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Advanced Gas Cooling Study for the Hospital at Davis-Monthan AFB, AZ

by
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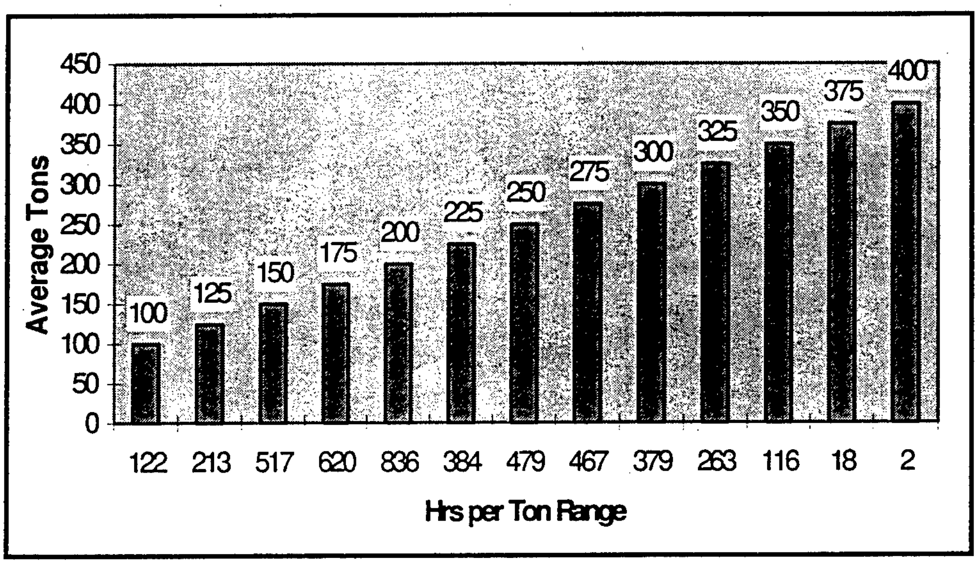

Based on its experience with a cogeneration project at Tyndall AFB, the Air Force Civil Engineering Support Agency (AFCESA) tasked the U.S. Army Construction Engineering Research Laboratories (USACERL) to perform an analysis to see if such a concept, or some other cooling options, could be of economic benefit at the Air Force medical facility at Davis-Monthan AFB, AZ, where the cost of purchased electrical power is relatively high compared to that of natural gas.

USACERL researchers developed a cooling load profile for the facility by reviewing plant records and interviewing plant operators. Boiler logs (daily and monthly) were consulted to determine heating loads, and a spreadsheet was developed to analyze nine options. Savings and first costs were input into the Life Cycle Cost in Design (LCCID) computer program to determine simple paybacks and savings-to-investment ratios for all options. Based on the results of the investigation, preferred options were recommended for meeting the facility cooling load.

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Based on its experience with a cogeneration project at Tyndall AFB, the Air Force Civil Engineering Support Agency (AFCESA) tasked the U.S. Army Construction Engineering Research Laboratories (USACERL) to perform an analysis to see if such a concept, or some other cooling options, could be of economic benefit at the Air Force medical facility at Davis-Monthan AFB, AZ, where the cost of purchased electrical power is relatively high compared to that of natural gas.

USACERL researchers developed a cooling load profile for the facility by reviewing plant records and interviewing plant operators. Boiler logs (daily and monthly) were consulted to determine heating loads, and a spreadsheet was developed to analyze nine options. Savings and first costs were input into the Life Cycle Cost in Design (LCCID) computer program to determine simple paybacks and savings-to-investment ratios for all options. Based on the results of the investigation, preferred options were recommended for meeting the facility cooling load.

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Foreword

This study was conducted for the Air Force Civil Engineering Support Agency (AFCESA) under Military Interdepartmental Purchase Request (MIPR) No. N94-92, Work Unit WL4, "Evaluation and Application of Gas Cooling Technologies." The technical monitor was Rich Bauman, AFCESA.

The work was performed by the Utilities Division (UL-U) of the Utilities and Industrial Operations Laboratory (UL), U.S. Army Construction Engineering Research Laboratories (CERL). The CERL Principal Investigator was Timothy W. Pedersen. Martin J. Savoie is Chief, CECER-UL-U, and Dr. John Bandy is Operations Chief, CECER-UL. The responsible Technical Director was Gary W. Schanche, CECER-TD. The CERL technical editor was William J. Wolfe, Technical Information Team.

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Distribution

1 Introduction

Background

The Air Force Civil Engineering Support Agency (AFCESA) has been actively involved with a cogeneration project at Tyndall AFB hospital. The project uses an absorption chiller to satisfy the hospital's base cooling load. The steam for activating the absorption chiller is obtained from waste heat, which is derived from an engine driving a generator to produce electrical power — which is also used by the hospital. Based on this experience, AFCESA funded USACERL to perform an analysis to see if such a concept, or some other cooling options, could be of economic benefit at the Air Force medical facility at Davis-Monthan AFB, AZ, where the cost of purchased electrical power is relatively high compared to that of natural gas. USACERL researchers evaluated the case of power generation providing sufficient waste heat to meet the facility base cooling load, and also considered options under which sufficient waste heat could be derived from power production so that a 250-ton absorption chiller could replace an existing motor-driven centrifugal chiller of equal capacity. (The centrifugal chiller uses a chlorofluorocarbon [CFC] refrigerant, R-11.) Heat produced as a result of power generation can be used to satisfy facility thermal, as well as cooling, loads.

Objectives

The objective of the study was to determine the approach that will minimize the cost of meeting the cooling requirements of the medical facility at Davis-Monthan AFB.

Approach

Cooling Load Profile

Considerable time was spent developing a cooling load profile for the facility. This was done by meticulously reviewing plant records and discussing plant operation with the operators (Appendix A). Where data appeared inconsistent or erroneous, or was missing, trends were examined and reasonable estimates made for the actual cooling loads. Figures 1 and 2 show the results of the data analysis.

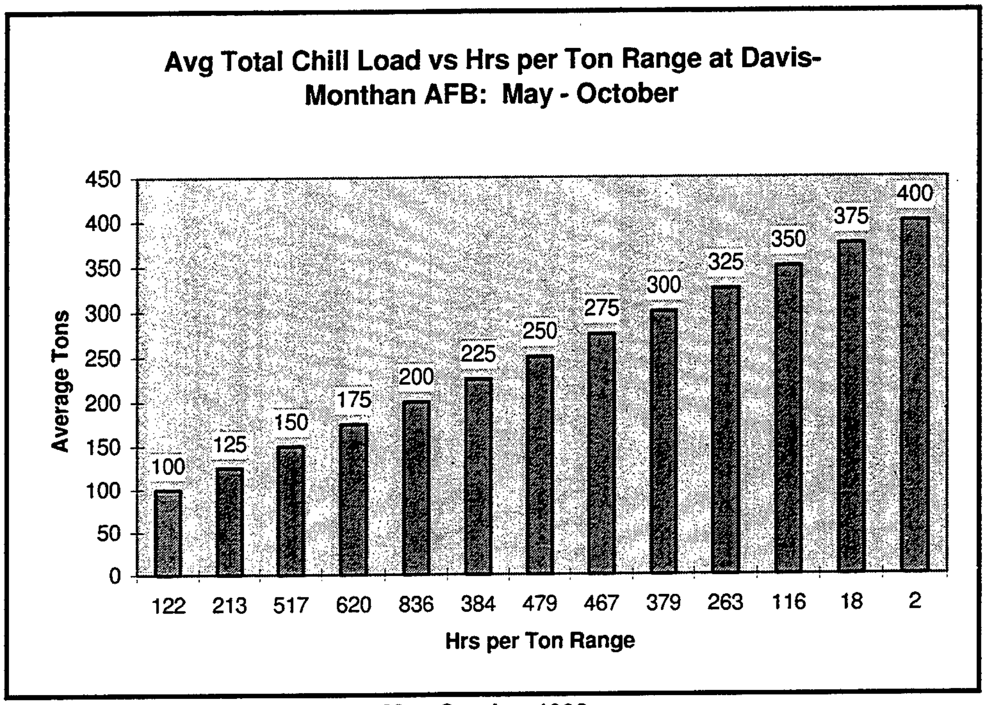

Figure 1. Cooling load estimate, May-October 1996.

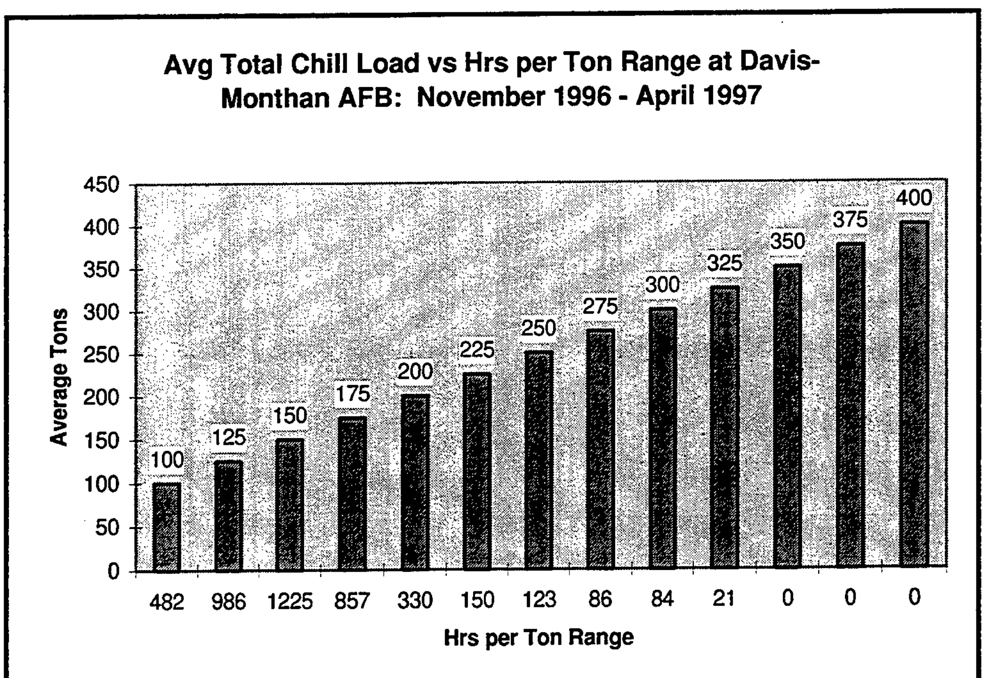

Figure 2. Cooling load estimate, November 1996-April 1997.

