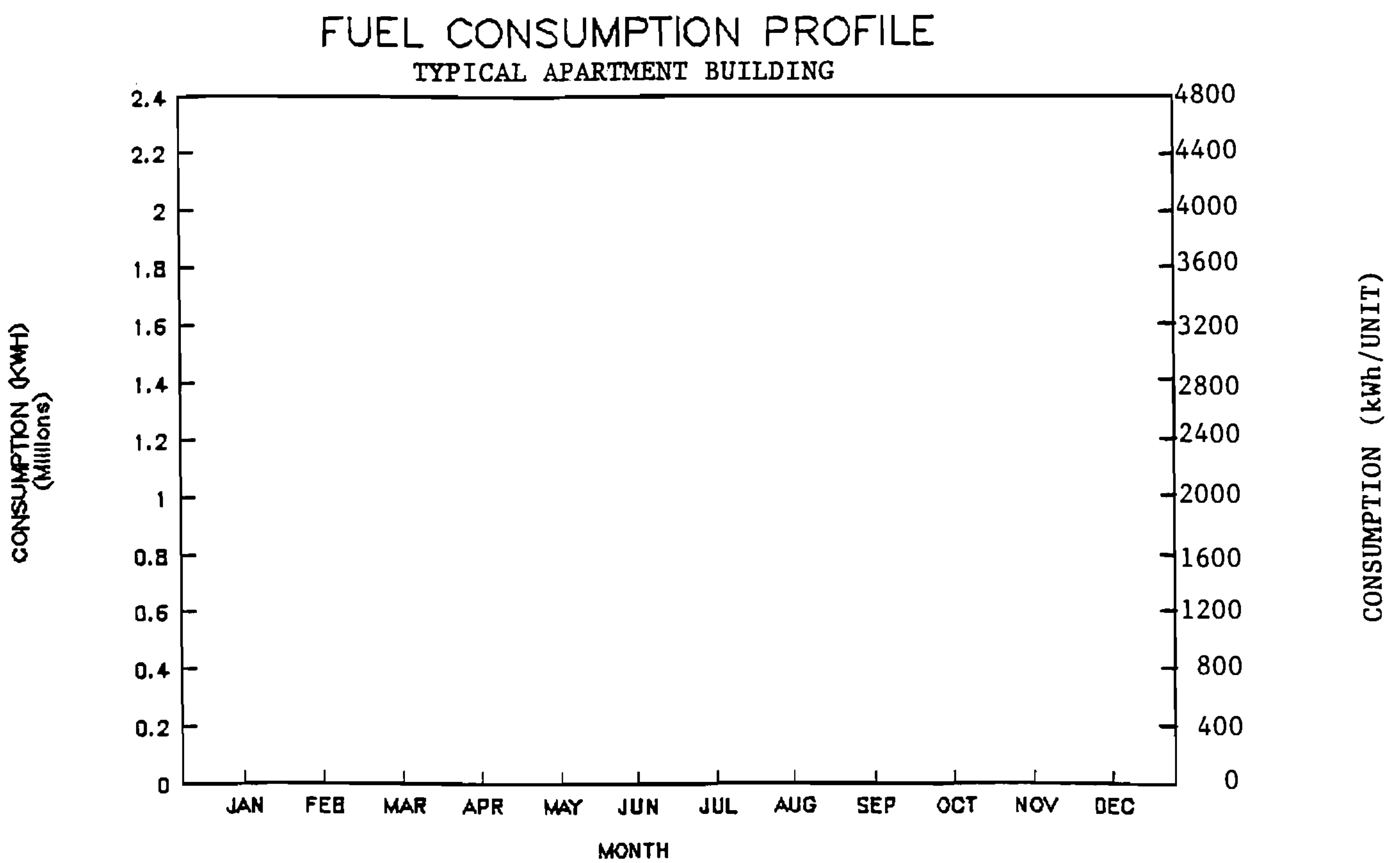


FIGURE 1.2(b)

2.3 Determining the Combined Heat and Power (CHP) Unit's Economic Viability

Once the technical assessment has been completed and a CHP unit size has been successfully selected, the analysis would proceed to determine if cogeneration would be economically viable.

The methodology to be used for this assessment is as follows:

1) Using Tables 1.1 and 1.3, fill in parts (a), (b) and (c) of Table 1.4.

2) For each month in the annual period being analyzed, determine what the thermal energy displaced by the CHP Unit would be and call this quantity "An", where "n" denotes the month (i.e. January through to December; months 1 to 12). To do this:

   - Use the data from column (4) of Table 1.3 and compare the fuel consumption of each month to the equivalent boiler input of the selected CHP Unit (identified in column (5) of Table 1.1).

   - If the monthly consumption is greater than or equal to the equivalent boiler input of the CHP Unit, then An = the equivalent boiler input (defined as Y in Table 1.4).

   - If the monthly consumption is less than the equivalent boiler input of the CHP Unit and greater than 40% of this value then An = monthly consumption for month "n" in column (4) of Table 1.3.

   - Lastly, if the monthly consumption is less than 40% of the capacity of the unit, then the system would be shut off and there would be no displaced energy; where An = 0.

3) Now that A_1 to A_{12} have been established, complete parts (d) and (e) of Table 1.4.

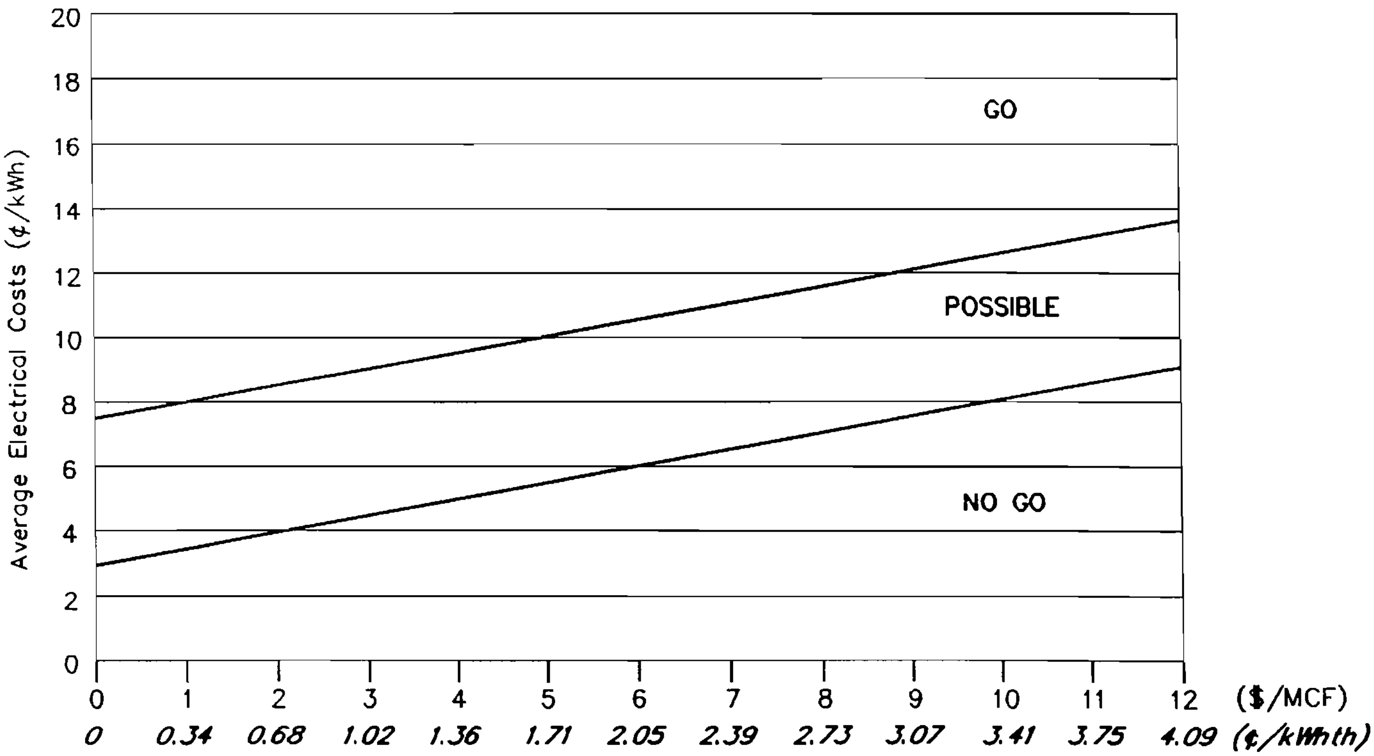
TABLE 1.4

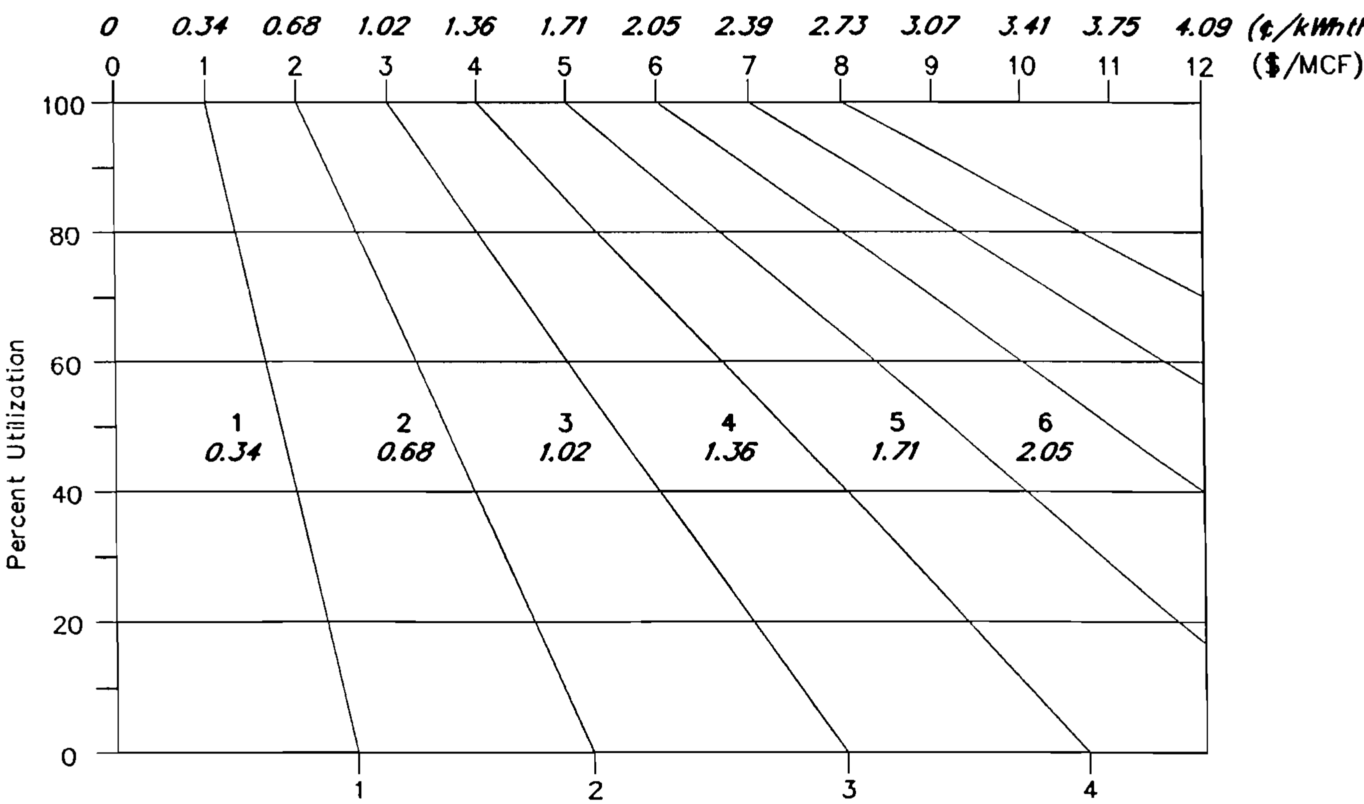
(a)	**Size of CHP Unit (from Table 1.1, Column (1)):** For at least 9 months of the year the monthly fuel consumption from Column (4) of Table 1.3 is greater than or equal to the equivalent boiler input of the unit (Column (5) of Table 1.1).	__ kW (Nominal Size)
(b)	**Average Cost of Electricity (from Table 1.3):** $\frac{\text{Column (3) Total}}{\text{Column (1) Total}}$ x 100¢/$	__ ¢/kWh
(c)	**Average Thermal Fuel Cost (from Table 1.3):** $\frac{\text{Column (5) Total}}{\text{Column (4) Total}}$	__ ¢/kWh*th* ($/MCF)
(d)	**Average Monthly Thermal Energy Displaced by CHP Unit:** $X = \frac{(A_1 + A_2 + \ldots + A_N)}{N} =$ where X = Average monthly thermal energy displaced by CHP Unit. An = Monthly thermal energy displaced by CHP Unit to a maximum of Y (defined below). "n" denotes the month (1 to 12). N = Number of months the system is utilized (i.e. where An > O).	__ kWh*th*/mth
(e)	**Percent Thermal Energy Utilized (% TU):** $\frac{X}{Y}$ x 100% =	__ %
	where Y = Equivalent boiler input of CHP Unit (from Column (5) of Table 1.1) =	__ kWh*th*/mth
(f)	Complete the nomograph illustration from Economic Assessment Sheet (Figure 1.3) to determine whether cogeneration is a GO, POSSIBLE, or NO GO and indicate here:	________

Derived from Texas A & M University.

ECONOMIC ASSESSMENT SHEET

(Based on $1,200/kW)





Derived from Texas A & M university

Figure 1.3

4) Complete the following steps, using the economic assessment sheet presented in Figure 1.3.:

- Locate intersection of % Thermal Utilization (from Part (e) of Table 1.4) and average fuel price (from Part (c) of Table 1.4) on bottom graph of economic assessment sheet.

- Draw line vertically upward to intersect average electrical cost (from part (b) of Table 1.4) on top graph of economic assessment sheet.

- Observe region on top graph where intersection of average electrical cost and vertical line from bottom graph occurs.

5) Fill in part (f) of Table 1.4 with "Go", "Possible", or "No Go" scenario obtained from the economic assessment sheet (Figure 1.3).

It should be noted, that the percent thermal utilization (%TU) defined above in part (e) of Table 1.4, is based on average monthly fuel consumption levels. If the CHP unit needs to cycle off regularly for a couple of hours per day in the summer during low load periods, the actual percent thermal utilization would be slightly lower than the value calculated using the above methodology.

2.4 Summary for Level I Analysis

Once the Level I technical and economic analyses have been completed, the general details of the building and overall assessment can be summarized in a format as illustrated in Table 1.5.

TABLE 1.5

Summary Sheet for Level I Analysis

Architectural: Space available in building for a CHP Unit? No. of Floors? No. of Apartments?
Mechanical: Type of fuel used? Does the building have a centralized boiler system? Location of boiler room? No. of boilers? No. of domestic hot water tanks? Location of domestic water heaters/tanks?
Electrical: Location of electrical service? Demand levels? Individual tenant metering or bulk metering?
Occupancy Type: Senior, family, high income, average income, low income, rental, condo?
Average Electrical Cost (¢/kWh): from part (b) of Table 1.4.
Average Fuel Cost (¢/kWh*th*($/MCF)): from part (c) of Table 1.4.
Nominal CHP Size (kW): from part (a) of Table 1.4.
Prime Electrical Output (kW): from column (2) of Table 1.1.
Thermal Output (kWth(kWh*th*/month)): from column (4) of Table 1.1.
Percent Thermal Energy Utilized (% TU): from part (e) of Table 1.4.
Additional Comments: Economic Evaluation: "Go", "Possible" or "No Go"?

2.5 Sample "First Screening" Analysis

For illustration purposes, an example of a Level I study is provided, using Building Nos. 6(a) and 6(b) from Table 1.2 in Section 1.5. This analysis is based on the application of cogeneration to two buildings which are adjacent to each other and physically connected. Thus, the overall assessment uses combined thermal and electrical billing data for the two buildings.

Sample copies of Table 1.3, Figures 2(a) and 2(b), Table 1.4, Figure 1.3, and Table 1.5 have been completed using the procedures outlined in Sections 2.2, 2.3 and 2.4. Also, sample worksheets, No. 1 and No. 2 are provided to demonstrate how to complete Table 1.4.

As mentioned in Section 2.1, in order for cogeneration to be viable for a given facility, there must be a substantial difference between the average electrical cost and average fuel rate. This is illustrated for the above sample analysis, in Figure 1.4, where it is evident that if the average electrical cost was higher at, say, 10¢/kWh, the analysis would yield a "Go" situation. If the cost was lower, at 4¢/kWh, the analysis would yield a "No Go" situation.

The facility's electrical metering arrangement can have an impact on the average electrical cost and hence, this analysis. Individual metering typically loses the lower cost advantage of bulk metered rates.

"First Screening" analysis summary sheets are provided in Appendix 'C' for the buildings examined under this study, which are listed in Table 1.2. of Section 1.5.

"SAMPLE"

TABLE 1.3

Electrical and Thermal Billing Details for Buildings 6A & 6B Combined (April 1991 - March 1992)

MONTH	ELECTRICITY			THERMAL	
	Energy[1] (kWh)	Peak Demand (kW)	Total Cost ($)	Consumption [3] (kWh*th*) [4]	Cost ($)
	Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
January	354,800	728	22,468	2,241,651	31,136
February	308,400	704	20,752	1,773,303	24,690
March	303,200	636	20,138	1,681,812	23,430
April	334,800	632	19,953	793,972	4,880
May	230,400	572	14,336	583,151	7,236
June	314,400	624	18,812	287,515	3,668
July	306,000	644	18,485	248,083	3,186
August	332,400	624	19,717	309,690	3,938
September	283,200	684	17,528	331,617	4,206
October	306,800	584	18,239	546,530	6,800
November	286,800	668	17,633	1,020,313	12,446
December	296,800	712	18,346	1,269,905	17,762
TOTALS	3,658,000	728[2]	226,407	11,087,543	143,378

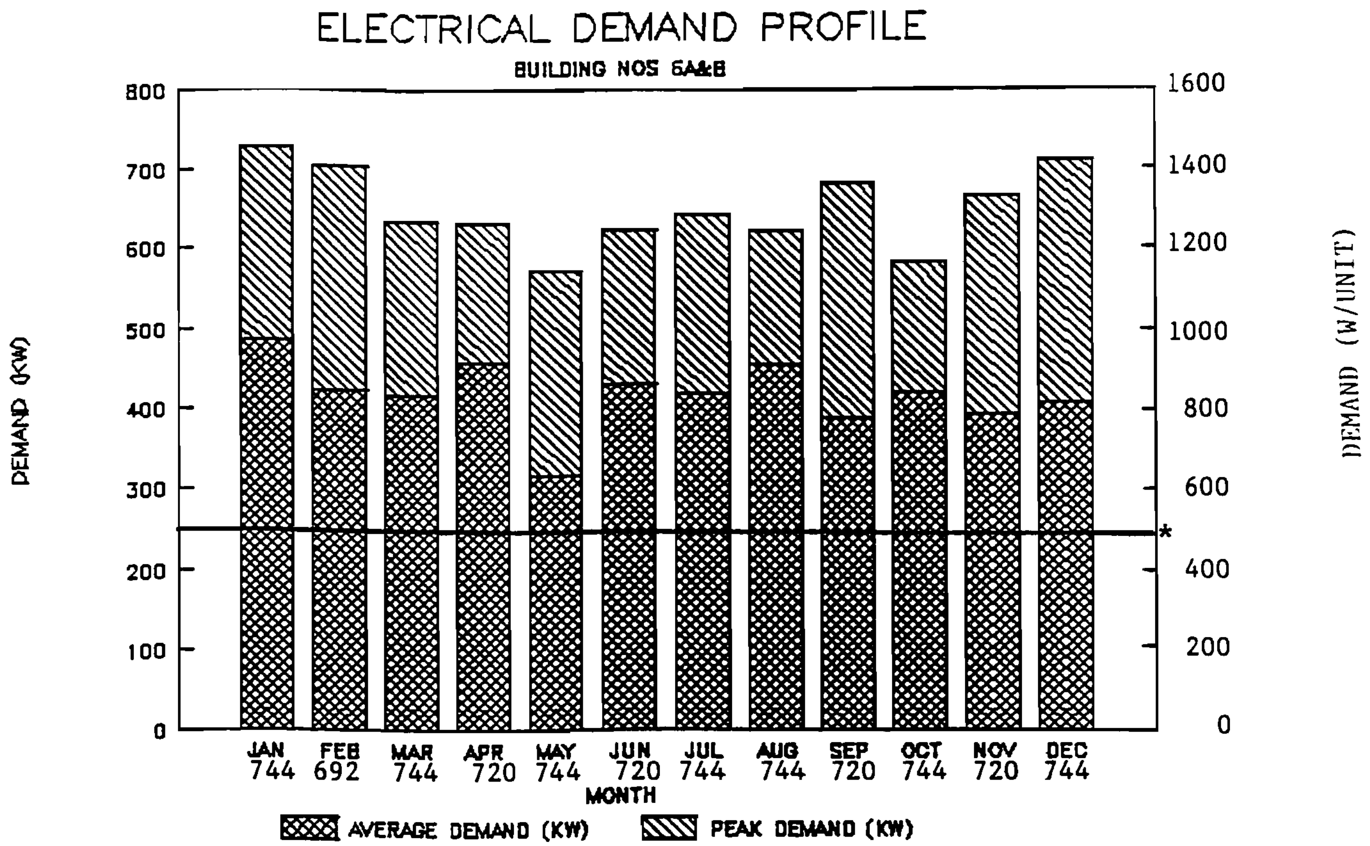
(1) An approximation of average demand can be found by dividing column (1) by the number of system operating hours per month.

(2) Peak electrical demand.

(3) For natural gas, 1 m^3 = 10.33 kWh*th*.

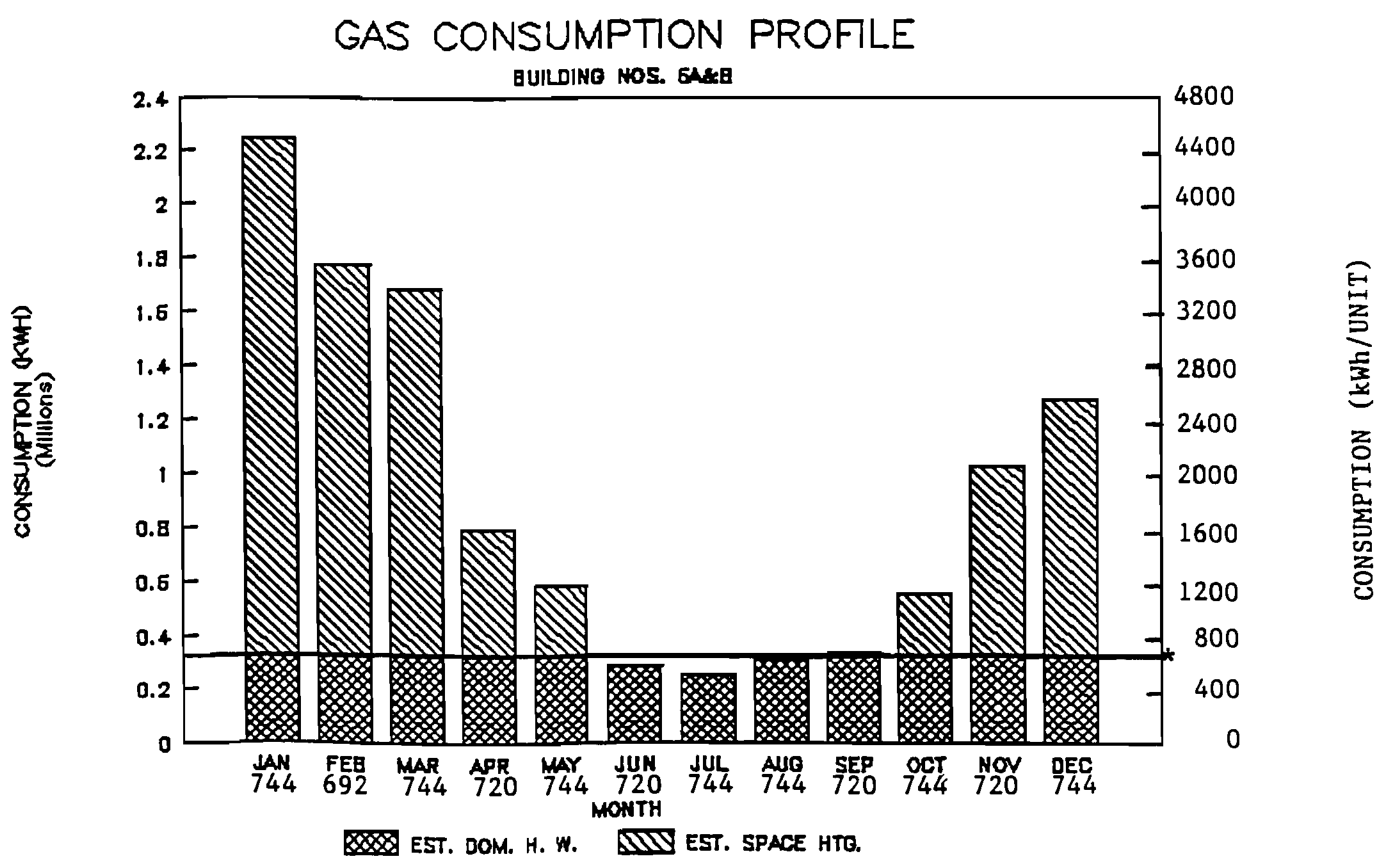
(4) subscript "*th*" denotes thermal energy.

"SAMPLE"



* ELECTRICAL OUTPUT FROM CHP UNIT (FROM TABLE 1.1).
(AT MAXIMUM OUTPUT RATING)

FIGURE 1.2(a



* EQUIVALENT BOILER INPUT OF CHP UNIT (FROM TABLE 1.1) (AT MAXIMUM OUTPUT RATING)

FIGURE 1.2(b)

WORK SHEET NO. 1

TABLE 1.3

ELECTRICAL AND THERMAL BILLING DETAILS FOR BUILDINGS 6A & 6B COMBINED (APRIL 1991 - MARCH 1992)

MONTH	ELECTRICITY			THERMAL	
	Energy[1] (kWh)	Peak Demand (kW)	Total Cost ($)	Consumption [3] (kWh*th*) [4]	Cost ($)
	Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
January	354,800	728	22,468	2,241,651	31,136
February	308,400	704	20,752	1,773,303	24,690
March	303,200	636	20,138	1,681,812	23,430
April	334,800	632	19,953	793,972	4,880
May	230,400	572	14,336	583,151	7,236
June	314,400	624	18,812	287,515	3,668
July	306,000	644	18,485	248,083	3,186
August	332,400	624	19,717	309,690	3,938
September	283,200	684	17,528	331,617	4,206
October	306,800	584	18,239	546,530	6,800
November	286,800	668	17,633	1,020,313	12,446
December	296,800	712	18,346	1,269,905	17,762
TOTALS	3,658,000	728[2]	226,407	11,087,543	143,378

(1) An approximation of average demand can be found by dividing column (1) by the number of system operating hours per month (i.e. 730 hours per month).

(2) Peak electrical demand.

(3) For natural gas, 1 m³ = 10.33 kWhth.

(4) subscript "*th*" denotes thermal energy.

TABLE 1.1

GENERIC RECIPROCATING COGENERATOR SIZES

Nominal CHP Size (kW)	Prime Electrical Output (kW)	Thermal Output (kW*th*) [1]	Thermal Output (kWh*th*/month) [1]	Equivalent Boiler Input [2] (kWhth/month)[1]
Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
5	4.5	6	4,665	5,830
10	9	13	9,325	11,655
20	18	25	18,650	23,315
25	23	33	23,830	29,790
30	27	40	27,975	34,970
40	35	50	36,265	45,330
50	45	65	46,625	58,280
60	55	75	55,950	69,940
75	70	95	70,455	88,070
100	90	130	93,250	116,565
125	115	160	117,085	146,355
150	135	190	139,880	174,845
175	160	225	165,780	207,225
200	180	255	186,505	233,130
225	205	290	212,405	265,510
250	225	320	233,130	291,410
275	250	355	259,030	323,790
300	275	390	284,935	356,170
350	320	455	331,560	414,450
400	365	520	378,185	472,735
475	425	605	440,355	550,445
500	455	645	471,440	589,300

(1) Note: Subscript "*th*" denotes thermal demand and energy consumption.

(2) Based on an assumed boiler efficiency of 80% where, Equivalent Boiler Input = $\frac{\text{Thermal Output}}{0.8}$

TABLE 1.4

(a) **Size of CHP Unit (from Table 1.1 Column (1)):** 275 kW (Nominal Size)

(b) **Average Cost of Electricity (from Table 1.3):**

$\frac{\text{Column (3) Total}}{\text{Column (1) Total}} \times 100¢/\$$ 6.2 ¢/kWh

(c) **Average Thermal Fuel Cost (from Table 1.3):**

$\frac{\text{Column (5) Total}}{\text{Column (4) Total}}$ 1.3 ¢/kWh*th* (3.8 $/MCF)

(d) **Average Monthly Thermal Energy Displaced by CHP Unit:**

$X = \frac{(A_1 + A_2 + \ldots + A_{12})^*}{12} =$ 313,280 kWh*th*/mth

where X = Average monthly thermal energy displaced by CHP Unit.
An = Monthly thermal energy displaced by CHP Unit to a maximum of Y (defined below). "n" denotes the month (1 to 12).

(e) **Percent Thermal Energy Utilized (% TU):**

$\frac{X}{Y} \times 100\% =$ 97 %

where Y = Equivalent boiler input of CHP Unit (from Column (5) of Table 1.1) = 323,790 kWh*th*/mth

(f) Complete the nomograph illustration from Economic Assessment Sheet (Figure 1.3) to determine whether cogeneration is a GO, POSSIBLE, or NO GO and indicate here:

POSSIBLE

Derived from Texas A & M University.

* The values for An are defined as follows, where all units are kWhth/month:
A_1 = 323,790; A_2 = 323,790; A_3 = 323,790; A_4 = 323,790; A_5 = 323,790; A_6 = 287,515;
A_7 = 248,083; A_8 = 309,690; A_9 = 323,790; A_{10} = 323,790; A_{11} = 323,790; A_{12} = 323,790.

TABLE 1.4

(a) Size of CHP Unit (from Table 1.1 Column (1)): 275 kW (Nominal Size)

(b) Average Cost of Electricity (from Table 1.3):

$\frac{\text{Column (3) Total}}{\text{Column (1) Total}} \times 100¢/\$$ 6.2 ¢/kWh

(c) Average Thermal Fuel Cost (from Table 1.3):

$\frac{\text{Column (5) Total}}{\text{Column (4) Total}}$ 1.3 ¢/kWhth (3.8 $/MCF)

(d) Average Monthly Thermal Energy Displaced by CHP Unit:

$X = \frac{(A_1 + A_2 + \ldots + A_{12})^*}{12} =$ 313,280 kWhth/mth

where X = Average monthly thermal energy displaced by CHP Unit.
An = Monthly thermal energy displaced by CHP Unit to a maximum of Y (defined below) "n" denotes the month (1 to 12).

(e) Percent Thermal Energy Utilized (% TU):

$\frac{X}{Y} \times 100\% =$ 97 %

where Y = Equivalent boiler input of CHP Unit (from Column (5) of Table 1.1) = 323,790 kWhth/mth

(f) Complete the nomograph illustration from Economic Assessment Sheet (Figure 1.3) to determine whether cogeneration is a GO, POSSIBLE, or NO GO and indicate here:

POSSIBLE

Derived from Texas A & M University.

* The values for An are defined as follows where all units are kWhth/month:
A_1 = 323,790; A_2 = 323,790; A_3 = 323,790; A_4 = 323,790; A_5 = 323,790; A_6 = 287,515;
A_7 = 248,083; A_8 = 309,690; A_9 = 323,790; A_{10} = 323,790; A_{11} = 323,790; A_{12} = 323,790

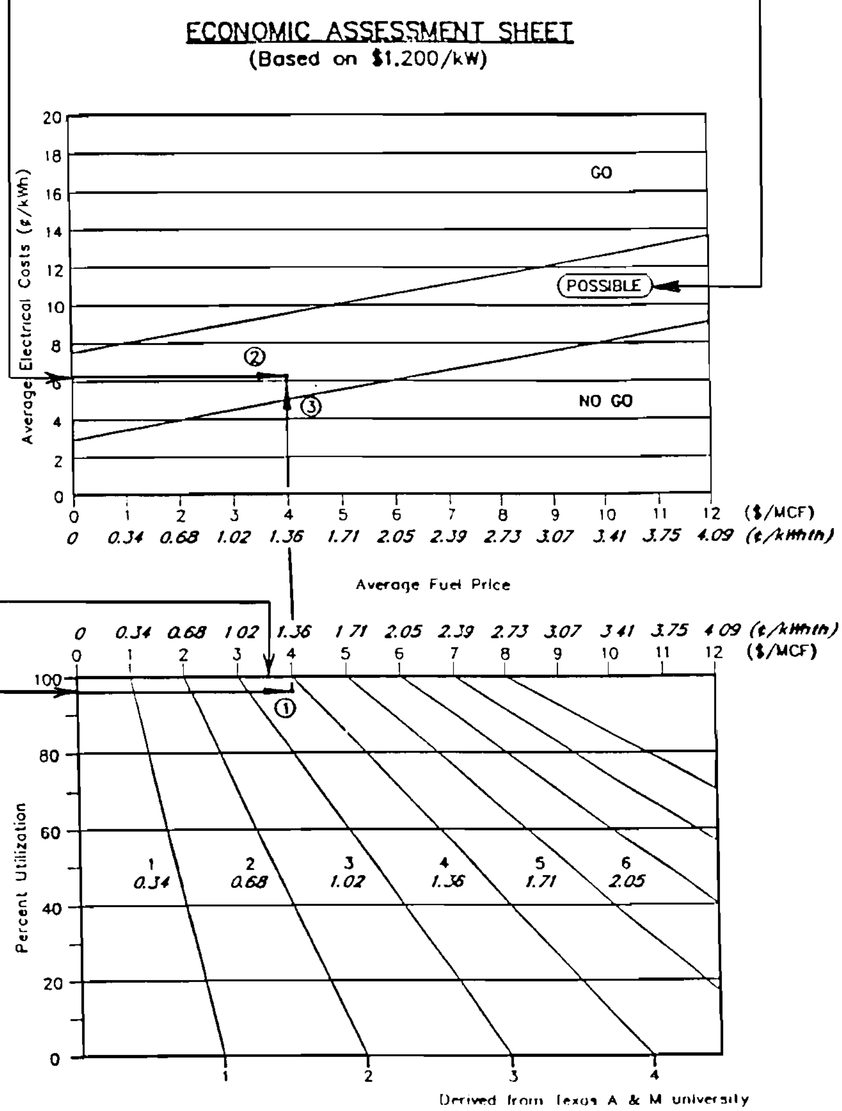


Figure 1.3

"SAMPLE"

TABLE 1.4

(a) Size of CHP Unit (from Table 1.1 Column (1)): 275 kW (Nominal Size)

For at least 9 months of the year the monthly fuel consumption from Column (4) of Table 1.3 is greater than or equal to the equivalent boiler input of the unit (Column (5) of Table 1.1).

