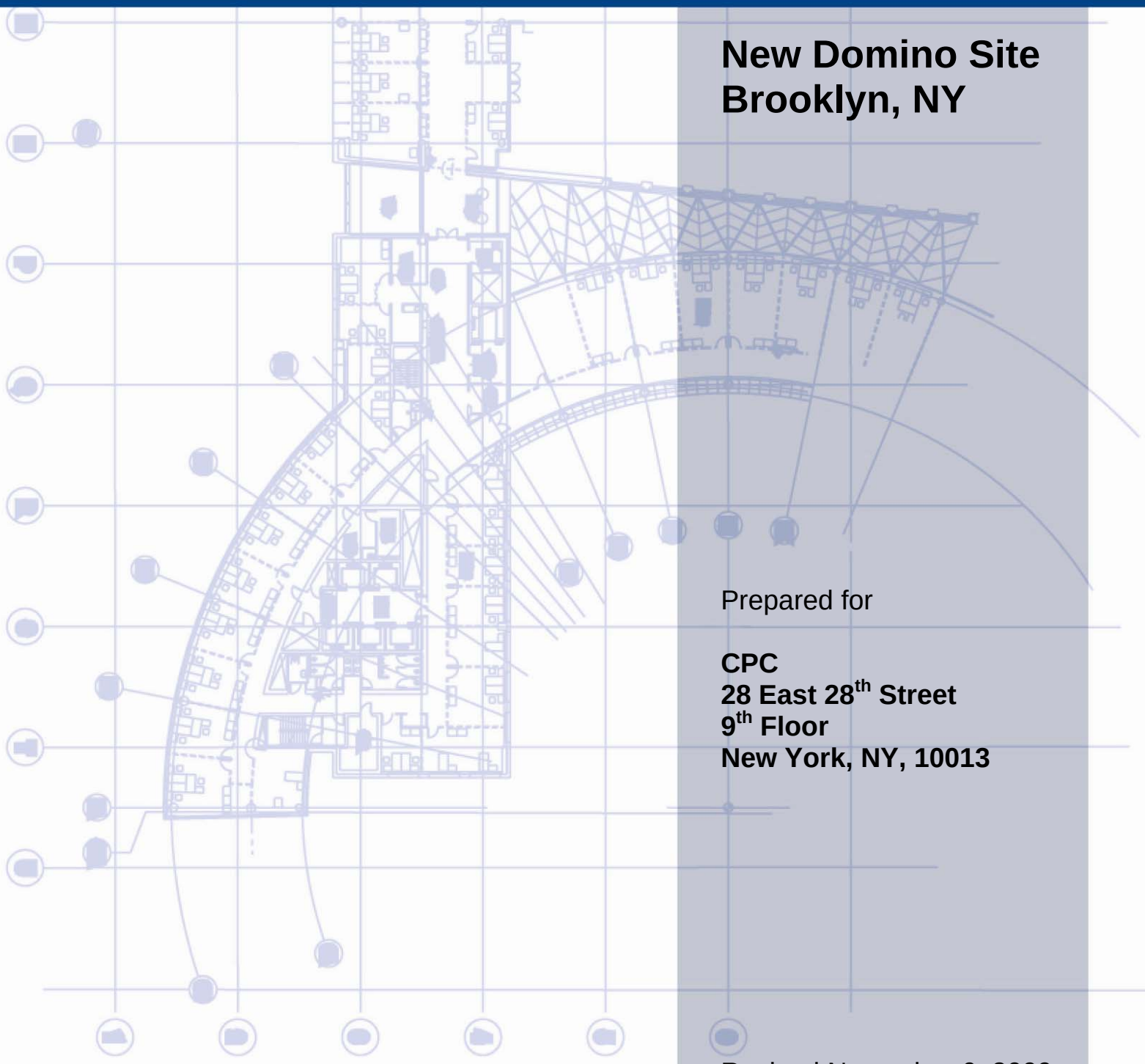
APPENDIX G
Cogeneration Feasibility Study

Combined Heat and Power (Cogeneration) Analysis

Cosentini
A TETRA TECH COMPANY

New Domino Site
Brooklyn, NY



Prepared for

CPC
28 East 28th Street
9th Floor
New York, NY, 10013

Revised November 6, 2009

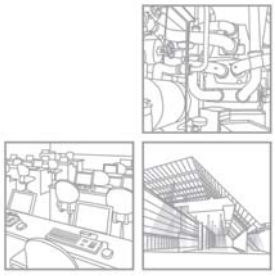
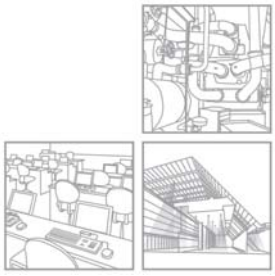


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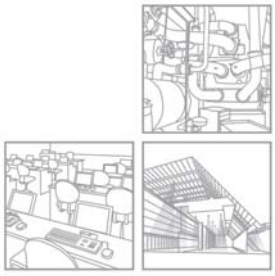
OBJECTIVE:

The purpose of this study was to determine whether a Combined Heat and Power facility (Cogeneration) for the New Domino site would be a cost effective option for supplying partial electrical and thermal energy to the project. A Preliminary Economic Feasibility study (Level 1) was performed for the project. The study was conducted for two basic configurations; Case A determined whether a cogeneration system is economical for a single phase of the proposed project, and chose for this configuration a representative site, Site E. Site E consists of 318,000 square feet of residential and retail space and 104,000 square feet of parking and back of house (BOH). The Case B study consists of examining the economics of cogeneration for the entire project from a central location.

A Cogeneration System utilizes a heat engine to produce electricity and a heat recovery system to capture the rejected heat as a thermal energy source for heating and cooling purposes. Several factors have to be analyzed in order to develop an economic model for the New Domino Site. Key factors are building electrical loads, heating and cooling loads and equipment occupancy profiles, utility rates, size of plant, capital and maintenance costs, etc. Environmental factors are not examined in this report.

The proposed Domino Project is approximately 3.2 million square feet, located in Brooklyn, NY. The project consisted of 6 separate sites. The majority of the sites would be developed as residential condos or rental units (market rate and affordable housing). In addition to the residential areas, there are commercial, retail and community areas throughout the project. Approximately 2.8 million square feet would be occupied and conditioned spaces, predominantly residential. Approximately 400,000 square feet would be parking and mechanical areas. The size of the cogeneration plants was based on estimating the continuous 24/7 electrical load. The continuous 24 hour load was used to size the engine/generator in order to maximize year round electrical production to the building. Waste heat as a by-product would be used for space heating, domestic hot water and cooling using absorption chillers, where economically appropriate. Typical 24 hour electric loads include lighting of lobbies, parking, ventilation systems and other back of house loads.

Two different engines using natural gas as a fuel source were evaluated: Reciprocating Engines and Gas Turbines. The reciprocating engine or gas turbine drive an electrical generator which produces electricity. Electricity not generated by cogeneration would be purchased from Con Edison. Energy in the high temperature exhaust from the engine is recovered to generate steam or hot water. This waste heat is used for heating and cooling purposes within the building(s).



EXECUTIVE SUMMARY:

The analysis is divided into 2 parts. Case A is an economic analysis of Site E, 300,000 square feet of residential spaces with minor retail and 100,000 square feet of parking.