Boiler Load Profile

Boiler logs (daily and monthly) were consulted to determine heating loads. The hospital cooling and heating plant was visited a number of times to obtain information on the plant equipment, including water chillers, cooling towers, boilers, pumps, and heat exchangers. It became obvious that the plant's boilers are grossly oversized for the load and, based on the pressure of the steam produced (50 psig>15 psig), that the boilers require onsite plant operators. Consequently, it became clear that waste heat from power generation could be used not only to meet facility cooling loads through absorption water chilling, but also to meet facility thermal loads, and in the process to possibly reduce manpower requirements and increase utility cost savings.

Analysis

An EXCEL® spreadsheet was developed to analyze the numerous options that were considered. The options considered were:

- *(Option #1)* Natural gas engine-driven chiller to replace existing 250-ton motor-driven centrifugal chiller, with waste heat used to offset facility thermal requirements
- *(Option #2a)* Natural gas-fired engine-generator set, waste heat used to provide steam for single-effect absorption water chiller to meet facility base cooling load (100 tons) with residual heat used for thermal requirement
- *(Option #2b)* Natural gas-fired engine-generator set, waste heat used to provide steam for double-effect absorption water chiller to meet facility base cooling load (100 tons), with residual heat used for thermal requirements
- *(Option #2c)* Natural gas-fired engine-generator set, waste heat used to provide steam for single-effect absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat used for thermal requirements
- *(Option #2d)* Natural gas-fired engine-generator set, waste heat used to provide steam for double-effect absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat used for thermal requirements
- *(Option #3a)* Natural gas-fired engine-generator set, waste heat used to provide steam for single-effect absorption water chiller to meet facility base cooling load (100 tons) with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only)
- *(Option #3b)* Natural gas-fired engine-generator set, waste heat used to provide steam for double-effect absorption water chiller to meet facility base cooling load (100 tons) with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only)

- *(Option #3c)* Natural gas-fired engine-generator set, waste heat used to provide steam for single-effect absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only)
- *(Option #3d)* Natural gas-fired engine-generator set, waste heat used to provide steam for double-effect absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only).

In essence, Option #1 did not entail the use of an engine-generator set, only a replacement of the existing 250-ton electric motor-driven centrifugal chiller with a natural gas engine-driven chiller, waste heat from which would partially offset facility thermal loads. Options #2a, 2b, 2c, and 2d entailed use of an engine-generator set, with the waste heat providing sufficient energy to activate the absorption chiller and also to meet a portion of the facility thermal load. Options #3a, 3b, 3c, and 3d entailed use of an engine-generator set sized so that the waste heat would not only be sufficient to activate the absorption water chiller, but also to meet the entire thermal load of the facility. Note that, at one time, another option was considered for analysis: use of a 250-ton capacity, direct-fired, double-effect, absorption chiller. This option was discarded prior to more in-depth analysis because the coefficient-of-performance would be less than for the engine-driven option, particularly when heat is recovered from the engine.

Once the spreadsheet calculated the operating cost savings for each option, the savings and first costs were input into the Life Cycle Cost in Design (LCCID) computer program to determine simple paybacks and savings-to-investment ratios for all options. Based on the results of the investigation, recommendations were made as to the preferred option for meeting the facility cooling load.

Scope

The scope of the project was to investigate feasible options for meeting the facility's cooling loads, with emphasis on using waste heat from electrical power generation for absorption cooling. An ancillary benefit was that waste heat could be used not only for absorption cooling, but also for partially or totally meeting the medical facility thermal loads.

Mode of Technology Transfer

This report documents the opportunities available and financial resources required for reducing cooling and overall utility costs for the Davis-Monthan AFB medical facility. USACERL would be amenable to developing a scope of work for architect-engineer (A-E) services to design the installation of the equipment for whatever option USAF management desires to pursue to reduce the medical facility's utility costs. Additionally, USACERL would be amenable to reviewing the design and participating in technical oversight during construction, as well as monitoring equipment performance to verify estimated savings. Additionally, the technologies considered here for possible application at the medical facility at Davis-Monthan AFB have the potential to benefit other DOD medical facilities. Consequently, it is recommended that this document be circulated to the larger DOD medical community for its consideration in applying the technologies at other sites.

Metric Conversion Factors

The following metric conversion factors are provided for standard units of measure used throughout this report:

1 in.	=	25.4 mm
1 lb	=	0.453 kg
1 gal	=	3.78 L
1 psi	=	6.89 kPa
1 ton (refrigeration)	=	3.516 kW
1 Btu	=	1.055 kJ

2 Cooling Options

Status Quo

At present, three electric motor-driven chillers in the Davis-Monthan AFB cooling plant meet the cooling requirements of the medical facility: a York centrifugal chiller nominally of 250-tons capacity, and two Dunham-Bush screw machines of nominal 75-tons capacity each. Performance characteristics of the York chiller were obtained for part load operation and for condenser water return temperatures coincident with load as determined from analyzing cooling logs provided by the base. An earlier analysis contained information as to the full-load performance of the screw machines. Part-load performance was estimated using Figure 14 of Chapter 42, *1994 ASHRAE Refrigeration Handbook*.

Two Hundred Fifty (250)-Ton Capacity Natural Gas Engine-Driven Chiller With Heat Recovery (Option #1)

This option did not involve electrical power generation, but offered a potentially economical approach for meeting the facility's cooling loads. This hypothesis was based on the fact that previous analyses indicated this technology should be economically viable at other sites on the base. Under this option, the existing 250-ton capacity York motor-driven centrifugal chiller would be replaced by a natural gas engine-driven chiller using HCFC-22. The engine would be capable of delivering jacket water at temperatures varying between 183 and 201 °F, depending on load, for heat exchange to produce water for space and domestic hot water heating. Return jacket water temperature would be 180 °F. Chiller performance took into account part load efficiencies and the return condenser water temperatures coincident with load as determined from analyzing cooling logs provided by the base.

Power Generation With Sufficient Waste Heat To Operate a Water Chilling Unit

Option #2a: One Hundred (100)-Ton Capacity Single-Effect Indirect-Fired Absorption Chiller

Analysis of the hospital's cooling loads indicated a year-round base load of 100 tons. Under this option, that base load would be met by a single-effect absorption chiller. The heat input would be provided by 15 psig steam produced from heat as the byproduct of power generation from a Caterpillar G3512 (600 kW) engine-generator set. Although the intent was to match, as far as possible, the estimated amount of "waste" heat to the chiller heat input required, some residual waste heat will result, which will be used to satisfy part of the facility's thermal load. Chiller performance was based on the assumption that the chiller would continuously provide 100 tons of cooling, but under variable condenser water return temperatures (as determined from logs provided by the base). Under this option (and for all [four] options involving a new base-loaded 100-ton capacity absorption chiller), the existing 250-ton capacity centrifugal chiller would not be removed. Replacing the existing chiller with only a 100-ton capacity absorption chiller would leave the plant short of capacity. (The data indicates there are periods when the total load on the plant exceeds 250 tons.) For this option and the next, the analysis is based on the assumption that, beyond 100 tons, screw machines will operate until the plant load reaches approximately 175 tons, at which point the operating screw machine will shut off and the 250-ton capacity centrifugal chiller will come on. The new 100-ton capacity absorption chiller would be located in the vicinity of the engine-generator set and heat recovery equipment.

Option #2b: One Hundred (100)-Ton Capacity Double-Effect Indirect-Fired Absorption Chiller

As stated above, analysis of the hospital's cooling loads indicated a year-round base load of 100 tons. Under this option, that base load would be met by a double-effect absorption chiller; the engine-generator set is a Caterpillar G-3516 (820 kW). The double-effect absorption chiller is about 50 percent more efficient than the single-effect unit. However, the double-effect requires a steam input at higher temperature – at the temperature of 115 psig versus the 15 psig of the single-effect unit. Also, the first cost of the double-effect unit is higher than that of the single-effect chiller. The performance at reduced condenser water temperatures was assumed to be the same as that of the single-effect unit. Under this option, the existing 250-ton capacity centrifugal chiller would not be removed. Replacing the existing chiller with only a 100-ton capacity absorption chiller would leave the plant short of capacity. (The data indicates there are periods when the total load on the plant exceeds 250 tons.) The analysis is based on the assumption that, beyond 100 tons, screw machines will operate until the plant load reaches approximately 175 tons, at which point the operating screw machine will shut off and the 250-ton capacity centrifugal chiller will come on. The new 100-ton capacity absorption chiller would be located in the vicinity of the engine-generator set and heat recovery equipment.

Option #2c: Two Hundred Fifty (250)-Ton Capacity Single-Effect Indirect-Fired Absorption Chiller

Under this option, two 820 kW Caterpillar G-3516s would be selected so that the waste heat matches the heat input requirement for the chiller as closely as possible. All residual heat over what the chiller requires will be used to at least partially meet the facility's thermal requirements (also like the two preceding options). However, the new indirect-fired absorption chiller under this option would be able to produce 250 tons of cooling, matching the capacity of the existing centrifugal chiller. Under this option (and for all [four] options involving a new 250-ton capacity absorption chiller), the existing centrifugal chiller will be physically replaced by the new absorption unit. Chiller performance characteristics were based not only on return condenser water temperature, but also on load since the intent is for the absorption chiller to meet all cooling loads up to the initial 250 tons. Above that threshold, one or both of the existing screw machines would operate.

Option #2d: Two Hundred Fifty (250)-Ton Capacity Double-Effect Indirect-Fired Absorption Chiller

For this option, the engine-generator set (three 820 kW Caterpillar G-3516s) would be selected so that its waste heat matches the heat input requirement for the chiller as closely as possible. Any residual heat over what the chiller requires will be used to at least partially meet the facility's thermal requirements. However, the new double-effect indirect-fired absorption chiller under this option would be able to produce 250 tons of cooling, matching the capacity of the existing centrifugal chiller. Under this option, the existing centrifugal chiller will be physically replaced by the new double-effect indirect-fired absorption unit. Chiller performance characteristics were based not only on return condenser water temperature, but also on load since the intent is for the absorption chiller to meet all cooling loads up to the initial 250 tons. Above that threshold, one or both of the existing screw machines would operate. This option is similar in all respects to that immediately preceding it except that a more efficient double-effect absorption chiller would be installed, requiring 115 psig steam instead of 15 psig.