(b) Average Cost of Electricity (from Table 1.3):

$$\frac{\text{Column (3) Total}}{\text{Column (1) Total}} \times 100¢/\$$$ 6.2 ¢/kWh

(c) Average Thermal Fuel Cost (from Table 1.3):

$$\frac{\text{Column (5) Total}}{\text{Column (4) Total}}$$ 1.3 ¢/kWh*th* (3.8 $/MCF)

(d) Average Monthly Thermal Energy Displaced by CHP Unit:

$$X = \frac{(A_1 + A_2 + \ldots\ldots + A_{12})^*}{12} =$$ 313,280 kWh*th*/mth

where X = Average monthly thermal energy displaced by CHP Unit.
An = Monthly thermal energy displaced by CHP Unit to a maximum of Y (defined below). "n" denotes the month (1 to 12).

(e) Percent Thermal Energy Utilized (% TU):

$$\frac{X}{Y} \times 100\% =$$ 97 %

where Y = Equivalent boiler input of CHP Unit (from Column (5) of Table 1.1) = 323,790 kWh*th*/mth

(f) Complete the nomograph illustration from Economic Assessment Sheet (Figure 1.3) to determine whether cogeneration is a **GO**, **POSSIBLE**, or **NO GO** and indicate here:

POSSIBLE

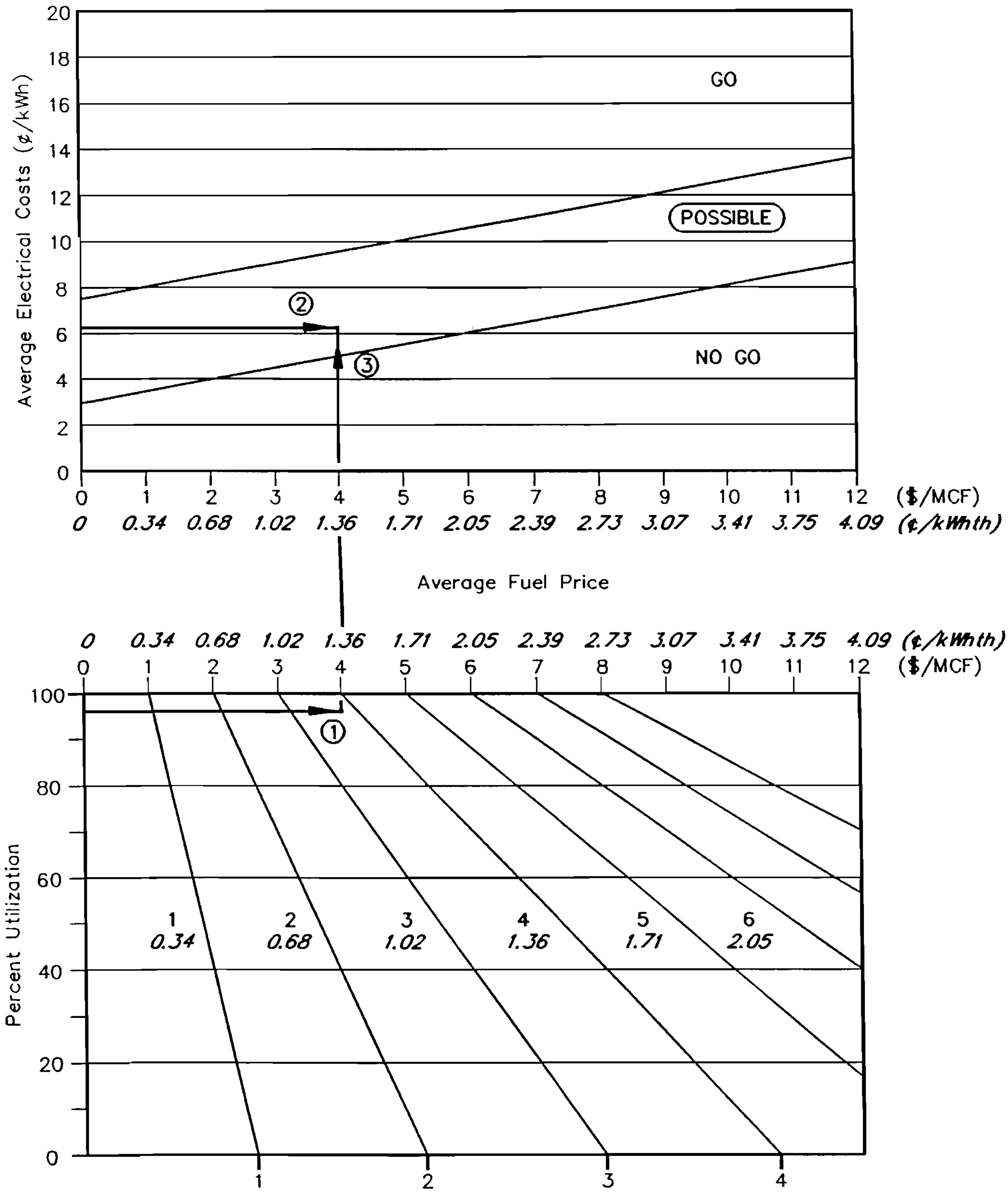
Derived from Texas A & M University.

* The values for An are defined as follows, where all units are kWh*th*/month:
A_1 = 323,790; A_2 = 323,790; A_3 = 323,790; A_4 = 323,790; A_5 = 323,790; A_6 = 287,515; A_7 = 248,083; A_8 = 309,690; A_9 = 323,790; A_{10} = 323,790; A_{11} = 323,790; A_{12} = 323,790.

"SAMPLE"

ECONOMIC ASSESSMENT SHEET

(Based on $1,200/kW)



Derived from Texas A & M university

Figure 1.3

"SAMPLE"

TABLE 1.5

Summary Sheet for Level I Analysis

Architectural: 2-12 floor apartment buildings, each with 251 apartments. Site contains recreation centre with pool. Space likely available in building for CHP Unit (at basement level).

Mechanical: Buildings use natural gas. Each building has 3 boilers of which one is dedicated to domestic hot water. Boiler rooms located at basement level.

Electrical: Electrical service on main level. Maximum peak demand is 728 kW for both buildings combined. Minimum peak demand is 570 kW. Minimum average demand is 310 kW. Buildings are bulk metered.

Occupancy Type: Family, medium income rental.

Average Electrical Cost (¢/kWh): 6.2¢/kWh

Average Fuel Cost (¢/kWh*th*($/MCF)): 1.3¢/kWh*th* ($3.8/MCF)

Nominal CHP Size (kW): 275 kW

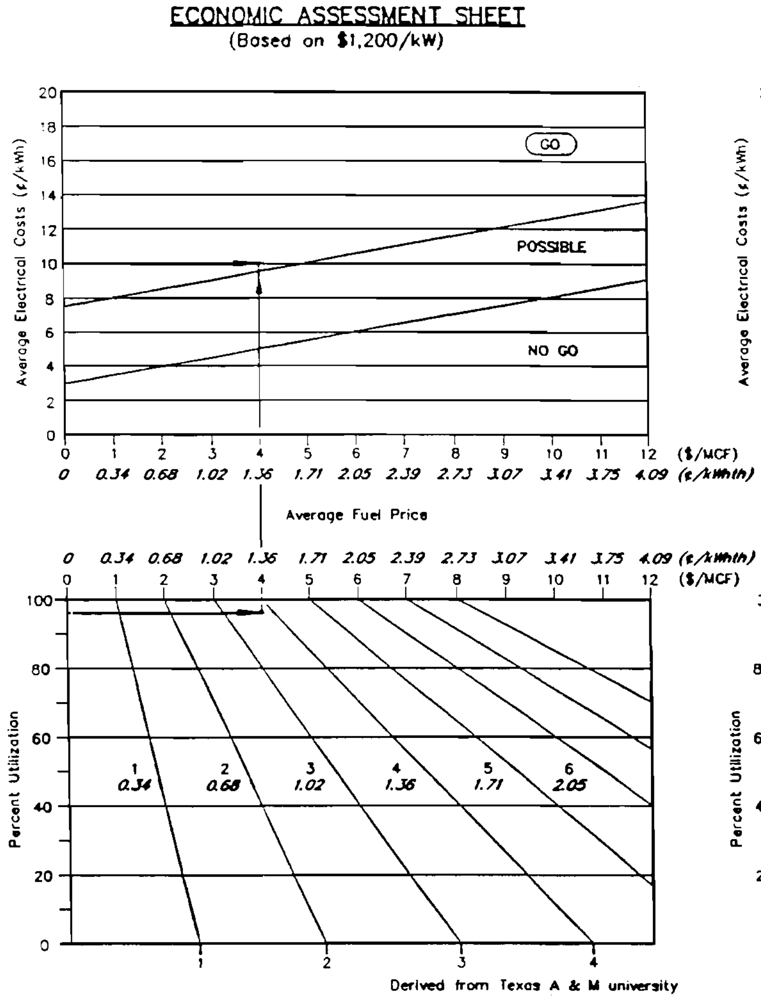
Prime Electrical Output (kW): 250 kW

Thermal Output (kWth(kWh*th*/month)): 355 kWth, (259,030 kWth/month)

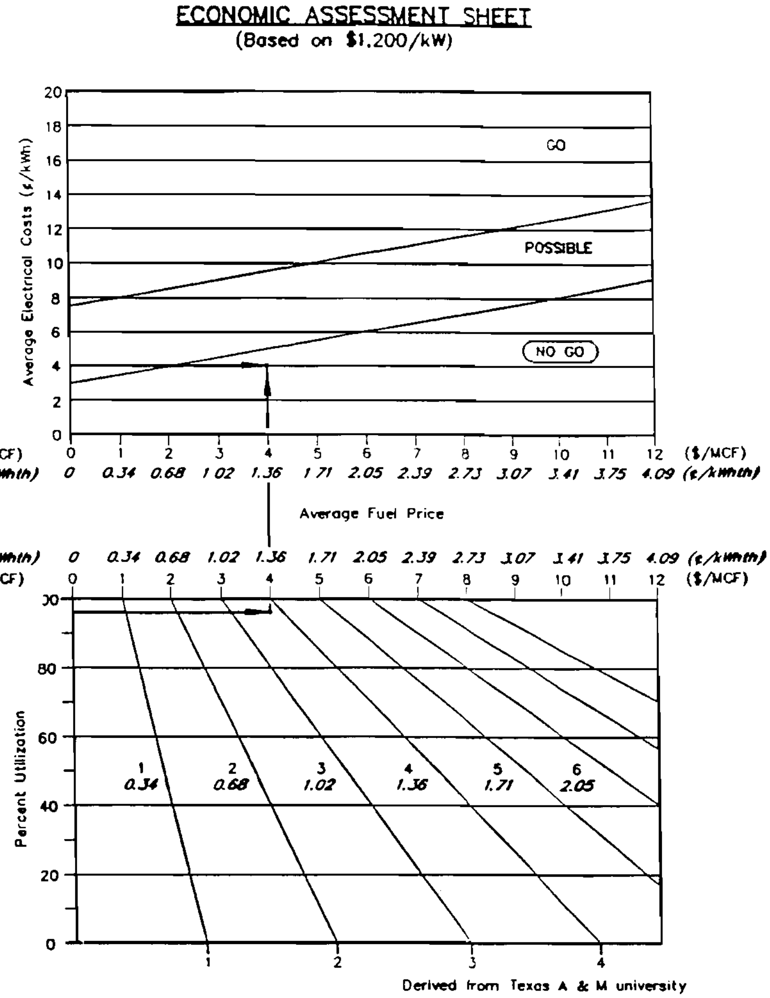
Percent Thermal Energy Utilized (% TU): 97%

Additional Comments:

Economic Evaluation: Possible



"GO"



"NO GO"

ILLUSTRATION OF IMPORTANCE FOR SUBSTANTIAL DIFFERENCE BETWEEN FUEL AND ELECTRICAL COSTS

Figure 1.4

2.6 Conclusions

In general, for the sample analysis presented in Section 2.5, on the basis of a "first screening" analysis, it appears that the application of cogeneration is technically and "possibly" economically feasible for buildings 6A and 6B. The following conclusions are highlighted:

- The site satisfies the requirement for full load thermal utilization for a recommended minimum of 9 months (at least 6,000 hours) per year.

- The average electrical baseload is greater than the electrical output from the CHP unit which ensures maximum utilization of the unit and enhances economic viability.

- A substantial difference between the average electrical cost and average fuel cost is apparent.

Further assessment of the economic feasibility of cogeneration would be performed under a level II study.

The following may be available to improve the economics of a cogeneration system:

- Tax advantage to the "purchaser" of a cogeneration system from Revenue Canada which will allow rapid depreciation of the investment.

- Innovative financing through an energy service company (ESCO) which will provide a method of reducing thermal and/or electrical energy at their cost.

- Incentives from utilities which would offset capital costs.

If the economic assessment of a project from a Level I study results in a "possible" or "go" scenario, then the project should proceed to a Level II analysis. However, if the Level I economic analysis yields a "no go", the proposed project should not be considered any further.

Most utilities in Canada expect the cost of electricity to rise 5% above inflation for the next few years, which should increase the economic viability of cogeneration substantially. Therefore, an economic evaluation which currently results in a "Possible" assessment may become a "Go" in the future. A Level II Study will model future avoided costs and demonstrate this element in greater detail.

PART II

This segment of the report is intended for engineers and technical resource practitioners who would be involved in the design, installation and operation of the cogeneration system.

3.0 LEVEL II ANALYSIS

3.1 General

The methodology required to perform a Level II study for the technical and economic feasibility of cogeneration is provided. Part I of the report is to be used in conjunction with this section, as it contains the basic procedures for sizing a CHP (combined heat and power) unit. The economic analysis is more detailed than that provided in Part I, where the average fuel cost is still used; however, for electrical cost savings, the marginal energy rates and peak demand costs are used. Furthermore, net present values are analyzed based on construction costs, maintenance costs, and increased fuel costs in conjunction with increases in energy, inflation and interest rates over a 7 and a 20 year period. Also, internal rates of returns are provided over a 20 year period.

A Level II analysis is performed on four typical residential building sites. Fact summary sheets are provided for each analysis, followed by conclusions which highlight the findings for all four projects. The detailed project analyses for each building are available in Appendix 'B' for immediate reference.

3.2 Thermal Load Analysis

It was established in Part I of the report that, in order for cogeneration to be feasible in Canada, the system must be sized on the thermal load requirements, while the electrical demand plays an important, but less valuable role. The main criteria necessary for cogeneration to be both technically and economically feasible are:

(1) A substantial difference between the average electrical cost and average fuel cost; and

(2) A centralized thermal system and energy consumption profile, whereby a suitable baseload can be utilized at a recommended minimum of 6,000 hours (between 8 and 9 months) a year.

The first requirement is largely dependent on where the facility is located. Regional variations in the differential between fuel and electrical costs will impact the viability of a system. Some of the current variations are identified in Appendix 'H'. For the second requirement to be satisfied in apartment buildings, it has been established that the cogeneration unit would normally have to be sized to primarily serve the buildings' domestic hot water system, rather than space heating, since its' use is usually less than 8 months (5840 hours) of the year. However, during the winter excess heat can be relieved to the building's space heating system.

A single line sketch of the distribution system serving the building's heating loads should be developed in order to identify the individual systems, and establish the base heating interrelationship.

Ideally, for a given facility, an hourly load profile for a typical day should be generated as well as a load duration curve for monthly peak steam or hot water flows throughout the year which would require detailed monitoring. Although this would be advantageous to produce historic data, it is often difficult to obtain without considerable expense and time. Thus, the thermal properties analyzed relate to average monthly thermal consumption profiles for a base loaded system, as illustrated in Part I of the report which is also sufficient for a Level II study.

CHP systems often incorporate a thermal storage vessel, to load level the unit by providing continuous supply to the vessel and subsequent heating of the thermal load on actual demand. Average thermal conditions would then tend to occur which allow for a fairly uniform utilization on a daily or weekly cycle. This load levelling technique was analyzed in the study, where the CHP sizing selection is based primarily on the domestic hot water load requirements. This is discussed further in the following section.

3.3 Thermal Load Levelling - Domestic Hot Water Tank Sizing

The thermal output of the CHP Unit will be subject to a varying load. In order to ensure a constant reliable heat sink, it is desirable that the heat sink (primarily the domestic hot water system) be equipped with a storage tank to dampen load fluctuations which will invariably occur.

The provision of such a storage tank was analyzed for the four Level II studies. This was done using a domestic hot water tank sizing methodology outlined in the ASHRAE 1991 Applications Handbook (Service Water Heating).

For three of the four projects, this analysis yielded thermal load levelling tank sizes which exceed the size of the existing storage tanks installed at these sites. For the fourth project, the tank size was slightly less than the existing storage capacity. Based on the maximum thermal recovery rates of the proposed CHP units, the calculated storage capacities were 4,450 USgal, 5,420 USgal, 7,890 USgal, and 3,180 USgal, where the existing storage capacities are approximately 240 USgal, 480 USgal, 2,400 USgal and 3,320 USgal.

The above range in existing storage capacities is due to building size and the fact that domestic hot water systems can be designed with a minimum recovery rate and maximum storage capacity, or with a high recovery rate and small storage capacity. For cogeneration systems it is desirable to have the former option applied.

It is evident that 2 of the buildings (the smaller ones) were designed with a high recovery rate and minimum storage capacity, while the larger buildings were designed with a smaller recovery rate and larger storage capacity.

In any event, the costs of adding additional storage capacity to any of the buildings was found to be excessive, and for the 2 smaller buildings, the calculated sizes were considered impractical due to very large tank sizes. As a result, the proposed cogeneration systems do not include the provision of additional domestic hot water storage.

An ASHRAE Research Paper (1988), by Perlman and Milligan on hot water and energy use in apartment buildings was reviewed. From this paper an hourly domestic hot water use profile (per apartment unit) was used for the four projects to compare the capacity of the CHP units to a typical domestic hot water consumption profile. This hot water use profile is based on a 95% confidence level which represents a reliable estimate of the maximum average daily usage expected for a particular building category.

For each project, the CHP unit's heat recovery rate was superimposed on the above-noted profile at 100% capacity and at 40% capacity. This was to provide an indicator of the unit's operating range in relation to typical domestic hot water consumption over a 24 hour period. Supporting data for this analysis is provided in Appendix 'C'.

In general, these graphs show that for each of the buildings, at 100% capacity the CHP thermal output is close to the average domestic hot water consumption. At 40% capacity the output of the unit is close to the low load requirements which occur for approximately six hours per day.

The 2 larger buildings analyzed in this study have domestic hot water storage capacities which would provide some load levelling to the system and, as such, the CHP units should not need to turn-down to the 40% output level. However, the 2 smaller buildings, which are designed on a high recovery rate and minimal storage capacity, may need to be turned off for a couple of hours per day when there is no space heating load. This is because most cogeneration systems only have the capability of turning-down to 40%.

3.4 CHP Sizing Sensitivity

In Part I of this document the procedures for sizing a CHP Unit were established and it was assumed that the thermal load in the summer would be entirely due to domestic hot water. For the winter months the unit would primarily serve the domestic hot water heating system and excess heat would be relieved to the space heating system. In actual fact, during the summer, the output of the system would have to be reduced below its maximum capacity level. Cogeneration units typically have the capability of reducing the output level to 40% of the maximum rated capacity, however, it is desirable to keep the average output level in a given month as high as possible in order to optimize system efficiency. During periods when thermal load requirements exceed the capacity of the CHP unit, the domestic hot water boilers will have to fire to supplement additional heating requirements.

It is recognized that the unit selection methodology may yield a sizing which does not exactly conform to any commercially available size.

Since the selection of a commercially available unit is the prime consideration, the sensitivity of selection, for example, a 250 kW unit or a 300 kW unit to match a 265 kW size as determined by the selection methodology may fall into question.

In general, the issue of sizing sensitivity revolves around the turn-down capability of the unit and the compatibility of the unit size with the thermal and electrical load profiles, as discussed previously.

Furthermore, in the sizing selection, the difference in the nominal CHP size (i.e. one size up verses one size down), will affect the quantity of displaced energy to some degree; however, the payback periods and projected return on the investment will remain in the same "ballpark".

Fine tuning of a specific size selection can be accomplished by completing the full analysis for one CHP unit size "up" and one size "down".

The final decision on the size selection depends solely on the conditions specific to a particular project and would be up to the discretion of the design engineer and system owner.

3.5 Electrical System Interface

The main goal of the electrical portion of the cogeneration system is to provide power to the facility which can displace a more expensive purchase from the utility. In order to optimize the efficiency and cost effectiveness of the unit, it is desirable to utilize the output of the system as close as possible to its capacity at all times.

There are two methods available for providing displaced power to a facility which are discussed below.

(a) Parallel Service. This system is the preferred method and provides a cogeneration unit in complete synchronization with the utility's service. The generator is "slaved" to the utility's characteristics of frequency, wave shape, etc. and is monitored to never generate more than 80% of building's electrical demand. The process ensures that the generator never supplies the Hydro grid to cause an unsafe condition. Additional check relays such as reverse current flow/negative sequence are provided for backup protection. This arrangement provides a good utilization of the available electrical capacity of the unit but needs to be connected to the main service equipment which may or may not be in reasonable proximity to the CHP system.

(b) Transfer Switch. This arrangement is a rarely used method and utilizes a closed transition transfer switch to totally isolate the cogeneration system and some dedicated loads from the remainder of the distribution circuits. During periods of scheduled down-time of the cogeneration unit, the transfer switch can be manually transferred back to the utility grid by a short 50 ms. parallel condition with the generator electrically "slaved" to the utility frequency, wave pattern, etc. This process enables a transfer to and from the cogeneration unit without a power interruption. If the cogeneration unit fails, the transfer switch automatically returns to the utility power, but with a very short power interruption. The transfer switch arrangement is utilized when access to the building's electrical distribution system is geographically excessive and therefore expensive. However, the connected loads must be of constant power draw and sequenced to utilize the turn down ratio of the cogeneration unit.

3.6 Technical and Economic Assessment Criteria

To begin the process of establishing a suitable size of unit and it's economic viability, it is necessary to consider and where applicable, obtain information on the following issues. Any items not available will have to be estimated, which can result in a less accurate assessment.

A. Electrical and Fuel Billing Summary for Past 12 Months (preferably 24 months)

In order to properly size a CHP Unit for an apartment building, actual thermal consumption data over a recent 12 month period is required to establish representative peak, operating and turn-down levels. Electrical consumption and demand data are required for the same time period in order that a comparison can be made with these levels to the prime electrical output capacity of the unit, and ensure that the utilization of electrical energy would be optimized.

In addition, the billing data helps to establish monthly trends for electricity and fuel costs.

B. Electrical Rate Structure

This data is required to project future costs for the modified electrical demand and consumption levels. Both demand and marginal energy rates are used to estimate electrical cost savings.

C. Fuel Costs and Rate Structure

The increased primary fuel consumption used to generate combined heat and power will increase total annual fuel costs which must be factored into the economic assessment. The primary fuel rate structure will influence the extent to which increased total consumption costs offset the total cost of displaced power, in order to arrive at a net annual savings.

Baseload operation of the cogeneration unit (placing the existing system in a secondary standby role) for annual operation at a high load factor may require a non-interruptible service if natural gas is used as the primary fuel. This may place the facility in a firm rate category by the utility, at a loss of the more favourable, interruptible rate schedule. Some utilities, however, currently offer a special rate structure for cogeneration systems which is more favourable than a firm rate (eg. Consumer's Gas Rate 115 which is currently being explored).

Other utilities, which do not yet have a special rate structure in place, may offer this in the future.

For large volume consumers, the gas utility may be willing to install a second, dedicated meter to supply the cogeneration unit and apply the special cogeneration rate to the CHP Unit while maintaining the interruptible rate structure on the existing boiler system.

D. <u>Boilers: Age, Capacity, Efficiencies, Condition</u>

A cogeneration unit is usually used as a "lead" boiler and existing boilers can be retained for peak conditions or as backup units during cogeneration down-time. Older boilers, ready for replacement, can be kept on serving as backup, resulting in an avoided cost for boiler replacement.

E. <u>Heating System Flow Diagram</u>

A flow diagram is a valuable tool in understanding the interrelationship of each heating system which will be modified by a new system.

F. <u>Electrical Single Line Diagram</u>

A single line diagram is a valuable tool in understanding the electrical distribution system, and establishing an effective method of interfacing the CHP Unit with the utility.

G. <u>Controls and Operating Modes</u>

A complete and detailed understanding of all of the controls, temperatures, daily and seasonal sequencing is required to engineer a new design which will work in complete concert with the original functions of the systems.

H. Standby Generator: Size and General Condition

A cogeneration system cannot be legally classified as a means of backup power to life safety circuits as classified by the Fire and Electrical Codes, since it is not usually fuelled from an on-site fuel source. However, it actually becomes the prime source of power with the utility as the alternate source and the generator as the third (and legal) source of backup power.

I. Future Expansion Plans

Any plans for expansion to the facility should be considered in the overall assessment.

J. Natural Gas Pressure

Most of the information provided below is based on discussions which were held with Consumers Gas, which is the largest gas utility in Canada. It is likely that the situation with other utilities would be very similar.

The pressure which is supplied by the natural gas utility is an important consideration if the CHP system will be fuelled by natural gas. Consumers Gas advised that, for highly populated residential areas, the supply pressure downstream of the meter is typically around ¼ psig. However, this pressure is site specific and depends on surrounding conditions. Most turbo-charged cogeneration units would require a nominal delivery pressure of approximately 25 psig, unless the unit is equipped with a "Draw-Thru" carburation system which will require only 3 to 5 psig. Naturally aspirated units usually require 5 to 10 psig.

According to a representative at Consumers Gas, if a site has a total natural gas requirement in excess of 350 m^3/hr., based on 2,000 hours per year of utilization, arrangements can sometimes be made with the local utility to obtain new gas services at higher pressures. This would be achieved by connecting a new service line to the gas main on the street, where it is often possible to obtain service pressures as high as 5 psig. If the site's natural gas requirements are not as high as 350 m^3/hr., but the utilization would be greater than 2,000 hours per year (i.e. with cogeneration, where at least 6,000 hours per year is recommended), it is possible that the utility would take this into consideration, and provide a new service at a higher pressure.

For projects where the cogeneration unit would be placed close to the ground level, the cost for the new service would typically be low and involve minimal pipework and valves. It would be necessary to ensure that all systems downstream of this new service could handle the higher pressure. A simple solution is to provide a "T" connection to the service, where one branch would feed the cogeneration unit at the higher pressure, and the other branch would have a pressure regulator to serve the rest of the gas fired systems at the original lower pressure.

The availability of a new gas service at a higher pressure which would meet the requirements for a cogeneration system is very site specific and would have to be confirmed with the utility. The farther the location of a cogeneration unit from the incoming gas service, the greater the costs become, associated with increased pipework, valves, etc. Therefore, if a CHP unit were to be located a significant distance from the gas service (i.e. on the roof of a high rise building), the costs for obtaining a new gas service at a higher pressure are likely to be excessive. If the required pressures are greater than those available, a natural gas booster compressor package would be required. Estimated costs for this application normally vary between $20,000 to $45,000.

K. Current and Future Efforts to Reduce Existing Thermal and Electrical Loads

Prior to the implementation of cogeneration, efforts should be made to increase the energy use efficiency of the facility, particularly through low cost/no cost measures.

L. Structural and Architectural Considerations

If there does not appear to be space available in the facility to house a cogeneration unit, a new structure is required. This would typically consist of a steel enclosure or a concrete block frame with a flat concrete slab. The economics of piping and electrical wiring dictate that the system should be located as close as possible to the boiler plant and electrical service.

M. Noise Considerations

The proposed location of the unit should be as far as possible from any structure where there would be a concern for noise, as CHP engines usually produce noise levels above 95 kB(A). Care must be taken to ensure that a cogeneration unit would operate within acceptable noise criteria at all times. If there is no space available within the building, the proposed unit should be mounted in a new structure and, if noise is a concern, the system should be acoustically designed. In any event, the structure should use acoustic dampers for the intake and discharge ductwork to limit noise to the outside.

Ontario Ministry of Environment regulations restrict noise levels to within the 50 dB range at the property line. Additional sound attenuation may be required to meet this criteria. Other Provinces may have similar regulations.

N. NO_x and SO_x

Each Provincial Government has jurisdiction regarding the emission of NO_x and SO_x within its boundaries. In Ontario, although regulations change frequently, there is no legislation which currently exists that specifically addressees NO_x and SO_x emissions from cogeneration installations. As such, the standard Ontario Ministry of Environment approval process is governed via a requirement for the following permits.

(1) Design/build for the unit.

(2) Operation of the facility.

The latter permit is valid for a 5 year period. In the last year of this time frame, applications to renew this permit must be submitted. A renewal is usually granted if current NO_x and SO_x emission control technology is applied to the system.

It should be noted that SO_x control is not usually a concern for reciprocating engine based systems. A target level of 45 ppm for NO_x emissions is within acceptable current practice and most designers are aware of this. Most reciprocating engine CHP manufacturers offer a "lean burn" option which adheres to current NO_x guidelines.

Federal Government facilities which are not regulated by their respective Provincial Government regulations obviously do not have to adhere to the regulations.

3.7 Control Systems

It is necessary to design two packages of controls, in addition to the utility interface package identified in Section 3.5. The first package is a standard block monitor panel which monitors, alarms and will shut down the reciprocating unit if necessary. Some of the usual components include:

- Run light
- Pre-warning for low oil pressure
- Pre-warning for high coolant temperature
- Low oil pressure shutdown
- High coolant temperature shutdown
- Overcrank shutdown
- Overspeed shutdown
- Tachometer
- H.O.A. plus stop switches

A sample of a typical control panel is included in Appendix 'A'.

The second control system is a Semi-Custom Control Package, Generally, known as a mini SCADA system (Supervisory Control and Data Acquisition System). This package monitors all the heating parameters and sequences the 3-way and modulating valves, block modulating valves, line and loop temperatures and interface logic with the existing Automatic Temperature Control (ATC) System. Although the specifics of each project require custom engineering, all the CHP suppliers offer "canned" mini SCADA systems which can be modified to suit the specific operating sequences.

A sample of a typical mini SCADA system is included in Appendix 'A'.

3.8 Project Summaries

For each of the project summaries presented below, the total net present value of savings for projected 7 and 20 year periods, and the internal rate of return are all based on the following estimated average rate increases:

Gas Rate	=	4%
Electricity Rate	=	10%
Inflation Rate	=	5%
Interest Rate	=	12%

3.8.1 Building No. 2

One of two high rise buildings physically connected together has 118 condominium apartments which are served by a centralized domestic hot water system, in a 24 storey tower.

Natural gas is used for space and domestic hot water heating. There are 6 boilers, located in the penthouse, of which 2 are dedicated to domestic hot water. Also, there are 2 existing domestic hot water tanks which are each estimated to be 120 USgal.

The proposed nominal CHP Unit size is 40 kW. Maximum thermal turn-down requirements are estimated to be 65%, which is based on a maximum thermal output capacity of 50 kWth (36,265 kWth/month) from the unit. The maximum prime electrical output is 35 kW, which is approximately 10% of the peak demand level in the building.

The proposed location for the CHP Unit is in the boiler room penthouse.

The average fuel cost is estimated at 1.54/kWh*th* ($4.5/MCF), while the average electrical cost is estimated at 6.7¢/kWh. To calculate electrical energy and demand savings, a demand cost of \$4.75/kW and a marginal energy rate of 5.21¢/kWh were used.

The cost assessment summary for the proposed cogeneration system is as follows:

- Construction Costs:	\$ 89,645
- Annual Maintenance Cost:	\$ 4,280
- Annual Electrical Cost Savings:	\$ 16,895
- Net Annual Fuel Cost Increase:	\$ 6,460
- Net Annual Energy Cost Savings:	\$ 6,155
- Simple Payback Period:	15 years
- Net Present Value (NPV) of Savings for Projected 7 Year Period:	\$ 35,040
- Net Present Value (NPV) of Savings for Projected 20 Year Period:	\$ 75,830
- Internal Rate of Return (IRR) for Projected 20 Year Period:	0.05

The internal rate of return corresponds with an annual return on the investment of 5% after a projected 20 years of operation.