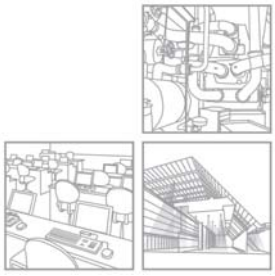
Case A – Site E

Table 1 provides a summary of energy costs and incremental first costs for the conventional base scheme which uses packaged terminal air conditioners (PTACs) and gas-fired boilers. The system is compared to 3 cogeneration systems sized at 250 kW using the electrical demand profile as shown in Figure 1. Alternative 1 uses a gas turbine/generator with supplemental gas boilers and absorption chillers for cooling. Perimeter 4 pipe fan coils are used for space heating and cooling. Alternative 2 uses reciprocating gas-fired engine/generator with supplemental boilers for heating and PTACs for cooling. Alternative 3 is similar to Alternative 2, except cooling is provided using waste heat to supply absorption chillers.

Table 1 indicates that Alternative 2, Reciprocating Cogeneration Plant for Site E, providing waste heat for heating only and conventional PTACs for air-conditioning, has the most favorable simple payback at 8.5 years. However, if we consider adding fuel escalation, cost of borrowing and maintenance personnel to monitor the 24/7 operation, payback would exceed 10-12 years. This result does not favor installing Cogeneration on economic benefits. Alternative 1 and 3 have much longer paybacks and are not considered economical. Technical details, load profile, etc. are described within the “Technical Sections” of this report.

Other sites with primarily residential programming (Sites B, C, D and the Refinery) would have somewhat different sized cogeneration plants, but the economics would be very similar to Site E.

In addition, Site A, which is primarily a commercial office site, was analyzed and found to have higher payback than Site E – Residential, due to a 12-hour office operating schedule, which utilizes very little power at night when the office space is unoccupied. Cogeneration utilization would not be as economical under this condition; payback would exceed 12-15 years. The primary reasons are that “buy back” criteria and associated first costs offered by Con Edison do not offer an incentive to selling cogeneration power to Con Edison during off-peak periods.



Case B

Table 2 provides the results for a similar analysis of the potential opportunities for a central cogeneration plant sized for the entire site. The proposed project would have a total peak electrical load which is estimated at 12,000kW. The cogeneration system was sized at 1,600kW, which would operate continuously over the year. See Figure 13 for the monthly electrical demand profile. Additional electricity, approximately 10,400kW, would be purchased from Con Edison. Supplemental heating would be provided from conventional gas-fired boilers. It is assumed the plant would be located centrally on the site. All power purchased from Con Edison and cogeneration power would be distributed in parallel to each building. Distribution at high voltage and transformers in each building site would be provided at the owner's cost. Con Edison would terminate high voltage feeders at a single central point. Similarly, hot water from the cogeneration plant would be distributed to each site through underground piping. Supplemental gas-fired boilers would be located in each building. First costs for electrical and hot water distribution would be borne by the owner, in addition to the cost of the 1,600kW cogeneration plant.

Table 2 indicates that none of the 3 analyzed cogeneration alternatives would be economical due primarily to the high first cost of the plant and associated electrical and hot water piping distribution. Power from Con Edison would be purchased from Con Edison using a primary service rate classification.

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Table 1:
ANNUAL ANALYSIS OF SYSTEM AND PAYBACK
Domino Sugar Site E (Single Building Cogeneration)

Table 1: Systems
Study Summary **Total Site Area: 460000 ft2**

Option	System	Estimated Annual Electrical Cost ($/yr)	Estimated Annual Gas Cost ($/yr)	Estimated Annual Energy Cost ($/yr)	Estimated Annual Energy Differential Cost Savings ($/yr)	Estimated Annual Differential Maint. Cost ($/yr)	Estimated Annual Operational Cost Savings ($/yr)	Estimated HVAC Differential First Cost ($)	Estimated Elec. Differential First Cost ($)	Simple Payback (yrs)
BASE	PTAC - Without Generator	$1,297,227	$136,718	$1,445,566	BASE	BASE	BASE	BASE	Base	BASE
ALT 1	Gas Turbine with hot water boiler, hot water absorption chillers, and fan coil units	$828,623	$533,291	$1,407,244	$72,031	$34,400	$37,631	$1,634,000	$34,625	44.3
ALT 2	Gas Reciprocating engine with hot water boiler, RTU, and PTACs	$956,735	$319,046	$1,302,900	$158,164	$77,100	$81,064	$652,900	$34,625	8.5 (1)
ALT 3	Gas Reciprocating engine with hot water boiler, hot water absorption chiller, and fan coils	$860,821	$395,080	$1,289,483	$178,044	$77,100	$100,944	$1,498,400	$34,625	15.2

Notes:

1 Considering fuel increases, personnel and cost of borrowing, payback may exceed 10-12 years
2 8.5% Add for taxes

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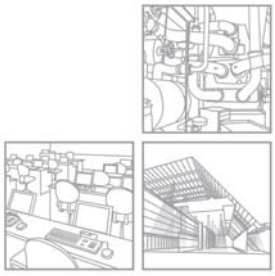
Table 2:
ANNUAL ANALYSIS OF SYSTEM AND PAYBACK
Domino Sugar - Central Plant

Table 1: Systems
Study Summary **Total Site Area: 3200000 ft2**

Option	System	Estimated Annual Electrical Cost ($/yr)	Estimated Annual Gas Cost ($/yr)	Estimated Annual Energy Cost ($/yr)	Estimated Annual Energy Differential Cost Savings ($/yr)	Estimated Annual Differential Maint. Cost ($/yr)	Estimated Annual Operational Cost Savings ($/yr)	Estimated HVAC Differential First Cost ($)	Estimated Elec. Differential First Cost ($)	Simple Payback (yrs)
BASE	PTAC - Without Generator	$7,704,643	$1,080,839	$8,877,353	BASE	BASE	BASE	BASE	Base	BASE
ALT 1	Gas Turbine with hot water boiler, hot water absorption chillers, and fan coil units	$4,857,163	$3,592,337	$8,754,849	$335,982	$224,200	$111,782	$13,684,100	$4,177,825	159.8
ALT 2	Gas Reciprocating engine with hot water boiler, RTU, and PTACs	$5,708,765	$2,242,844	$8,142,251	$833,873	$518,500	$315,373	$5,213,500	$4,177,825	29.8
ALT 3	Gas Reciprocating engine with hot water boiler, hot water absorption chiller, and fan coils	$5,141,359	$2,840,486	$8,223,286	$803,637	$518,500	$285,137	$12,816,100	$4,177,825	59.6

Notes:

1 2% Added to electrical cost for transformer losses
2 8.5% Add for taxes
3 Simple Pay Back does not include increases in fuel, interest rates and maintenance costs



TECHNICAL SECTION:

The following sections provide a detailed discussion about the site, the assumptions being made, the alternatives studied, the resulting loads, energy consumption and economics of the cogeneration systems analyzed.