Power Generation With Sufficient Waste Heat To Operate a Water Chilling Unit and Satisfy Facility Thermal Requirements

Option #3a

This option is identical to Option #2a, except the engine-generator capacity is sized to meet the thermal requirements of the facility in addition to the energy requirements of the chiller. Under this option, that base load would be met by a single-effect indirect-fired absorption chiller. The heat input would be provided by 15 psig steam produced from heat as the byproduct of power generation from two Caterpillar G3516 (820 kW) engine-generator sets. The intent was to match the estimated amount of "waste" heat to the chiller heat input required and satisfy the facility's thermal load. Chiller performance was based on the assumption that the chiller would continuously provide 100 tons of cooling, but under variable condenser water return temperatures (as determined from logs provided by the base). Under this option, the existing 250-ton capacity centrifugal chiller would not be removed. Replacing the existing chiller with only a 100-ton capacity absorption chiller would leave the plant short of capacity. For this option, the analysis is based on the assumption that, beyond 100 tons, screw machines will operate until the plant load reaches approximately 175 tons, at which point the operating screw machine will shut off and the 250-ton capacity centrifugal chiller will come on. The new 100-ton capacity single-effect indirect-fired absorption chiller would be located in the vicinity of the engine-generator set and heat recovery equipment.

Option #3b

This option is identical to Option #2b, except the engine-generator capacity is sized to meet the thermal requirements of the facility in addition to the energy requirements of the chiller. Analysis of the hospital's cooling loads indicated a year-round base load of 100 tons. Under this option, that base load would be met by a 100 ton, double-effect, indirect-fired absorption chiller; the engine-generator sets are four Caterpillar G-3516s (820 kW). The double-effect absorption chiller is about 50 percent more efficient than the single-effect unit. However, the double-effect requires a steam input at higher temperature – at the temperature of 115 psig versus the 15 psig of the single-effect unit. Also, the first cost of the double-effect unit is higher than that of the single-effect chiller. The performance at reduced condenser water temperatures was assumed to be the same as that of the single-effect unit. Under this option, the existing 250-ton capacity centrifugal chiller would not be removed. Replacing the existing chiller with only a 100-ton capacity absorption chiller would leave the plant short of capacity. The analysis is based on the assumption that, beyond 100 tons, screw machines will operate until the plant load reaches approximately 175 tons, at which point the operating screw machine will shut off and the 250-ton capacity centrifugal chiller will come on. The new 100-ton capacity absorption chiller would be located in the vicinity of the engine-generator set and heat recovery equipment.

Option #3c

This option is identical to Option #2c, except the engine-generator capacity is sized to meet the thermal requirements of the facility in addition to the energy requirements of the chiller. Under this option, three 820 kW Caterpillar G-3516s would be selected so that the waste heat matches the heat input requirement for the chiller and will meet the thermal requirements of the facility. The new single-effect indirect-fired absorption chiller under this option would be able to produce 250 tons of cooling, matching the capacity of the existing centrifugal chiller. Under this option, the existing centrifugal chiller will be physically replaced by the new absorption unit. Chiller performance characteristics were based not only on return condenser water temperature, but also on load since the intent is for the absorption chiller to meet all cooling loads up to the initial 250 tons. Above that threshold, one or both of the existing screw machines would operate.

Option #3d

This option is identical to Option #2d, except the engine-generator capacity is sized to meet the thermal requirements of the facility in addition to the energy requirements of the chiller. For this option, the engine-generator set, six 820 kW Caterpillar G-3516s, would be selected so that its waste heat matches the heat input requirement for the chiller and meets the thermal requirements of the facility. However, the new double-effect indirect-fired absorption chiller under this option would be able to produce 250 tons of cooling, matching the capacity of the existing centrifugal chiller. The existing centrifugal chiller will be physically replaced by the new double-effect indirect-fired absorption unit. Chiller performance characteristics were based not only on return condenser water temperature, but also on load since the intent is for the absorption chiller to meet all cooling loads up to the initial 250 tons. Above that threshold, one or both of the existing screw machines would operate. This option is similar in all respects to that immediately preceding it except a more efficient double-effect absorption chiller would be installed, requiring 115 psig steam instead of 15 psig.

3 Boiler Load and Heating Requirements

The maximum hourly boiler load was found from the daily boiler logs to be 3,491 pounds per hour (#/hr) of steam at 0800 on 1 February 94. With the steam produced at 50 psig, this equates approximately to 3,491 #/hr x 912 Btu/# = 3,184 MBH. The steam was used indirectly for space heating and domestic hot water production, and directly for humidification, dining hall requirements, and medical equipment sterilization.

Space Heating Requirements

Based on the time of day and year, the space heating requirement was probably very close to that of the basis of design. Schedules on the design drawings were used to calculate design space heating loads, as follows: (13,400 + 4,570) gal/hr x hr/60 min x 500 x (150 - 130) °F = 2,995 MBH.

Direct Steam Requirements

Previous analysis estimated that direct steam usage constitutes some 5 percent of the boiler output. On that basis, the direct steam used was about 0.05 x 3,184 MBH = 159 MBH. Requirements for direct steam usage will be substantially reduced as the dining portion of the hospital will be eliminated. Further, local sterilizers are now being used in some instances instead of imported steam from the central heat plant. Clearly, local humidifiers are also readily available that can be used for humidification, without use of imported steam.

Domestic Hot Water Heating Requirements

The remainder of the boiler output is attributed to domestic hot water production, or:

3,184 MBH - 2,995 MBH - 159 MBH = 30 MBH

This figure is in line with an estimate found in an earlier analysis, but is small compared to the domestic hot water heating capacity determined from the schedule on the design drawings, which is:

640 gal/hr x 62.4 #/cu ft/7.48 gal/cu ft x 1 Btu/#- °F x 80 °F = 427 MBH

It may well be that the domestic hot water load was grossly overestimated, similar to the required boiler capacity, or there may have actually been, at one time, that much load. Mr. Domako of the Base Civil Engineering (BCE) staff has indicated that he anticipates domestic hot water load will decrease in the future as the hospital is converted to an outpatient facility.

The maximum thermal load for the purposes of this analysis will be considered to be the sum of the space heating and domestic hot water load, above, or 3,025 MBH. The direct steam requirements will not be provided by way of waste heat. Those requirements should be met by continuing the trend toward local sterilization and installation of grid (or other type) humidifiers at the air handling units. This will permit the plant to be unmanned. The thermal space and domestic hot water heating loads will still be met as they are already satisfied by 15 psig steam from a pressure reducing valve station from the central heat plant boilers. The thermal energy requirements will be determined from the monthly boiler logs for Summer and for Winter (Table 1), and will be compared against the Btus of waste heat energy generated for those seasons to see if there will be an overall surplus or shortfall of energy.

Table 1. Identification of energy requirements from monthly boiler logs for 1995.

Summer (May - Oct):	**Energy Requirements (# of Steam)**
May	1,551,000
June	1,163,100
July	902,500
August	703,600
September	841,800
October	1,200,800
Summer Total =	6,362,800 (x 912 Btu/# = 5,802.874 Mbtu)
Winter (Nov - Apr):	
November	1,200,800
December	1,559,800
January	1,622,700
February	1,334,200
March	1,369,200
April	1,766,200
Winter Total =	8,852,900 = (x 912 Btu/# = 8,073.845 Mbtu)
* Indicates data that was averaged using September and December data	

4 Heat Recovery

Heat recovery is a feature of all options considered except (of course) the base option.

Option #1

Under this option, heat is potentially recoverable from both the engine and the exhaust. Due to the fact there would be light load conditions experienced during the year, USACERL was advised that heat should be extracted from the engine only. Extracting heat at low load will lower the temperature of the exhaust gas to the point where some condensation will occur with resulting corrosion. Consequently, only heat recovery from the engine was considered.

Remaining Options (Heat Recovery from Engine-Generator Sets)

Remaining options considered heat recovery from the engine and/or the exhaust, depending on whether high (115 psig) or low (15 psig) pressure steam was required (i.e., depending on whether a double or single-effect absorption chiller was under consideration). Low load that would promote corrosion is not a problem – the engine-generator sets, when operating, would be running at full load, generating the maximum amount of electricity possible. As pointed out earlier in the discussion regarding options, the amount of heat recovery considered was either that necessary to operate the absorption chiller at full load, with any excess used to offset facility thermal requirements, or was that required to operate the absorption chiller at full load and to meet the facility thermal load as well. The analysis does not allow more heat energy to be recovered than required. This limitation is imposed seasonally (Winter, Summer) and thus is somewhat broad. For cases where equipment is sized to produce waste heat to operate the chiller and meet the facility thermal load, the seasonal excess of energy available over required is sufficiently large that short duration thermal requirements should still be met for the vast majority of the time. The excess heat would be "dumped" to the generously sized existing cooling tower that currently cools the condenser water for the existing 250-ton capacity motor-driven centrifugal chiller. USACERL acknowledges and appreciates the assistance of Mr. Warner Bauer of Engineering Controls, Inc., St. Louis, MO, in selecting the engine-generator models and quantities, and heat recovery equipment that would meet the performance criteria under each option considered. Capital costs for the equipment were also provided by Engineering Controls. The equipment selections and capital costs as provided by Engineering Controls, Inc. appear in Appendix B. Note that Waukesha and Caterpillar selections were made so that sole source procurement would not be required and to ensure that performance should be comparable.

5 Utility Rate Structures

Electrical Rates

Appendix C contains recent monthly electric bills for Davis-Monthan AFB for a year (with the exception of September, for which interpolated data was used). Using the electric bills, the rates were determined for use in the spreadsheet. The basic demand charge of \$10.28/billable kW (bkW) is applicable for the entire year. The demand charge is apparently subject to 5 percent Arizona state sales tax, applied to 92 percent of the total (demand plus energy charges) due to a hospital exemption. Power factor adjustment and the Arizona Corporation Commission Assessment were not considered as individually they are well within the "noise" level of the total monthly electric charge and their difference (the former is typically a credit, the latter a debit) is even more so. Consequently, the basic demand cost was figured as:

$$\$10.28/\text{bkW} \times \text{bkW} = \text{demand cost (DC)}$$

upon which the sales tax is levied, subject to the allowable exemption, or:

$$\text{DC} = \$10.28 \times \text{bkW} + \$10.28 \times \text{bkW} \times 0.92 \times 0.05$$

so that the actual demand cost would be:

$$\text{DC} = \$10.28 \times \text{bkW} \times (1 + 0.92 \times 0.05) = \$10.75 \times \text{bkW}.$$

The electrical *energy* rate is subject to the same levy. The basic Summer rate is \$0.047457/kWh and the basic Winter rate is \$0.045084/kWh. Adjusted for the same levy as applied to the demand charge, the rates become, respectively:

$$1.046 \times \$0.047457/\text{kWh} = \$0.0496/\text{kWh}$$

and

$$1.046 \times \$0.045084/\text{kWh} = \$0.0472/\text{kWh}.$$

Additionally, the electrical rate schedule includes a 0.667 ratchet applied to the peak KW demand experienced over the previous 11 months. The contract with Tucson Electric Power Company includes a minimum monthly buy of 3,000 kW. None of the options regarding power generation will penetrate this floor, based on the data in Appendix C.