3.8.2 Building No. 4

This building is 14 storey, with 230 low rental apartment units.

The building uses natural gas for space and domestic hot water heating. There are 3 boilers for space heating and 4 domestic hot water heaters, serving 4 domestic water tanks, which are each 120 US gal.

The proposed nominal CHP Unit size is 125 kW. Maximum thermal turn-down requirements are estimated to be 52%, which is based on a maximum thermal output capacity of 160 kWth (117,085 kWh*th*/month) from the unit. The maximum prime electrical output is 115 kW, which is approximately 35% to 50% of the peak demand level in the building.

The proposed location for the CHP Unit is in an enclosure, located above the mechanical penthouse.

The average fuel cost is estimated at 1.56/kWh*th* ($4.5/MCF), while the average electrical cost is estimated at 6.2¢/kWh. To calculate electrical energy and demand savings, a demand cost of $4.75/kW and a marginal energy rate of 5.21¢//kWh were used.

The cost assessment summary for the proposed cogeneration system is as follows:

- Construction Costs:	$280,715
- Annual Maintenance Cost:	$ 12,670
- Annual Electrical Cost Savings:	$ 52,545
- Net Annual Fuel Cost Increase:	$ 19,970
- Net Annual Energy Cost Savings:	$ 19,905
- Simple Payback Period:	14 years
- Net Present Value (NPV) of Savings for Projected 7 year Period:	$113,320
- Net Present Value (NPV) of Savings for Projected 20 Year Period:	$245,230
- Internal Rate of Return (IRR) for Projected 20 Year Period:	0.05

The internal rate of return corresponds with an annual return on the investment of 5% after a projected 20 years of operation.

3.8.3 Building Nos. 6A and 6B

The site consists of two 12 floor buildings which are physically connected together and each have 251 medium income rental apartment units. The site contains an indoor recreation pool, which is not used in the summer, and therefore, not considered in the sizing for the CHP Unit.

The site uses natural gas for space and domestic hot water heating. There are 3 boilers in each building, of which one boiler is dedicated to domestic hot water. The existing domestic hot water tank sizes are estimated to be 1,200 US gal (one in each building).

The proposed nominal CHP Unit size is 275 kW. Maximum thermal turn-down requirements are estimated to be 75%, which is based on a maximum thermal output capacity of 355 kWh*th* (259,030 kWh*th*/month) from the unit. The maximum prime electrical output is 250 kW, which is approximately 40% of the peak demand level in the buildings combined.

The proposed location for the CHP Unit is in a room, adjacent to the boiler room of Building 6A, located at the basement level.

The average fuel cost is estimated at 1.36/kWh*th*/ ($.38/MCF), while the average electrical cost is estimated at 6.2¢/kWh. To calculate electrical energy and demand savings, a demand cost of $4.8/kW and a marginal energy rate of 5.25¢/kWh were used.

The cost assessment summary for the proposed cogeneration system is as follows:

- Construction Costs:	$396,060
- Annual Maintenance Cost:	$ 30,375
- Annual Electrical Cost Savings:	$125,465

- Net Annual Fuel Cost Increase:	$ 41,830
- Net Annual Energy Cost Savings:	$ 53,260
- Simple Payback Period:	7 years
- Net Present Value (NPV) of Savings for Projected 7 year Period:	$303,215
- Net Present Value of Savings for Projected 20 Year Period:	$656,165
- Internal Rate of Return (IRR) for Projected 20 Year Period:	0.15

The internal rate of return corresponds with an annual return on the investment of 15% after a projected 20 years of operation.

3.8.4 Building No. 7

The building is 20 storey, with 270 medium income rental apartment units. A swimming pool is contained within the building which is used throughout the year and is served by the domestic hot water boilers. Thus, this load was considered in the sizing for the CHP Unit.

The facility uses natural gas for space and domestic hot water heating. There are 4 boilers for space heating, and 4 boilers for domestic hot water. Also, there are 2 domestic hot water storage tanks, which are each estimated to be approximately 1660 US gal.

The proposed nominal CHP Unit size is 175 kW. Maximum thermal turn-down requirements are estimated to be 73%, which is based on a maximum thermal output capacity of 225 kWth (165,780 kWh*th*/month) from the unit. The maximum prime electrical output is 160 kW, which is approximately 35% of the peak demand level in the building.

The best location for the unit appears to be on the roof of the penthouse, above the boilers. Thus, an enclosure would be required.

The average fuel cost is estimated at 1.59/kWth ($4.6/MCF) while the average electrical cost is estimated at 6.4¢/kWh. To calculate electrical energy and demand savings, a demand cost of $5.10/kW and a marginal energy rate of 5.36/kWh were used.

The cost assessment summary for the proposed cogeneration system is as follows:

- Construction Costs:	$329,245
- Annual Maintenance Cost:	$ 18,930
- Annual Electrical Cost Savings:	$ 80,735
- Net Annual Fuel Cost Increase:	$ 30,880
- Net Annual Energy Cost Savings:	$ 30,915
- Simple Payback Period:	11 years
- Net Present Value (NPV) of Savings for Projected 7 Year Period:	$176,005
- Net present value (NPV) of Savings for Projected 20 Year Period:	$380,875
- Internal Rate of Return (IRR) for Projected 20 Year Period:	0.09

The internal rate of return corresponds with an annual return on the investment of 9% after a projected 20 years of operation.

3.9 Conclusions

The four project summaries presented in the previous section cast doubt onto the economical viability for the application of cogeneration technology to multi-unit residential structures. From the analyses of these four projects, it appears that units sized at 100 kW or below, and projects with substantial retrofit costs (ie. requiring substantial structural work, electrical modifications, increased gas pressure, crane, etc.), are not economically feasible for the implementation of cogeneration at this time or in the foreseeable future.

The results show simple payback periods ranging from 15 years for the smallest cogeneration unit (40 kW) to 7 years for the largest unit (275 kW). Also, for these same projects, the annual rates of return after a projected 20 year period vary between 5% to 15%. It should be noted however, that potential incentives from utilities (such as kW reduction, gas pressure boosters, etc.) have not been factored into the analyses.

From an economic standpoint, the most desirable location for a CHP unit is inside the facility, as close as possible to the boilers and electrical service. Construction costs can increase substantially with added structural work, piping, and electrical wiring requirements. Gas pressure requirements and available supply pressures can also have a substantial effect on construction costs. If the required pressure is greater than that available, then a gas booster compressor package may be required, where prices normally range from $20,000 to $45,000.

Capital costs can vary from over $2,000/kW for major retrofit projects to less than $1,200/kW for new construction projects or projects involving minor retrofit work. In addition, the economics of cogeneration can be further enhanced if based on premium cost for modifications which would have to be carried out in any event. Capital costs of cogeneration systems are expected to decrease with increased demand and market availability in Canada.

In order to optimize the operation of a cogeneration system, it is essential to maximize the thermal and electrical output levels. Constraints on the system are that the electrical output is to be no more than 80% of the building's electrical demand level. Also, neither the domestic hot water or space heating systems are to overheat. As such, a dedicated control system is required to monitor pipeline and tank temperatures, motorized valve operation, etc. This system must be integrated into the CHP unit's mini SCADA control scheme as outlined in Section 3.7 and the system operation optimized to receive the maximum possible utilization.

CHP units tend to have improved economic viability when load levelling devices, such as large domestic hot water storage tanks, which require a minimum thermal recovery rate, are contained within the existing system. Smaller domestic storage vessels require a higher thermal recovery rate and, therefore more frequent cycling of CHP output levels which reduces system optimization.

Of the four projects which were analyzed, the domestic hot water systems on the two smaller buildings were designed with relatively small storage tank capacities, and high thermal recovery rates; while the larger buildings were designed with smaller recovery rates and larger storage capacities.

For all four projects, it appears that when the CHP unit operates at 100% capacity, the thermal output is close to the average daily domestic hot water consumption. At 40% capacity (typical minimum turn-down level), the output of the unit appears close to low load requirements which occur for approximately six hours per day. As a result, it appears that the cogeneration units in the smaller buildings may be removed from service for a few hours each day in the summer. Since the larger buildings have some load-levelling capacity, they should not need to turn-down to the 40% output level.

This report has limitations in that the findings are based on four (4) representative projects. All cogeneration applications must be addressed on a site specific basis. Those who wish to pursue detailed assessments on the feasibility of a specific cogeneration installation should follow the methodology outlined in the foregoing to substantiate their conclusions.

Regional energy rates vary substantially across Canada based on the availability of gas/fuel and on the purchase price of electricity. Relative energy rates can range from areas such as British Columbia and Manitoba where low electricity and medium fuel rates exist, the high arctic where very high electricity and fuel rates exist, central Canada where medium electricity and medium gas rates exist, and the Maritimes where higher electricity and medium to high fuel rates exist. A comparison of energy rates across Canada is provided in Appendix 'H'.

Fuel and electricity rates are expected to continue varying in future years, and the designer of a specific project will have to forecast energy rates for the specific geographic condition. As discussed in Part I of the report, electricity costs are expected to continue rising for the next few years, and since average gas rates are currently increasing at a slower rate, the margin between the two energy rates is expected to widen. This will have a positive impact on the economic viability of the application of cogeneration.

APPENDIX 'A'

WORK SHEETS

<u>**TABLE 1.1**</u>

GENERIC RECIPROCATING COGENERATOR SIZES

Nominal CHP Size (kW)	Prime Electrical Output (kW)	Thermal Output (kW*th*) (1)	Thermal Output (kWh*th*/month) (1)	Equivalent Boiler Input (2) (kWhth/month)(1)
Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
5	4.5	6	4,665	5,830
10	9	13	9,325	11,655
20	18	25	18,650	23,315
25	23	33	23,830	29,790
30	27	40	27,975	34,970
40	35	50	36,265	45,330
50	45	65	46,625	58,280
60	55	75	55,950	69,940
75	70	95	70,455	88,070
100	90	130	93,250	116,565
125	115	160	117,085	146,355
150	135	190	139,880	174,845
175	160	225	165,780	207,225
200	180	255	186,505	233,130
225	205	290	212,405	265,510
250	225	320	233,130	291,410
275	250	355	259,030	323,790
300	275	390	284,935	356,170
350	320	455	331,560	414,450
400	365	520	378,185	472,735
475	425	605	440,355	550,445
500	455	645	471,440	589,300

(1) Note: Subscript "*th*" denotes thermal demand and energy consumption.

(2) Based on an assumed boiler efficiency of 80% where, Equivalent Boiler

$$\text{Input} = \frac{\text{Thermal Output}}{0.8}$$

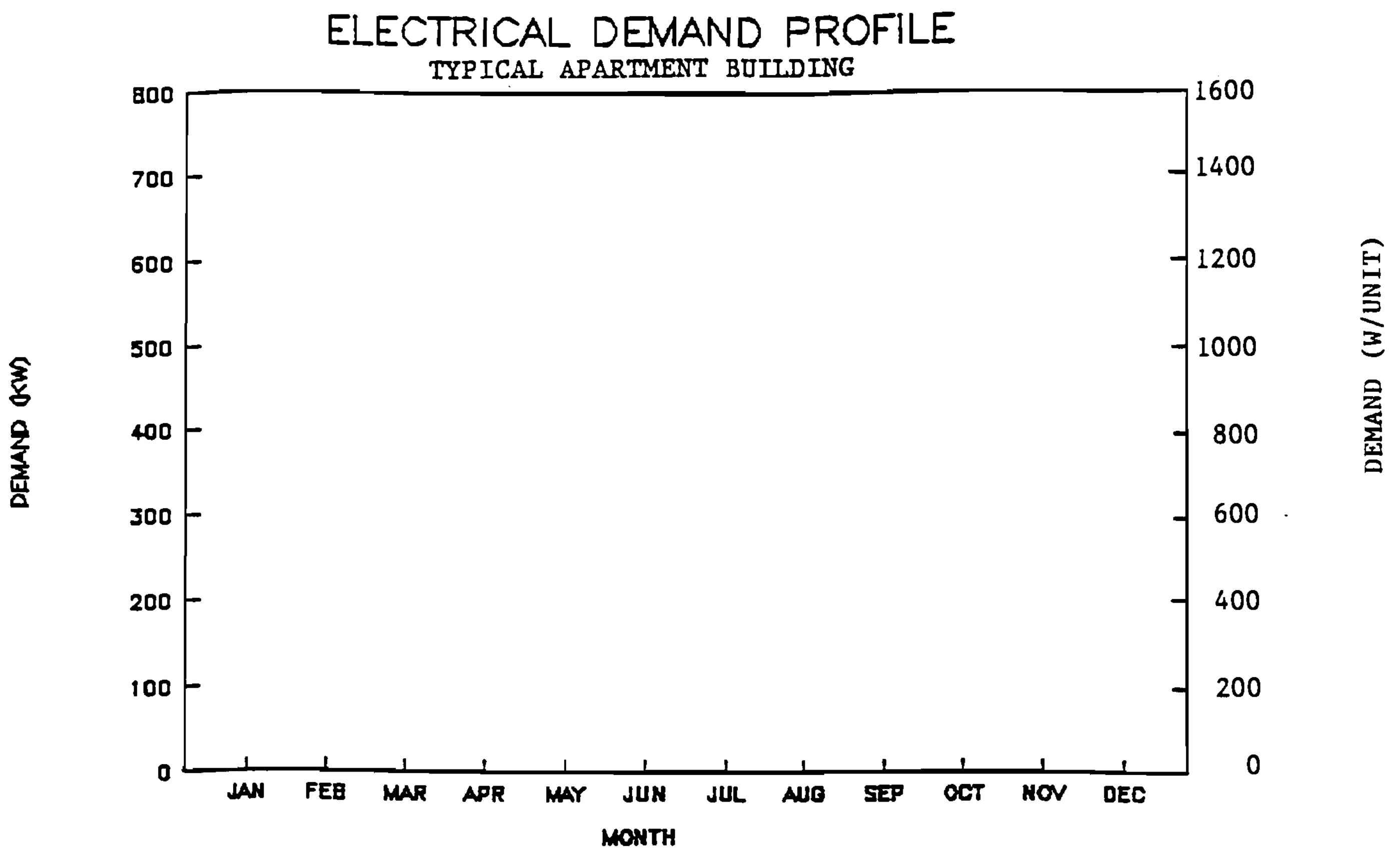


FIGURE 1.2(a)

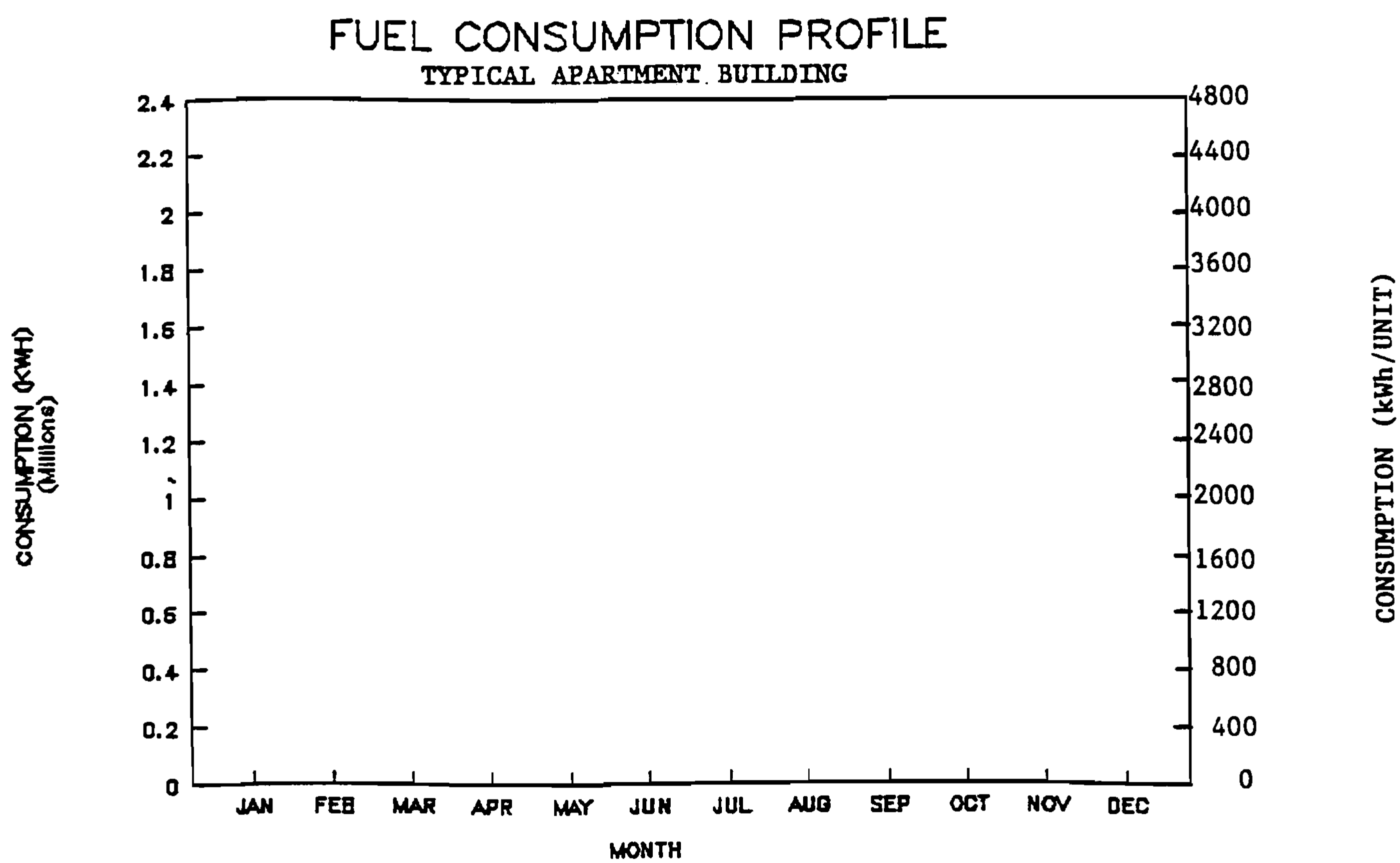
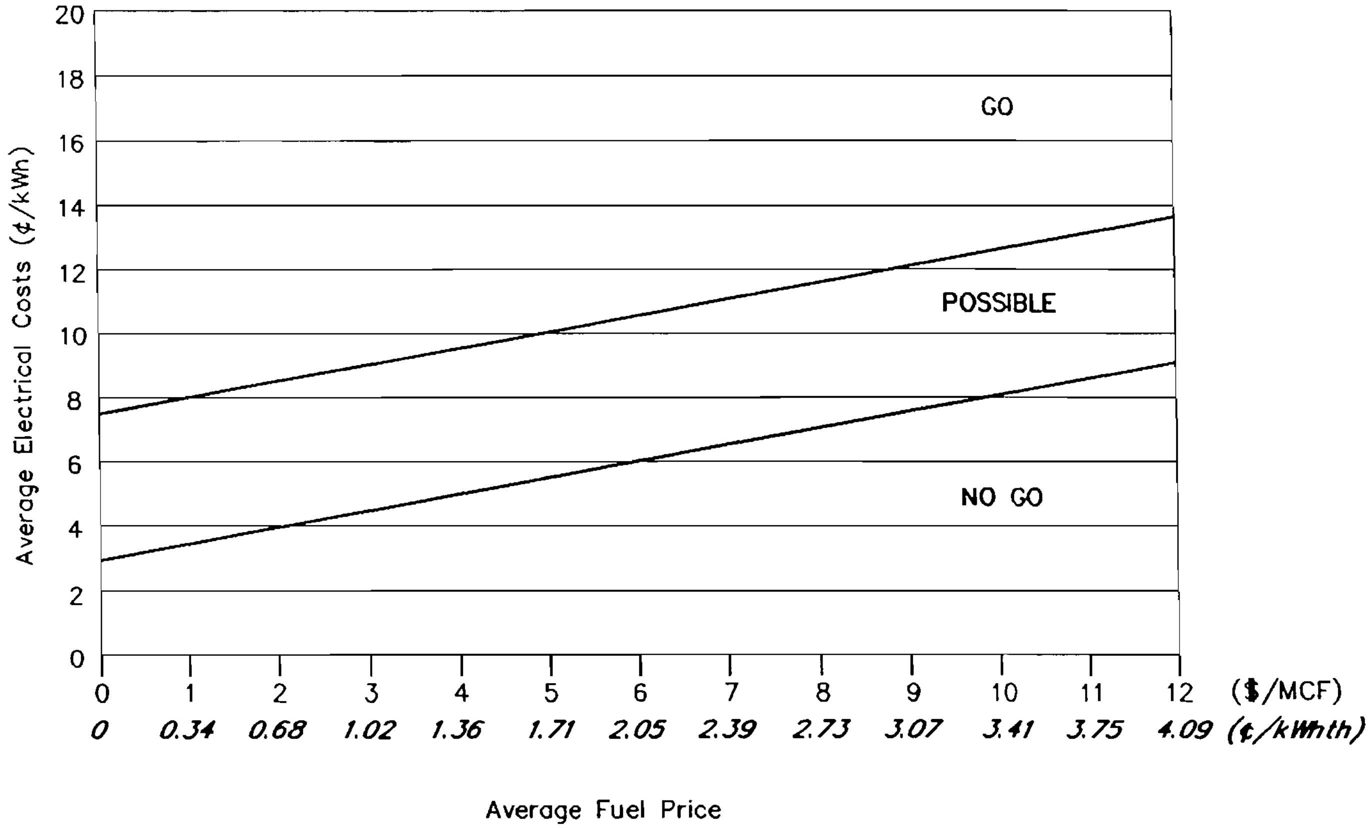
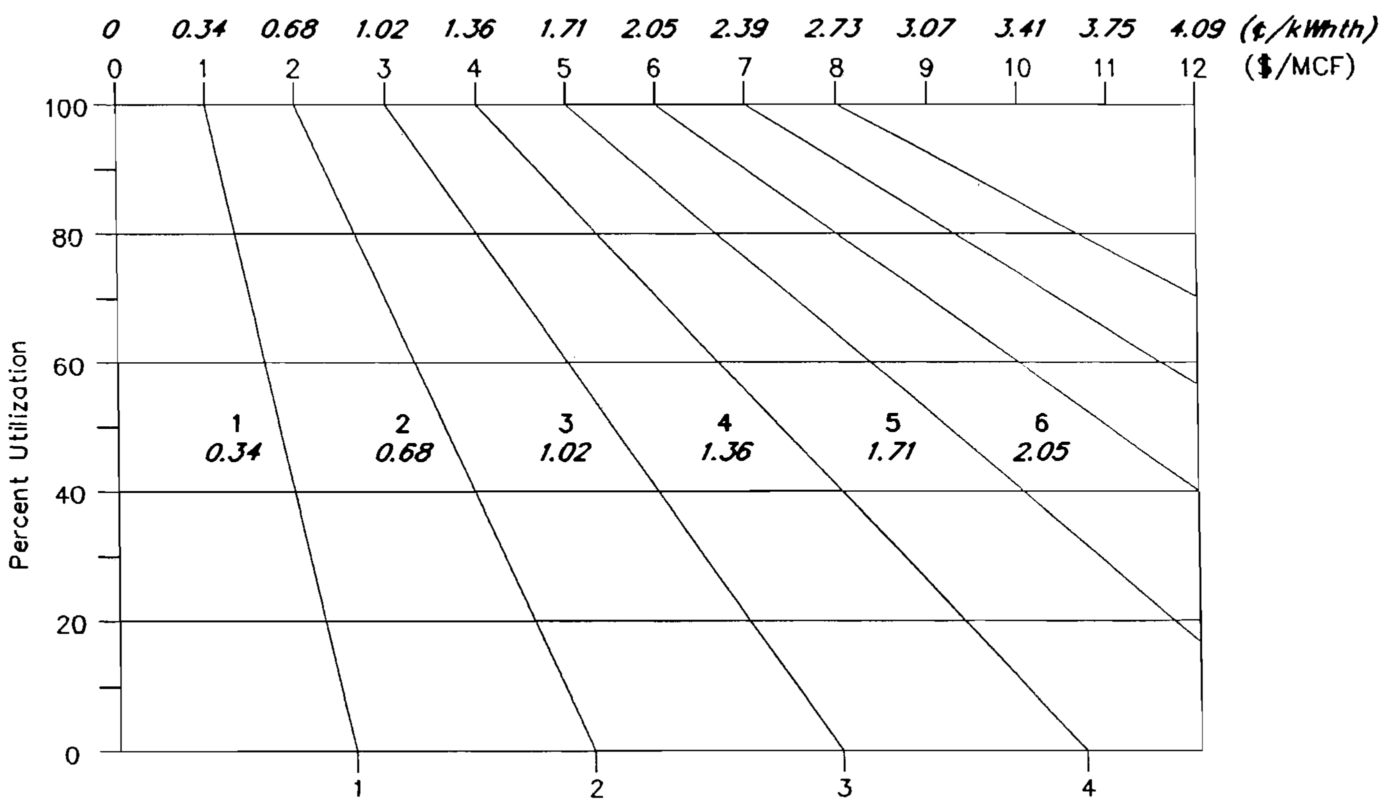


FIGURE 1.2(b)

ECONOMIC ASSESSMENT SHEET

(Based on $1,200/kW)



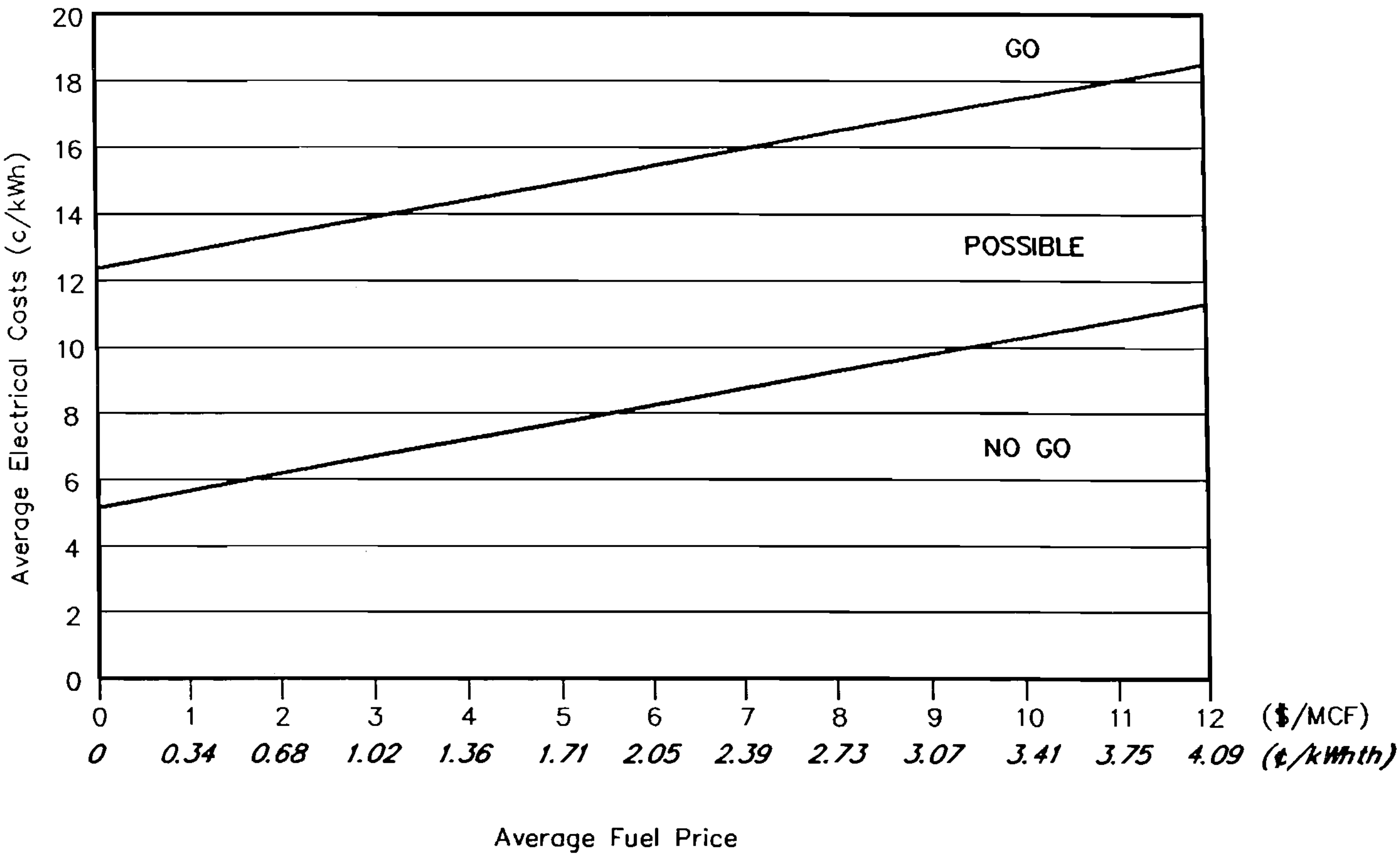


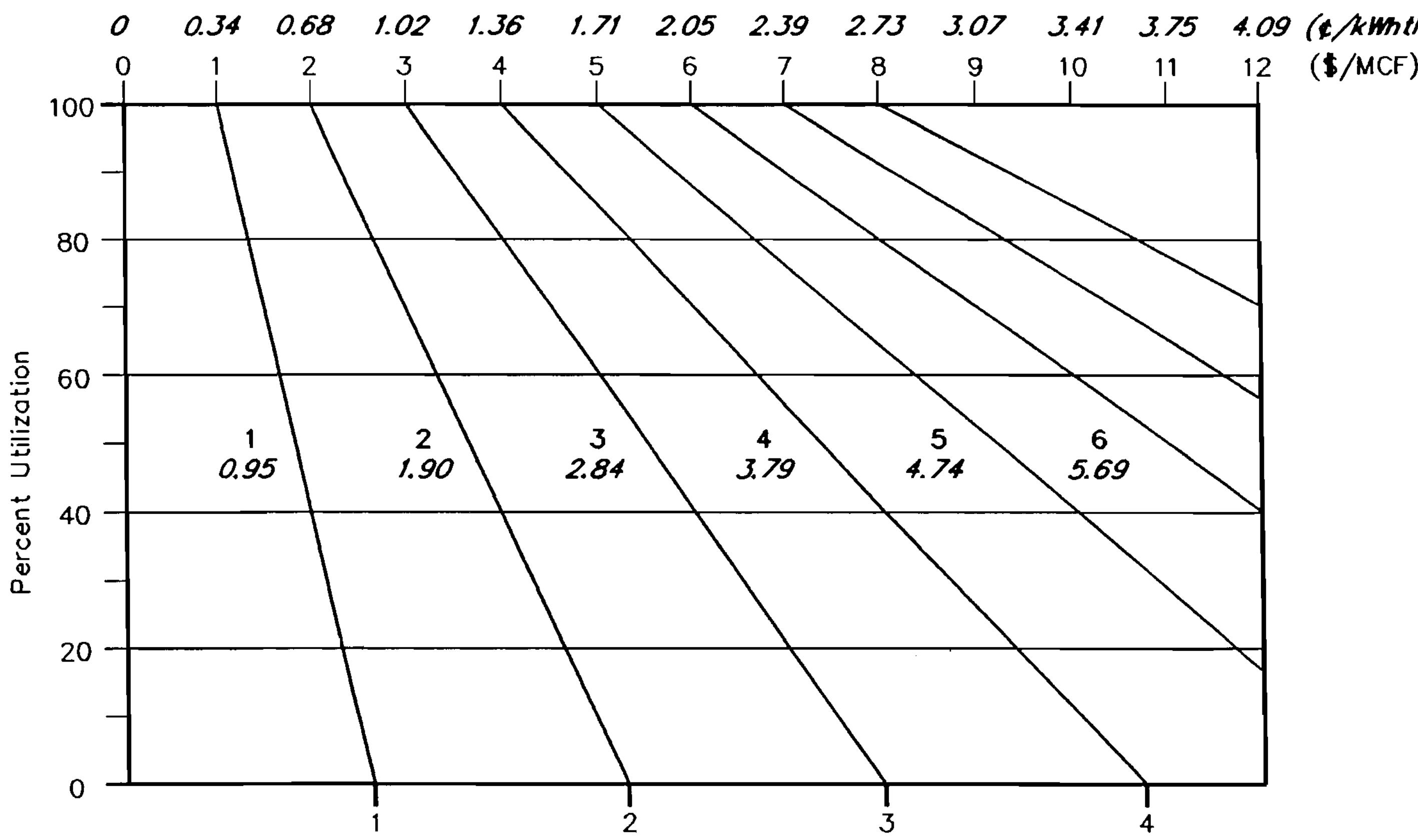
Derived from Texas A & M university

Figure 1.3

ECONOMIC ASSESSMENT SHEET

(Based on $ 2,000/kW)





Derived from Texas A & M university

Figure 1.3b

TABLE 1.3

Electrical and Thermal Billing Details for a Recent 12 Month Period

MONTH	ELECTRICITY			THERMAL	
	Energy[1] (kWh)	Peak Demand (kW)	Total Cost ($)	Consumption [2] (kWh*th*) [3]	Cost ($)
	Column (1)	Column (2)	Column (3)	Column (4)	Column (5)
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
TOTALS					

(1) An approximation of average demand can be found by dividing column (1) by the number of system operating hours per month.

(2) For natural gas, 1 m^3 = 10.33 kWh*th*.

(3) subscript "*th*" denotes thermal energy.