SITE DESCRIPTION:

In Case A, the single building program was modeled to provide a small-scale application for a Cogeneration System. Building E was chosen for this study. Building E would consist of 318,000 square feet of residential space, 36,000 square feet of retail space and 104,000 square feet of parking/BOH space. The building was modeled using several assumptions:

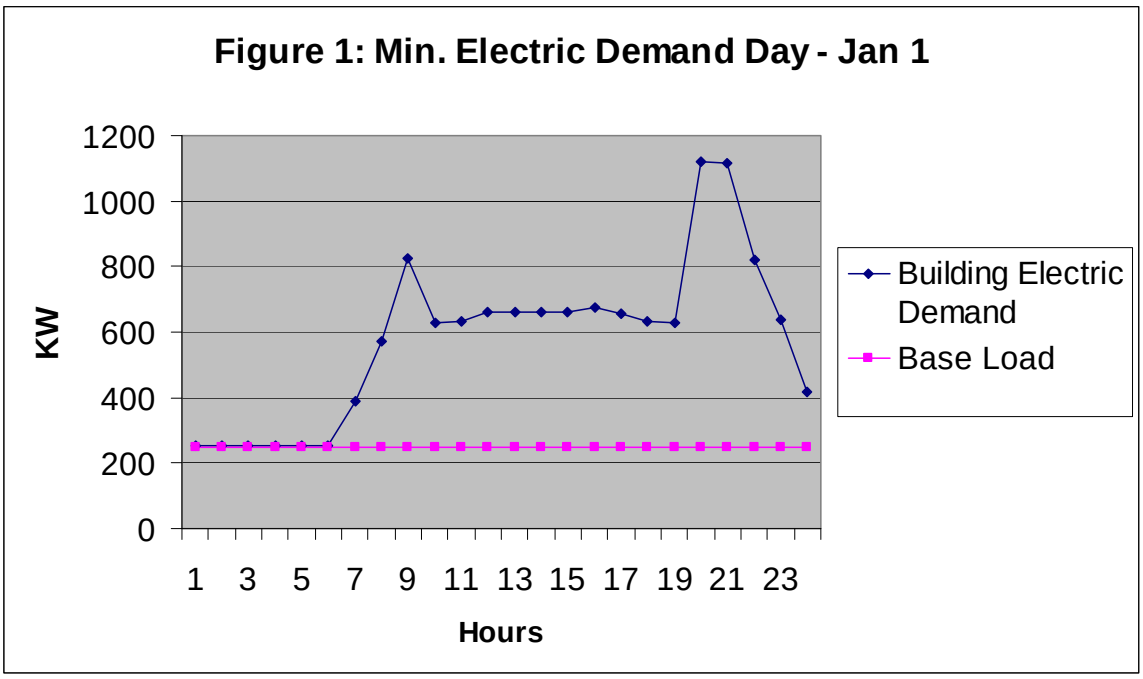
- 300 apartments at a scale of 350 square feet per person
- 50% glass percentage for apartments
- Back of house square footage - 36,800 12% of Residential square footage
- Lobby square footage - 12,000
- Building materials such as walls, roofs, and u values follow ASHRAE 90.1 2004 for residential high rise

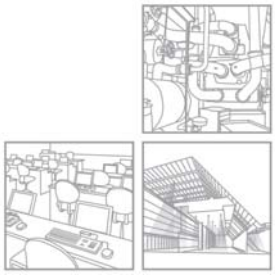
In Case B, the central cogeneration plant, all 6 sites were modeled together to yield a load profile to size the plant. The load profiles for the entire project would take into account Residential, Commercial, Back of House, Retail and Community Facility areas. The overall size of the development would be approximately 3.2 million square feet. The building materials all follow ASHRAE 90.1 2004 for residential high rise.

In both cases a computer energy model was developed to establish a baseline load profile that could then be used to analyze the energy performance of a cogeneration system. The computer model calculates energy consumption for all 8,760 hours throughout the year. The Base System for this study uses PTACs (Package Terminal Air Conditioners). PTACs provide cooling by local air cooled compressors/condensers and heating through hot water coils served from boiler water located in the building. Peak, average and off-peak electrical loads are estimated based on occupancy and equipment schedules. The minimum electric demand was used to determine the size of the Cogeneration Plant. This allows for 24/7 operation of the plant.

The baseline electrical power requirement was calculated to be 250kW for Case A By sizing the CHP plant at 100% of the minimum off-peak electrical load, it results in better economics for the Cogeneration System.

The minimum electric demand load for Case A is shown in Figure 1:





COMBINED HEAT AND POWER (COGENERATION) OPTIONS:

There are several Cogeneration options to generate electricity and heat. The three systems that were considered for the study are as follows:

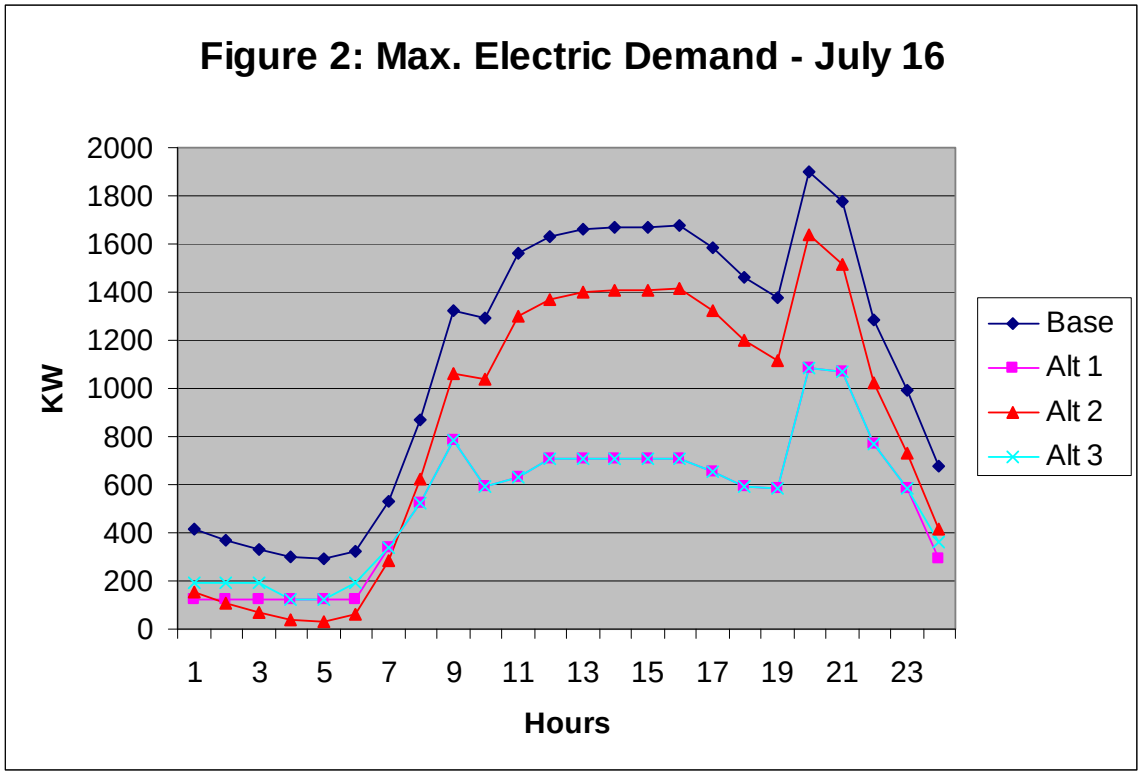
Alternative 1	Gas Turbine with hot water boilers, hot water absorption chillers, and fan coil units.
Alternative 2	Gas Reciprocating engine with hot water boilers and PTACs
Alternative 3	Gas Reciprocating engine with hot water boilers, hot water absorption chillers, and fan coils.