Natural Gas Rates

Information received from Mr. Weleck of the BCE staff indicated the gas rates are now $2.75/MBtu in Summer and $3.90 in Winter.

6 Methodology for Analysis

Based on the cooling load profile, hours at various loads were determined. The spreadsheet then modeled how these loads would be met, either using the existing cooling equipment or the equipment described above under the various options considered. Note that the hours at the various loads do not total the entire hours of the year (8,760), although there is apparently a requirement for year-round cooling. This simplification was introduced since, once a load over 250 tons is experienced, the equipment that will operate to meet that additional load will be the same under any of the options considered. However, for options involving onsite electrical power generation, all hours of the year were considered, except for the estimated periods of time when the equipment would be inoperative for maintenance (95 and 98 percent availability on average in Summer and Winter, respectively). The hours of operation are divided between Summer (May through October, inclusive) and Winter (November through April) due to the variation in utility rates between the two seasons. The engine-generator sets have been derated to account for altitude (Tucson's elevation is 2,654 feet above sea level) and outdoor temperature.

Maintenance costs for the Caterpillar G3516 were based on a previous analysis by Empire Power Systems, Phoenix, AZ. This included all parts and labor for oil changes, makeup oil, scheduled preventive maintenance, overhauls, unscheduled stoppages due to out-of-tolerance conditions, etc. The maintenance required for the G3512 was assumed to be essentially equal to that of the G3516. An interruption for over 15 minutes in the monthly operation of a given generator will render demand savings from that generator moot for the month (although savings in billable demand may still be possible where operation has reduced peak and the month is one in which billable demand would exceed actual demand). This would be the case regardless of the estimated overall Summer 95 percent or Winter 98 percent availability rates. If units must be down, clearly the preference is to take them down during periods of months when demand is relatively low, keeping the units in service during months when peak demands are typically experienced. Preference should be given to pulling operationally interruptive maintenance during months when billable demand typically exceeds actual demand. It is, of course, recognized that this isn't always possible. The operational assumptions made in the spreadsheet are based on operating the equipment according to the recommendations above, but allowing for the possibility that unscheduled events will occur. Operating scenarios were developed for all options based on the practices recommended above and are indicated in the following.

Option #2a

With only one Caterpillar G3512 engine-generator set, it was assumed that there would be totally uninterrupted service for 3 of the 6 summer months. It is assumed that, of the 3 months, due diligence has been taken to ensure uninterrupted operation for 2 of the 3 months with the highest actual demand, but the unit went down for the month with the third-highest demand. For Winter, it is assumed that there will be uninterrupted service for 3 months, and interrupted service for 3 months. (Actually, it really does not matter from a demand reduction viewpoint whether the engine-generator does or does not operate during months in which the minimum billable amount is determined by the ratchet; i.e., November to February, inclusive.) Appendix D indicates the situation, incorporating the data from Appendix E. Table 2 lists the projected demand reductions by month.

For input to the spreadsheet, there would be 3 months in Summer when the demand reduction would be 555 kW, and for Winter, there would be 4 months for which the reduction would be 370 kW and 1 month for which the reduction would be 555 kW.

Option #2b

This option is considered identical to Option #2a from an operational standpoint. However, the power production is greater for the Caterpillar G3516 engine-generator that would be installed under this option. Appendix E shows the results. Note again that, in Winter, for the 4 months when the ratchet is in effect, it does not matter from a demand reduction perspective whether any unit does or does not operate. This pattern is characteristic for all the options involving onsite power production.

Table 2. Projected demand reductions, by month.

Jul	555 kW
Aug	555 kW
Sep	0 kW
Oct	555 kW
Nov	370 kW (= 12,543 - 12,173)
Dec	370 kW
Jan	370 kW
Feb	370 kW
Mar	0 kW
Apr	555 kW
May	0 kW
Jun	0 kW

Option #2c (also applicable to Option #3a)

Under this option, it is assumed that in Summer, one Caterpillar G3516 unit will be available to achieve demand reductions for 3 months and two such units will be available to achieve reductions for the remaining 3 months. It is assumed that Winter operation will replicate Summer. Appendix F shows operation for the year. Since two Caterpillar G3516 engine-generators are being considered for Option #3a, the same results apply for that option.

Option #2d (also applicable to Option #3c)

This option involves three Caterpillar G3516 engine-generator sets. It is assumed that in Summer, all three will be available for 2 months and two will be continuously available for 4 months. In Winter, the same assumption is made. Appendix G shows the results. The same results also apply to Option #3c.

Option #3b

This option involves four Caterpillar G3516 engine-generator sets. It is assumed that in Summer all four will be available for 2 months and three will be available for the remaining 4 months. In Winter, the same availability is assumed. Appendix H shows the results.

Option #3d

Six Caterpillar G3516 engine-generator sets were considered for installation under this option. For operation in Summer, it is assumed that all six units will operate for 2 months, five units will operate continuously for 2 months, and four units will be maintained in continuous operation for 2 months. Winter operation will be assumed to be identical. Appendix I shows the results.

First Costs

Appendix J contains the construction cost estimates for each option. The cost estimates for the heat recovery equipment and associated engine-generator sets were those provided by Engineering Controls, Inc., as previously discussed. All other costs were based on *Means Mechanical Cost Data 1997.*

The cost estimates do not include the construction of an enclosure for equipment located exterior to the central energy plant building. Estimating the cost of such a structure would be difficult since the architectural requirements vary for each base. However, it does include the cost of a concrete pad on which to install the equipment.

Life Cycle Cost Analysis

The life cycle cost analysis for each option was calculated using Life Cycle Cost In Design (LCCID) software.* The life cycle cost analysis accounts for the construction, overhead, and design costs associated with each option. The sum of these values is the total investment. The economic life is taken over a 20-year period and accounts for all scheduled maintenance activities as detailed by the manufacturer. No service contracts were considered as part of this study.

* Linda K. Lawrie, Technical Report (TR) E-85/07/ADA162522, *Development and Use of the Life Cycle Cost in Design Computer Program (LCCID)* (U.S. Army Construction Engineering Research Laboratories [USACERL], November 1985).

7 Results

Appendix K shows the EXCEL® spreadsheet that contains the raw energy data. Appendixes L to T and Table 3 contain calculated payback and savings-to-investment ratio for each option. The table below summarizes the economic results. These results form the basis for the recommendations in the next paragraph. This report does not include potential savings that may be achievable under Options #3a, 3b, 3c, and 3d by having an unmanned plant. Under these options, there would be initial first cost incurred due to installation of humidification units at the air handling units and use of sterilizers where the energy input for sterilization would be at the point of use. Estimating overall savings through removing the plant manning requirement was beyond the scope of a cooling study. However, in addition to the considerable utility savings identified for Options #3a through 3d, inclusive, there would likely be considerable savings from eliminating the requirement for a manned plant.

Table 3. Calculated payback and savings-to-investment ratios for options.

Option	Payback (years)	SIR	Total Investment	Recommendation
3a	1.01	9.29	$269,507	implement
3b	1.21	6.61	$536,817	implement
3c	1.49	5.83	$538,392	
3d	1.43	5.44	$934,974	
2c	1.65	5.96	$476,529	
2d	1.75	4.96	$639,087	
2b	2.51	2.77	$235,412	
2a	2.87	2.32	$196,252	
1	9.35	1.32	$290,974	do not implement

8 Conclusions and Recommendations

The medical facility at Davis-Monthan AFB can realize considerable utility cost savings by implementing any of several options analyzed in this study. It is likely such savings can be replicated at other DOD medical facilities where there are year-round air conditioning requirements, large thermal energy requirements, and utility rates where the unit cost of purchased electricity is high compared to that of natural gas.

Based on these results, this study recommends the projects be prioritized for implementation, from most to least highly recommended, as follows:

1. *Option 3a*: Two natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for a 100 ton single-effect indirect-fired absorption water chiller to meet facility base cooling load (100 tons) with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only). This option *is* recommended for implementation.

2. *Option 3b*: Four natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for a 100 ton double-effect indirect-fired absorption water chiller to meet facility base cooling load (100 tons) with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only). This option *is* recommended for implementation.

3. *Option 3c*: Three natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for 250 ton single-effect indirect-fired absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only).

4. *Option 3d*: Six natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for a 250 ton double-effect indirect-fired absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat adequate to satisfy facility thermal requirements (existing boilers as backup only).

5. *Option 2c*: Two natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for a 250 ton single-effect indirect-fired absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat used for thermal requirements.

6. *Option 2d*: Three natural gas-fired Caterpillar G-3516 (820 kW) engine-generator sets, waste heat used to provide steam for a 250 ton double-effect indirect-fired absorption water chiller to replace existing 250-ton motor-driven centrifugal chiller, with residual heat used for thermal requirements.

7. *Option 2b*: One natural gas-fired Caterpillar G-3516 (820 kW) engine-generator set, waste heat used to provide steam for a 100 ton double-effect indirect-fired absorption water chiller to meet facility base cooling load (100 tons) with residual heat used for thermal requirements.

8. *Option 2a*: One natural gas-fired Caterpillar G-3512 (600 kW) engine-generator set, waste heat used to provide steam for a 100 ton single-effect indirect-fired absorption water chiller to meet facility base cooling load (100 tons) with residual heat used for thermal requirement.

9. *Option 1*: A 250 ton natural gas engine-driven chiller to replace existing 250-ton motor-driven centrifugal chiller, with waste heat used to offset facility thermal requirements. Note that this option *is not* recommended for implementation.