TABLE 1.4

(a)	**Size of CHP Unit (from Table 1.1, Column (1)):**	__ kW (Nominal Size)
	For at least 9 months of the year the monthly fuel consumption from Column (4) of Table 1.3 is greater than or equal to the equivalent boiler input of the unit (Column (5) of Table 1.1).	
(b)	**Average Cost of Electricity (from Table 1.3):**	
	$\dfrac{\text{Column (3) Total}}{\text{Column (1) Total}} \times 100¢/\$$	__ ¢/kWh
(c)	**Average Thermal Fuel Cost (from Table 1.3):**	
	$\dfrac{\text{Column (5) Total}}{\text{Column (4) Total}}$	__ ¢/kWh*th* ($/MCF)
(d)	**Average Monthly Thermal Energy Displaced by CHP Unit:**	
	$X = \dfrac{(A_1 + A_2 + \ldots\ldots + A_N)}{N} =$	__ kWh*th*/mth
	where X = Average monthly thermal energy displaced by CHP Unit. An = Monthly thermal energy displaced by CHP Unit to a maximum of Y (defined below). "n" denotes the month (1 to 12). N = Number of months the system is utilized (i.e. where An > O).	
(e)	**Percent Thermal Energy Utilized (% TU):**	
	$\dfrac{X}{Y} \times 100\% =$	__ %
	where Y = Equivalent boiler input of CHP Unit (from Column (5) of Table 1.1) =	__ kWh*th*/mth
(f)	Complete the nomograph illustration from Economic Assessment Sheet (Figure 1.3) to determine whether cogeneration is a GO, POSSIBLE, or NO GO and indicate here:	________

Derived from Texas A & M University.

TABLE 1.5

SUMMARY SHEET FOR LEVEL I
ANALYSIS

Architectural:
Mechanical:
Electrical:
Occupancy Type:
Average Electrical Cost (¢/kWh):
Average Fuel Cost (¢/kWhth($/MCF)):
Nominal CHP Size (kW):
Prime Electrical Output (kW):
Thermal Output (kWth(kWhth/month)):
Percent Thermal Energy Utilized (% TU):
Additional Comments: Technical Evaluation: Economic Evaluation:

APPENDIX 'B'

LEVEL II STUDIES

APPENDIX 'B'

B.1.0 Building No. 2

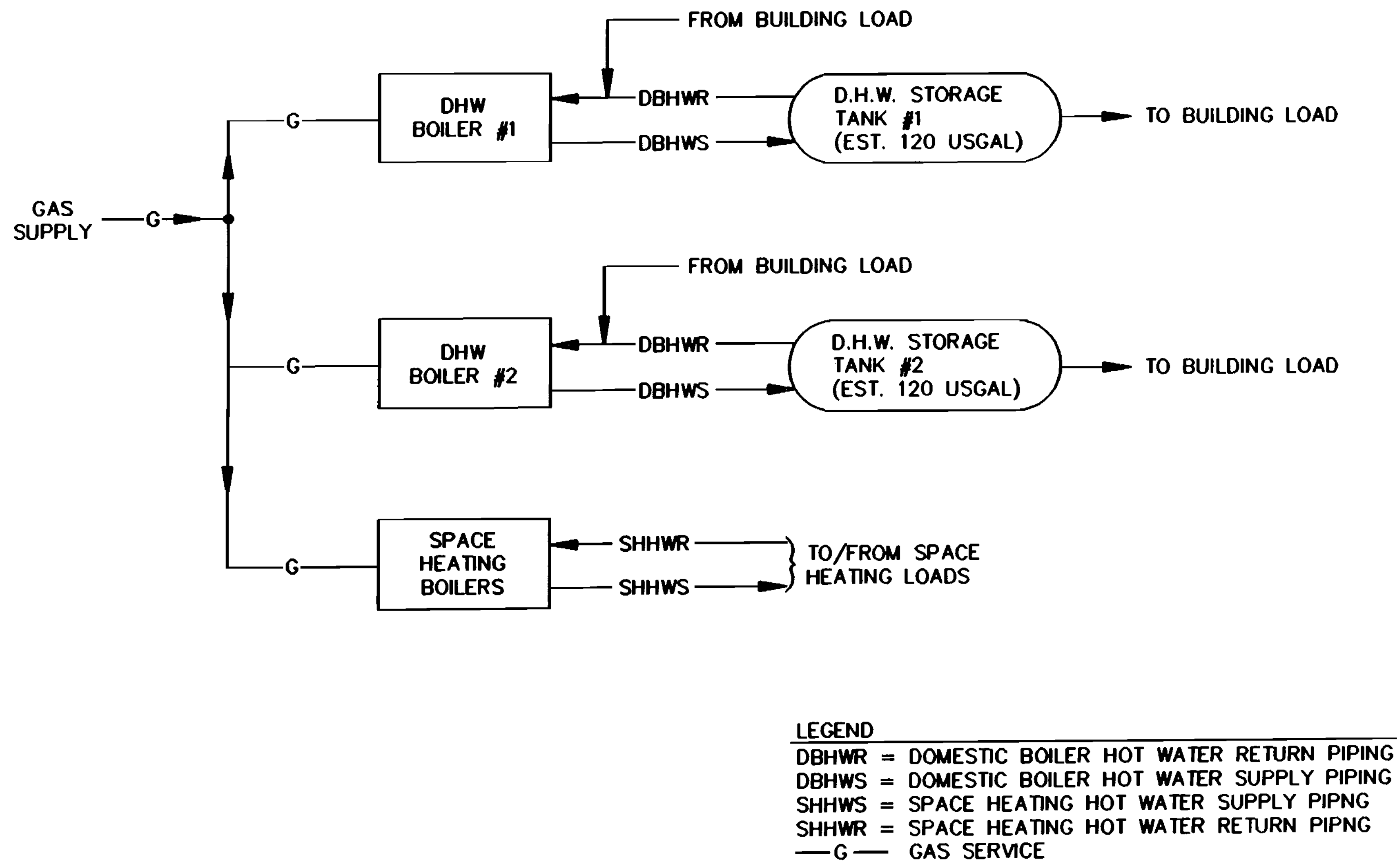
B.1.1 General Description of the Facility

Building No. 2 is one of two high rise apartment buildings which are physically connected together with a low rise block of apartment units in between. Also, there are 33 townhouses located on the site which all have individual electric hot water tanks. One gas meter serves the high rise buildings which are each 24 storey, and have boiler rooms located on the top floors. The boiler rooms contain centralized domestic hot water systems and provide space heating for the buildings and garage areas.

The bottom 6 floors of each high rise are part of the low structure. There are 125 apartments in the low rise, of which 105 have individual electric hot water tanks, and the remainder are served by the centralized domestic hot water systems. Each high rise building has 108 apartment units located on the top 18 floors.

Consideration was given to sizing a cogeneration system for both high rise buildings and the low rise structure combined. However, because of the location of the 2 boiler rooms, this option was dismissed due to the integration costs.

Thus, for the purposes of this study, Building No. 2 consists of the top 18 floors in one of the high rise buildings, plus 10 apartment units from the low rise structure which are served by the centralized domestic hot water system. It should be noted that the building which was selected has a more spacious boiler room than the other building, and appears to offer the best location for housing a CHP unit.



BUILDING No.2
EXISTING HOT WATER SYSTEM

Figure B-1

B-1.2 Heating System

B-1.2.1 General Description:

The boiler room penthouse in Building No. 2 contains 6 boilers, of which 4 are for space heating requirements and 2 serve the domestic hot water system. The space heating systems are controlled and operated separately from the domestic hot water system. The space heating consists of radiant heating for the perimeter of each apartment unit as well as heating for air handling units which provide make-up air for corridor pressurization. The 4 space heating boilers are rated at a maximum output of 2170 MBH.

The domestic hot water boilers, which are approximately 20 years old, are in relatively good condition. They serve 2 storage tanks which are each estimated to be 120 US gal. Both boilers are fired with natural gas and have a maximum input rating of 1,050 MBH each. A site contractor advised that the boilers are normally modulated such that the storage tanks provide a hot water supply temperature between 54°C (130°F) and 57°C (135°F).

A single line sketch of the hot water system is provided in Figure B-1.

1.2.2 Gas Service, Fuel Costs and Consumption Data:

In general, for apartment buildings, the supplied gas pressure is likely to be around 7" w.c. (0.25 psig), which is typical for highly populated residential areas. The actual conditions are site specific and would need to be confirmed with the utility. The required pressure for a new CHP system is likely to be greater than that available; thus, a natural gas booster compressor package would be required.

The monthly gas consumption and corresponding costs for 1991 are presented in Table B-1. Further analysis of the thermal demand profile is provided in Section B-1.4
The current gas rate come into effect as of October 1, 1991. In comparing the billing data of October through to December to the overall average of 1991, it appears that the overall average rate of 1.54¢/kWh*th* ($4.5/MCF) is representative of current costs.

TABLE B-1

GAS BILLING DATA (BUILDING NO. 2) FOR 1991

Month	Gas Consumption		Cost
	(cu.m.)	(kWh*th*)	($)
January	117,631	1,215,515	18,609
February	82,666	854,210	13,222
March	68,003	702,693	10,902
April	44,768	462,603	7,546
May	17,210	177,832	2,618
June	4,327	44,712	707
July	2,862	29,569	486
August	2,897	29,931	491
September	4,551	47,027	763
October	34,739	358,965	5,163
November	47,751	493,427	7,043
December	88,433	913,808	14,610
Total	**515,835**	**5,330,290**	**82,156**

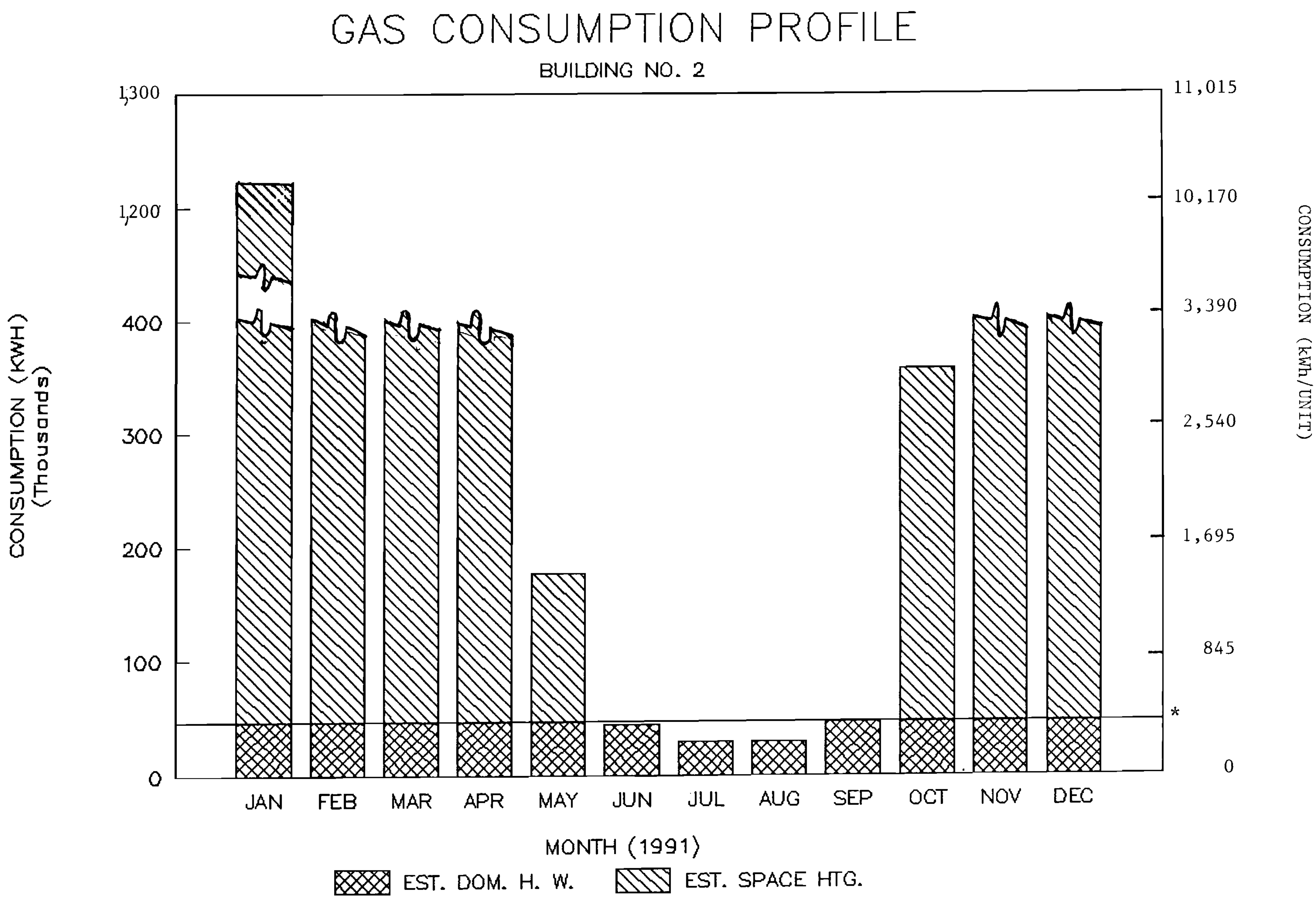
B-1.3 Electrical System

B-1.3.1 General Description:

The building is currently fed from Ottawa Hydro to a main switchboard. Utility metering is centralized and bulk measured with no sub-metering for individual tenant loads.

B-1.3.2 Electrical Costs and Consumption/Demand Data

The monthly electrical consumption, demand and corresponding costs during 1991 for Building No. 2 are listed in Table B-.2.



* EQUIVALENT BOILER INPUT OF CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-2

TABLE B-2

ELECTRICAL BILLING DATA FOR BUILDING NO. 2

Month	Building No. 2		
	Energy (kWh)	Demand (kW)	Cost ($)
January	243,600	400	13,165
February	164,400	378	9,356
March	164,400	367	9,309
April	172,800	367	9,703
May	184,800	351	10,196
June	147,600	335	8,381
July	165,600	346	9,272
August	171,600	324	9,459
September	163,200	356	9,206
October	180,000	383	10,112
November	172,800	400	9,844
December	145,200	410	8,597
Total	**2,076,000**	**410 (Peak)**	**116,600**

The facility is billed by Ottawa Hydro on a General Service Rate Structure.

In the economic analysis (Section B-1.8), the marginal energy rate of 5.21¢/kWh and the demand rate of $4.75/kW per month are used to calculate savings on displaced electrical power from the CHP unit.

B-1.4 Thermal Load Analysis

The gas consumption data from Table B-1 was used to develop the thermal demand profile presented in Figure B-2. This figure illustrates the variation between the higher gas consumption requirements during the winter months for space heating and the significantly lower consumption levels which occur during the summer to satisfy the domestic hot water requirements.

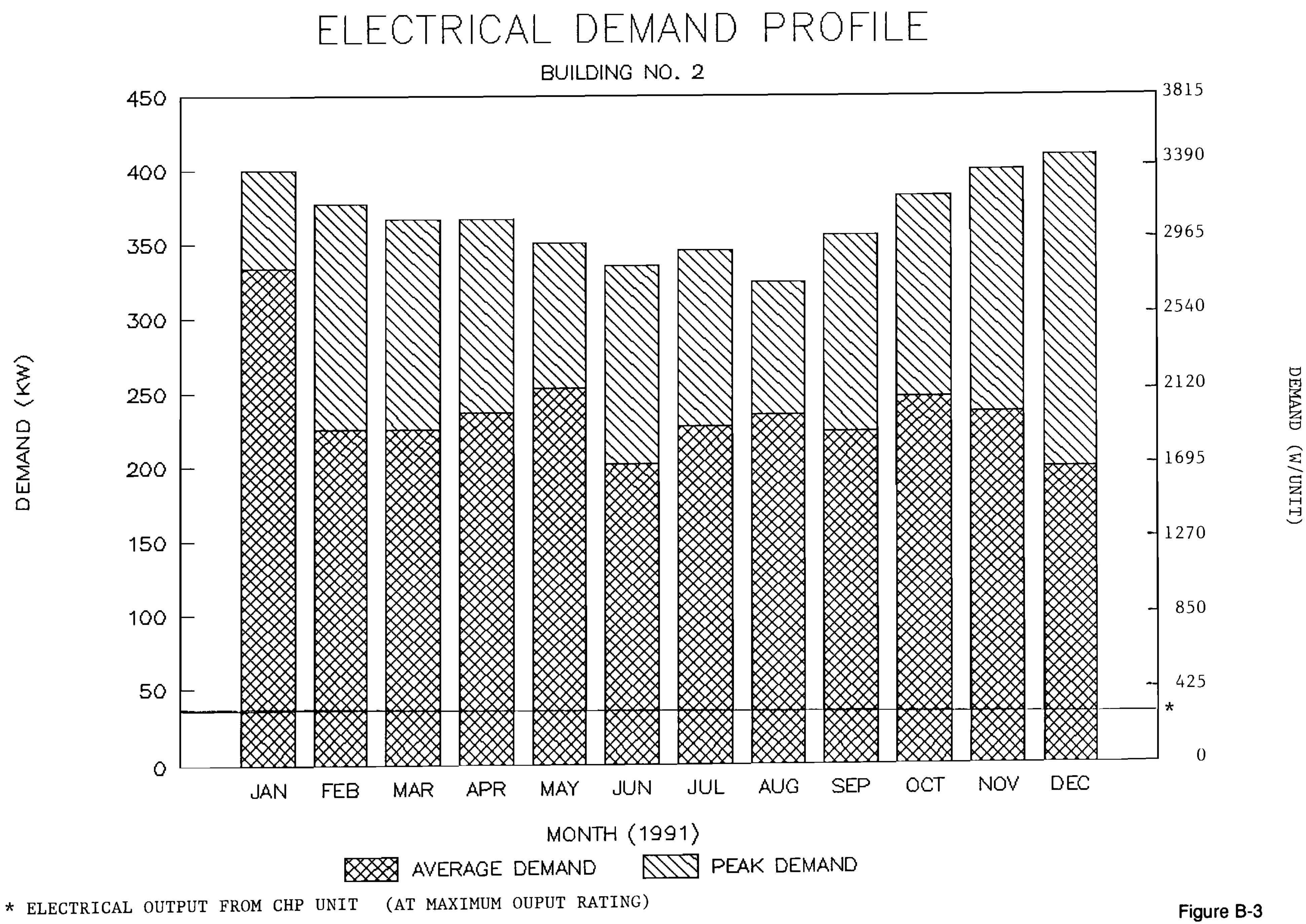
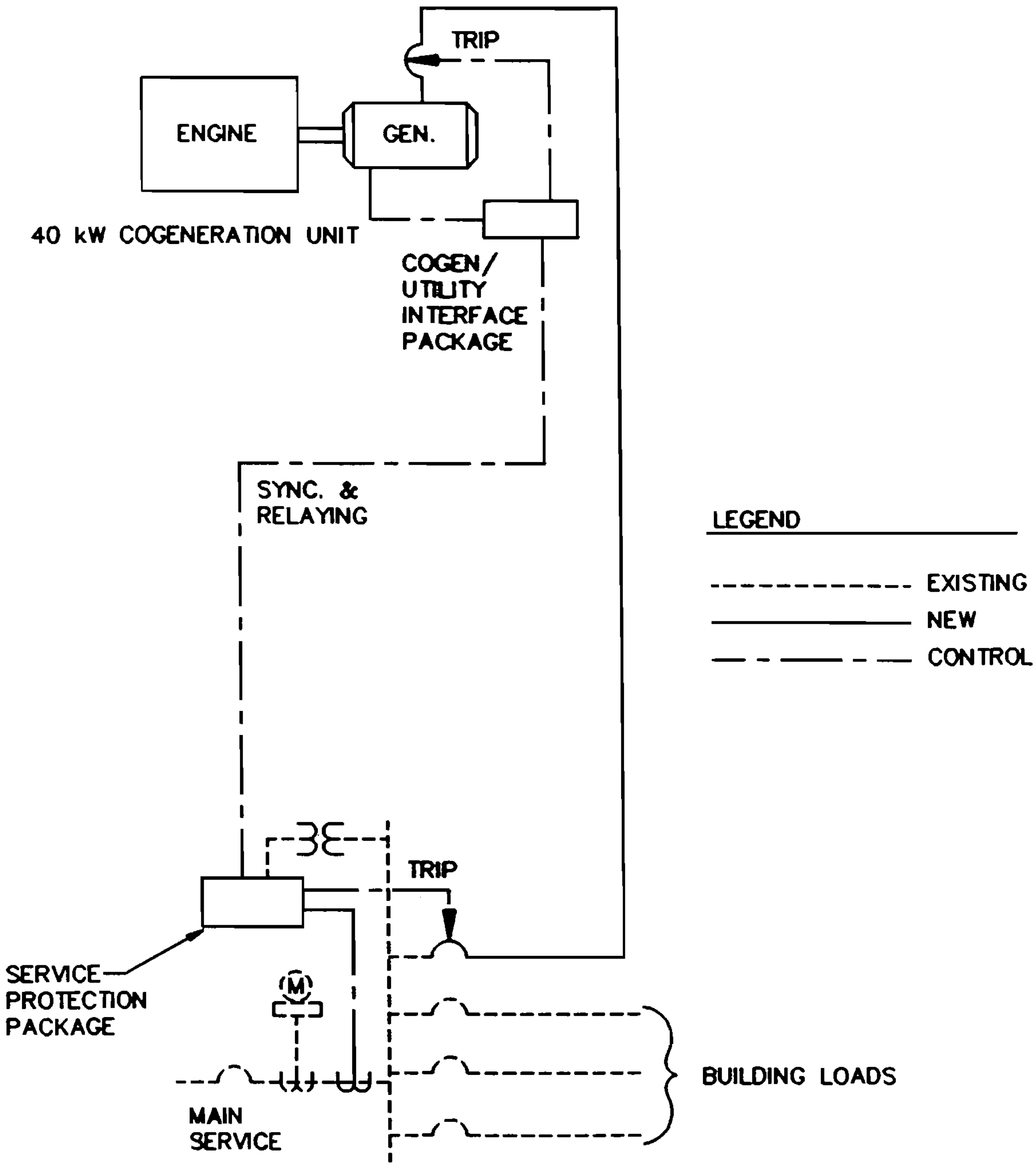

ELECTRICAL DEMAND PROFILE
BUILDING NO. 2
DEMAND (KW)
450
400
350
300
250
200
150
100
50
0
DEMAND (W/UNIT)
3815
3390
2965
2540
2120
1695
1270
850
425
0
*
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
MONTH (1991)
AVERAGE DEMAND
PEAK DEMAND
* ELECTRICAL OUTPUT FROM CHP UNIT (AT MAXIMUM OUPUT RATING)

Figure B-3



BUILDING No.2
PROPOSED ELECTRICAL INTERCONNECTIONS

Figure B-4

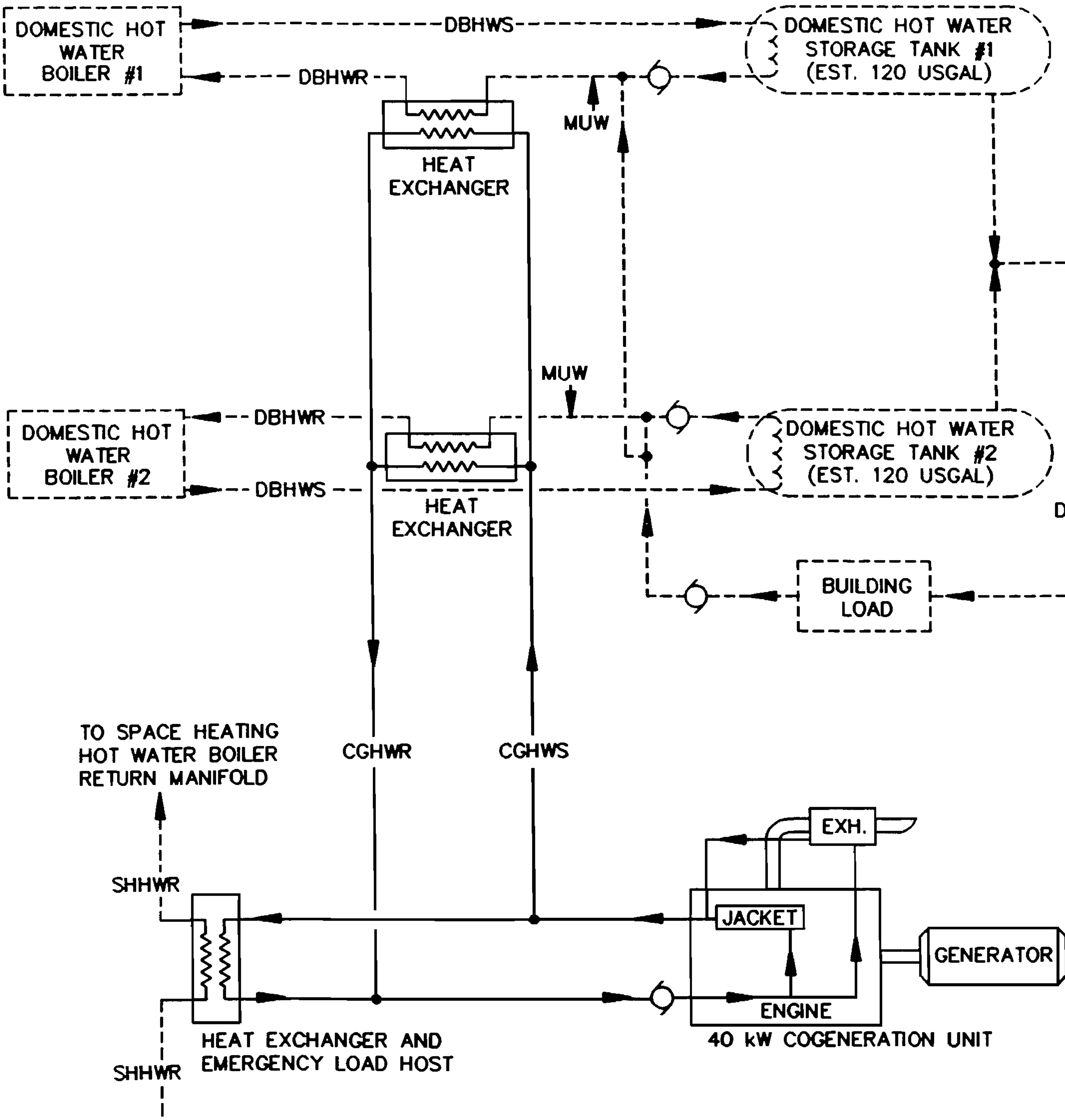
The consumption curve and corresponding data in Table B-1 show an average baseload input of 2,862 m^3 (29,569 kWh*th*) for the month of July. Further analysis of this curve reveals that the load requirements for the months of June and September account for more than 9 months (at least 6000 hours) per year. Thus, it was decided that September's thermal baseload of 4,550 m^3 (47,027 kWh*th*) input would serve as a useful benchmark for a combined heat and power unit, which would provide a turn-down ratio to average baseload conditions of 65%.

B-1.5 Electrical Load Analysis

To analyze the electrical demand profile for Building No. 2, the monthly demand data from Table B-2 was used to plot the electrical demand curve presented in Figure B-3. Generally speaking, the curve has minor fluctuations in demand throughout the year with a peak occurring in the winter months which is about 20% higher than the peak summer demand.

The proposed cogeneration interconnection would consist of a direct power tie into the 208 Volt main switchboard to provide AC power for consumption 'in-house' and would not be in a position to export to Hydro's grid. The amount of power available would be directly proportionate to the turn-down thermal output of the unit. The net result would be an almost continuous level of 35 kW of power which would not have to be purchased from Hydro. This would amount to approximately 10% of the peak power supply.

The system would have a power interface package which would continuously monitor the output of the unit and the actual current draw on the main building service. The unit would be automatically synchronized to the utility grid and at no time would the unit be allowed to produce more than 80% of the building's total current draw. In addition, a full relay package would backup the synchronizing and current check relays with reverse current, phase unbalance, etc. to automatically shut the unit down in the event of a failure of any system. Figure B-4 illustrates the proposed electrical interconnections.



BUILDING No.2
PROPOSED COGENERATION
THERMAL SYSTEM INTERFACE

LEGEND

DHWR = DOMESTIC HOT WATER RETURN PIPING
DHWS = DOMESTIC HOT WATER SUPPLY PIPING
DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
CGHWR = COGEN HOT WATER RETURN PIPING
CGHWS = COGEN HOT WATER SUPPLY PIPING
SHHWR = SPACE HEATING H.W. RETURN PIPING
MUW = MAKE UP WATER
------- EXISTING
——— NEW

Figure B-5

B-1.6 Proposed Cogeneration System

Consideration of the benchmark thermal load established in Section B-1.4 (4,550 m^3, 47,027 kWh*th*/month input of natural gas) establishes the basis for sizing a reciprocating cogeneration unit.

Based on methodology used in Section 2.2 for sizing the CHP system and the generic Table No. 1.1 from Section 1.4, a nominal unit size of 40 kW was selected with a maximum thermal output of 36,265 kWh*th*/month. Also, from Table 1.1, the corresponding electrical output capacity of the unit would be 35 kW. As discussed in Section B-1.5, this would provide approximately 10% of the peak power supply to the building. The electrical output of the system is to never be more than 80% of the building's electrical demand level. The proposed cogeneration unit would be interfaced with the domestic hot water and space heating systems as illustrated in Figure B-5.

In order to maximize the use of the CHP unit, it would primarily serve the domestic hot water system, where heat would be recovered from the CHP engine exhaust and jacket water cooling. This would be done through two new heat exchangers; one on each return line to the domestic water boilers. Thus, the unit would essentially act as a lead boiler to the domestic hot water system. Any load requirements in excess of the unit's capacity, would be supplemented by the existing boilers. During the summer, when domestic hot water load requirements are less than the capacity of the CHP unit, the output level of the system would need to be reduced ("turned-down"). Cogeneration units normally have turn-down capabilities to 40%; however, if the load requirements were less than this, the unit would have to be turned off.

An ASHRAE research paper (1988), by Perlman and Milligan on hot water and energy use in apartment buildings was reviewed. The paper provides a typical domestic hot water consumption profile at a 95% confidence level which represents a reliable estimate of the maximum average daily usage expected for a particular building category. This profile was used to model the domestic hot water consumption for the building, where the thermal recovery rate of the proposed CHP unit at 100% capacity and 40% capacity have been superimposed on the graph.

This profile, along with a chart which identifies the estimated recovery rate of the CHP unit, are provided in Appendix 'C'. Here it is illustrated, that since the building has a small domestic hot water storage capacity, the CHP unit may need to turn off for 2 to 3 hours per day in the summer.

While the cogeneration system is operating, an emergency condition may result from a loss of the CHP unit's ability to cool itself, such as a pipe break, a jammed valve, etc. Depending on manufacturer's recommendations, all CHP units require a cool down period of at least 5 to 15 minutes under no load conditions to equalize the thermal expansion of the engine block. Therefore, in the design of any cogeneration system, it is essential that an emergency heat sink be provided.

During emergency conditions, and in the winter, excess heat from the CHP unit would be relieved to the space heating system through a heat exchanger on the main hot water return line to the space heating boilers. In emergency conditions, if space heating is not in use, a pump would likely be activated to ensure an adequate flow of water is being circulated in the space heating loop. It is recommended that such a pump be powered from the emergency diesel generator to provide circulation during the first few minutes of a power failure. If space heating proved to be an impractical means of providing an emergency heat sink to the system, there are alternative methods of meeting this requirement such as the installation of an outdoor condenser unit, or the rejection of excess heat to a swimming pool.

The thermal energy currently produced in the building for the domestic hot water system is in the form of hot water from the boilers. A site contractor indicated that the supply temperature to the storage tank is typically around 70°C (160°F) to 75°C (167°F), where the storage tanks provide a supply temperature of between 54°C (130°F) and 57°C (137°F) to the building. Hot water temperatures as high as 100°C (210°F) are possible to obtain through the combined recovery of heat from jacket water cooling and exhaust heat from the engine of the CHP unit.

A manufacturer advised that a CHP unit would require a minimum gas pressure of 11" w.c. (0.4 psig) at the engine carburettor.

As discussed in Section B-1.2, the gas service to the site is likely to be around 7" w.c. (0.25 psig). Also, since the proposed CHP unit would be located in the penthouse of the building, the costs of providing a new gas service at a higher pressure would likely be excessive. Thus, for the purposes of the economic assessment provided in Section B-1.8, a gas booster compressor package has been included.

B-1.7 Structural and Architectural Considerations

The boiler room of Building No. 2 appears to have adequate space to house the cogeneration system. The room has an exterior concrete block wall which is not load bearing. To place the CHP unit in the room, it is likely that this wall would have to be removed and replaced. Air intake and exhaust ducts would have to be provided to the room from outside, which would require acoustic treatment.

If this location can be used to house the unit, there should be no need for additional sound attenuation material other than the ductwork mentioned above.

B-1.8 Economic Analysis

The following is a summary of the economics for this proposed project:

a) Construction Costs

Item	Cost
40 kW Cogeneration Unit (installed)	$ 45,000
Gas Pressure Booster	$ 20,000
Electrical Distribution	$ 5,000
Structural Work	$ 7,500
Insurance (1% cogeneration cost)	$ 450

Subtotal	$ 77,950
Design Engineering (10%)	$ 7,795
Contingency (5%)	$ 3,898
TOTAL IMPLEMENTATION COSTS:	$ 89,645

b) Maintenance Costs/Year

Based on 1.3¢/kWh, full maintenance contract for a 5 year period, including: $ 4,280/year

- remote alarm monitoring
- cylinder overhaul (30,000 hour interval)
- head maintenance (12-15,000 hour interval)
- lube oil and spark plug changes (400 hour interval)

c) Cost Savings of Displaced Power

Estimated Annual kWh Displaced:	288,205 kWh
Estimated kW Displaced (Jan.-June, Sept.-Dec.)	35 kW/month
Estimated kW Displaced (July, August)	23 kW/month
Estimated Annual Energy Cost Savings (5.21¢/kWh):	$ 15,015
Estimated Annual Demand Savings ($4.75/kW):	$ 1,880
Total Annual Electrical Cost Savings:	$ 16,895

d) Net Fuel Consumption

The average thermal output of the CHP unit is illustrated in Figure B-2, where the unit would be able to displace a maximum equivalent boiler input of 45,330 kWh*th*/month (4,390 m^3/month) of natural gas for almost 10 months of the year. The minimum equivalent boiler input of the unit would be between 29,000 kWh*th*/month and 30,000 kWh*th*/month (2800 m^3/month and 2,900 m^3/month) for the months of July and August.