Alternative 1 is a Gas Turbine Plant; gas is burned in a turbine to produce electricity. Heat is expelled through the flue gases of the turbine. This exhaust heat is captured by a heat exchanger which preheats the hot water before it either enters the boiler (during heating mode) or can be used to drive an absorption chiller (cooling mode). The Turbine also powers the generator to produce the electricity for the building. Alternative 2 is a Gas Reciprocating engine which uses an engine to drive a generator to produce electricity. The heat generated from the engine is captured and transferred to the hot water system for use in the heating and domestic hot water for the site. Alternative 2 utilizes PTACs for building cooling and heating. Alternative 3 is similar to Alternative 2 except it uses Absorption Chillers and Fan Coil Units for cooling and heating.

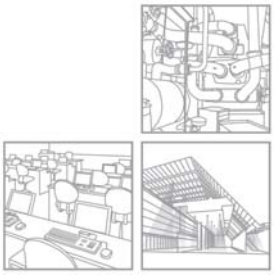
Case A:

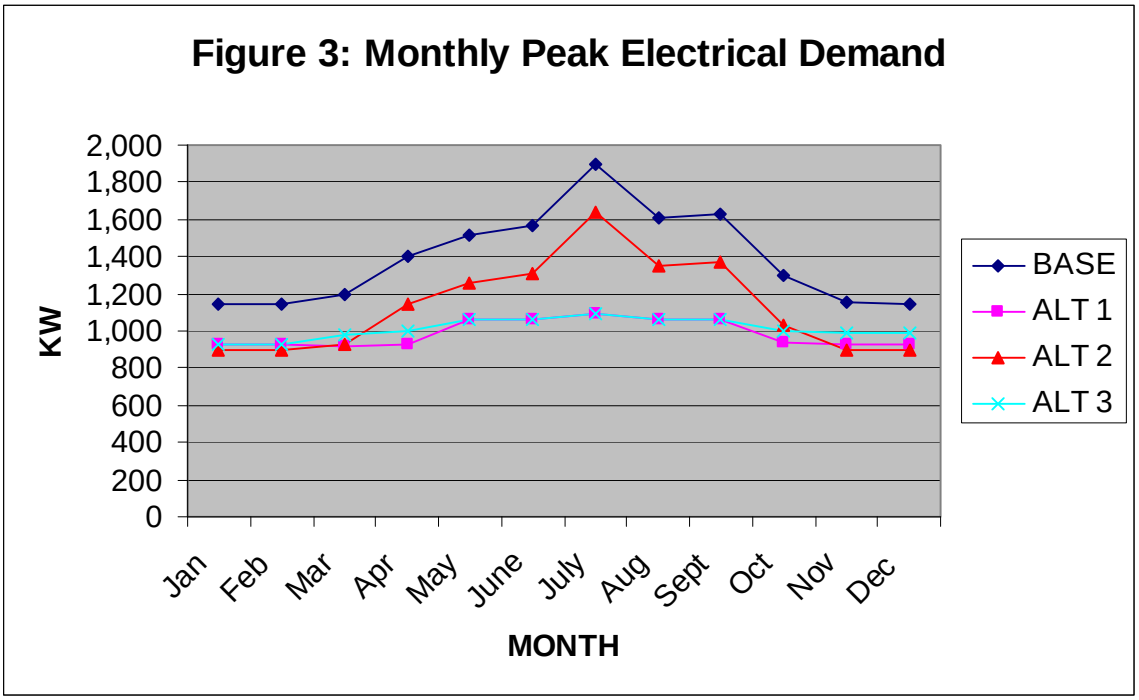
The electrical demand for a summer day is shown in Figure 2 for the base case and cogeneration alternatives in a single site cogeneration plant. Alternative 1 and Alternative 3 have lower electrical demand compared to the base line system because of the use of absorption of cooling.

Figure 2 provides the estimated maximum electric demand for all 4 systems during a peak day in July:

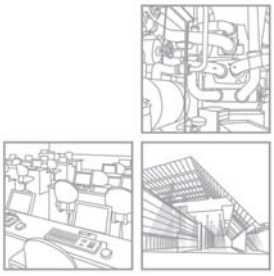


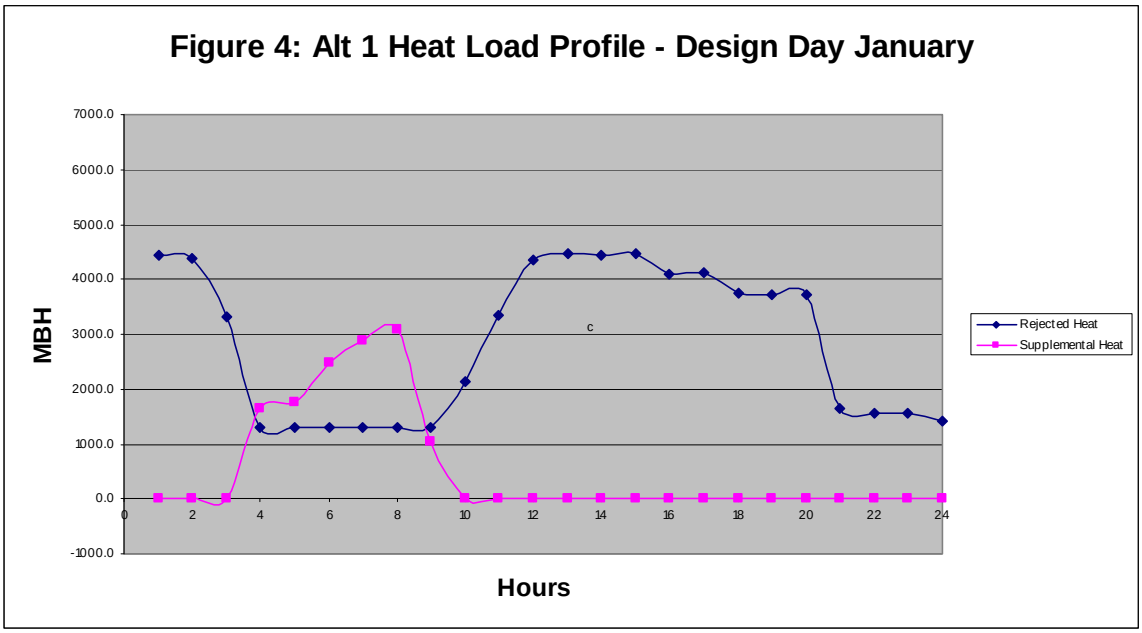
The monthly electrical demand was calculated for the entire design year. Alternatives 1 and 3 provide the lowest electric consumption when compared to the Base system and Alternative 2. The monthly peak demand for electricity for a single building is represented on Figure 3:

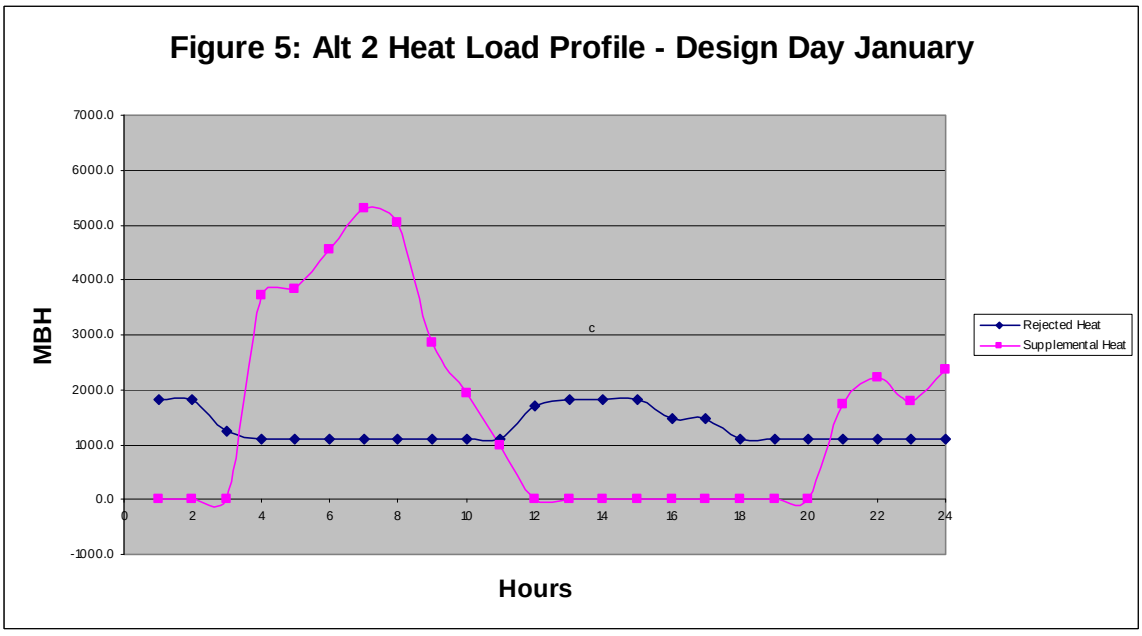


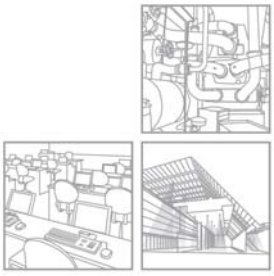


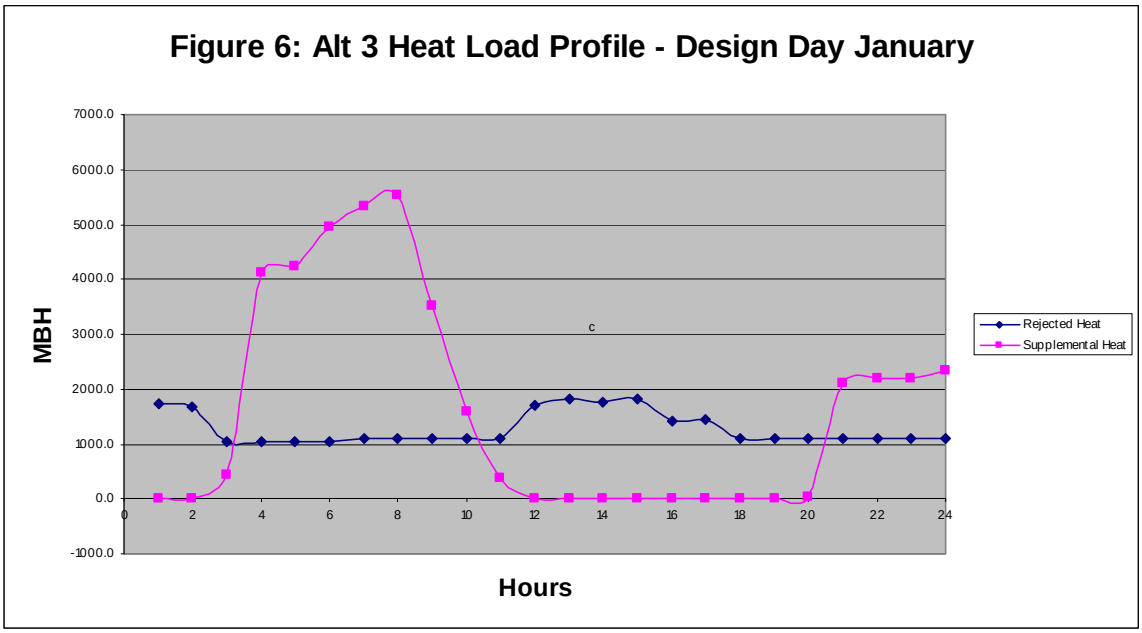
Figures 4, 5, 6, 7, 8 and 9 provide the amount of rejected heat for the various Cogeneration Plant alternatives as compared to the supplemental heat that is needed to supply 100% of a building thermal load during that period. Figures 4, 5, and 6 provide data for the month of January when site is in heating mode. Figures 7, 8, and 9 provide data for the month of July when a site is in cooling mode. As shown in Figure 4, the gas turbine alternative (Alternative 1) produces too much waste heat. As shown in Figure 5, the reciprocating engine alternative, (Alternative 2) requires supplemental energy to be used during the year to meet the heat load.

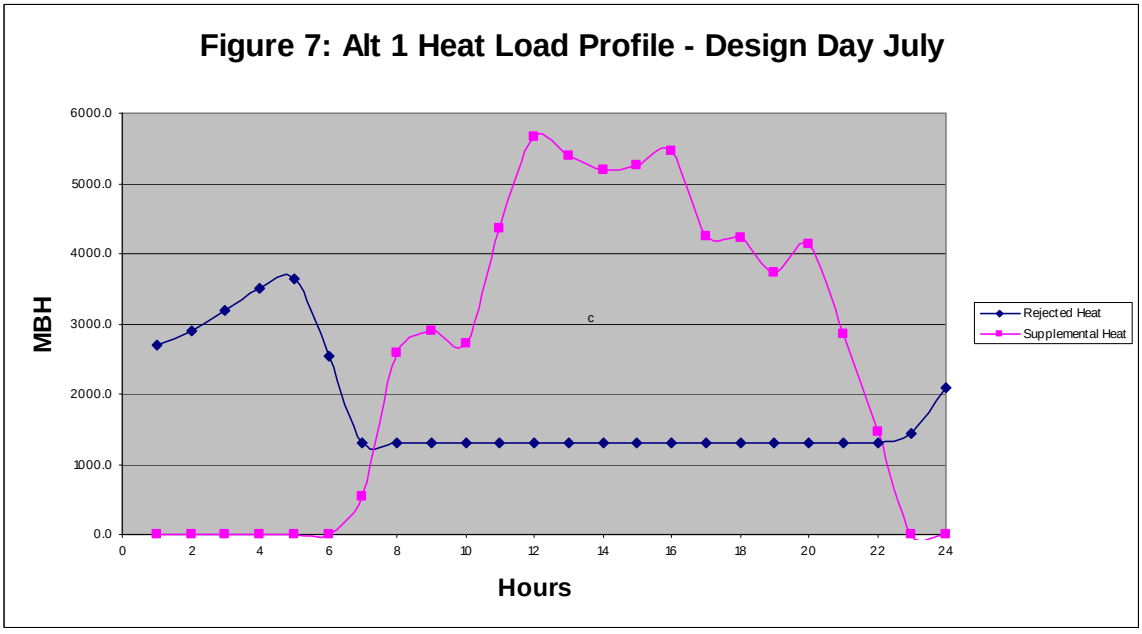



Figure 4: Alt 1 Heat Load Profile - Design Day January
MBH
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
0
2
4
6
8
10
12
14
16
18
20
22
24
Hours
Rejected Heat
Supplemental Heat