Appendix A: Notes Regarding Interviews and Discussions for Chiller Study at Davis-Monthan AFB

SSgt Rinn, TSgt Farmer, Central Plant Operators –

A. As of 1 Apr 97, the foregoing operators have been on temporary assignment pending award of a contract for private sector O&M for the hospital, including the central plant. The operators provided chilled water logs for the previous year (to be returned to Steve Weleck). They also furnished monthly boiler logs for the months (Jan – Jun 97, logs to be returned to Weleck) and referred us to Lt. Doolittle for the balance of the previous year's monthly boiler logs. Lt. Doolittle furnished CERL with monthly logs from Jan 94 – Sep 95. In an attempt to determine peak plant thermal load, CERL went back to boiler log data for Feb 94 (records to be returned to Weleck).

B. Upon initial arrival, CERL was appraised that a cogeneration study had already been completed, Dec 95, with design drawings based on the study results also provided. The study and drawings were loaned to CERL for review, and CERL will return same to Weleck. While meeting with Weleck, CERL learned that two significant projects are planned for the hospital, a 6,000 SF addition and a follow-on 30,000 SF addition (both projects discussed in greater detail below). Additionally, Weleck furnished a document "FY88 MCP ECIP Facility Energy Improvements" for CERL's perusal to see if it might contain helpful information. Mr. Weleck also provided utility rate schedules and sample billings.

C. SSgt Rinn and TSgt Farmer retrieved plant drawings on file for CERL's review, particularly drawings containing schedules for space heating and domestic hot water equipment. Inquiry verified there is no separate metering of steam usage – some is used for space heating, some for domestic hot water production, and the remainder is direct steam usage. Therefore, the schedule sheets were used with other input to determine the relative uses for the steam produced. Of prime concern was the amount of steam used directly for various applications (dining facility, humidification, and medical sterilizers). The requirement for high pressure steam (> 15 psig [the plant operates at 50 psig]) drives the requirement for 24-hour manning of the plant.

D. Lt. Chicotah, facility manager at the hospital, was contacted by phone in an attempt to find out about future projects planned for the hospital. She Faxed a Preliminary Statement of Work for design of a FY00 30,000 SF addition (Ambulatory Health Care Center) to the existing medical facility. This is in addition to the 6,000 SF Aerospace Medicine Clinic programmed for FY98. Neither this document nor the DD Form 1391 or the Requirements and Management Plan (the latter two provided by SMSgt Mortenson) provided insight as to the mechanical equipment that is anticipated for use in heating and cooling either the planned 6,000 SF addition or the 30,000 SF addition. In a final attempt to get this information, CERL called Horace Hopper of AFCEE. The information Hopper currently has basically leaves the issue of the mechanical equipment to be used for the facility additions at the discretion of the designer. At this time, per Mr. Hopper, the designer has not been selected (contrary to information provided by Lt. Chicotah who indicated an A-E contract is to be awarded by the end of July 97). Numerous references were made to a Capt Reinhardt in San Francisco as the prime source of information regarding future plans for the hospital. Attempts to reach Reinhardt to date have been unsuccessful; however, CERL's plan is to use his information to resolve any conflicting or missing information. Mr. Ken Domako indicated he would attempt to resolve the issue of future requirements for direct steam use. He also indicated his estimate that domestic hot water usage at this time has been reduced significantly from what was the original basis of design, and that future requirements will likely be only about half that of the original basis of design. This is due to removal of the dining facility and elimination of showers for patients. Mr. Domako stated that the two planned hospital projects will be undertaken.

Approach

A. Contact Capt Reinhardt regarding future hospital requirements.

B. Compute heating loads (process steam, space heating, and domestic hot water).

C. Plot cooling load profiles.

D. Consider the following options:

1. gas fired dual-effect absorption unit
2. gas engine-driven chiller
3. cogen system made up of a generator and indirect fired absorption unit

E. Analyze data and produce report.

Determination of Heating Loads

A. The existing boilers in the hospital central plant are greatly oversized. They are products of Nebraska Boiler, each rated at 7.5 million British Thermal Units per hour (MBH) with a mass flow of 7,000 pounds per hour (#/hr) of 50 pounds per square inch gauge (psig) saturated steam. Examination of the boiler logs available indicated that the maximum boiler load experienced over the last 5 years (on 4 Feb 94) was 3,500 #/hr, which translates into a heating load of

$$3{,}500\ \#/\text{hr} \times 7{,}500{,}000\ \text{Btu}/7{,}000\ \#/\text{hr} = 3{,}750{,}000\ \text{Btu/hr}$$

This indicates a peak load of only 25 percent of the existing plant boiler capacity (3.75 MBH/[2 x 7.5 MBH]). Most of the time, the load is significantly less. The load will decrease even more due to the factors described in the following paragraphs.

B. Domestic Hot Water Loads

Mr. Domako indicated that hospital care is going to be limited basically to outpatient care, including outpatient surgery. Showers for patients will be significantly reduced compared to that anticipated when the plant was constructed. Mr. Domako's estimate of the reduction is 50 percent. There are currently two domestic hot water generators in the plant, the original design intent being that either one could provide 100 percent redundancy. The schedule on the design drawings indicates the generators are capable of heating 640 gal of water from 60 to 120 °F in 1 hour. The design also provided for what appears to be a booster heater to heat the water initially from 60 to 90 °F, with the 90 °F water then heated to 120 °F by the hot water generators. Since the heating from the booster actually supplants (although it also accelerates) the heating that would otherwise be required by the domestic hot water generators (increasing the domestic hot water temperature from 60 to 90 °F), only the full capacity of the hot water generators need be calculated, which is

$$640 \text{ gal/hour} \times 8.34 \text{ lb/gal} \times 1 \text{ Btu/lb °F} \times (120\text{-}60) \text{ °F}$$

$$= 320{,}256 \text{ Btu/hr}$$

Assuming a 50 percent reduction in load, the estimated domestic hot water heating requirement would be 320,256 Btu/hr/2 = 160,128 Btu/hr.

C. Space Preheating, Heating, and Reheating Loads

Drawings that contained schedules indicating the required capacities for preheat, heating, and reheat coils were reviewed. Rather than add these all up and then assume some diversity factor, the schedule for the converters was checked. Based on those schedules, the design heating water requirement was determined from

$$\text{Converter \#1: } 500 \times 13{,}400 \text{ gal/hr/60 min/hr} \times (150\text{-}128) \text{ °F}$$

$$= 2{,}456{,}667 \text{ Btu/hr}$$

where operators indicated that the temperature of the supply hot water is 150 °F and the return is typically the 128 °F indicated.

$$\text{Converter \#2: } 500 \times 4{,}570 \text{ gal/hr/60 min/hr} \times (150\text{-}128) \text{ °F}$$

$$= 837{,}333 \text{ Btu/hr}$$

Since both converters operate simultaneously, the capacities are summed to produce a joint capacity of (2,456,667 + 837,333) Btu/hr = 3,294,500 Btu/hr.

D. Process Steam Loads

Boiler plant steam is used directly for a number of purposes/ applications: sterilization, dining hall requirements, and humidification. Unfortunately, this steam (nor the domestic hot water or heating water used for space conditioning) has been metered. Therefore, the quantity of steam used directly (as opposed to heat exchange within the plant to produce domestic hot water and heating water for space conditioning) was calculated by subtracting the quantities in subparagraphs b) and c) from the peak steam load identified in subparagraph a). The quantity was calculated as:

3,750,000 Btu/hr - 160,171 Btu/hr - 3,294,500 Btu/hr = 295,329 Btu/hr

Based on discussions with Mr. Domako and TSgt Mortenson, the dining hall will be eliminated and the space used for an alternative function. This will eliminate a portion of the present direct steam usage. Additionally, discussion with plant operators indicated that in a number of instances, steam from the plant is not being used for sterilization. Rather, portable units are being used for sterilization. Mr. Domako expects use of this type of sterilization to be expanded. He indicated he will check with medical personnel to try to ascertain future steam requirements.

Appendix B: Equipment Selections and Capitol Costs

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BUDGET COST FOR
U.S. ARMY CONSTRUCTION ENGINEERING
RESEARCH LABORATORIES

REF 2A: 1,714,300 BTU/HR required at 15 PSIG.
Option #2a

One Caterpillar G3512, 600 KWe, 2,091,660 BTU/HR:	$ 54,560.00
One Waukesha VHP-2900GSI, 425 KWe, 2,201,942 BTU/HR:	$ 53,780.00
Feedwater unit adds:	$ 13,560.00

REF 2B: 4,507,750 BTU/HR required at 15 PSIG.
Option #2c

Two Caterpillar G-3516, 820 KWe, 2,886,660 BTU/HR/Engine:	$108,480.00
Two Waukesha VHP-2900GSI, 425 KWe, 2,201,942 BTU/HR/Engine:	$101,240.00
Feedwater unit adds:	$ 19,340.00

REF 2C: 1,000,000 BTU/HR required at 115 PSIG.
Option #2b

One Caterpillar G-3516, 820 KWe, 1,010,000 BTU/HR:	$ 80,660.00
One Waukesha VHP-3600GSI, 550 KWe, 1,063,000 BTU/HR:	$ 68,620.00
Feedwater unit adds:	$ 18,540.00

REF 2D: 2,500,000 BTU/HR required at 115 PSIG.
Option #2d

Three Caterpillar G-3516, 820 KWe, 1,010,000 BTU/HR/Engine:	$232,920.00
Two Waukesha 7100GSI, 1100 KWe, 2,212,000 BTU/HR/Engine:	$183,500.00
Feedwater unit adds:	$ 23,920.00

The 15 PSIG systems include the heat recovery unit, back pressure control valve, excess steam control valve and excess steam condenser.

The 115 PSIG systems include the heat recovery unit, back pressure control valve and external by-pass tee.

ENGINEERING CONTROLS, INC.
SAINT LOUIS, MISSOURI

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BUDGET COST FOR
U.S. ARMY CONSTRUCTION ENGINEERING
RESEARCH LABORATORIES

REF 4A:	4,739,300 BTU/HR required at 15 PSIG.	
Option #3a	Two Caterpillar G3516, 820 KWe, 2,886,660 BTU/HR/Engine:	$106,920.00
	Two Waukesha VHP-7100GSI, 1100 KWe, 5,487,129 BTU/HR/Engine:	$ 76,940.00
	Feedwater unit adds:	$ 19,340.00
REF 4B:	7,532,750 BTU/HR required at 15 PSIG.	
Option #3c	Three Caterpillar G-3516, 820 KWe, 2,886,660 BTU/HR/Engine:	$154,080.00
	Two Waukesha VHP-5900GSI, 900 KWe, 4,352,552 BTU/HR/Engine:	$100,100.00
	Feedwater unit adds:	$ 22,840.00
REF 4C:	4,025,000 BTU/HR required at 115 PSIG.	
Option #3b	Four Caterpillar G-3516, 820 KWe, 1,010,000 BTU/HR:	$312,620.00
	Two Waukesha VHP-7100GSI, 1100 KWe, 2,212,000 BTU/HR:	$183,820.00
	Feedwater unit adds:	$ 25,800.00
REF 4D:	5,525,000 BTU/HR required at 115 PSIG.	
Option #3d	Six Caterpillar G-3516, 820 KWe, 1,010,000 BTU/HR/Engine:	$461,220.00
	Two Waukesha VHP-9500GSI, 1475 KWe, 3,058,312 BTU/HR/Engine:	$224,660.00
	Feedwater unit adds:	$ 30,460.00

The 15 PSIG systems include the heat recovery unit, back pressure control valve, excess steam control valve and excess steam condenser.