Estimated fuel consumption for the cogeneration unit at full load (based on the energy balance provided in Section 1.3 of the report), is 82,420 kWh*th*/month, while at 65% load it is estimated to be 53,575 kWh*th*/month.

Based on the above data, annual net fuel consumption costs are estimated as follows:

Estimated Annual Fuel Consumption of CHP Unit:	932,365 kWh*th* (90,230 m^3)
Estimated Annual Equivalent Boiler Natural Gas Consumption:	512,800 kWh*th* (49,625 m^3)
Estimated Net Annual Natural Gas Consumption:	419,565 kWh*th* (40,605 m^3)

Thus, it is estimated that the CHP unit will require an additional 419,565 kWh*th* (40,605 m^3) of natural gas per year to displace the thermal loads which are currently being supplied by the boilers. With an estimated average natural gas price of 1.54¢/kWh*th* ($4.5/MCF), this translates into an additional cost of $6,460/year.

e) **Cost Benefit**

The following economic summary applies to the net annual energy cost savings from displaced electrical power and thermal loads:

Estimated Annual Electrical Cost Savings:	$ 16,895
Less Annual Maintenance Cost/Year:	$(4,280)
Less Estimated Increased Natural Gas Consumption Cost:	$(6,460)
Estimated Net Annual Energy Cost Savings:	$ 6,155
Estimated Implementation Cost:	$ 89,645
Estimated Simple Payback Period: $= \frac{\$\ 89,645}{\$\ 6,155} =$	15 years

f) Present Value of Savings

The following parameters are used to project the present value of savings over a 7 and 20 year period:

Estimated Average Gas Increase Rate, A	= 4%
Estimated Average Electrical Increase Rate, B	= 10%
Estimated Average Inflation Rate, C	= 5%
Estimated Average Interest Rate, D	= 12%
Average Real Annual Increase of Energy Cost, E	= Avg (A+B) - C
	= 7%-5% = 2%
Average Real Interest Rate, R	= D-C
	= 12%-5% = 7%

The following Table projects the present value of savings over a 20 year period.

Year	Energy Cost (per Unit)	Energy Saved Year End ($)	Discount Factor	Present Value of Energy Saved ($)
1	1	6,155	1/1.07	5,752
2	1.02	6,278	$1/1.07^{2}$	5,484
3	1.02^{2}	6,404	$1/1.07^{3}$	5,227
4	1.02^{3}	6,532	$1/1.07^{4}$	4,983
5	1.02^{4}	6,662	$1/1.07^{5}$	4,750
6	1.02^{5}	6,796	$1/1.07^{6}$	4,528
7	1.02^{6}	6,932	$1/1.07^{7}$	4,317
8	1.02^{7}	7,070	$1/1.07^{8}$	4,115
9	1.02^{8}	7,212	$1/1.07^{9}$	3,923
10	1.02^{9}	7,356	$1/1.07^{10}$	3,739
11	1.02^{10}	7,503	$1/1.07^{11}$	3,565
12	1.02^{11}	7,653	$1/1.07^{12}$	3,398
13	1.02^{12}	7,806	$1/1.07^{13}$	3,239
14	1.02^{13}	7,962	$1/1.07^{14}$	3,088
15	1.02^{14}	8,121	$1/1.07^{15}$	2,944
16	1.02^{15}	8,284	$1/1.07^{16}$	2,806
17	1.02^{16}	8,449	$1/1.07^{17}$	2,675
18	1.02^{17}	8,618	$1/1.07^{18}$	2,550
19	1.02^{18}	8,791	$1/1.07^{19}$	2,431
20	1.02^{19}	8,967	$1/1.07^{20}$	2,317

From the above Table, the sum of the present value of savings after 7 years is $35,040. After 20 years, the sum of the present value of savings is $75,830.

g) Internal Rate of Return

The internal rate of return is calculated based on the following equation using data from the Table in Part (f):

$$X = \frac{Y_1}{(1+I)} + \frac{Y_2}{(1+I)^2} + \frac{Y_3}{(1+I)^3} + \ldots + \frac{Y_{20}}{(1+I)^{20}}$$

where X = Estimated Implementation Cost

Y_n = Energy saved at year end for year "n" (i.e. 1 to 20)

I = Internal rate of return

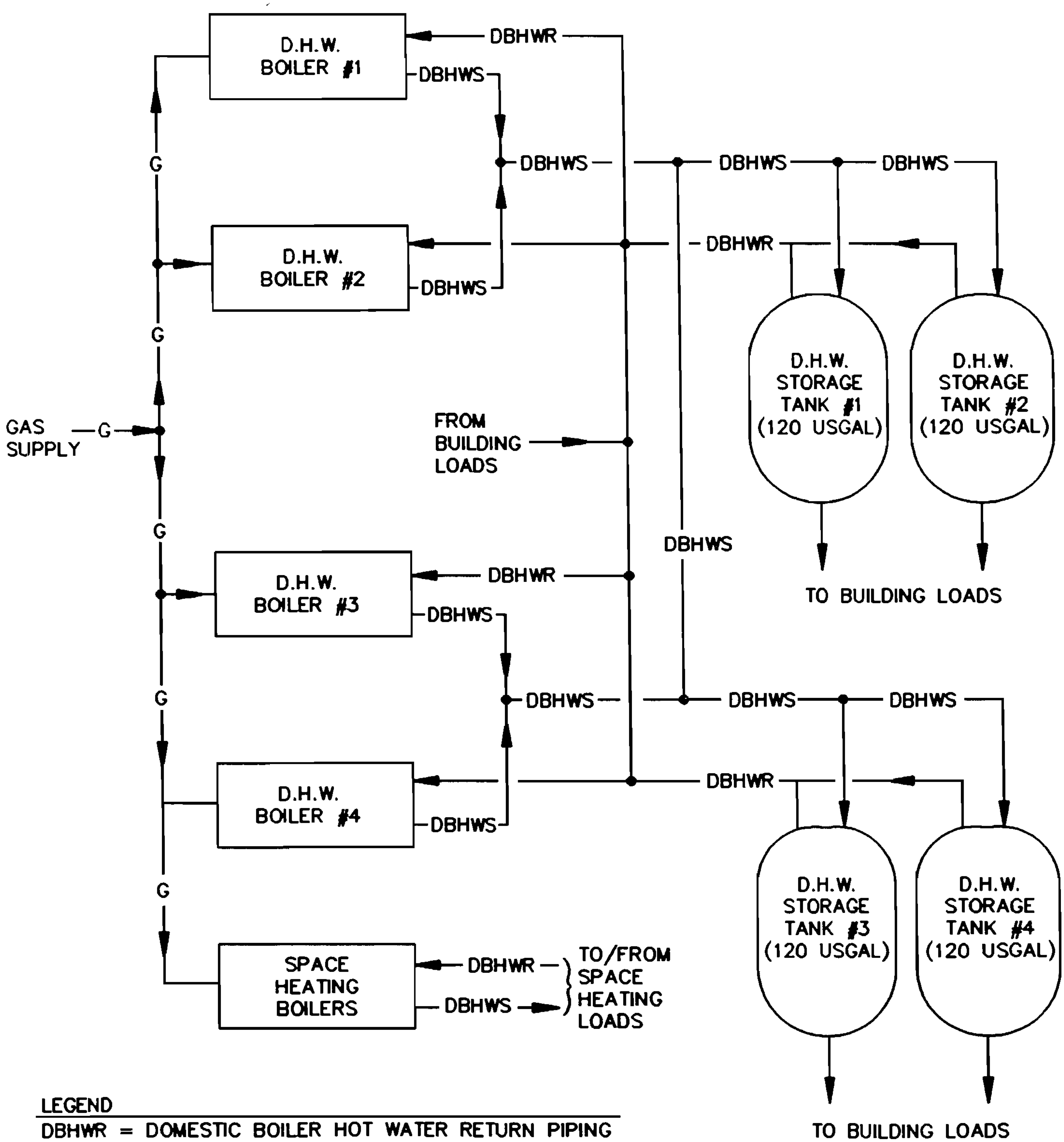
The solution to this equation can only be obtained by successive approximation. For the purposes of this study, the above equation was solved using a scientific calculator which has this solving capability.

On this basis, $I = 0.05$

B-2.0 Building No. 4

B-2.1 General Description of Facility

Building No. 4 is a 14 storey building with 230 apartment units. The mechanical room is located on the top floor of the building. It contains 3 boilers for space heating, 4 domestic water heaters, 4 domestic water storage tanks, and a central air handling unit for corridor pressurization.



LEGEND

DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
SHHWS = SPACE HEATING HOT WATER SUPPLY PIPNG
SHHWR = SPACE HEATING HOT WATER RETURN PIPNG
——G—— GAS SERVICE

BUILDING No.4
EXISTING HOT WATER SYSTEM

Figure B-6

B-2.2 Heating System

B-2.2.1 General Description:

The space heating system is controlled and operated separately from the domestic hot water system. There are 3 equally sized boilers for space heating, each rated at a maximum output of 2,400 MBH. The space heating boilers serve radiant heating for the perimeter of each apartment unit as well as heating for a centralized air handling unit which provides make-up air to the corridors. Also, space heating is provided to the garage area of the building.

The domestic water heaters are approximately 20 years old and in relatively good condition. The 4 heaters are fired with natural gas and have a maximum input rating of 670 MBH. The Property Managers advised that the boilers are normally modulated to provide a hot water supply temperature from the storage tanks between 54°C (130°F) and 60°C (140°F). Originally there were two 375 US gal tanks which have just recently been replaced with four 120 US gal storage tanks.

A single line sketch of the hot water system is provided in Figure B-6.

B-2.2.2 Gas Service, Fuel Costs and Consumption Data

The site uses the Firm General Service Rate Number 100.

In general, for apartment buildings, the supplied gas pressure is likely to be around 7" w.c. (0.25 psig), which is typical for highly populated areas. The actual conditions are site specific and would need to be confirmed with the utility. The required pressure for a new CHP system is likely to be greater than that available; thus, a natural gas booster compressor package would be required.

The monthly gas consumption and corresponding costs at the site for the period of April 1991 through to March 1992 are presented in Table B-3. The consumption profile is analyzed further in Section B-2.4.

The current gas rate came into effect as of October 1, 1991. Thus, by examining the building data from October 1991 through until March 1992, the current average gas price is estimated to be 1.56¢/kWh*th* ($4.58 MCF).

TABLE B-3

GAS BILLING DATA (BUILDING NO. 4)
FOR PERIOD APRIL 1991 THROUGH TO MARCH 1992

Month	Gas Consumption		Cost
	(cu.m.)	(kWh*th*)	($)
January	99,055	1,023,568	16,491
February	91,553	946,048	15,264
March	71,551	739,360	10,377
April	49,945	516,098	7,503
May	15,708	162,316	2,472
June	7,323	75,671	1,212
July	8,779	90,716	1,432
August	7,768	80,269	1,279
September	25,354	261,991	3,897
October	60,038	620,393	8,961
November	66,704	689,275	11,199
December	105,173	1,086,788	17,492
Total	**608,951**	**6,292,494**	**97,577**

B-2.3 Electrical System

B-2.3.1 General Description:

The building is currently fed from Ottawa Hydro to a grid of power transformers feeding a 208 Volt system and a 600 Volt system. Utility metering is centralized and bulk measured with no submetering for individual tenant loads.

B-2.3.2 Electrical Costs and Consumption/Demand Data:

The monthly electrical consumption, demand and corresponding costs during April 1991 through to March 1992 for Building No. 4 are listed in Table B-4.

TABLE B-4

ELECTRICAL BILLING DATA FOR BUILDING NO. 4

Month	Building No. 6		
	Energy (kWh)	Demand (kW)	Cost ($)
January	201,000	330	12,302
February	147,000	330	9,873
March	147,000	300	9,721
April	129,000	252	7,648
May	123,600	240	7,322
June	107,400	222	6,425
July	123,600	240	7,322
August	111,000	228	6,633
September	106,800	234	6,451
October	133,800	240	7,833
November	119,400	270	7,250
December	103,800	324	6,719
Total	**1,553,400**	**330 (Peak)**	**95,499**

The facility is billed by Ottawa Hydro on a General Service rate structure.

In the economic analysis (Section B-2.8), the marginal energy rate of 5.21¢/kWh and the demand rate of $4.75/kW per month are used to calculate savings on displaced electrical power from the CHP unit.

B-2.4 Thermal Load Analysis

The gas consumption data from Table B-3 was used to develop the thermal demand profile presented in Figure B-7. This figure illustrates the variation between the higher gas consumption requirements during the winter months for space heating and the significantly lower consumption levels which occur during the summer to satisfy the domestic hot water requirements.

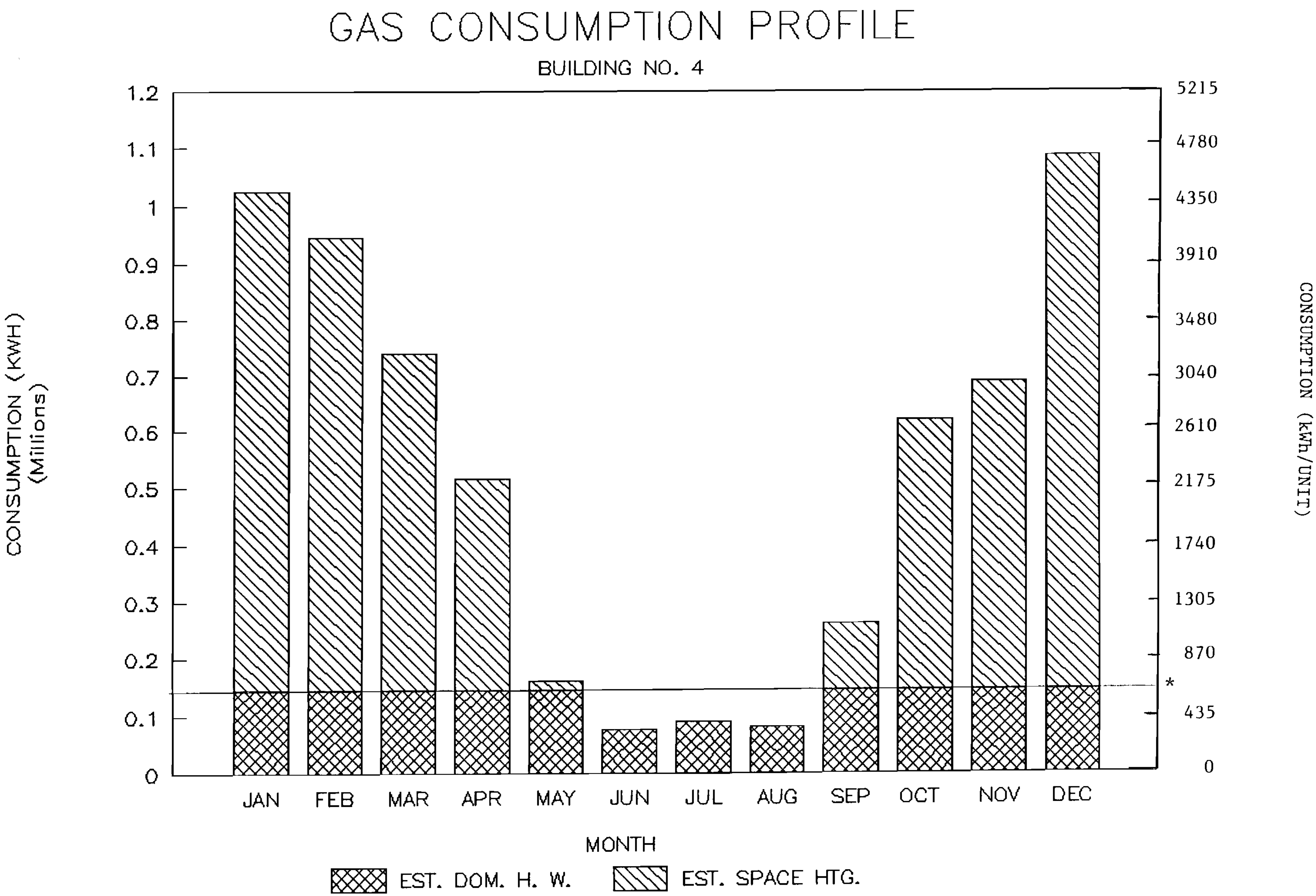
The consumption curve and corresponding data in Table B-3, show an average baseload input of 7,323 m^3 (75,671 kWh*th*) for the month of June, which is close to the consumption levels for July and August. Further analysis of this curve reveals that the load requirements for the month of May, 15,708 m^3 (162,316 kWh*th*), account for more than 9 months (at least 6,000 hours) per year. Thus, it was decided that May's thermal baseload of 15,708 m^3 (162,316 kWh*th*) input would serve as a useful benchmark for a combined heat and power unit, which would provide a turn-down ratio to average baseload conditions of 47%.

B-2.5 Electrical Load Analysis

To analyze the electrical demand profile for Building No. 4, the monthly demand data from Table B-4 was used to plot the electrical demand curve presented in Figure B-8. Generally speaking, the curve has minor fluctuations in demand throughout the year with peaks occurring in the winter months which are about 35% higher than the peak summer demand.

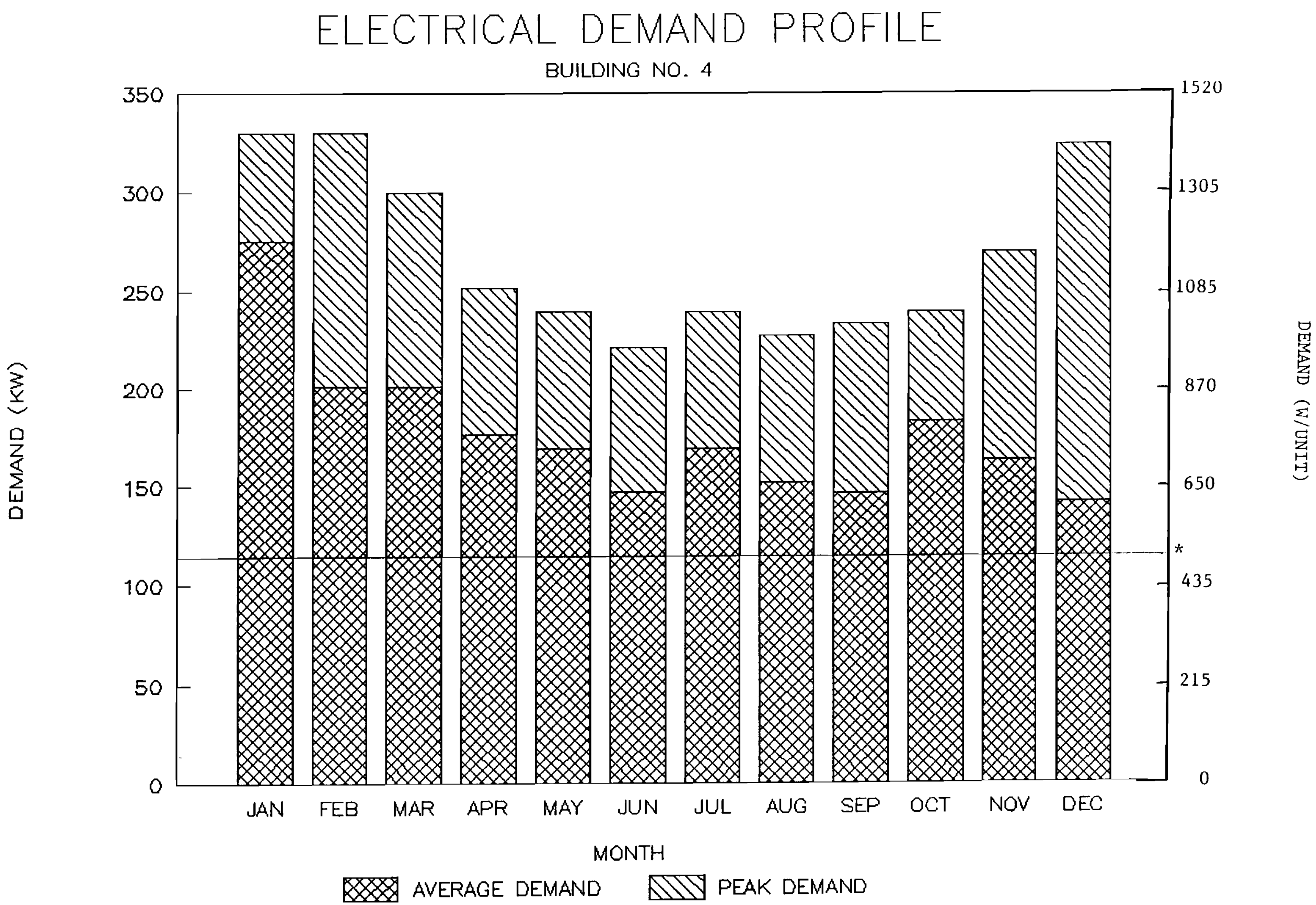
The access to the main electrical service of the building is fairly easy to achieve at this site. The proposed cogeneration interconnection would consist of a direct power tie into the 208 Volt main switchboard to provide AC power for consumption 'in-house' and would not be in a position to export to Hydro's grid. The amount of power available would be directly proportionate to the turn-down thermal output of the unit. The net result would be an almost continuous level of 115 kW of power which would not have to be purchased from Hydro. This would amount to between 35% and 51% of the peak power supply.

The system would have a power interface package which would continuously monitor the output of the unit and the actual current draw on the main building service. The unit would be



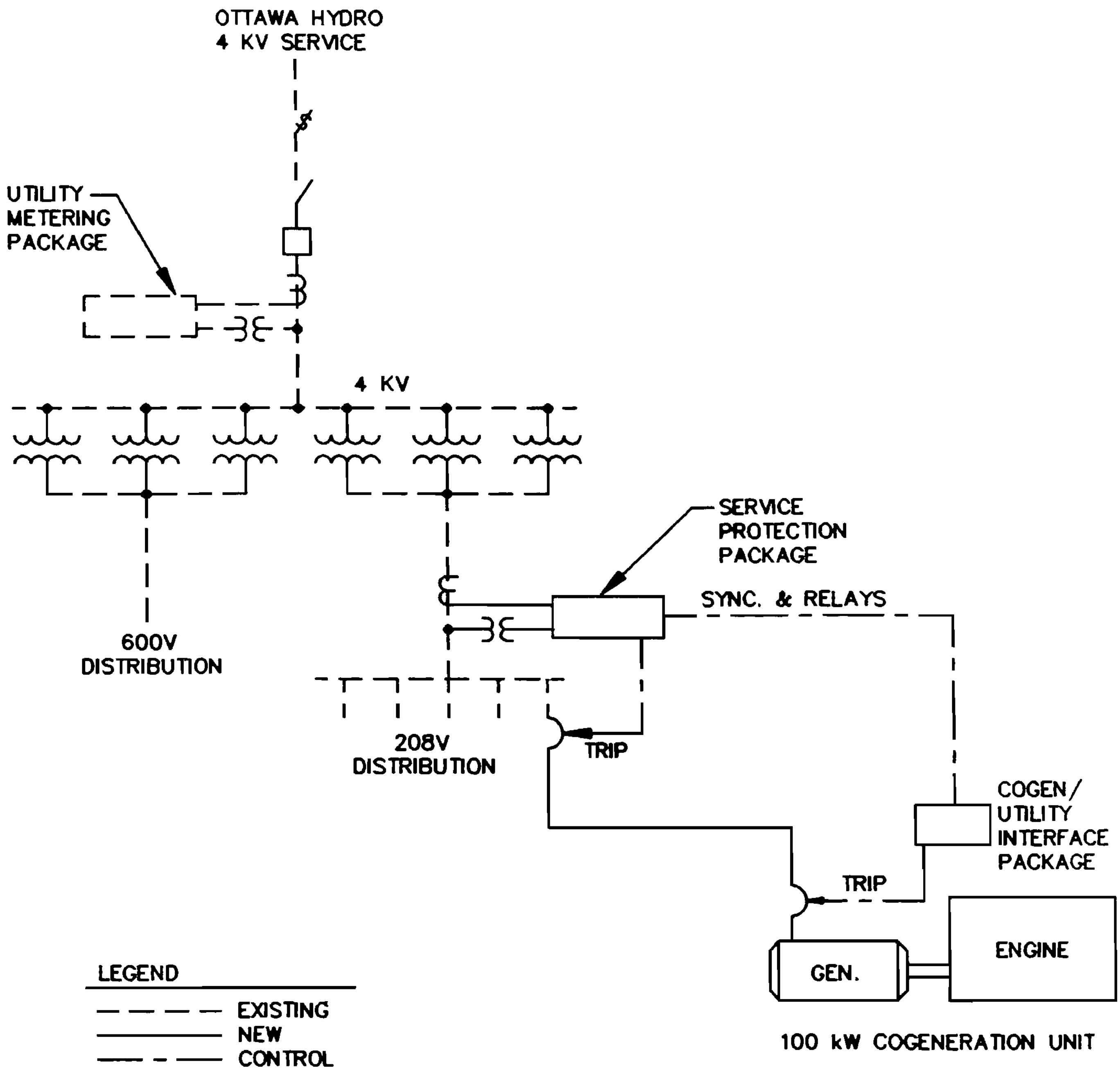
* EQUIVALENT BOILER INPUT OF CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-7



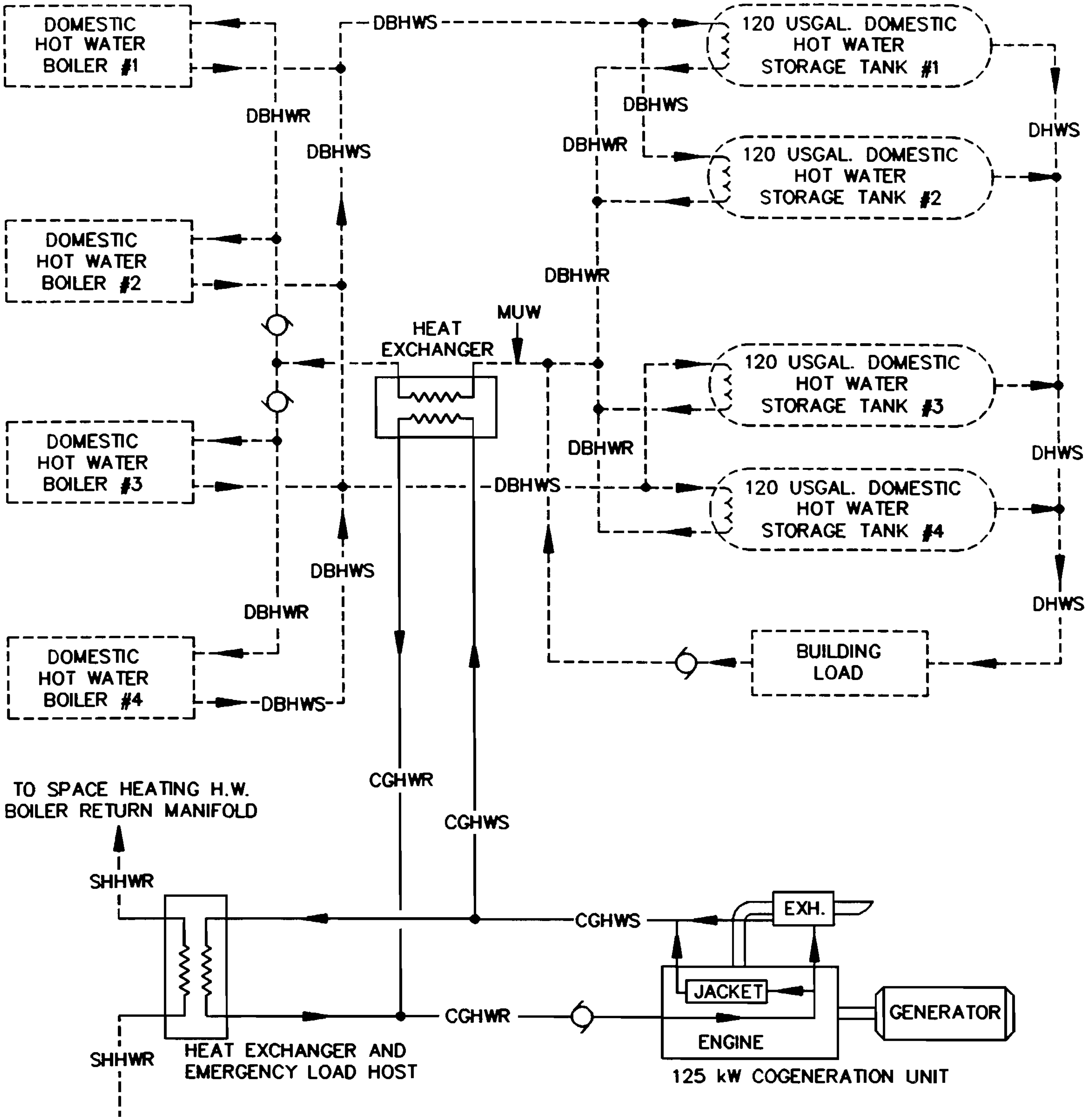
* ELECTRICAL OUTPUT FROM CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-8



BUILDING No.4
PROPOSED ELECTRICAL INTERCONNECTION

Figure B-9



BUILDING No.4
PROPOSED COGENERATION
THERMAL SYSTEM INTERFACE

LEGEND

DHWR = DOMESTIC HOT WATER RETURN PIPING
DHWS = DOMESTIC HOT WATER SUPPLY PIPING
DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
CGHWR = COGEN HOT WATER RETURN PIPING
CGHWS = COGEN HOT WATER SUPPLY PIPING
SHHWR = SPACE HEATING H.W. RETURN PIPING
MUW = MAKE UP WATER
------- EXISTING
——— NEW

Figure B-10

automatically synchronized to the utility grid and at no time would the unit be allowed to produce more than 80% of the site's total current draw. In addition, a full protective relay package would backup the synchronizing and current check relays with reverse current, phase unbalance, etc. to automatically shut the unit down in the event of a failure of any system. Figure B-9 illustrates the proposed electrical interconnections.

B-2.6 Proposed Cogeneration System

Consideration of the benchmark thermal load established in Section B-2.4 (15,708 m^3, 162,316 kWh*th*/month input of natural gas) establishes the basis for sizing a reciprocating cogeneration unit.

Based on the methodology used in Section 2.2 for sizing the CHP system and the generic Table 1.1 from Section 1.4, a nominal unit size of 125 kW was selected with a maximum thermal output of 117,085 kWh*th*/month. Also, from Table 1.1, the corresponding electrical output capacity of the unit would be 115 kW. As discussed in Section B-2.5, this would provide approximately 35% to 50% of the peak power supply to the building. The proposed cogeneration unit would be interfaced with the domestic hot water and space heating systems as illustrated in Figure B-10.

In order to maximize the use of the CHP unit, it would primarily serve the domestic hot water system, where heat would be recovered from the CHP engine exhaust and jacket water cooling. This would be done through a heat exchanger on the main return line to the domestic water boilers. Thus, the unit would essentially act as a lead boiler to the domestic hot water system. Any load requirements in excess of the unit's capacity, would be supplemented by the existing boilers. During the summer, when domestic hot water load requirements are less than the capacity of the CHP unit, the output level of the system would need to be reduced ("turned-down"). Cogeneration units normally have turn-down capabilities to 40%; however, if the load requirements were less than this, the unit would have to be turned off.

An ASHRAE research paper (1988), by Perlman and Milligan on hot water and energy use in apartment buildings was reviewed. The paper provides a typical domestic hot water consumption profile at a 95% confidence level which represents a reliable estimate of the maximum average daily usage expected for a particular building category. This profile was used to model the domestic hot water consumption for the building, where the thermal recovery rate of the proposed CHP unit at 100% capacity and 40% capacity have been superimposed on the graph.

This profile, along with a chart which identifies the estimated recovery rate of the CHP unit, are provided in Appendix 'C'. Here it is illustrated, that since the building has a small domestic hot water storage capacity, the CHP unit may need to turn off for a couple of hours per day in the summer.

While the cogeneration system is operating, an emergency condition may result from a loss of the CHP unit's ability to cool itself, such as a pipe break, a jammed valve, etc. Depending on manufacturer's recommendations, all CHP units require a cool down period of at least 5 to 15 minutes under no load conditions to equalize the thermal expansion of the engine block. Therefore, in the design of any cogeneration system, it is essential that an emergency heat sink be provided.

During emergency conditions, and in the winter, excess heat from the CHP unit would be relieved to the space heating system through a heat exchanger on the main hot water return line to the space heating boilers. In emergency conditions, if space heating is not in use, a pump would likely be activated to ensure an adequate flow of water is being circulated in the space heating loop. It is recommended that such a pump be powered from the emergency diesel generator to provide circulation during the first few minutes of a power failure. If space heating proved to be an impractical means of providing an emergency heat sink to the system, there are alternative methods of meeting this requirement such as the installation of an outdoor condenser unit, or the rejection of excess heat to a swimming pool.

The thermal energy currently produced in the building for the domestic hot water system is in the form of hot water from the boilers. The Property Managers advised that the hot water supply temperature setpoint from the tanks is maintained between 54°C (130°F) and 60°C (140°F). Hot water temperatures as high as 100°C (210°F) are possible to obtain from the CHP unit through the combined recovery of heat from jacket water cooling and exhaust heat from the engine.