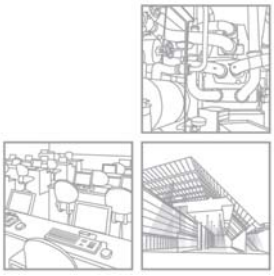

Figure 5: Alt 2 Heat Load Profile - Design Day January
MBH
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
0
2
4
6
8
10
12
14
16
18
20
22
24
Hours
Rejected Heat
Supplemental Heat

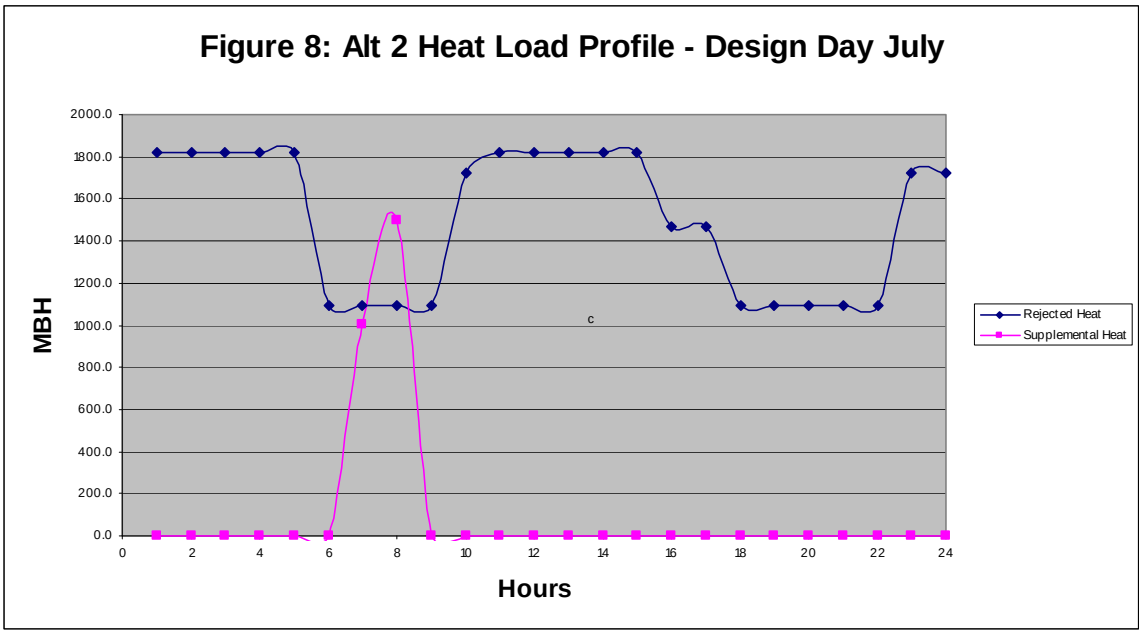


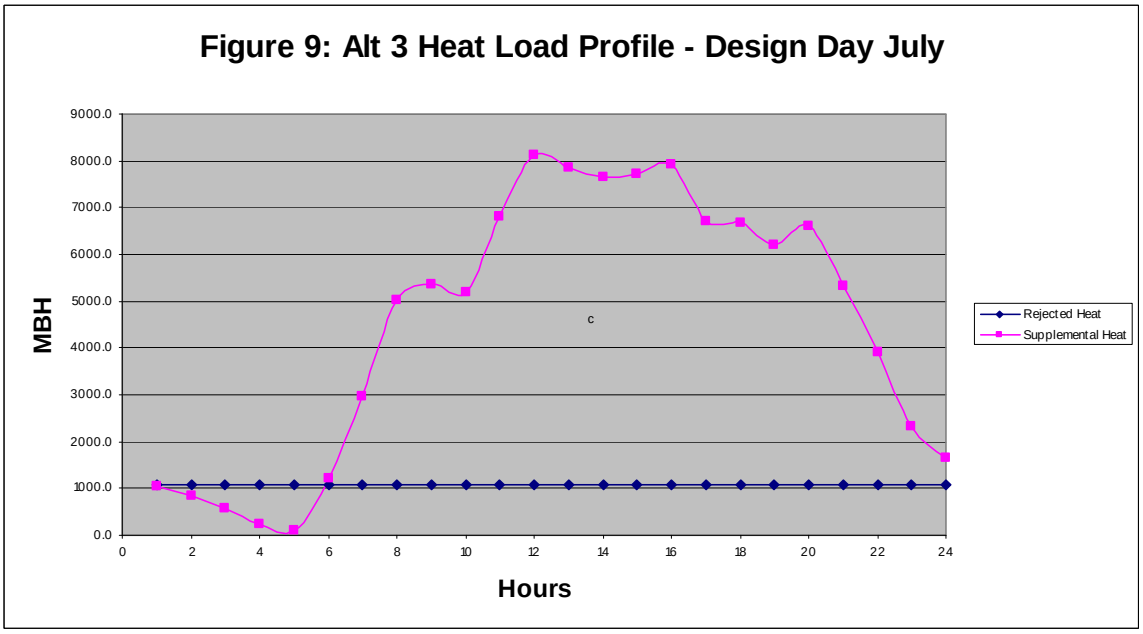




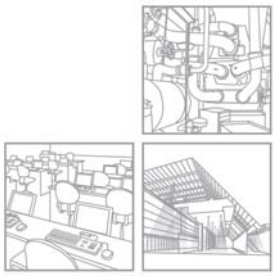
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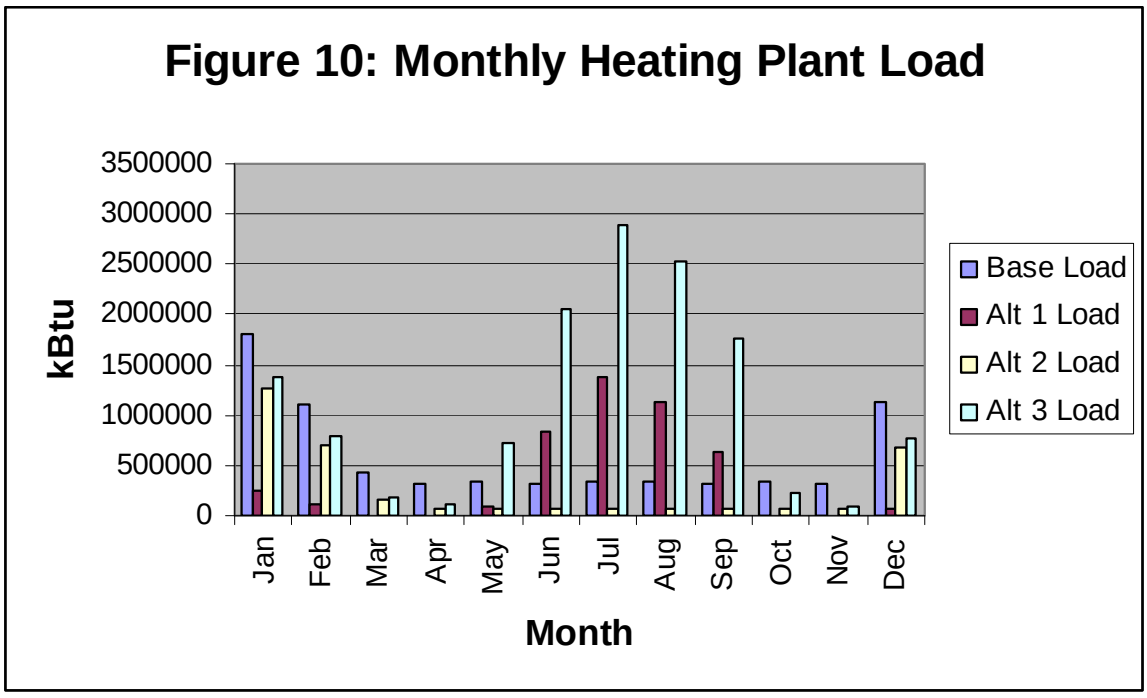