The 115 PSIG systems include the heat recovery unit, back pressure control valve and external by-pass tee.

ENGINEERING CONTROLS, INC.
SAINT LOUIS, MISSOURI

13 Aug 97 phone discussion with Terry Hurley, Engineering Controls, St. Louis, MO

Mr. Hurley provided the following natural gas flow rates for the Caterpillar engines, as follows:

3512 TA, 600 KWe ------------ 100,431 Btu/minute
3516 TA 90, 820 KWe ------------ 132,221 Btu/minute

Appendix C: Recent Electric Bills for Davis-Monthan AFB

TUCSON ELECTRIC POWER COMPANY
P. O. Box 711
Tucson, Arizona 85702

Dear Customer:

At your request, we submit our Large Light and Power Rate No. 14 showing current adjustments:

LARGE LIGHT AND POWER RATE NO. 14

	Billing Months Summer May-Oct.	Winter Nov.-Apr.
DEMAND CHARGE: Per kW of Billing Demand per month	\$10.28	\$10.28
ENERGY CHARGE: All kWh per month @	4.7457¢	4.5084¢

BILLING DEMAND:
The Billing Demand shall be specified in the contract, but shall not be less than 3,000 kW.

POWER FACTOR ADJUSTMENT:
The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

By law, the following tax and assessment percentages are applied where appropriate to calculations on the above rates:

FRANCHISE TAX: (Tucson, South Tucson)	2.0%
CITY SALES TAX: (Tucson, South Tucson, Marana)	2.0% (Tucson); 2.5% (South Tucson); and 4.0% (Marana) (also applied to Arizona Corporation Commission Assessment and Residential Utility Consumer Assessment amounts)
STATE SALES TAX: (Applicable to all sales)	5.0% (also applied to City Franchise Tax amount and Arizona Corporation Commission Assessment and Residential Utility Consumer Assessment amounts)
ARIZONA CORPORATION COMMISSION ASSESSMENT: (Applicable to all sales)	.14% (also applied to City Franchise Tax amount, City Sales Tax amount and State Sales Tax amount)
RESIDENTIAL UTILITY CONSUMER ASSESSMENT: (Residential Customers Only)	.05% (also applied to City Franchise Tax amount, City Sales Tax amount and State Sales Tax amount)

Very truly yours,

TUCSON ELECTRIC POWER COMPANY

Effective August 1996 Billings
(Change due to revision of ACC and RUCO Assessments)

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: June 26, 1997
DATE DELINQUENT: July 10, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
MAY 27, 1997 TO JUNE 24, 1997

DEMAND CHARGE

18,099 KW	@	$10.28	PER KW	$186,057.72

18,099.1 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
18,099 KW BILLING DEMAND

ENERGY CHARGE

7,962,400 KWH	@	0.047457	KWH	$377,871.62

POWER FACTOR ADJUSTMENT

93.96	-90.00	=	3.96		
3.96	X	0.013	=	-0.05148	
-0.05148	X	18,099	KW BILLING DEMAND		($931.74)

SUBTOTAL		$562,997.60
SUBTOTAL HOSPITAL EXEMPTION (STATE SALES TAX ON 92% OF TOTAL)	$517,957.79	
ARIZONA CORPORATION COMMISSION ASSESSMENT		$827.61
STATE SALES TAX		$25,934.15
TOTAL AMOUNT DUE		$589,759.36

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: May 29, 1997
DATE DELINQUENT: June 11, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
APRIL 25, 1997 TO MAY 27, 1997

DEMAND CHARGE 17,026 KW	@	$10.28	PER KW	$175,027.28

17,026.0 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
17,026 KW BILLING DEMAND

ENERGY CHARGE 8,119,360 KWH	@	0.047457	KWH	$385,320.47

POWER FACTOR ADJUSTMENT

94.83	-90.00	=	4.83		
4.83	X	0.013	=	-0.06279	
-0.06279	X	17,026	KW BILLING DEMAND		($1,069.06)

SUBTOTAL	$559,278.69
ARIZONA CORPORATION COMMISSION ASSESSMENT	$822.14
STATE SALES TAX	$28,003.08
CURRENT AMOUNT DUE	$588,103.91
PREVIOUS BALANCE	$457,844.38
TOTAL AMOUNT DUE	$1,045,948.29

Page 1

:COUNT
.!25-2001-1
ONTRACT NO.
)26O1-79-DOO23

DATE OF BILL: April 30, 1997
DATE DELINQUENT: May 13, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
MARCH 24, 1997 TO APRIL 25, 1997

EMAND CHARGE

14,142 KW	@	$10.28	PER KW	$145,379.76

14,141.7 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
14,142 KW BILLING DEMAND

NERGY CHARGE

6,447,240 KWH	@	0.045084	PER KWH	$290,667.37

OWER FACTOR ADJUSTMENT

93.50	-90.00	=	3.50		
3.50	X	0.013	=	-0.0455	
-0.0455	X	14,142	KW BILLING DEMAND		($643.46)

JBTOTAL	$435,403.67
RIZONA CORPORATION COMMISSION ASSESSMENT	$640.05
TATE SALES TAX	$21,800.66
URRENT AMOUNT DUE	$457,844.38
REVIOUS BALANCE	
OTAL AMOUNT DUE	$457,844.38

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: March 26, 1997
DATE DELINQUENT: April 8, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
FEBRUARY 25, 1997 TO MARCH 24, 1997

DEMAND CHARGE
12,613 KW @ $10.28 PER KW $129,661.64

12,612.9 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
12,613 KW BILLING DEMAND

ENERGY CHARGE
5,321,080 KWH @ 0.045084 PER KWH $239,895.57

POWER FACTOR ADJUSTMENT

91.14	-90.00	=	1.14		
1.14	X	0.013	=	-0.01482	
-0.01482	X	12,613	KW BILLING DEMAND		($186.92)

SUBTOTAL	$369,370.29
ARIZONA CORPORATION COMMISSION ASSESSMENT	$542.98
STATE SALES TAX	$18,494.37
CURRENT AMOUNT DUE	$388,407.64
PREVIOUS BALANCE	$4,553.58
TOTAL AMOUNT DUE	$392,961.22

Page 1

ACCOUNT
2325-2001-1
CONTRACT NO.
F02601-79-D0023

DATE OF BILL: February 27, 1997
DATE DELINQUENT: March 12, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
JANUARY 24, 1997 TO FEBRUARY 25, 1997

DEMAND CHARGE				
12,543 KW	@	$10.28	PER KW	$128,942.04

10,696.2 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
12,543 KW BILLING DEMAND

ENERGY CHARGE				
5,953,040 KWH	@	0.045084	PER KWH	$268,386.86

POWER FACTOR ADJUSTMENT

91.68	-90.00	=	1.68		
1.68	X	0.013	=	-0.02184	
-0.02184	X	12,543	KW BILLING DEMAND		($273.94)

SUBTOTAL	$397,054.96
ARIZONA CORPORATION COMMISSION ASSESSMENT	$583.67
STATE SALES TAX	$19,880.54
TOTAL AMOUNT DUE	$417,519.17

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: January 28, 1997
DATE DELINQUENT: February 10, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
DECEMBER 26, 1996 TO JANUARY 24, 1997

DEMAND CHARGE				
12,543 KW	@	$10.28	PER KW	$128,942.04

11,141.3 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS. 18,805 KW —AUGUST 1996
12,543 KW BILLING DEMAND

ENERGY CHARGE					
5,313,640 KWH	@	0.045084	PER KWH		$239,560.15
POWER FACTOR ADJUSTMENT					
91.86	-90.00	=	1.86		
1.86	X	0.013	=	-0.02418	
-0.02418	X	12,543	KW BILLING DEMAND		($303.29

SUBTOTAL	$368,198.90
ARIZONA CORPORATION COMMISSION ASSESSMENT	$541.25
STATE SALES TAX	$18,435.72
TOTAL CURRENT AMOUNT	$387,175.87
ARREARS AMOUNT	$403,754.44
TOTAL AMOUNT DUE	$790,930.31

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: December 30, 1996
DATE DELINQUENT: January 10, 1997

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
NOVEMBER 25, 1996 TO DECEMBER 26, 1996

DEMAND CHARGE

12,543 KW	@	$10.28	PER KW	$128,942.04

10,787.2 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND) EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
12,543 KW BILLING DEMAND

ENERGY CHARGE

5,662,800 KWH	@	0.045084	PER KWH	$255,301.68

POWER FACTOR ADJUSTMENT

91.71	-90.00	=	1.71		
1.71	X	0.013	=	-0.02223	
-0.02223	X	12,543	KW BILLING DEMAND		($278.83)

SUBTOTAL	$383,964.89
ARIZONA CORPORATION COMMISSION ASSESSMENT	$564.43
STATE SALES TAX	$19,225.12
TOTAL CURRENT AMOUNT	$403,754.44
ARREARS AMOUNT	$417,054.18
TOTAL AMOUNT DUE	$820,808.62

Page 1

ACCOUNT
2325-2001-1
CONTRACT NO.
FO2601-79-DOO23

DATE OF BILL: November 27, 1996
DATE DELINQUENT: December 12, 1996

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
OCTOBER 24, 1996 TO NOVEMBER 25, 1996

DEMAND CHARGE				$128,942.04
12,543 KW	@	$10.28	PER KW	

11,605.7 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
12,543 KW BILLING DEMAND

ENERGY CHARGE				$268,843.11
5,963,160 KWH	@	0.045084	PER KWH	

POWER FACTOR ADJUSTMENT

97.19	-90.00	=	7.19		
7.19	X	0.013	=	-0.09347	
-0.09347	X	12,543	KW BILLING DEMAND		($1,172.39)