A manufacturer advised that a typical CHP unit would utilize a naturally aspirated engine which requires about 5 psig pressure at the engine regulator. However, the fuel would flow through a "fuel train", which would impose a 2-3 psig pressure drop. Therefore, a minimum delivery pressure of 8 psig would be required. It is likely that a booster compressor would be necessary to achieve this pressure.

Therefore, for the purposes of the economic assessment provided in Section B-8, a gas booster compressor package has been included.

B-2.7 Structural and Architectural Considerations

There does not appear to be any space available in or near the mechanical penthouse to house the CHP system. As a result, the best location for the unit appears to be on the roof of the penthouse above the main air handling unit for the building. The unit would need to be placed in an enclosure which would provide adequate protection from the weather and ensure that the system operates within acceptable noise criteria at all times. Air intake and exhaust ducts would have to be provided to the room from outside, which would require acoustic treatment.

Furthermore, the structural integrity of the roof would need to be examined and modified if necessary to ensure that the support for the system is sound.

B-2.8 Economic Analysis

The following is a summary of the economics for this proposed project:

a) Construction Costs

Item	Cost
125 kW Cogeneration Unit Package	$110,000
Installation	$ 60,000
Gas Pressure Booster	$ 20,000
Electrical Distribution	$ 15,000

Crane	$ 8,000
Enclosure	$ 15,000
Structural Work	$ 15,000
Insurance (1% Cogeneration Cost)	$ 1,100
Subtotal:	$244,100
Design Engineering (10%)	$ 24,410
Contingency (5%)	$ 12,205
TOTAL IMPLEMENTATION COSTS:	$280,715

b) Maintenance Costs/Year

Based on 1.3¢/kWh, full maintenance contract for a 5 year period, including:	$12,670/year

- remote alarm monitoring
- cylinder overhaul (30,000 hour interval)
- head maintenance (12-15,000 hour interval)
- lube oil and spark plug changes (400 hour interval)

c) Cost Savings of Displaced Power

Estimated Annual kWh Displaced:		896,585 kWh
Estimated kW Displaced	(Jan.-May, Sept.-Dec.)	115 kW
Estimated kW Displaced	June	60 kW
Estimated kW Displaced	July	71 kW
Estimated kW Displace	August	63 kW
Estimated Annual Energy Cost Savings (5.21¢/kWh):		$46,710
Estimated Annual Demand Savings ($4.75/kW):		$ 5,835
Total Annual Electrical Cost Savings:		$52,545

d) **Net Fuel Consumption**

The average thermal output of the CHP unit is illustrated in Figure B-7, where the unit would be able to displace a maximum equivalent boiler input of 146,355 kWh*th*/month of natural gas (14,165 m^3/month) for 9 months of the year. The minimum equivalent boiler input of the unit would be 76,105 kWh*th*/month of natural gas (7,365 m^3/month) in June.

From the energy balance provided in Section 1.3 of this Report, the estimated fuel consumption for the cogeneration unit at full load is 266,100 kWh*th*/month while at 52% load it is estimated to be 138,370 kWh*th*/month.

Based on the above data, annual net fuel consumption costs are estimated as follows:

Estimated Annual Fuel Consumption of CHP Unit:	2,844,610 k*Whth* (275,285 m^3)
Estimated Annual Equivalent Boiler Natural Gas Consumption:	1,564,535 kWh*th* (151,405 m^3)
Estimated Net Annual Natural Gas Consumption:	1,280,075 kWh*th* (123,880 m^3)

Thus, it is estimated that the unit will require an additional 1,280,075 kWh*th* (123,880 m^3) of natural gas per year to displace the thermal loads which are currently being supplied by the boilers. With an estimated average natural gas price of 1.56¢/kWh*th* ($4.58/MCF), this translates into an additional cost of $19,970/year.

e) **Cost Benefit**

The following economic summary applies to the net annual energy cost savings from displaced electrical power and thermal loads:

Estimated Annual Electrical Cost Savings:	$ 52,545
Less Annual Maintenance Cost/Year:	$(12,670)
Less Estimated Increased Natural Gas Consumption Cost:	$(19,970)
Estimated Net Annual Energy Cost Savings:	$ 19,905
Estimated Implementation Cost:	$280,715

Estimated Simple Payback Period:

$$= \frac{\$280{,}715}{\$\ 19{,}905} = \qquad 14 \text{ years}$$

f) Present Value of Savings

The following parameters are used to project the present value of savings over a 7 and 20 year period:

Estimated Average Gas Increase Rate, A	= 4%
Estimated Average Electrical Increase Rate, B	= 10%
Estimated Average Inflation Rate, C	= 5%
Estimated Average Interest Rate, D	= 12%
Average Real Annual Increase of Energy Cost, E	= Avg (A+B) - C
	= 7%-5% = 2%
Average Real Interest Rate, R	= D-C
	= 12%-5%
	= 7%

The following Table projects the present value of savings over a 20 year period.

Year	Energy Cost (per Unit)	Energy Saved Year End ($)	Discount Factor	Present Value of Energy Saved ($)
1	1	19,905	$1/1.07$	18,603
2	1.02	20,303	$1/1.07^2$	17,734
3	1.02^2	20,709	$1/1.07^3$	16,905
4	1.02^3	21,123	$1/1.07^4$	16,115
5	1.02^4	21,546	$1/1.07^5$	15,362
6	1.02^5	21,977	$1/1.07^6$	14,644
7	1.02^6	22,416	$1/1.07^7$	13,960
8	1.02^7	22,865	$1/1.07^8$	13,307
9	1.02^8	23,322	$1/1.07^9$	12,686
10	1.02^9	23,788	$1/1.07^{10}$	12,093
11	1.02^{10}	24,264	$1/1.07^{11}$	11,528
12	1.02^{11}	24,749	$1/1.07^{12}$	10,989
13	1.02^{12}	25,244	$1/1.07^{13}$	10,476
14	1.02^{13}	25,749	$1/1.07^{14}$	9,986
15	1.02^{14}	26,264	$1/1.07^{15}$	9,519
16	1.02^{15}	26,790	$1/1.07^{16}$	9,075
17	1.02^{16}	27,325	$1/1.07^{17}$	8,650
18	1.02^{17}	27,872	$1/1.07^{18}$	8,246
19	1.02^{18}	28,429	$1/1.07^{19}$	7,861
20	1.02^{19}	28,998	$1/1.07^{20}$	7,494

From the above Table, the sum of the present value of savings after 7 years is $113,320. After 20 years, the sum of the present value of savings is $245,230.

g) Internal Rate of Return

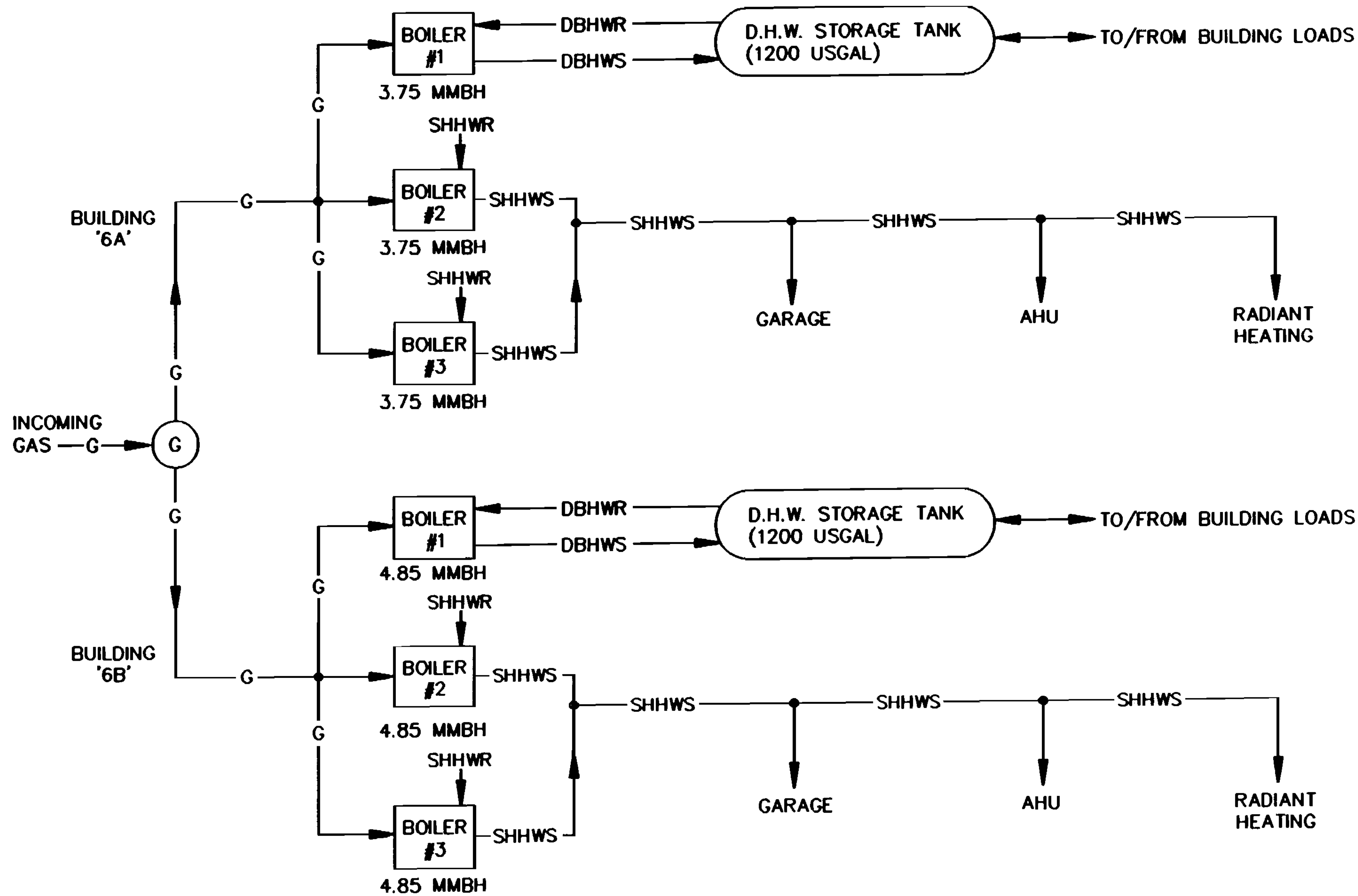
The internal rate of return is calculated based on the following equation using data from the Table in Part (f):

$$X = \frac{Y_1}{(1+I)} + \frac{Y_2}{(1+I)^2} + \frac{Y_3}{(1+I)^3} + \dots + \frac{Y_{20}}{(1+I)^{20}}$$

where X = Estimated Implementation Cost

Y_n = Energy saved at year end for year "n" (i.e. 1 to 20)

I = Internal rate of return



BUILDING Nos. 6A & 6B
EXISTING DOMESTIC HOT WATER
AND SPACE HEATING SYSTEMS

Figure B-11

LEGEND

DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
SHHWS = SPACE HEATING HOT WATER SUPPLY PIPING
SHHWR = SPACE HEATING HOT WATER RETURN PIPING
——G—— GAS SERVICE

The solution to this equation can only be obtained by successive approximation. For the purposes of this study, the above equation was solved using a scientific calculator which has this solving capability.

On this basis, $I = 0.05$

B-3.0 Building Nos. 6A and 6B

B-3.1 General Description of the Facility

The site consists of two high rise residential buildings (referred to as Buildings 6A and 6B in Part I of the report) with a recreation centre located in between. The three buildings are physically connected together by a tunnel which is located below grade at the basement level. Each apartment building has 12 floors with 3 wings (A, B and C) and 251 apartment units in total. The recreation centre contains showers and a swimming pool which is not used during the summer months.

There are two gas meters on site; one serving the two apartment buildings and one serving the recreation centre. Each of the apartment buildings has boiler rooms, located at the basement level, which contain three boilers; two for space heating and one for domestic hot water. The recreation centre also has its own boiler room which serves the space heating, domestic hot water and heating for the pool.

B-3.2 Heating System

B-3.2.1 General Description:

The heating systems in Buildings 6A and 6B operate in a similar manner. A single line sketch of the distribution system is presented in Figure B-11. Each building contains three equally sized boilers, of which two are dedicated to space heating requirements and the third serves the domestic hot water system.

The space heating systems consist of radiant heating for the perimeter of each apartment unit and heating for the air handling units which provide make-up air for corridor pressurization. Also, space heating is provided to the garage areas of both buildings. The three boilers feed into common hot water supply and return headers which serve each of the space heating systems as well as the domestic hot water system. There is an individual pair of supply and return lines to the domestic hot water storage tank (est. size 1200 USgal) from the domestic water boiler. These lines are branched off the common hot water loop with isolation valves, which separate the space heating and domestic hot water systems.

The boilers, which are approximately 20 years old, are well maintained and in relatively good condition. Each of the systems are fired with natural gas and have #2 oil for back-up. In Building 6A, the boilers are rated at a maximum input of 3750 MBH, while in Building 6B, the boilers are rated at a maximum input of 4850 MBH.

All of the boilers have controls for low fire and high fire; however, in each building the two space heating boilers are continuously set to run on high fire. The corresponding hot water supply temperature is modulated between 32°C (90°F) and 100°C (210°F) with an indoor/outdoor temperature sensor.

The domestic hot water boiler utilizes the low and high fire setpoints, where the low fire temperature setpoint is 71°C (160°F) to 76°C (170°F), the high fire setpoint is 93°C (200°F) to 100°C (210°F) and the target maintenance temperature is 82°C (180°F) to 88°C (190°F). Originally, in both buildings, the domestic hot water systems were on a temperature setback control at night, where the supply temperature from the storage tank was set at 52°C (126°F) from 12:00 a.m. until 6:00 a.m. From 6:00 a.m. until 12:00 a.m., the supply temperature was controlled between 63°C (145°F) and 66°C (150°F). Building 6A still operates in this manner; however, just recently Building 6B was removed from the control system and the tank temperature is now continuously maintained at approximately 60°C (140°F).

B-3.3.2 Gas Service, Fuel Costs and Consumption Data:

The site uses the interruptible General Service Rate Number 6. The owners of the facility advised that they have a supply of #2 oil on site for backup service in the event of a gas interruption.

In general, for apartment buildings, the supplied gas pressure is likely to be around 7" w.c. (0.25 psig), which is typical for highly populated areas. It may be possible to have a new service connected to the building with a pressure as high as 5 psig. The actual conditions are site specific and would need to be confirmed with the utility.

The monthly gas consumption and corresponding costs at the site for the period of April 1991 through to March 1992 are presented in Table B-5. The consumption profile is analyzed further in Section B-3.4.

The current gas rate came into effect as of October 1, 1991. Thus, by examining the building data from October 1991 through until March 1992, the current average gas price is estimated to be 1.36¢/kWh*th* ($4/MCF).

TABLE B-5

TOTAL GAS BILLING DATA (BUILDINGS 6A AND 6B)
FOR PERIOD APRIL 1991 THROUGH TO MARCH 1992

Month	Gas Consumption		Cost
	(cu.m.)	(kWh)	($)
January	216,934	2,241,651	31,136
February	171,610	1,773,303	24,690
March	162,756	1,681,812	23,430
April	76,836	793,972	4,880
May	56,434	583,151	7,236
June	27,824	287,515	3,668
July	24,008	248,083	3,186
August	29,970	309,690	3,938
September	32,092	331,617	4,206
October	52,890	546,530	6,800
November	98,740	1,020,313	12,446
December	122,894	1,269,905	17,762
Total	**1,072,988**	**11,087,543**	**143,378**

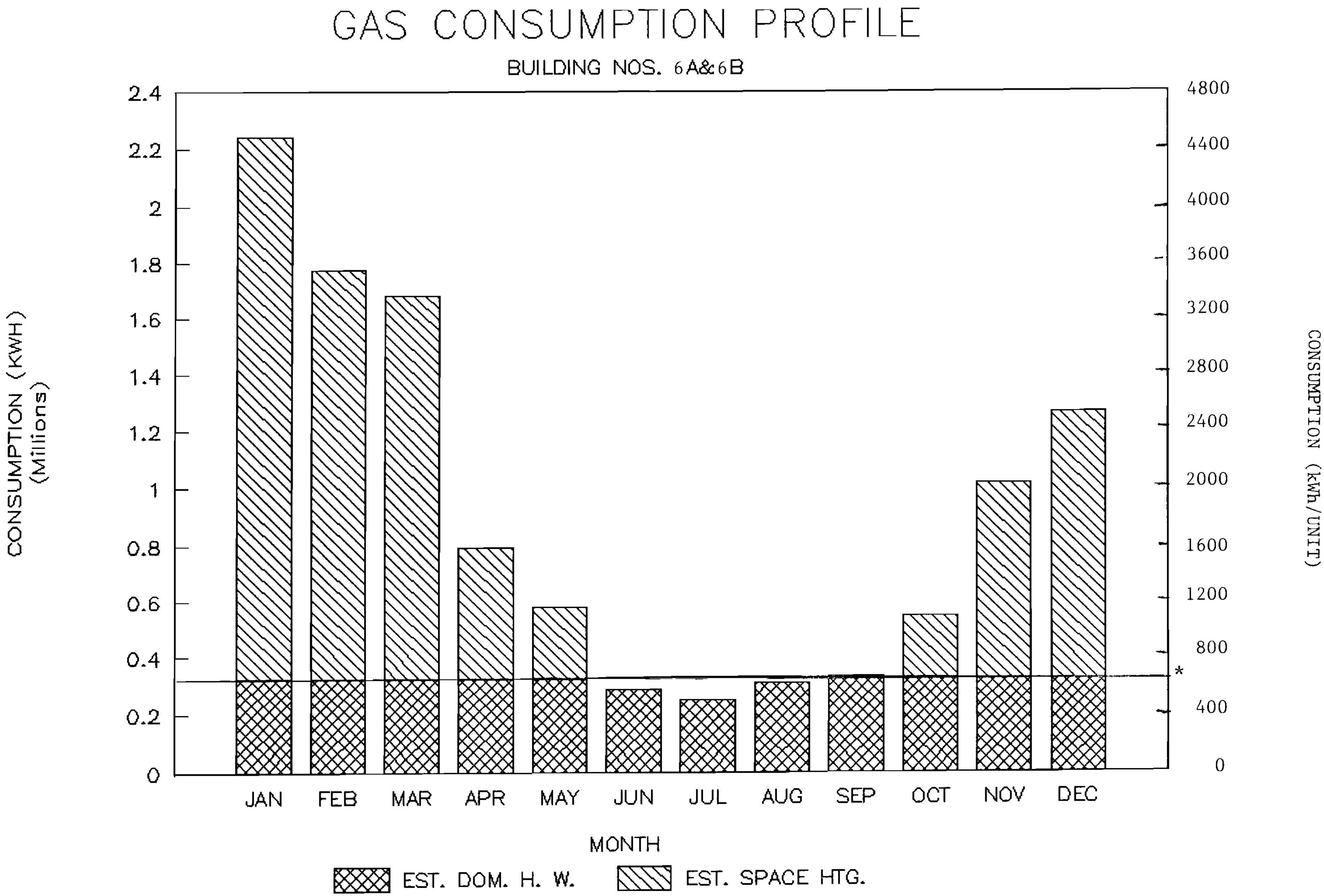
B-3.3 Electrical System

B-3.3.1 General Description:

The buildings are currently each fed from Nepean Hydro via a single feeder to a main switchboard at the lowest level. Each building is individually metered to provide total kW and kWh. No individual tenant submetering is installed.

B-3.3.2 Electrical Costs and Consumption/Demand Data

The monthly electrical consumption, demand and corresponding costs during April 1991 through to March 1992 for Buildings 6A and 6B are listed in Table B-6.



* EQUIVALENT BOILER INPUT OF CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-12

TABLE B-6

ELECTRICAL BILLING DATA FOR BUILDINGS 6A AND 6B

Month	Building 6A			Building 6B		
	Energy (kWh)	Demand (kW)	Cost ($)	Energy (kWh)	Demand (kW)	Cost ($)
January	166,400	344	10,551	188,400	384	11,917
February	146,400	328	9,820	162,000	376	10,932
March	146,400	320	9,800	156,800	316	10,338
April	162,400	304	9,706	172,400	328	10,247
May	108,000	280	6,778	122,400	292	7,558
June	144,800	304	8,744	169,600	320	10,068
July	143,200	304	8,664	162,800	340	9,821
August	156,800	296	9,309	175,600	328	10,408
September	134,400	320	8,297	148,800	364	9,231
October	148,800	288	8,869	158,000	296	9,370
November	136,000	344	8,492	150,800	324	9,141
December	145,600	352	9,013	151,200	360	9,333
Total	**1,739,200**	**352 (Peak)**	**108,043**	**1,918,800**	**384 (Peak)**	**118,364**

The facility is billed by Nepean Hydro on a General Service rate structure.

In the economic analysis (Section B-3.8), the marginal energy rate of 5.25¢/kWh and the demand rate of $4.8/kW per month are used to calculate savings on displaced electrical power from the CHP unit.

B-3.4 Thermal Load Analysis

The gas consumption data from Table B-5 was used to develop the thermal demand profile presented in Figure B-12.

This figure illustrates the variation between the higher gas consumption requirements during the winter months for space heating and the significantly lower consumption levels which occur during the summer to satisfy the domestic hot water requirements.

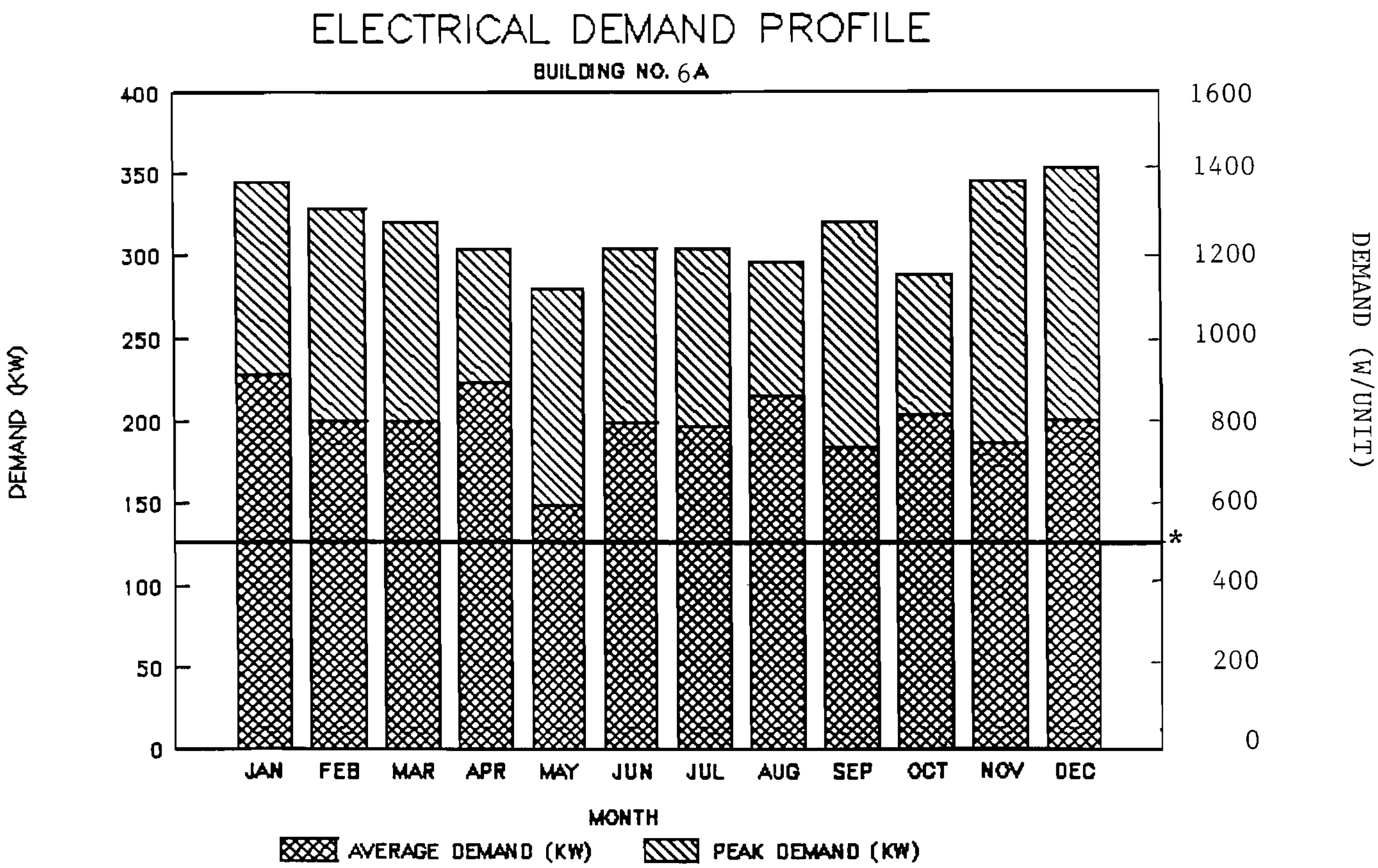
The consumption curve and corresponding data in Table B-5, show an average baseload input of 24,008 m^3 (248,083 kWh*th*) for the month of July. Further analysis of this curve reveals that the load requirements for the months of August and September account for more than 9 months (at least 6,000 hours) per year. Thus, it was decided that September's thermal baseload of 32,092 m^3 (331,617 kWh*th*) input would serve as a useful benchmark for a combined heat and power unit, which would provide a turn-down ratio to average baseload conditions of 75%.

B-3.5 Electrical Load Analysis

To analyze the electrical demand profiles for Buildings 6A and 6B, the monthly demand data from Table B-6 was used to plot the electrical demand curves presented in Figures B-13(a) and B-13(b). Generally speaking, the curves have minor fluctuations in demand throughout the year with peaks occurring in the winter months and late summer.

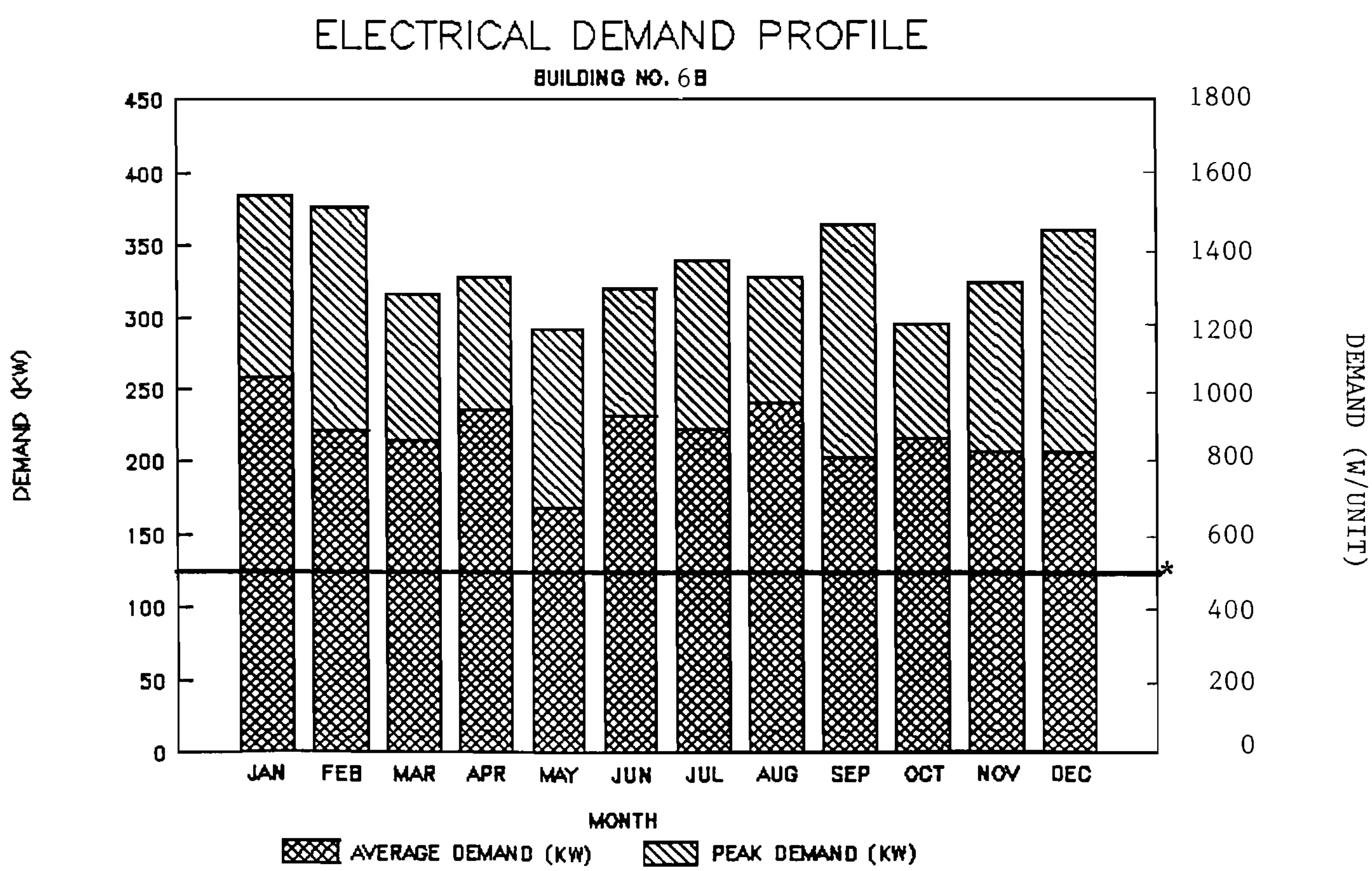
The proposed cogeneration interconnection would consist of a direct power tie to the main switchboard in each building. This would provide AC power for consumption "in-house" and would not be in a position to export to Hydro's grid. The amount of power available would be directly proportionate to the turn-down thermal output of the unit. The net result would be an almost continuous level of power at 250 kW, approximately 40% of the peak power supply to each building grid, which would not have to be purchased from Hydro.

The system would have a power interface package which would continuously monitor the output of the unit and the actual current draw on the building main service. The unit would be automatically synchronized to the utility grid and at no time would the unit be allowed to produce more than 80% of the site's total current draw. In addition, a full protective relay package would backup the synchronizing and the current check relays with reverse current, phase unbalance, etc. to automatically shut the unit down in the event of a failure of any system.



* ELECTRICAL OUTPUT FROM CHP UNIT ÷ 2 (AT MAXIMUM OUTPUT RATING)

Figure B-13 a



* ELECTRICAL OUTPUT FROM CHP UNIT ÷ 2 (AT MAXIMUM OUTPUT RATING)

Figure B-13 b

Figure B-14 illustrates the proposed electrical interconnections.

B-3.6 Proposed Cogeneration System

Consideration of the benchmark thermal load established in Section B-3.4 (24,000 m^3, 248,080 kWh*th*/month input of natural gas) establishes the basis for sizing a reciprocating cogeneration unit.

Based on the methodology used in Section 2.2 for sizing the CHP system and the generic Table No. 1.1 from Section 1.4, this unit would have a nominal size of 275 kW with a maximum thermal output of 259,030 kWh*th*/month. Also from Table 1.1, the corresponding electrical output capacity of the unit would be 250 kW. As discussed in Section B-3.5, this would provide approximately 40% of the peak power supply to each building. The proposed cogeneration unit would be interfaced with the building heating systems as illustrated in Figure B-15.

In order to maximize the use of the CHP unit, it would primarily serve the domestic hot water system, where heat would be recovered from the CHP engine exhaust and jacket water cooling. This would be done through two new hot water coils; one in each of the domestic hot water tanks. Thus, the unit would essentially act as a lead boiler to the domestic hot water system. Any load requirements in excess of the unit's capacity, would be supplemented by the existing boilers. During the summer, when domestic hot water load requirements are less than the capacity of the CHP unit, the output level of the system would need to be reduced ("turn-down"). Cogeneration units normally have turn-down capabilities to 40%. If the load requirements drop below this level, the unit would have to be turned off. The likelihood of this happening would be minimal since the tanks would provide some load levelling to the system.