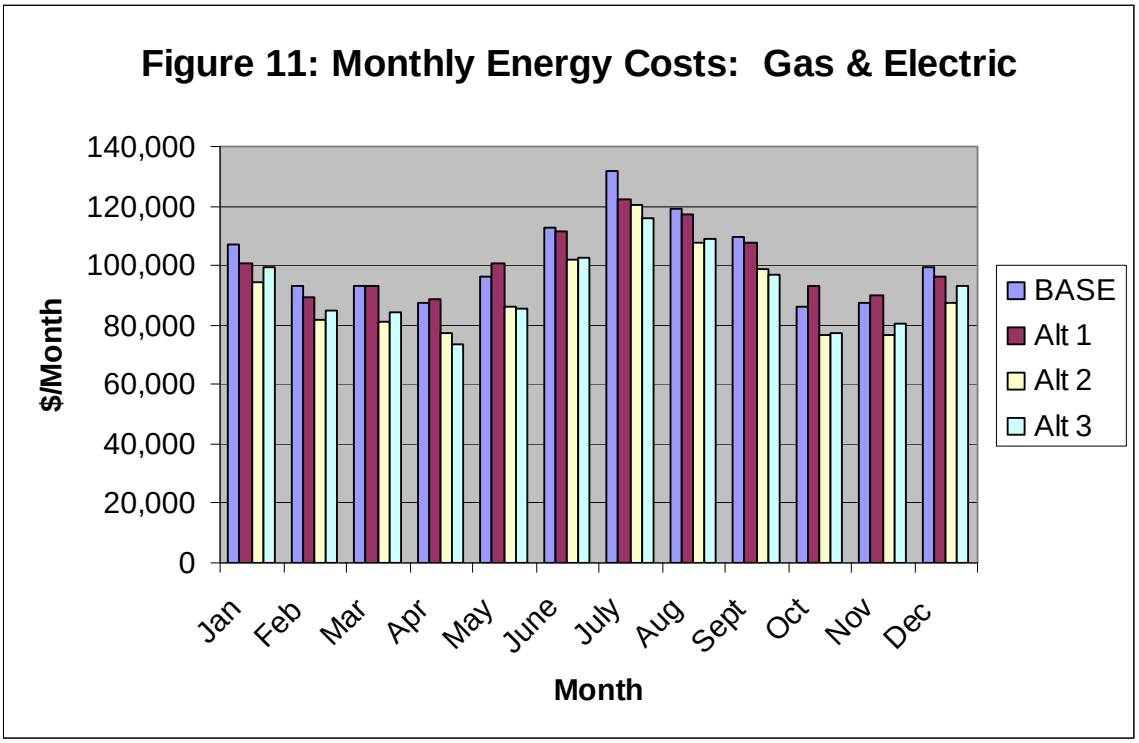
Figures 7, 8 and 9 depict that in the summer months the plants with Absorption Chillers have a large thermal demand that is not being met because of the small size of the Cogeneration Plant. Additional heat needs to be provided into the chillers to match the full cooling load. Figure 10 below provides a graphical representation of the total quantity of heat (BTUs) being used for the Base system and all alternatives.




Figure 10: Monthly Heating Plant Load
3500000
3000000
2500000
2000000
1500000
1000000
500000
0
kBtu
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Base Load
Alt 1 Load
Alt 2 Load
Alt 3 Load

Utility costs can greatly affect the pay back period and the system that will be selected. The average monthly cost calculated for all the systems have been based on the current Con Edison rates. The utility service provider has classified these buildings under service classification No. 8 Rate III for electricity and Service Classification 2 Rate I for natural gas.

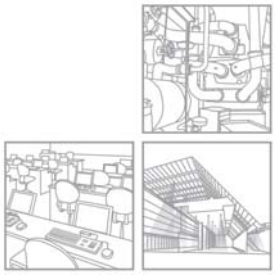
The estimated monthly operating costs for all the options are shown in Figure 11:



In this study, the Cogeneration Plant is assumed to run for approximately 8,000 hours (92% availability) throughout the year. The 8% down time is used to perform scheduled maintenance. However, a standby generator could be provided to handle the maintenance periods, so the system can run all year.

It should be noted that this analysis does not consider the potential environmental compliance issues associated with siting and permitting a cogeneration plant. Any additional equipment that may be necessary, such as duct burners and flue scrubbers to comply with emission requirements, are not included in the analysis.

All of these alternatives will be designed to operate in parallel with Con Ed (the utility), however, Con Ed will not allow any excess (low tension) power to be fed back into their grid. This regulation makes a larger