SUBTOTAL	$396,612.76
ARIZONA CORPORATION COMMISSION ASSESSMENT	$583.02
STATE SALES TAX	$19,858.40
TOTAL CURRENT AMOUNT	$417,054.18
ARREARS AMOUNT	$534,627.34
TOTAL AMOUNT DUE	$951,681.52

ACCOUNT
2325-2001-1
CONTRACT NO.
FO2601-79-DOO23

DATE OF BILL: October 28, 1996
DATE DELINQUENT: November 8, 1996

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
SEPTEMBER 25, 1996 TO OCTOBER 24, 1996

DEMAND CHARGE				
16,947 KW	@	$10.28	PER KW	$174,215.16

16,947.4 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,542.9 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 18,805 KW —AUGUST 1996
16,947.0 KW BILLING DEMAND

ENERGY CHARGE				
7,065,360 KWH	@	0.047457	PER KWH	$335,300.79

POWER FACTOR ADJUSTMENT

94.96	-90.00	=	4.96		
4.96	X	0.013	=	-0.06448	
-0.06448	X	16,947	KW BILLING DEMAND		($1,092.74)

SUBTOTAL	$508,423.21
ARIZONA CORPORATION COMMISSION ASSESSMENT	$747.38
STATE SALES TAX	$25,456.75
TOTAL CURRENT AMOUNT	$534,627.34
ARREARS AMOUNT	$589,803.27
TOTAL AMOUNT DUE	$1,124,430.61

ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: August 28, 1996
DATE DELINQUENT: September 11, 1996

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
JULY 25, 1996 TO AUGUST 26, 1996

DEMAND CHARGE				
18,805 KW	@	$10.28	PER KW	$193,315.40

18,804.7 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
12,560.3 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS LF = 71.5% 18,831 KW —SEPTEMBER 1995
18,805.0 KW BILLING DEMAND

ENERGY CHARGE				
9,816,480 KWH	@	0.047457	PER KWH	$465,860.69

POWER FACTOR ADJUSTMENT

92.72	-90.00	=	2.72		
2.72	X	0.013	=	-0.03536	
-0.03536	X	18,805	KW BILLING DEMAND		($664.94)

SUBTOTAL	$658,511.15
ARIZONA CORPORATION COMMISSION ASSESSMENT	$968.02
STATE SALES TAX	$32,971.66
TOTAL CURRENT AMOUNT	$692,450.83
ARREARS AMOUNT	$661,960.08
TOTAL AMOUNT DUE	$1,354,410.91

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$0.0705/kwH
9/29/96

ACCOUNT
2325-2001-1
CONTRACT NO.
FO2601-79-DO023

DATE OF BILL: July 29, 1996
DATE DELINQUENT: August 9, 1996

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
JUNE 25, 1996 TO JULY 25, 1996

DEMAND CHARGE				
18,659 KW	@	$10.28	PER KW	$191,814.5:

18,659.4 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
13,278.0 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 19,907 KW —AUGUST 1995
18,659.0 KW BILLING DEMAND

ENERGY CHARGE				
9,237,720 KWH	@	0.047457	PER KWH	$438,394.4

POWER FACTOR ADJUSTMENT					
92.59	-90.00	=	2.59		
2.59	X	0.013	=	-0.03367	
-0.03367	X	18,659	KW BILLING DEMAND		($628.2

SUBTOTAL	$629,580.7
ARIZONA CORPORATION COMMISSION ASSESSMENT	$859.3
STATE SALES TAX	$31,519.9
TOTAL CURRENT AMOUNT	$661,960.(
ARREARS AMOUNT	$647,774.9
TOTAL AMOUNT DUE	$1,309,734.9

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ACCOUNT
2325-2001-1
CONTRACT NO.
FO26O1-79-DOO23

DATE OF BILL: June 27, 1996
DATE DELINQUENT: July 11, 1996

TUCSON ELECTRIC POWER COMPANY
SERVICES RENDERED
U. S. A. F. DAVIS MONTHAN AIR FORCE BASE
MAY 24, 1996 TO JUNE 25, 1996

DEMAND CHARGE

18,344 KW	@	$10.28	PER KW	$188,576.32

18,344.0 KW ACTUAL DEMAND
9,250.0 KW MINIMUM DEMAND (18,500 KW MAXIMUM DEMAND)
EFFECTIVE APRIL 7, 1987
13,278.0 KW 66.7% OF THE HIGHEST BILLING DEMAND IN THE PAST
ELEVEN (11) MONTHS 19,907 KW —AUGUST 1995
18,344.0 KW BILLING DEMAND

ENERGY CHARGE

9,024,360 KWH	@	0.047457	PER KWH	$428,269.05

POWER FACTOR ADJUSTMENT

93.17	-90.00	=	3.17		
3.17	X	0.013	=	-0.04121	
-0.04121	X	18,344	KW BILLING DEMAND		($755.96)

UBTOTAL	$616,089.41
RIZONA CORPORATION COMMISSION ASSESSMENT	$840.97
TATE SALES TAX	$30,844.52
OTAL CURRENT AMOUNT	$647,774.90
RREARS AMOUNT	$575,399.82
OTAL AMOUNT DUE	$1,223,174.72

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Appendix D: Spreadsheet Calculation Based on Option #2a

Historic

With Engine Generator
Operating 3 of 6 Months (Summer)
Operating 3 of 6 Months (Winter)

Month	Billing Demand	Actual Demand	Month	Billing Demand	Actual Demand
JUL 96 (S)	18,659	18,659	+JUL 98 (S)	18,104	18,104
AUG 96(S)	18,805	18,805	+AUG 98 (S)	18,250	18,250
*SEP 96(S)	17,876	17,876	++SEP 98 (S)	17,876	17,876
OCT 96 (S)	16,947	16,947	+OCT 98 (S)	16,392	16,392
NOV 96(W)	12,543	11,606	++NOV 98 (W)	12,173	11,606
DEC 96(W)	12,543	10,787	+DEC 98 (W)	12,173	10,232
JAN 97 (W)	12,543	11,141	++JAN 99 (W)	12,173	11,141
FEB 97 (W)	12,543	10,696	+FEB 99 (W)	12,173	10,141
MAR 97(W)	12,613	12,613	++MAR 99 (W)	12,613	12,613
APR 97 (W)	14,142	14,142	+APR 99 (W)	13,587	13,587
MAY 97 (S)	17,026	17,026	++MAY 99 (S)	17,026	17,026
JUN 97 (S)	18,099	18,099	++JUN 99 (S)	18,099	18,099

SAVINGS		RECAP FOR SEASON
JUL	555 kW	Summer:
AUG	555 kW	3 months @ 555 kW reduction each
SEP	0 kW	3 months @ 0 kW reduction each
OCT	555 kW	Winter:
NOV	370 kW	4 months @ 370 kW reduction each
DEC	370 kW	1 month @ 555 kW reduction each
JAN	370 kW	1 month @ 0 kW reduction each
FEB	370 kW	
MAR	0 kW	
APR	555 kW	
MAY	0 kW	
JUN	0 kW	

"*" indicates data that has been averaged between the month preceding and that following.
"+" symbol indicates a month in which the engine-generator operated continuously,
"++" indicates a month when it did not.
(S) denotes a Summer month, while (W) denotes a Winter month.

Appendix E: Spreadsheet Calculation Based on Option #2b

Historic			With Engine Generator Operating 3 of 6 Months (Summer) Operating 3 of 6 Months (Winter)		
Month	**Billing Demand**	**Actual Demand**	**Month**	**Billing Demand**	**Actual Demand**
JUL 96 (S)	18,659	18,659	+JUL 98 (S)	17,900	17,900
AUG 96(S)	18,805	18,805	+AUG 98 (S)	18,046	18,046
*SEP 96(S)	17,876	17,876	++SEP 98 (S)	17,876	17,876
OCT 96 (S)	16,947	16,947	+OCT 98 (S)	16,188	16,188
NOV 96(W)	12,543	11,606	++NOV 98 (W)	12,037	11,606
DEC 96(W)	12,543	10,787	+DEC 98 (W)	12,037	10,028
JAN 97 (W)	12,543	11,141	++JAN 99 (W)	12,037	11,141
FEB 97 (W)	12,543	10,696	+FEB 99 (W)	12,037	9,937
MAR 97(W)	12,613	12,613	++MAR 99 (W)	12,613	12,613
APR 97 (W)	14,142	14,142	+APR 99 (W)	13,383	13,383
MAY 97 (S)	17,026	17,026	++MAY 99 (S)	17,026	17,026
JUN 97 (S)	18,099	18,099	++JUN 99 (S)	18,099	18,099

SAVINGS		**RECAP FOR SEASON**
JUL	759 kW	Summer:
AUG	759 kW	3 months @ 759 kW reduction each
SEP	0 kW	3 months @ 0 kW reduction each
OCT	759 kW	Winter:
NOV	506 kW	4 months @ 506 kW reduction each
DEC	506 kW	1 month @ 759 kW reduction each
JAN	506 kW	1 month @ 0 kW reduction each
FEB	506 kW	
MAR	0 kW	
APR	759 kW	
MAY	0 kW	
JUN	0 kW	

"*" indicates data that has been averaged between the month preceding and that following.
"+" symbol indicates a month in which the engine-generator operated continuously,
"++" indicates a month when it did not.
(S) denotes a Summer month,
(W) denotes a Winter month.
( )-number within = #units operating continuously for that month

Appendix F: Spreadsheet Calculation Based on Options #2c and 3a

Historic			With Engine Generator		
Month	**Billing Demand**	**Actual Demand**	**Month**	**Billing Demand**	**Actual Demand**
JUL 96 (S)	18,659	18,659	JUL 98 (S)	17,141	17,141 (2)
AUG 96(S)	18,805	18,805	AUG 98 (S)	17,287	17,287 (2)
*SEP 96(S)	17,876	17,876	SEP 98 (S)	17,117	17,117 (1)
OCT 96 (S)	16,947	16,947	OCT 98 (S)	15,429	15,429 (2)
NOV 96(W)	12,543	11,606	NOV 98 (W)	11,530	10,847 (1)
DEC 96(W)	12,543	10,787	DEC 98 (W)	11,530	9,269 (2)
JAN 97 (W)	12,543	11,141	JAN 99 (W)	11,530	10,382 (1)
FEB 97 (W)	12,543	10,696	FEB 99 (W)	11,530	9,178 (2)
MAR 97(W)	12,613	12,613	MAR 99 (W)	11,854	11,854 (1)
APR 97 (W)	14,142	14,142	APR 99 (W)	12,624	12,624 (2)
MAY 97 (S)	17,026	17,026	MAY 99 (S)	16,267	16,267 (1)
JUN 97 (S)	18,099	18,099	JUN 99 (S)	17,340	17,340 (1)