An ASHRAE research paper (1988), by Perlman and Milligan on hot water and energy use in apartment buildings was reviewed. The paper provides a typical domestic hot water consumption profile at a 95% confidence level which represents a reliable estimate of the maximum average daily usage expected for a particular building category. This profile was used to model the

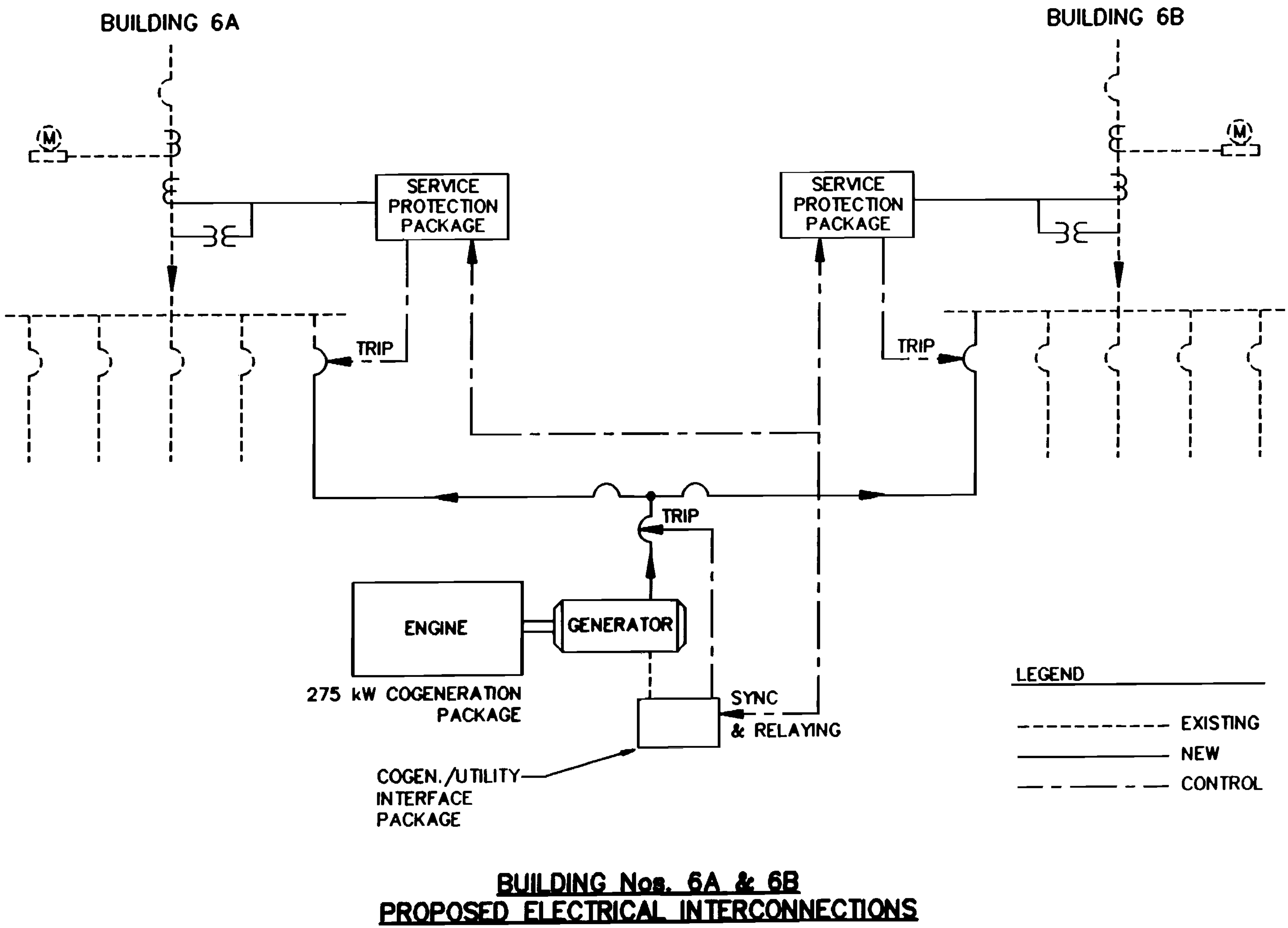
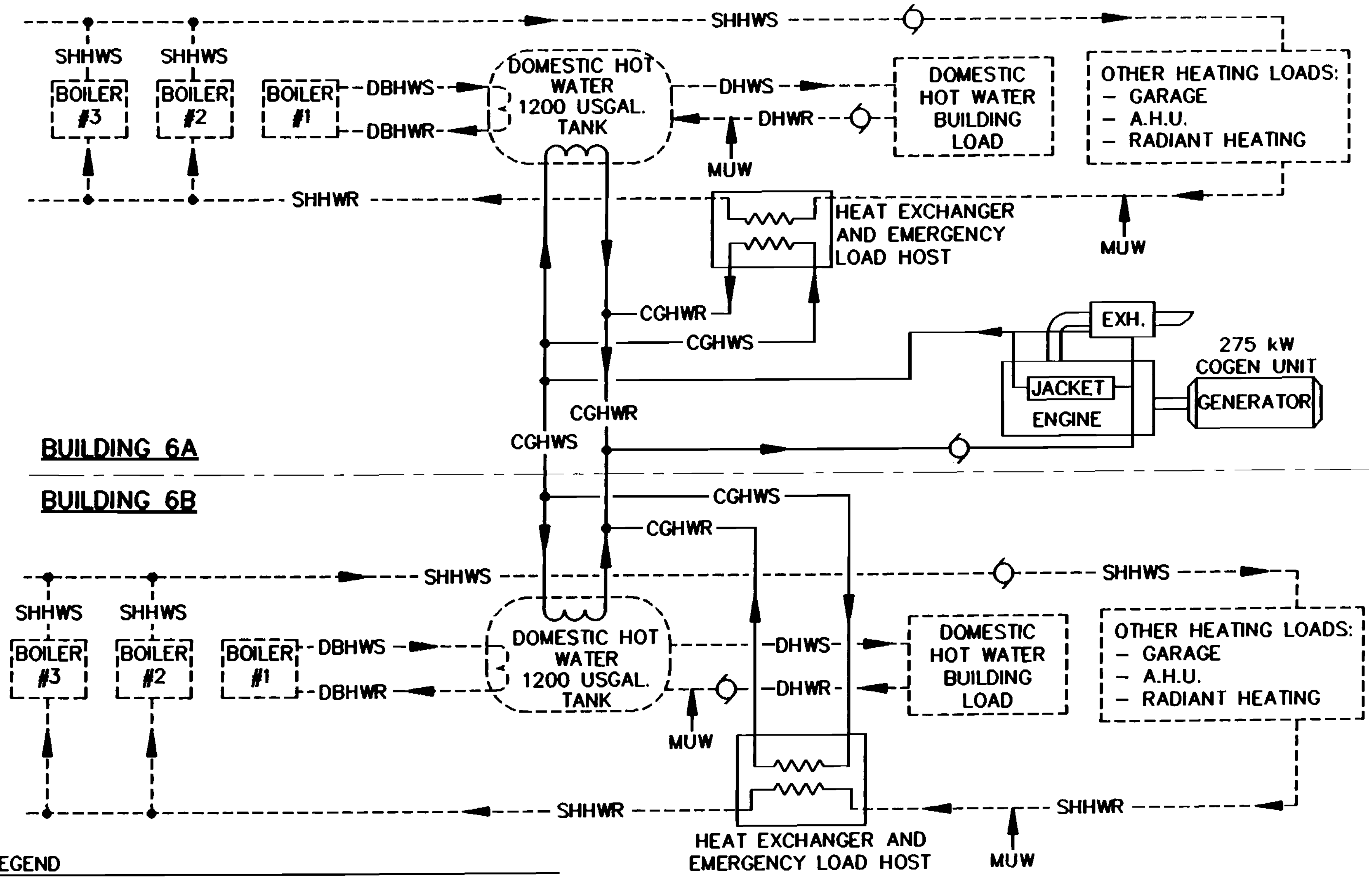

BUILDING 6A
BUILDING 6B
M
M
SERVICE PROTECTION PACKAGE
SERVICE PROTECTION PACKAGE
TRIP
TRIP
TRIP
ENGINE
GENERATOR
275 kW COGENERATION PACKAGE
SYNC & RELAYING
COGEN./UTILITY INTERFACE PACKAGE
LEGEND
EXISTING
NEW
CONTROL
BUILDING Nos. 6A & 6B
PROPOSED ELECTRICAL INTERCONNECTIONS

Figure B-14



LEGEND

DHWR = DOMESTIC HOT WATER RETURN PIPING
DHWS = DOMESTIC HOT WATER SUPPLY PIPING
DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
SHHWS = SPACE HEATING HOT WATER SUPPLY PIPING
SHHWR = SPACE HEATING HOT WATER RETURN PIPING
CGHWR = COGEN HOT WATER RETURN PIPING
CGHWS = COGEN HOT WATER SUPPLY PIPING
MUW = MAKE UP WATER
------- EXISTING
——— NEW

BUILDING Nos. 6A & 6B
PROPOSED COGENERATION
THERMAL SYSTEM INTERFACE

Figure B-15

domestic hot water consumption for the building, where the thermal recovery rate of the proposed CHP unit at 100% capacity and 40% capacity have been superimposed on the graph.

This profile, along with a chart which identifies the estimated recovery rate of the CHP unit, are provided in Appendix 'C'. Here it is illustrated that the CHP unit should not have to be turned off at all since at a 40% turn-down ratio the CHP output would be very close to the domestic hot water consumption during low load periods and as noted above, the storage tanks would be able to provide some load levelling to the system. Thus, the unit should never have to turn-down to the 40% level.

While the cogeneration system is operating, an emergency condition may result from a loss of the CHP unit's ability to cool itself, such as a pipe break, a jammed valve, etc. Depending on manufacturer's recommendations, all CHP units require a cool down period of at least 5 to 15 minutes under no load conditions to equalize the thermal expansion of the engine block. Therefore, in the design of any cogeneration system, it is essential that an emergency heat sink be provided.

During emergency conditions, and in the winter, excess heat from the CHP unit would be relieved to the space heating system through a heat exchanger on the main hot water return line to the space heating boilers. In emergency conditions, if space heating is not in use, a pump would likely be activated to ensure an adequate flow of water is being circulated in the space heating loop. It is recommended that such a pump be powered from the emergency diesel generator to provide circulation during the first few minutes of a power failure. If space heating proved to be an impractical means of providing an emergency heat sink to the system, there are alternative methods of meeting this requirement such as the installation of an outdoor condenser unit, or the rejection of excess heat to a swimming pool.

The thermal energy currently produced for each building from the three existing boilers is in the form of hot water, which varies in temperature from 32°C (90°F) to 100°C (210°F), and is used to serve space heating requirements as well as the domestic hot water load. The domestic hot water supply temperature to the tenants is modulated between 52°C (125°F) and 66°C (150°F). Hot water temperatures as high as 100°C (210°F) are possible to obtain through the combined recovery of heat from jacket water cooling and exhaust heat from the engine of the CHP unit.

A manufacturer advised that a typical CHP unit has a low fuel pressure option, requiring as little as 5" w.c. pressure at the engine regulator. However, the fuel would flow through a "fuel train", which would impose a 2-3 psig pressure drop. Therefore, a minimum delivery pressure of 3.5 psig would be required. The proposed location for the cogeneration unit (refer to Section B-3.7) is at the basement level. As discussed in Section 3.6, it may be possible to have a new service connected to the building with a pressure as high as 5 psig; however, this would have to be confirmed with the utility. For the purposes of the economic assessment provided in Section B-3.8, it is assumed that the higher gas pressure could be provided.

B-3.7 Structural and Architectural Considerations

There does not appear to be any space available in the boiler rooms of either building to house the cogeneration system. However, in Building 6A, there is a room across the hall from the boiler room which appears to be an option. This room has an exterior concrete block wall which is not likely to be load bearing. To place the CHP unit in the room, it is likely that this wall would have to be removed and replaced. Also, the exterior surface, is covered with a berm which would need to be excavated. It would be necessary to provide air intake and exhaust ducts to the room from outside, which would require acoustic treatment.

If this location can be used to house the CHP unit, there should be no need for additional sound attenuation material other than the ductwork mentioned above.

B-3.8 Economic Analysis

The following is a summary of the economics proposed for this project:

a) **Construction Costs**

Item	Cost
275 kW Cogeneration Unit Package	$190,000
Installation	$ 85,000
Gas Pressure Booster	$ 25,000
Electrical Distribution	$ 10,000
Crane	$ 7,500
Structural Work	$ 25,000
Insurance (1% Cogeneration Cost)	$ 1,900
Subtotal:	$344,400
Design Engineering (10%)	$ 34,440
Contingency (5%)	$ 17,220
TOTAL IMPLEMENTATION COSTS:	$396,060

b) **Maintenance Costs/Year**

Based on 1.3¢/kWh full maintenance contract for a 5 year period, including:	$ 30,375/year

- remote alarm monitoring
- cylinder overhaul (30,000 hour interval)
- head maintenance (12-15,000 hour interval)
- lube oil and spark plug changes (400 hour interval)

c) Cost Savings of Displaced Power

Estimated Annual kWh Displaced:		2,124,300 kWh
Estimated kW Displaced	(Jan.-May, Sept.-Dec.)	250 kW
Estimated kW Displaced	June	222 kW
Estimated kW Displaced	July	192 kW
Estimated kW Displaced	August	240 kW
Estimated Annual Energy Cost Savings (5.25¢/kWh):		$111,525
Estimated Annual Demand Savings ($4.8/kW):		$ 13,940
Total Annual Electrical Cost Savings:		$125,465

d) Net Fuel Consumption

The average thermal output of the CHP unit is illustrated in Figure B-12, where the unit would be able to displace a maximum equivalent boiler input of 323,790 kWh*th*/month of natural gas (31,335 m^3/month) for 9 months of the year. The minimum equivalent boiler input of the unit would be 248,085 kWh*th*/month of natural gas (24,010 m^3/month) in June.

From the energy balance presented in Section 1.3 of the report, the estimated fuel consumption for the cogeneration unit at full load is 588,870 kWh*th*/month, while at 77% load it is estimated to be 453,305 kWh*th*/month.

Based on the above data, annual net fuel consumption costs are estimated as follows:

Estimated Annual Fuel Consumption of CHP Unit:	6,835,235 kWh*th* (661,475 m^3)
Estimated Annual Equivalent Boiler Natural Gas Consumption:	3,759,380 kWh*th* (363,820 m^3)
Estimated Net Annual Natural Gas Consumption:	3,075,855 kWh*th* (297,665 m^3)

Thus, it is estimated that the unit will require an additional 3,075,855 kWh*th* (297,665 m^3) of natural gas per year to displace the thermal loads which are currently being supplied by the boilers. With an estimated average natural gas price of 1.36¢/kWh*th* ($4/MCF), this translates into an additional cost of $41,830/year.

e) Cost Benefit

The following economic summary applies to the net annual energy cost savings from displaced electrical power and thermal loads:

Estimated Annual Electrical Cost Savings:	$125,465
Less Annual Maintenance Cost/Year:	$(30,375)
Less Estimated Increased Natural Gas Consumption Cost:	$(41,830)
Estimated Net Annual Energy Cost Savings:	$ 53,260
Estimated Implementation Cost:	$396,060
Estimated Simple Payback Period: $= \frac{\$396{,}060}{\$53{,}260} =$	7 years

f) Present Value of Savings

The following parameters are used to project the present value of savings over a 7 and 20 year period:

Estimated Average Gas Increase Rate, A	= 4%
Estimated Average Electrical Increase Rate, B	= 10%
Estimated Average Inflation Rate, C	= 5%
Estimated Average Interest Rate, D	= 12%
Average Real Annual Increase of Energy Cost, E	= Avg (A+B) - C
	= 7%-5% = 2%
Average Real Interest Rate, R	= D-C
	= 12%-5% = 7

The following Table projects the present value of savings over a 20 year period.

Year	Energy Cost (per Unit)	Energy Saved Year End ($)	Discount Factor	Present Value of Energy Saved ($)
1	1	53,260	1/1.07	49,776
2	1.02	54,325	$1/1.07^2$	47,450
3	1.02^2	55,412	$1/1.07^3$	45,232
4	1.02^3	56,520	$1/1.07^4$	43,119
5	1.02^4	57,650	$1/1.07^5$	41,104
6	1.02^5	58,803	$1/1.07^6$	39,183
7	1.02^6	59,979	$1/1.07^7$	37,352
8	1.02^7	61,179	$1/1.07^8$	35,607
9	1.02^8	62,403	$1/1.07^9$	33,943
10	1.02^9	63,651	$1/1.07^{10}$	32,357
11	1.02^{10}	64,924	$1/1.07^{11}$	30,845
12	1.02^{11}	66,222	$1/1.07^{12}$	29,403
13	1.02^{12}	67,547	$1/1.07^{13}$	28,029
14	1.02^{13}	68,897	$1/1.07^{14}$	26,720
15	1.02^{14}	70,275	$1/1.07^{15}$	25,471
16	1.02^{15}	71,681	$1/1.07^{16}$	24,281
17	1.02^{16}	73,115	$1/1.07^{17}$	23,146
18	1.02^{17}	74,577	$1/1.07^{18}$	22,065
19	1.02^{18}	76,068	$1/1.07^{19}$	21,034
20	1.02^{19}	77,590	$1/1.07^{20}$	20,051

From the above Table, the sum of the present value of savings after 7 years is $303,215. After 20 years, the sum of the present value of savings is $656,165.

g) Internal Rate of Return

The internal rate of return is calculated based on the following equation using data from the Table in Part (f):

$$X = \frac{Y_1}{(1+I)} + \frac{Y_2}{(1+I)^2} + \frac{Y_3}{(1+I)^3} + \ldots + \frac{Y_{20}}{(1+I)^{20}}$$

where X = Estimated Implementation Cost

Y_n = Energy saved at year end for year "n" (i.e. 1 to 20)

I = Internal rate of return

The solution to this equation can only be obtained by successive approximation. For the purposes of this study, the above equation was solved using a scientific calculator which has this solving capability.

On this basis, I $= 0.15$

B-4.0 Building No. 7

B-4.1 General Description of the Facility

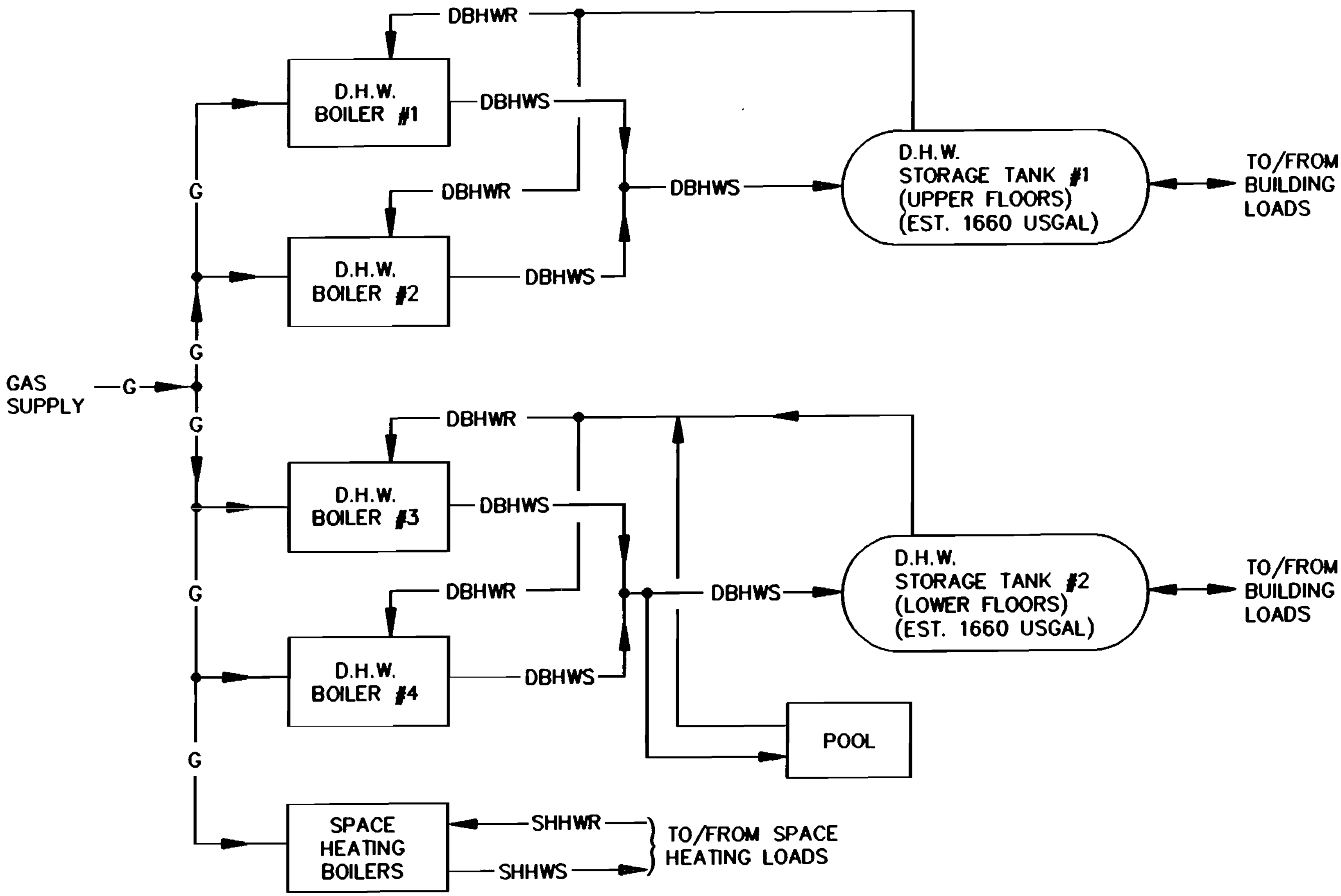
Building No. 7 is a 20 storey building, with 270 apartment units. The main mechanical room is located on the top floor of the building. It contains 4 boilers for space heating, 4 boilers for domestic hot water, a domestic hot water storage tank for the upper floors of the building, 2 air handling units and a chiller system for air conditioning during the summer. The domestic hot water tank for the lower floors of the building is located in the basement. Also, there is a swimming pool which is used throughout the year.

B-4.2 Heating System

B-4.2.1 General Description:

The space heating system is controlled and operated separately from the domestic hot water system. There are 4 space heating boilers, each rated at a maximum output of approximately 990 MBH. These boilers serve 2 air handling units which are used to ventilate the entire building. The air handling units operate on a "split system" for heating and cooling. A common circulation loop is connected to the units which provides hot water from the boilers in the winter, and cold water from the chiller in the summer.

The domestic hot water boilers, which are approximately 10 years old, are serviced on a regular basis and are in relatively good condition. All of the boilers are fired with natural gas, where 2 have a maximum output rating of 1,123 MBH, and the other 2 are rated at a maximum output of 1,082 MBH. The property manager advised that the boilers are modulated between low fire at



BUILDING No.7
EXISTING HOT WATER SYSTEM

Figure B-16

LEGEND

DBHWR = DOMESTIC BOILER HOT WATER RETURN PIPING
DBHWS = DOMESTIC BOILER HOT WATER SUPPLY PIPING
SHHWS = SPACE HEATING HOT WATER SUPPLY PIPING
SHHWR = SPACE HEATING HOT WATER RETURN PIPING
——G—— GAS SERVICE

71°C (160°F) and high fire at 93°C (200°F) to provide a hot water supply temperature between 52°C (125°F) and 63°C (145°F) from the 2 storage tanks which are each estimated to be 1660 US gal. In addition to the storage tanks, the 2 boilers with the higher output rating also provide heat to the pool throughout the year.

A single line sketch of the hot water system is provided in Figure B-16.

B-4.2.2 Gas Service, Fuel Costs and Consumption Data:

The site uses the firm General Service Rate Number 100.

In general, for apartment building, the supplied gas pressure is likely to be around 7" w.c. (0.25 psig), which is typical for highly populated residential areas. The actual conditions are site specific and would need to be confirmed with the utility. The required pressure for a new CHP system is likely to be greater than that available, thus, a natural gas booster compressed package would be required.

The monthly gas consumption and corresponding costs at the site for the period of April 1991 through to March 1992 are presented in Table B-7. The consumption profile is analyzed further in Section B-4.4.

The current gas rate came into effect as of October 1, 1991. Thus, by examining the building data from October 1991 through until March 1992, the current average gas price is estimated to be 1.59¢/kWh*th* ($4.66 MCF).

TABLE B-7

GAS BILLING DATA (BUILDING NO. 7)
FOR PERIOD APRIL 1991 THROUGH TO MARCH 1992

Month	Gas Consumption		Cost
	(cu.m.)	(kWh*th*)	($)
January	78,024	806,248	13,051
February	74,953	774,514	12,548
March	77,964	805,628	13,040
April	45,917	474,476	7,480
May	47,118	486,886	7,094
June	19,745	204,032	3,068
July	16,155	166,935	2,538
August	19,830	204,910	3,081
September	14,359	148,376	2,273
October	19,252	198,937	2,995
November	50,755	524,468	7,620
December	54,356	561,679	9,179
Total	**518,428**	**5,357,089**	**83,967**

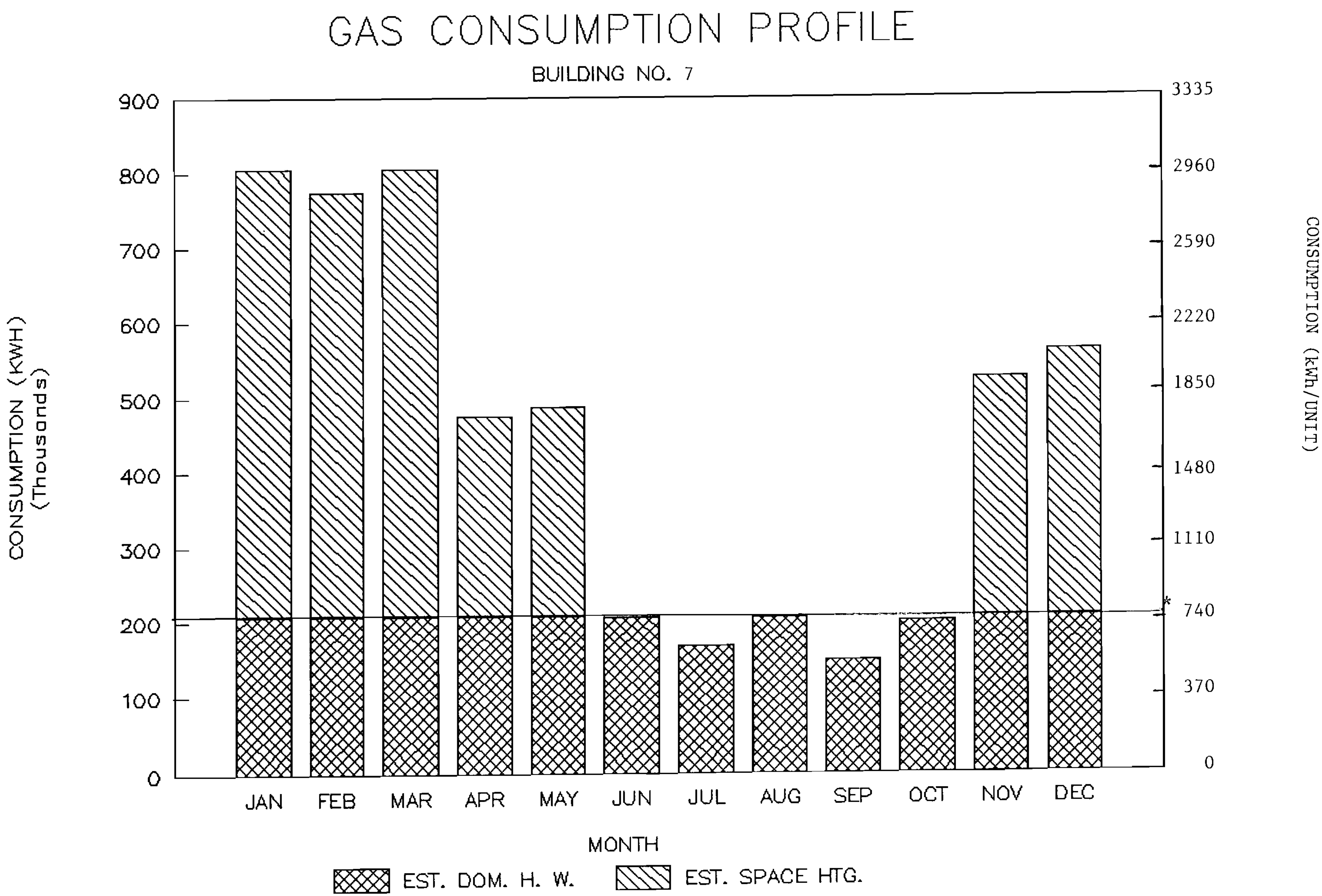
B-4.3 Electrical System

B-4.3.1 General Description:

The building is currently fed from Mississauga Hydro to a main switchboard. Utility metering is centralized and bulk measured with no submetering for individual tenant loads.

B-4.3.2 Electrical Costs and Consumption/Demand Data

The monthly electrical consumption, demand and corresponding costs during April 1991 through to March 1992 for Building No. 7 are listed in Table B-8.



* EQUIVALENT BOILER INPUT OF CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-17

TABLE B-8

ELECTRICAL BILLING DATA FOR BUILDING NO. 7

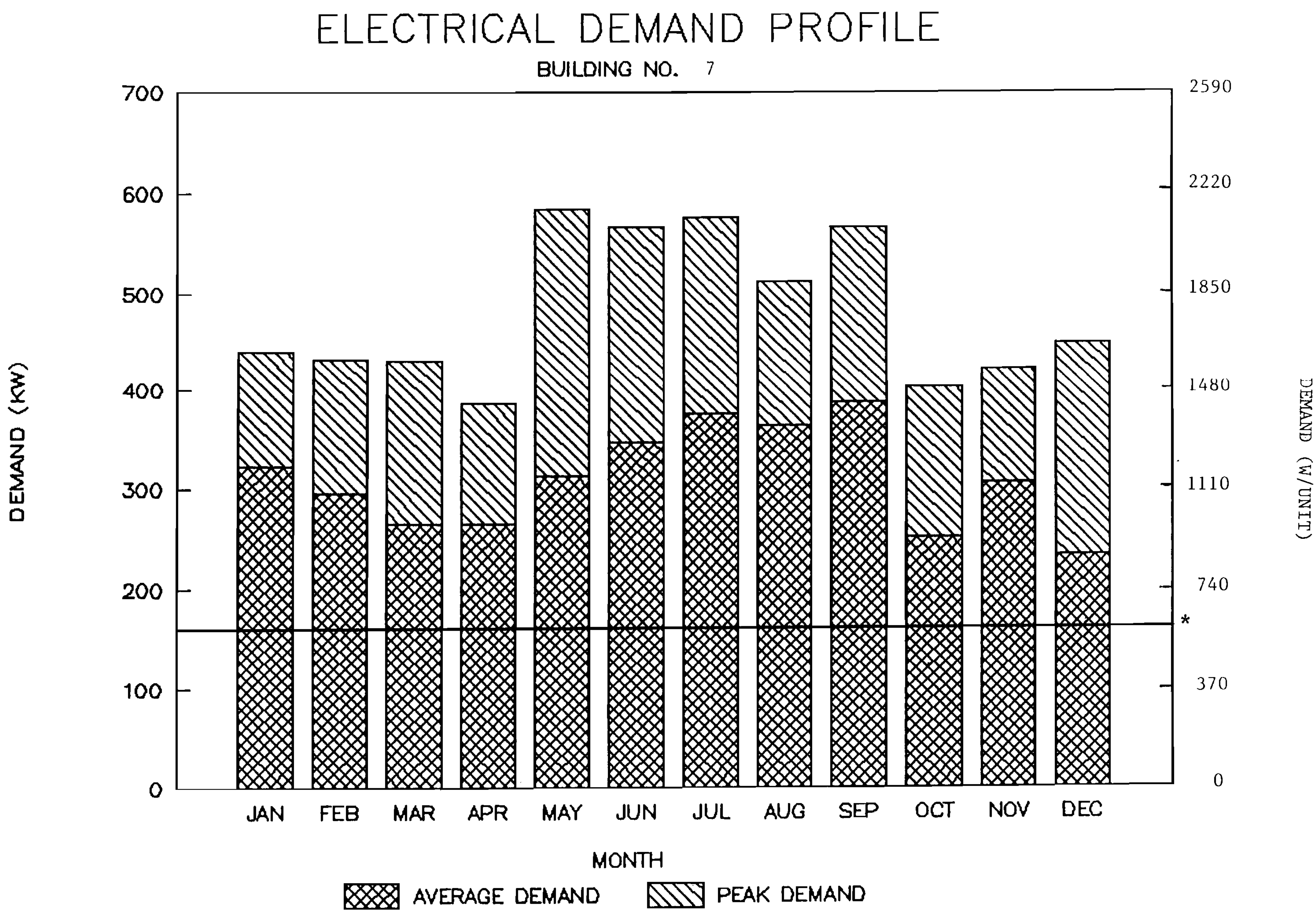
Month	Building No.12		
	Energy (kWh)	Demand (kW)	Cost ($)
January	235,800	441	15,663
February	216,000	432	14,877
March	193,500	432	13,353
April	193,500	387	11,907
May	228,600	585	15,696
June	252,900	567	15,601
July	274,500	576	16,748
August	265,500	513	16,075
September	283,500	567	17,442
October	183,600	405	11,231
November	224,100	423	13,796
December	171,000	450	10,571
Total	**2,722,500**	**585 (Peak)**	**172,960**

The site is billed by Mississauga Hydro on a General Service rate structure.

In the economic analysis (Section B-4.8), the marginal energy rate of 5.36¢/kWh and the demand rate of $5.10/kW per month are used to calculate savings on displaced electrical power from the CHP unit.

B-4.4 Thermal Load Analysis

The gas consumption data from Table B-7 was used to develop the thermal demand profile presented in Figure B-17. This figure illustrates the variation between the higher gas consumption requirements during the winter months for space heating and the significantly lower consumption levels which occur during the summer to satisfy the domestic hot water requirements.



* ELECTRICAL OUTPUT FROM CHP UNIT (AT MAXIMUM OUTPUT RATING)

Figure B-18

The consumption curve and corresponding data in Table B-7, show an average baseload input of 14,359 m^3 (148,376 kWh*th*) for the month of September. Further analysis of this curve reveals that the load requirements for the months of June and August account for more than 9 months (at 6000 hours) per year. Thus, it was decided that the average of these loads, approximately 19,790 m^3 (204,500 kWh*th*) input would serve as a useful benchmark for a combined heat and power unit, which would provide a turn-down ratio to average baseload conditions of 73% in September.