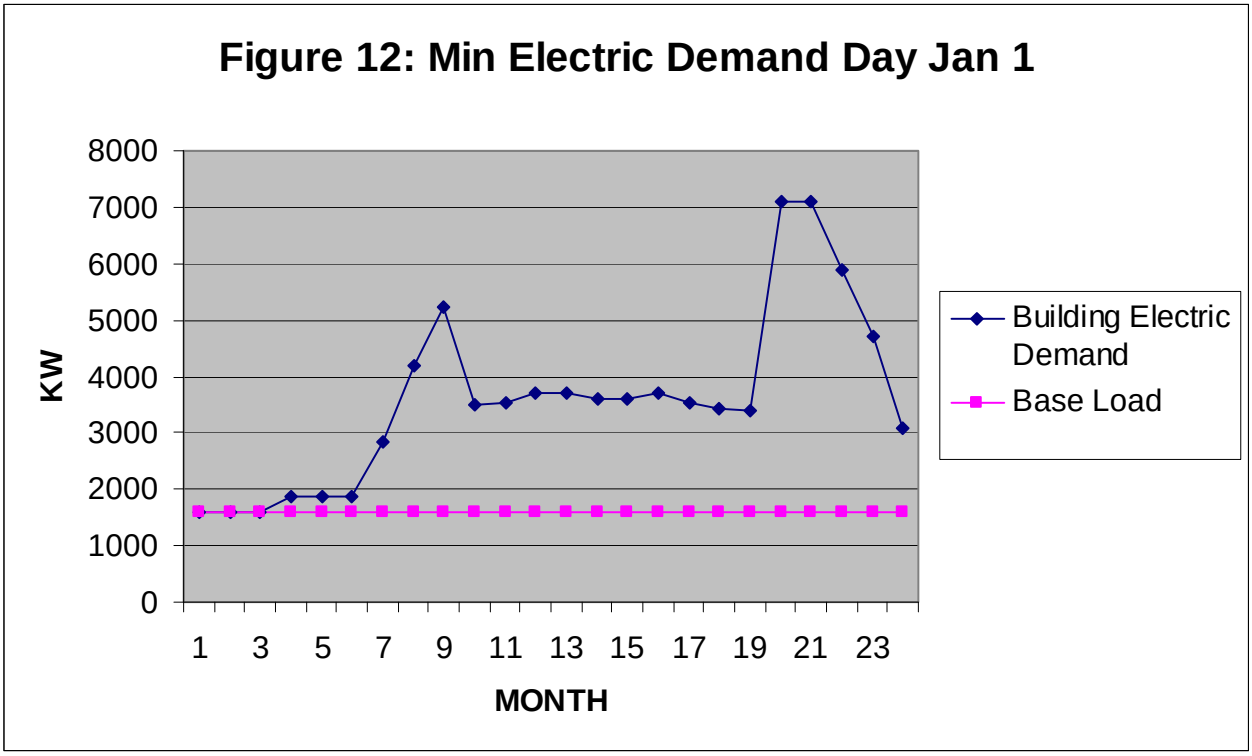


plant less cost effective because the excess power can not be transferred to utility under a “Buy-Back” Plan. Should a more detailed Level 2 analysis be required, preliminary discussions with Con Ed to discuss possible incentives, and regulations regarding interconnection, can be undertaken.

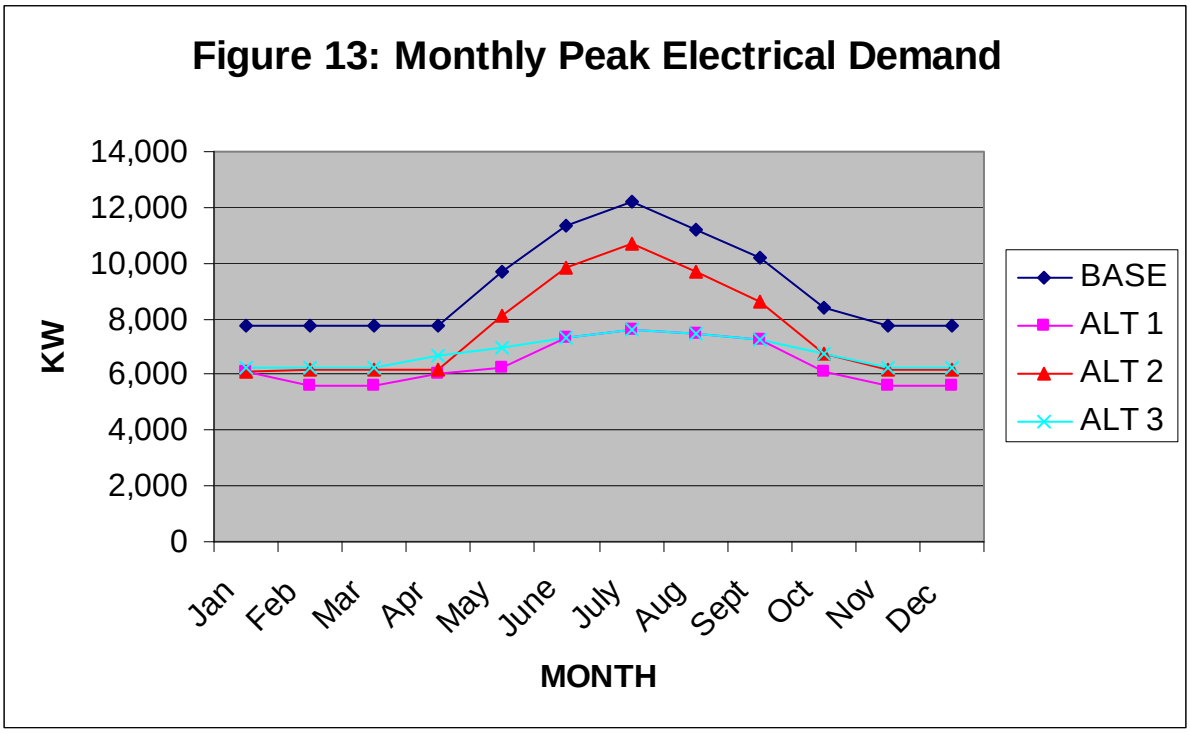
Table 1 provides a simple payback study for all alternatives studied which includes an estimate of capital costs. This simple pay back analysis does not take into account the rising cost of fuel, taxes and incentives that might affect the cost of the project.

Case B:

The Case B study used the same systems that were designed for Case A (single building cogeneration) but on a larger scale. After developing the model, it was found that the base line energy demand for the entire project would be about 1600kw. Figure 13 provides an hour by hour account of a sample day in January.



The maximum load that the central plant sees is approximately 12,000kw. This load is very substantial. This is only seen during the summer months due to the increase in compressor load from the air conditioning units. Figure 14 provides a monthly account of the peak demand that the plant would see.



Similar results were evident in the cogeneration calculations between Case A and Case B. The consumption and demand of electricity, gas, and the heat load profiles all were very similar and proportional to the Case A findings. Alternative 2, the gas reciprocating engine with PTACs, provides the earliest pay back (30 years) when compared to Alternative 1 (Gas turbine and fan coils) and Alternative 3 (Gas Reciprocating Engine and Fan coils). Alternative 1 and 3 have much higher installation costs compared to Alternative 2.

A central Cogeneration plant however would be less efficient when compared to a single site plant. The majority of the project is residential based. In a more diversified make up the load profiles between retail, commercial and residential could offset each other. This would allow for greater effectiveness in the sizing of the cogen plant. There are additional costs associated with developing a central plant vs. a stand alone plant. A central plant facility would have to accept high tension power from Con Ed, and produce the additional power in high tension at the Cogeneration plant. The equipment cost for high tension producing Cogeneration assemblies is greater than low tension assemblies. This power would then be distributed through conduits to the respective sites. This power would have to be transformed down to low tension in order for the building to use it. This transformer loss along with other services such as underground conduit, piping and pumping horsepower required to distribute the services from the central plant to the buildings would be at the cost of the owner. This additional first cost could be upwards of 6 million dollars.

In the single site alternative the utility company incurs the cost of the transformation and the site work required to bring the power into the building. Another factor not considered with this central Cogeneration Plant would be the costs associated with expanding and connecting the Cogeneration plant to each site as they are constructed.

One advantage to producing high tension power is that currently there is a program that allows Con Ed to "Buy Back" high tension power. This alternative would have to be explored with Con Ed if this project would qualify for this type of program.

Table 2: Provides a detailed estimate for a central plant facility to be installed for the Domino Project. It provides an estimate of several factors, such as utility costs, first costs, maintenance cost and simply payback.

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