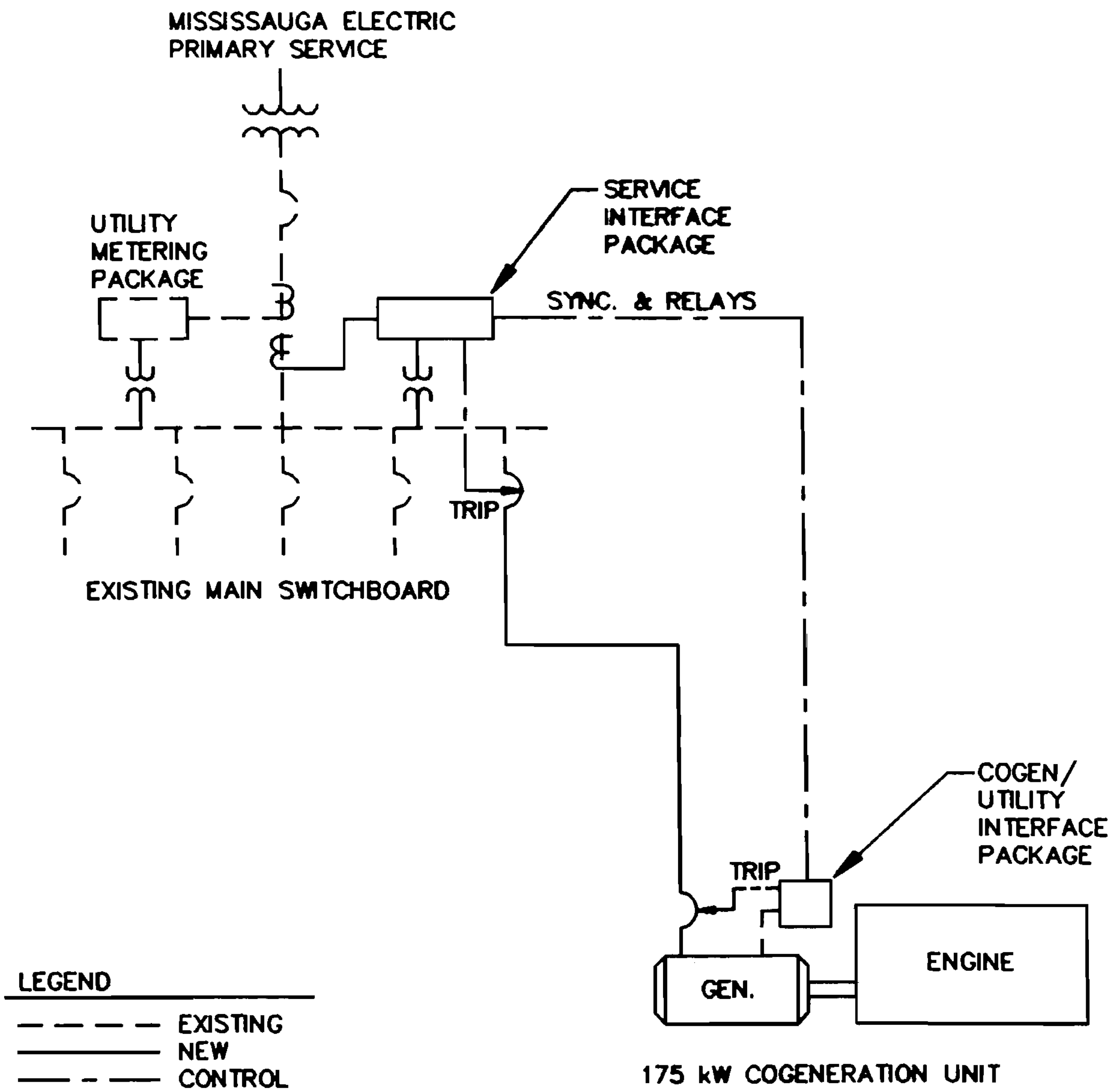
B-4.5 Electrical Load Analysis

To analyze the electrical demand profile for Building No. 7, the monthly demand data from Table B-8 was used to plot the electrical demand curve presented in Figure B-18. Generally speaking, the summer demand is higher than the winter demand by about 30%. This is likely due to the chiller systems being in operation during the summer months.

The access to the main electrical service of the building is fairly easy to achieve at this site. The proposed cogeneration interconnection would consist of a direct power tie into the main switchboard to provide AC power for consumption 'in-house' and would not be in a position to export to Hydro's grid. The amount of power available would be directly proportionate to the turn-down thermal output of the unit. The net result would be an almost continuous level of power at 160 kW which would provide approximately 30% to 35% of the peak power for the building which would not have to be purchased from Hydro.

The system would have a power interface package which would continuously monitor the output of the unit and the actual current draw on the building main service. The unit would be automatically synchronized to the utility grid and at no time would the unit be allowed to produce more than 80% of the site's total current draw. In addition, a full protective relay package would backup the synchronizing and current check relays with reverse current, phase unbalance, etc. to automatically shut the unit down in the event of a failure of any system.

Figure B-19 illustrates the proposed electrical interconnections.



BUILDING No.7
PROPOSED ELECTRICAL INTERCONNECTION

Figure B-19

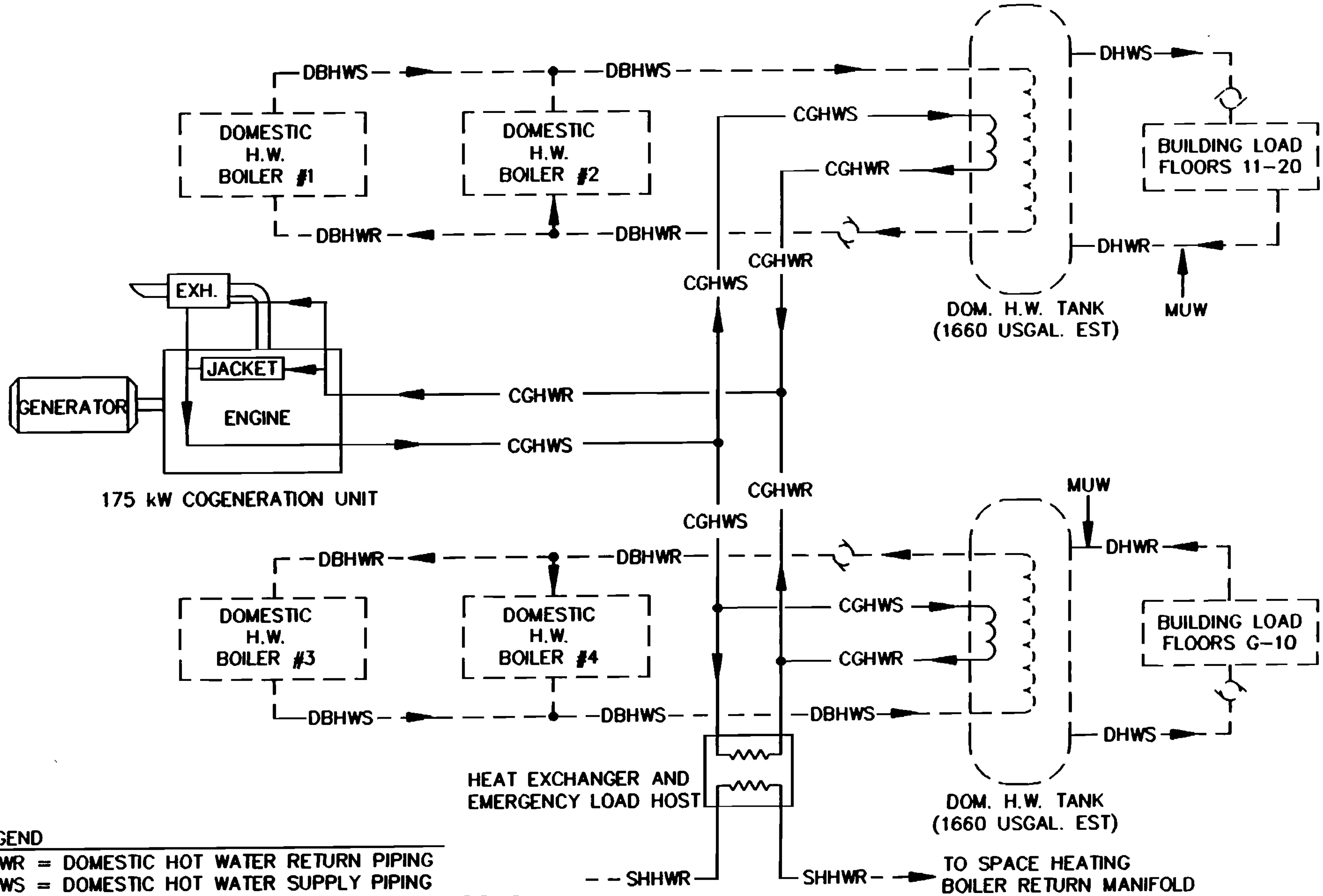
B-4.6 Proposed Cogeneration System

Consideration of the benchmark thermal load established in Section B-4.4 (19,970 m^3, 204,500 kWh*th*/month input of natural gas) establishes the basis for sizing a reciprocating cogeneration unit.

Based on the methodology used in Section 2.2 for sizing the CHP system and the generic Table No. 1.1 from Section 1.4, a nominal unit size of 175 kW was selected with a maximum thermal output of 165,780 kWh*th*/month. Also, from Table 1.1, the corresponding electrical output capacity of the unit would be 160 kW. As discussed in Section B-4.5, this would provide approximately 28% to 35% of the peak power supply to the building. The proposed cogeneration unit would be interfaced with the domestic hot water and space heating systems as illustrated in Figure B-20.

In order to maximize the use of the CHP unit, it would primarily serve the domestic hot water system, where heat would be recovered from the CHP engine exhaust and jacket water cooling. This would be done through two new hot water coils; one in each of the domestic hot water tanks. Any load requirements in excess of the unit's capacity, would be supplemented by the existing boilers. During the summer, when domestic hot water load requirements are less than the capacity of the CHP unit, the output level of the system may need to be reduced ("turned-down"). Cogeneration units normally have turn-down capabilities to 40%. If the load requirements drop below this level, the unit would have to be turned off. The likelihood of this happening would be minimal since the storage tanks would provide some load levelling to the system.

An ASHRAE research paper (1988), by Perlman and Milligan on hot water and energy use in apartment buildings was reviewed. The paper provides a typical domestic hot water consumption profile at a 95% confidence level which represents a reliable estimate of the maximum average daily usage expected for a particular building category. This profile was used to model the domestic hot water consumption for the building, where the thermal recovery rate of the proposed CHP unit at 100% capacity and 40% capacity have been superimposed on the graph. This profile, along with a chart which identifies the estimated recovery rate of the CHP unit, are provided in Appendix 'C'. Here it is illustrated that the CHP unit should not have to be turned off at all since



LEGEND

DHWR = DOMESTIC HOT WATER RETURN PIPING
DHWS = DOMESTIC HOT WATER SUPPLY PIPING
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MUW = MAKE UP WATER
——— NEW
– – – – EXISTING

BUILDING No.7
PROPOSED COGENERATION
THERMAL SYSTEM INTERFACE

Figure B-20

at a 40% turn-down ratio, the output of the CHP unit would be close to the domestic hot water consumption during low load periods. Also, as noted above, the storage tanks would be able to provide some load levelling to the system, and the unit should never have to turn-down to the 40% level.

While the cogeneration system is operating, an emergency condition may result from a loss of the CHP unit's ability to cool itself, such as a pipe break, a jammed valve, etc. Depending on manufacturer's recommendations, all CHP units require a cool down period of at least 5 to 15 minutes under no load conditions to equalize the thermal expansion of the engine block. Therefore, in the design of any cogeneration system, it is essential that an emergency heat sink be provided.

During emergency conditions, and in the winter, excess heat from the CHP unit would be relieved to the space heating system through a heat exchanger on the main hot water return line to the space heating boilers. In emergency conditions, if space heating is not in use, a pump would likely be activated to ensure an adequate flow of water is being circulated in the space heating loop. It is recommended that such a pump be powered from the emergency diesel generator to provide circulation during the first few minutes of a power failure. If space heating proved to be an impractical means of providing an emergency heat sink to the system, there are alternative methods of meeting this requirement such as the installation of an outdoor condenser unit, or the rejection of excess heat to a swimming pool.

The thermal energy currently produced in the building for the domestic hot water system is in the form of hot water from the boilers. The Property Manager advised that the hot water supply temperature from the tanks is maintained between 52°C (125°F) and 63°C (145°F). Hot water temperatures as high as 100°C (210°F) are possible to obtain through the combined recovery of heat from jacket water cooling and exhaust heat from the engine of the CHP unit.

A manufacturer advised that a typical CHP unit has a low fuel pressure option, requiring as little as 5" w.c. pressure at the engine regulator. However, the fuel would flow through a "fuel train", which would impose a 2-3 psig pressure drop. Therefore, a minimum delivery pressure of 3.5 psig would be required. The proposed location for the cogeneration unit (see Section B-4.7) is on the roof in an enclosure. As discussed in Section 3.6, the cost of a new gas service would be excessive.

For the purposes of the economic assessment provided in Section B-4.8, a gas booster compressor package has been included.

B-4.7 Structural and Architectural Considerations

There does not appear to be any space available in or near the mechanical room penthouse to house the CHP system. As a result, the best location for the unit appears to be on the roof above the penthouse. The unit would need to be placed in an enclosure which would provide adequate protection from the weather and ensure that the system operates within acceptable noise criteria at all times. Air intake and exhaust ducts would have to be provided to the room from outside, which would require acoustic treatment.

Furthermore, the structural integrity of the roof would need to be examined and modified if necessary to ensure that the support for the system is sound.

B-4.8 Economic Analysis

The following is a summary of the economics for this proposed project:

a) Construction Costs

Item	Cost
175 kW Cogeneration Unit Package	$130,000
Installation	$ 75,000
Gas Pressure Booster	$ 25,000
Electrical Distribution	$ 10,000
Crane	$ 12,000
Enclosure	$ 18,000
Structural Work	$ 15,000
Insurance (1% Cogeneration Cost)	$ 1,300
Subtotal:	$286,300
Design Engineering (10%)	$ 28,630
Contingency (5%)	$ 14,315
TOTAL IMPLEMENTATION COSTS:	$329,245

b) Maintenance Costs/Year

Based on 1.3¢/kWh full maintenance contract for a 5 year period, including: $ 18,930/year

- remote alarm monitoring
- cylinder overhaul (30,000 hour interval)
- head maintenance (12-15,000 hour interval)
- lube oil and spark plug changes (400 hour interval)

c) Cost Savings of Displaced Power

Estimated Annual kWh Displaced:		1,331,250 kWh
Estimated kW Displaced	(Jan.-June, Aug., Nov.-Dec.)	160 kW
Estimated kW Displaced	July	130 kW
Estimated kW Displaced	September	115 kW
Estimated kW Displaced	October	154 kW

Estimated Annual Energy Cost Savings (5.36¢/kWh):	$71,355
Estimated Annual Demand Savings ($5.10/kW):	$ 9,380
Total Annual Electrical Cost Savings:	$80,735

d) Net Fuel Consumption

The average thermal output of the CHP unit is illustrated in Figure B-17, where the unit would be able to displace a maximum equivalent boiler input of 207,225 kWh*th*/month of natural gas (20,055 m^3/month) for close to 10 months of the year. The minimum equivalent boiler input of the unit would be 148,375 kWh*th*/month of natural gas (14,360 m^3/month) in September.

From the energy balance provided in Section 1.3 of the report, the estimated fuel consumption for the cogeneration unit at full load is 376,775 kWh*th*/month, while at 72% load it is estimated to be 271,275 kWh*th*/month.

Based on the above data, annual net fuel consumption costs are estimated as follows:

Estimated Annual Fuel Consumption of CHP Unit:	4,315,935 kWh*th* (417,670 m^3)
Estimated Annual Equivalent Boiler Natural Gas Consumption:	2,373,765 kWh*th* (229,720 m^3)
Estimated Net Annual Natural Gas Consumption:	1,942,170 kWh*th* (187,955 m^3)

Thus, it is estimated that the unit will require an additional 1,942,170 kWh*th* (187,955 m^3) of natural gas per year to displace the thermal loads which are currently being supplied by the boilers. With an estimated average natural gas price of 1.59¢/kWh*th* ($4.66/MCF), this translates into an additional cost of $30,880/year.

e) **Cost Benefit**

The following economic summary applies to the net annual energy cost savings from displaced electrical power and thermal loads:

Estimated Annual Electrical Cost Savings:		\$ 80,735
Estimated Annual Maintenance Cost/Year:		\$(18,940)
Less Estimated Increased Natural Gas Consumption Cost:		\$(30,880)
Estimated Net Annual Energy Cost Savings:	\$ 30,915	
Estimated Implementation Cost:		\$329,245
Estimated Simple Payback Period: $= \frac{\$329,245}{\$30,915} =$		11 years

f) **Present Value of Savings**

The following parameters are used to project the present value of savings over a 7 year period:

Estimated Average Gas Increase Rate, A	= 4%
Estimated Average Electrical Increase Rate, B	= 10%
Estimated Average Inflation Rate, C	= 5%
Estimated Average Interest Rate, D	= 12%
Average Real Annual Increase of Energy Cost, E	= Avg (A+B) - C
	= 7%-5% = 2%
Average Real Interest Rate, R	= D-C
	= 12%-5%
	= 7%

The following Table projects the present value of savings over a 7 year period.

Year	Energy Cost (per Unit)	Energy Saved Year End ($)	Discount Factor	Present Value of Energy Saved ($)
1	1	30,915	1/1.07	28,893
2	1.02	31,533	$1/1.07^2$	27,542
3	1.02^2	32,164	$1/1.07^3$	26,255
4	1.02^3	32,807	$1/1.07^4$	25,028
5	1.02^4	33,463	$1/1.07^5$	23,859
6	1.02^5	34,133	$1/1.07^6$	22,744
7	1.02^6	34,815	$1/1.07^7$	21,681
8	1.02^7	35,512	$1/1.07^8$	20,668
9	1.02^8	36,222	$1/1.07^9$	19,702
10	1.02^9	36,946	$1/1.07^{10}$	18,782
11	1.02^{10}	37,685	$1/1.07^{11}$	17,904
12	1.02^{11}	38,439	$1/1.07^{12}$	17,067
13	1.02^{12}	39,208	$1/1.07^{13}$	16,270
14	1.02^{13}	39,992	$1/1.07^{14}$	15,510
15	1.02^{14}	40,792	$1/1.07^{15}$	14,785
16	1.02^{15}	41,608	$1/1.07^{16}$	14,094
17	1.02^{16}	42,440	$1/1.07^{17}$	13,435
18	1.02^{17}	43,288	$1/1.07^{18}$	12,807
19	1.02^{18}	44,154	$1/1.07^{19}$	12,209
20	1.02^{19}	45,037	$1/1.07^{20}$	11,638

From the above Table, the sum of the present value of savings after 7 years is $176,005.

After 20 years, the sum of the present value of savings is $380,875.

g) Internal Rate of Return

The internal rate of return is calculated based on the following equation using data from the Table in Part (f):

$$X = \frac{Y_1}{(1+I)} + \frac{Y_2}{(1+I)^2} + \frac{Y_3}{(1+I)^3} + \ldots + \frac{Y_{20}}{(1+I)^{20}}$$

where X = Estimated Implementation Cost

Y_n = Energy saved at year end for year "n" (i.e. 1 to 20)

I = Internal rate of return

The solution to this equation can only be obtained by successive approximation. For the purposes of this study, the above equation was solved using a scientific calculator which has this solving capability.

On this basis, $I = 0.09$

APPENDIX 'C'

DOMESTIC HOT WATER CONSUMPTION PROFILES

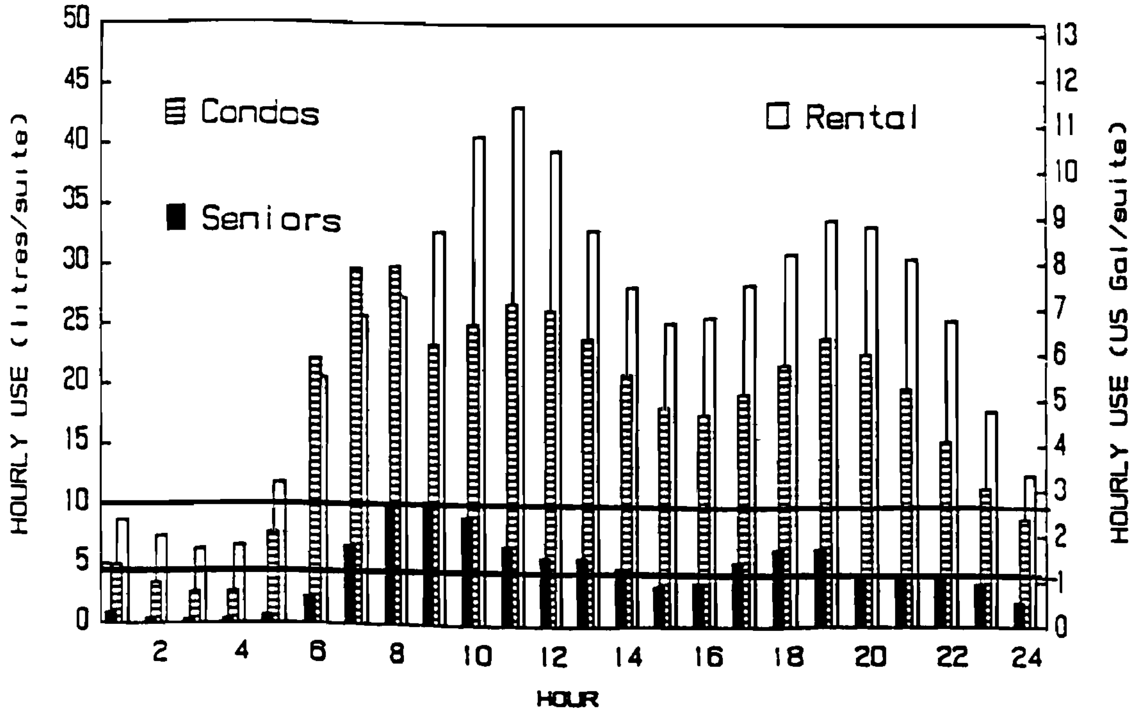
THERMAL CAPACITY OF PROPOSED CHP SYSTEMS AS A FUNCTION OF DOMESTIC HOT WATER CONSUMPTION

BUILDING NO.	2	4	6 A & B	7
Occupancy Type	Condo	Low Income Rental - High-Rise	Medium Income Rental - High-Rise	Medium Income Rental - High-Rise w/Pool
No. of Apartment Units	118	230	502	270
Nominal CHP Size (kW)	40	125	275	175
Thermal Output of CHP Unit (kW) (100%)	50	160	355	227
Thermal Output of CHP Unit (Btu/hr) (100%)	170,600	545,920	1,211,260	774,524
Thermal Output of CHP Unit (Btu/hr) (40%)	68,240	218,365	484,504	309,810
U.S. gpm* (40%)	2.11	6.8	14.95	9.56
U.S. gph (40%)	126	405	897	574
U.S. gph/Unit (40%)	1.1	1.76	1.79	2.12
U.S. gph/Unit (100%)	2.7	4.41	4.48	5.3

* $Q = 500 \times gpm \times dT \times 0.9 \times 0.8$

Where $dT = 90°F$
0.9 and 0.8 are efficiencies of heat exhangers

Building No. 2

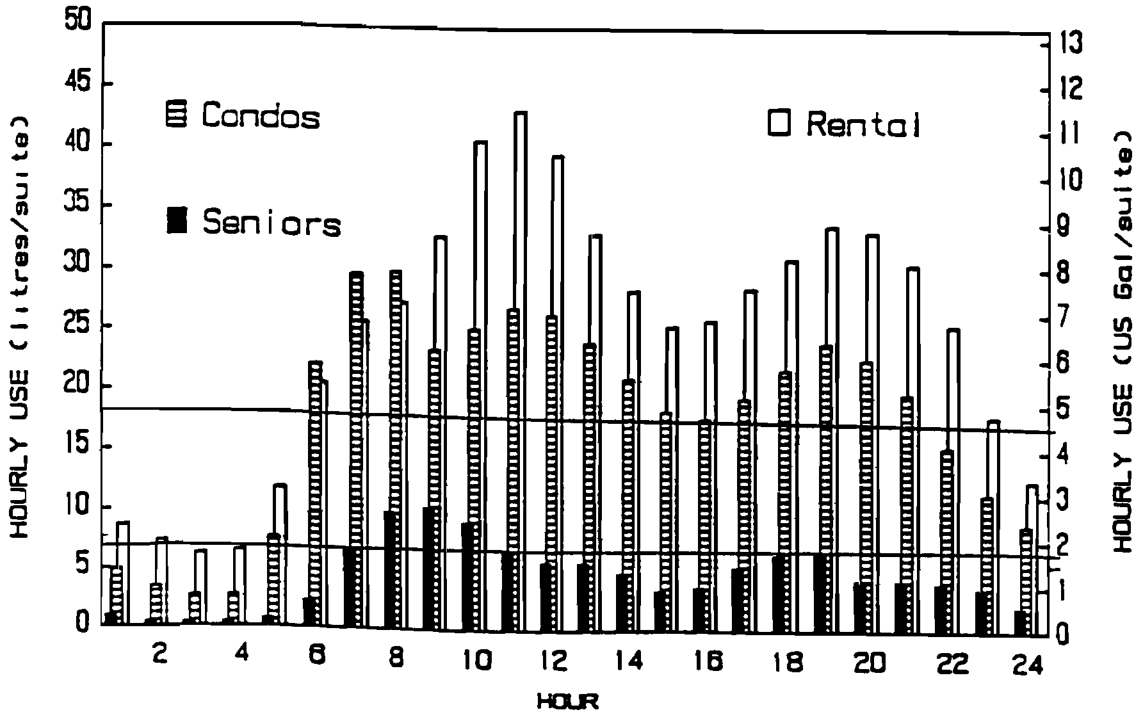


2.7 (100%)

1.1 (40%)

Thermal Recovery Rate of Proposed CHP Unit at 100% and 40% superimposed on hourly hot water use – overall average at 95% confidence level (per suite)
Profile from research paper by Perlman and Milligan (1988)

Building No. 4

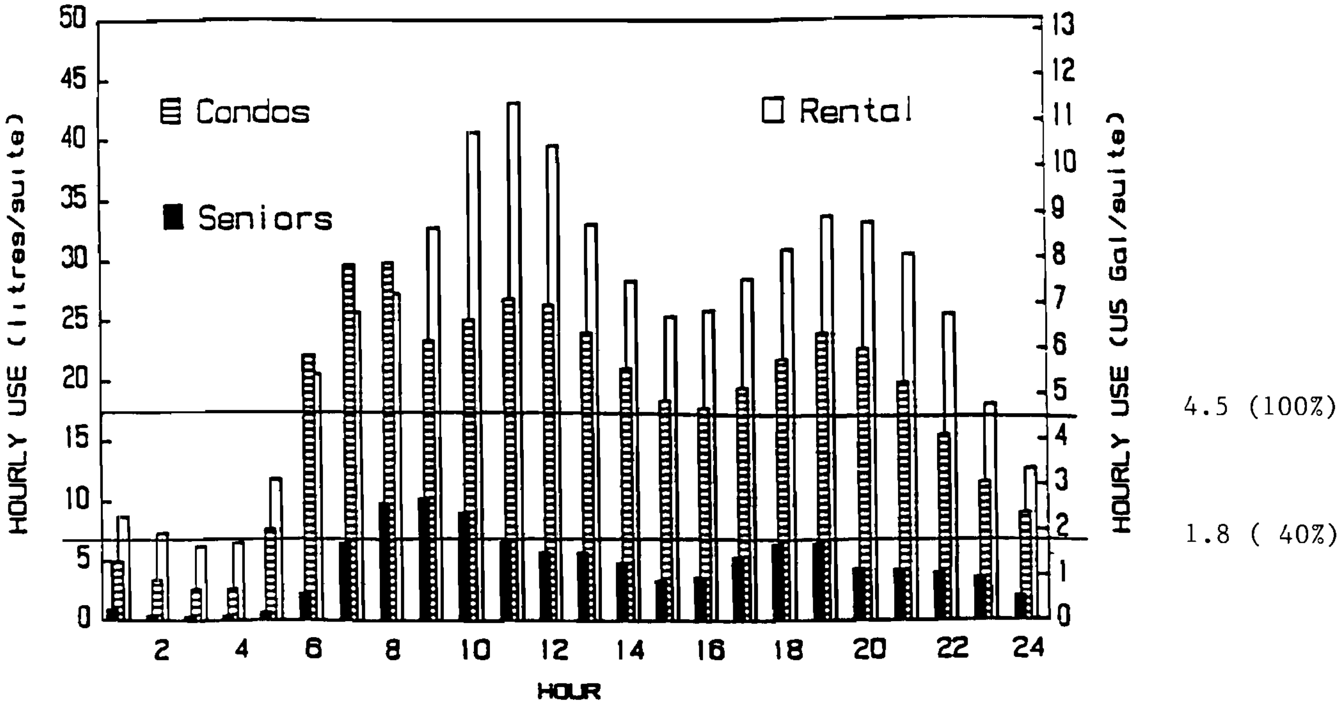


4.4 (100%)

1.7 (40%)

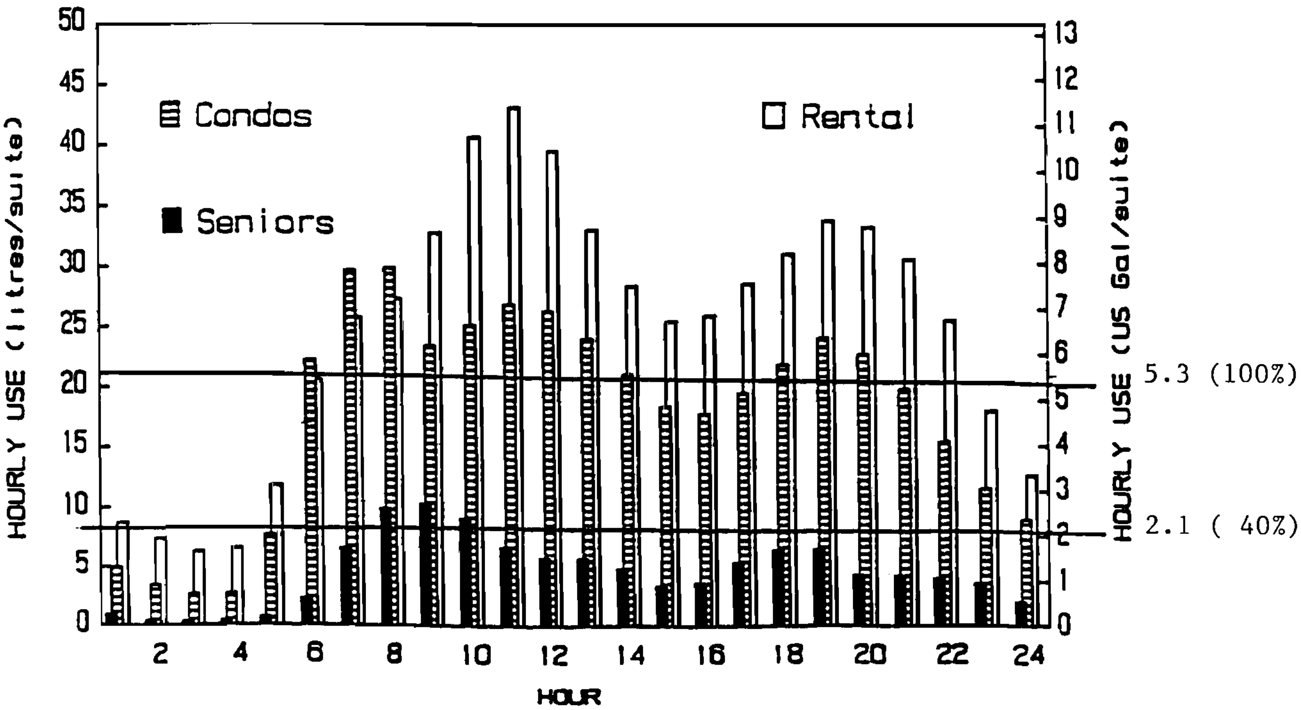
Thermal Recovery Rate of Proposed CHP Unit at 100% and 40% superimposed on hourly hot water use - overall average at 95% confidence level (per suite)
Profile from research paper by Perlman and Milligan (1988)

Building Nos. 6a & 6b



Thermal Recovery Rate of Proposed CHP Unit at 100% and 40%
superimposed on hourly hot water use - overall average at
95% confidence level (per suite)
Profile from research paper by Perlman and Milligan (1988)

Building No. 7



Thermal Recovery Rate of Proposed CHP Unit at 100% and 40%
superimposed on hourly hot water use - overall average at
95% confidence level (per suite)
Profile from research paper by Perlman and Milligan (1988)

APPENDIX 'D'

COMPARISON OF ENERGY RATES ACROSS CANADA

APPENDIX 'D'

Comparison of Energy Rates Across Canada

The following identifies average fuel and electricity costs and the ratio of an equivalent quantity of energy for several canadian sites.

Location	Average Cost of Electricity	Average Cost of Fuel	Ratio[1] (Electricity/Fuel)
Prince George, B.C.	3.1¢/kWh	1.5¢/kWh ($ 4.1/GJ (Gas))	2.1
Yellowknife, N.W.T.	12.5¢/kWh	3.6¢/kWh ($10.0/GJ (Propane))	3.5
High Arctic, N.W.T.	42.0¢/kWh	6.7¢/kWh ($0.72/L ($18.6/GJ) (Oil))	6.3
Winnipeg, Manitoba	4.0¢/kWh	1.3¢/kWh ($3.72/GJ (Gas))	3.1
Sarnia, Ontario	6.8¢/kWh	1.6¢/kWh ($4.43/GJ (Gas))	4.3
Sudbury, Ontario	8.1¢/kWh	1.9¢/kWh ($5.25/GJ (Gas))	4.3
Toronto, Ontario	6.4¢/kWh	1.6¢/kWh ($4.42/GJ (Gas))	4.0
Ottawa, Ontario	6.5¢/kWh	1.5¢/kWh ($4.28/MJ (Gas))	4.1
Atlantic Region	8.7¢/kWh	2.1¢/kWh ($0.23/L ($5.9/GJ) (Oil))	4.1
		4.9¢/kWh ($0.36/L ($13.5/GJ) (Propane))	1.8

[1] This ratio is one measure of the potential for cogeneration in a location, where a higher ratio of electricity to fuel costs indicates better viability.