SAVINGS		RECAP FOR SEASON
JUL	1,518 kW	Summer:
AUG	1,518 kW	3 months @ 1,518 kW reduction each
SEP	759 kW	3 months @ 759 kW reduction each
OCT	1,518 kW	Winter:
NOV	1,013 kW	4 months @ 1,013 kW reduction each
DEC	1,013 kW	1 month @ 759 kW reduction each
JAN	1,013 kW	1 month @ 1,518 kW reduction each
FEB	1,013 kW	
MAR	759 kW	
APR	1,518 kW	
MAY	759 kW	
JUN	759 kW	

"*" indicates data that's been averaged between the month preceding and that following.
(S) denotes a Summer month
(W) denotes a Winter month
( )-number within = #units operating continuously for that month

Appendix G: Spreadsheet Calculation Based on Options #2d and 3c

Historic Month	Billing Demand	Actual Demand	With Engine Generator Month	Billing Demand	Actual Demand
JUL 96 (S)	18,659	18,659	JUL 98 (S)	16,382	16,382 (3)
AUG 96(S)	18,805	18,805	AUG 98 (S)	16,528	16,528 (3)
*SEP 96(S)	17,876	17,876	SEP 98 (S)	16,358	16,358 (2)
OCT 96 (S)	16,947	16,947	OCT 98 (S)	15,429	15,429 (2)
NOV 96(W)	12,543	11,606	NOV 98 (W)	11,024	9,329 (3)
DEC 96(W)	12,543	10,787	DEC 98 (W)	11,024	9,269 (2)
JAN 97 (W)	12,543	11,141	JAN 99 (W)	11,024	9,623 (2)
FEB 97 (W)	12,543	10,696	FEB 99 (W)	11,024	9,178 (2)
MAR 97(W)	12,613	12,613	MAR 99 (W)	11,095	11,095 (2)
APR 97 (W)	14,142	14,142	APR 99 (W)	11,865	11,865 (3)
MAY 97 (S)	17,026	17,026	MAY 99 (S)	15,508	15,508 (2)
JUN 97 (S)	18,099	18,099	JUN 99 (S)	16,581	16,581 (2)

SAVINGS		RECAP FOR SEASON
JUL	2,277 kW	Summer:
AUG	2,277 kW	4 months @ 1,518 kW reduction each
SEP	1,518 kW	2 months @ 2,277 kW reduction each
OCT	1,518 kW	Winter:
NOV	1,519 kW	4 months @ 1,519 kW reduction each
DEC	1,519 kW	1 month @ 2,277 kW reduction each
JAN	1,519 kW	1 month @ 1,518 kW reduction each
FEB	1,519 kW	
MAR	1,518 kW	
APR	2,277 kW	
MAY	1,518 kW	
JUN	1,518 kW	

"*" indicates data that has been averaged between the month preceding and that following.
(S) denotes a Summer month
(W) denotes a Winter month
( )-number within = #units operating continuously for that month

Appendix H: Spreadsheet Calculation Based on Option #3b

Historic			With Engine Generator		
Month	**Billing Demand**	**Actual Demand**	**Month**	**Billing Demand**	**Actual Demand**
JUL 96 (S)	18,659	18,659	JUL 98 (S)	15,623	15,623 (4)
AUG 96(S)	18,805	18,805	AUG 98 (S)	15,769	15,769 (4)
*SEP 96(S)	17,876	17,876	SEP 98 (S)	15,599	15,599 (3)
OCT 96 (S)	16,947	16,947	OCT 98 (S)	14,670	14,670 (3)
NOV 96(W)	12,543	11,606	NOV 98 (W)	10,518	8,570 (4)
DEC 96(W)	12,543	10,787	DEC 98 (W)	10,518	8,510 (3)
JAN 97 (W)	12,543	11,141	JAN 99 (W)	10,518	8,864 (3)
FEB 97 (W)	12,543	10,696	FEB 99 (W)	10,518	8,419 (3)
MAR 97(W)	12,613	12,613	MAR 99 (W)	10,518	10,336 (3)
APR 97 (W)	14,142	14,142	APR 99 (W)	11, 106	11,106 (4)
MAY 97 (S)	17,026	17,026	MAY 99 (S)	14,749	14,749 (3)
JUN 97 (S)	18,099	18,099	JUN 99 (S)	15,822	15,822 (3)

SAVINGS		RECAP FOR SEASON
JUL	3,036 kW	Summer:
AUG	3,036 kW	4 months @ 2,277 kW reduction each
SEP	2,277 kW	2 months @ 3,036 kW reduction each
OCT	2,277 kW	Winter:
NOV	2,025 kW	4 months @ 2,025 kW reduction each
DEC	2,025 kW	1 month @ 2,095 kW reduction each
JAN	2,025 kW	1 month @ 3,036 kW reduction each
FEB	2,025 kW	
MAR	2,095 kW	
APR	3,036 kW	
MAY	2,277 kW	
JUN	2,277 kW	

"*" indicates data that's been averaged between the month preceding and that following.

(S) denotes a Summer month

(W) denotes a Winter month

( )-number within = #units operating continuously for that month

Appendix I: Spreadsheet Calculation Based on Option #3d

Historic			With Engine Generator		
Month	Billing Demand	Actual Demand	Month	Billing Demand	Actual Demand
JUL 96 (S)	18,659	18,659	JUL 98 (S)	14,105	14,105 (6)
AUG 96(S)	18,805	18,805	AUG 98 (S)	14,251	14,251 (6)
*SEP 96(S)	17,876	17,876	SEP 98 (S)	14,081	14,081 (5)
OCT 96 (S)	16,947	16,947	OCT 98 (S)	13,911	13,911 (4)
NOV 96(W)	12,543	11,606	NOV 98 (W)	9,505	7,052 (6)
DEC 96(W)	12,543	10,787	DEC 98 (W)	9,505	6,992 (5)
JAN 97 (W)	12,543	11,141	JAN 99 (W)	9,505	8,105 (4)
FEB 97 (W)	12,543	10,696	FEB 99 (W)	9,505	6,901 (5)
MAR 97(W)	12,613	12,613	MAR 99 (W)	9,577	9,577 (4)
APR 97 (W)	14,142	14,142	APR 99 (W)	9,588	9,588 (6)
MAY 97 (S)	17,026	17,026	MAY 99 (S)	13,990	13,990 (4)
JUN 97 (S)	18,099	18,099	JUN 99 (S)	14,304	14,304 (5)

SAVINGS		RECAP FOR SEASON
JUL	4,554 kW	Summer:
AUG	4,554 kW	2 months @ 4,554 kW reduction each
SEP	3,795 kW	2 months @ 3,795 kW reduction each
OCT	3,036 kW	2 months @ 3,036 kW reduction each
NOV	4,554 kW	Winter:
DEC	3,795 kW	4 months @ 3,038 kW reduction each
JAN	3,036 kW	1 month @ 4,554 kW reduction each
FEB	3,795 kW	1 month @ 3,036 kW reduction each
MAR	3,036 kW	
APR	4,554 kW	
MAY	3,036 kW	
JUN	3,795 kW	

"*" indicates data that has been averaged between the month preceding and that following.
(S) denotes a Summer month
(W) denotes a Winter month
( )-number within = #units operating continuously for that month.

Appendix J: Construction Cost Estimates for Each Option

Equipment (Option 1)	*Material Cost*	*Installation Cost*	*Total Cost*
250-Ton Natural Gas Engine-Driven Chiller	168,000		$168,000
Chiller Startup		4,000	$4,000
Shipping		4,350	$4,350
Exhaust Heat Recovery		16,000	$16,000
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$230,940**
Bond @ 2% (4,619) + Contractors fee @ 6% (13,856) + State taxes @ 5% (11,547)			$30,022
Alternate bid estimate			**$260,963**

Equipment (Option #2a)	*Material Cost*	*Installation Cost*	*Total Cost*
One (1) Caterpillar G3512 Natural Gas-Fired Engine Generator Unit, 600 KWe, 2,091,660 Btu/hr	54,560		$54,560
100-Ton Single-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $28,750 (matl), $17,750 (inst))	28,750	17,750	$46,500
Feedwater Unit	13,560		$13,560
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			$155,762
Bond @ 2% ($3,115) + Contractors fee @ 6% ($9,346) + State taxes @ 5% ($7,788)			$20249
Alternate bid estimate			$176,011

Equipment (Option #2b)	*Material Cost*	*Installation Cost*	*Total Cost*
One (1) Caterpillar G3516 Natural Gas-Fired Engine Generator Unit, 820 KWe, 1,010,000 Btu/hr	80,660		80,660
100-Ton Double-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $28,750 (matl), $17,750 (inst))	28,750	17,750	$46,500
Feedwater Unit	18,540		18,540
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,17[illegible]
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$186,842**
Bond @ 2% ($3,737) + Contractors fee @ 6% ($11,211) + State taxes @ 5% ($9,342)			$24,290
Alternate bid estimate			**$211,132**

Equipment (Option #2c)	***Material Cost***	***Installation Cost***	***Total Cost***
Two (2) Caterpillar G3516 Natural Gas-Fired Engine Generator Units, 1,640 KWe, 5,773,320 Btu/hr	108,480		108,480
250-Ton Single-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $145,375 (matl), $63,875 (inst))	145,375	63,875	$209,250
Feedwater Unit	19,340		19,340
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$378,212**
Bond @ 2% ($7,564) + Contractors fee @ 6% ($22,693) + State taxes @ 5% ($18,911)			$49,168
Alternate bid estimate			**$427,380**

Equipment (Option #2d)	Material Cost	Installation Cost	Total Cost
Three (3) Caterpillar G3516 Natural Gas-Fired Engine Generator Units, 2,460 KWe, 3,030,000 Btu/hr	232,920		$232,920
250-Ton Single-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $145,375 (matl), $63,875 (inst))	145,375	63,875	$209,250
Feedwater Unit	23,920		$23,920
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			$507,232
Bond @ 2% ($10,145) + Contractors fee @ 6% ($30,434) + State taxes @ 5% ($25,362)			$65,941
Alternate bid estimate			$573,173

Equipment (Option #3a)	*Material Cost*	*Installation Cost*	*Total Cost*
Two (2) Caterpillar G3512 Natural Gas-Fired Engine Generator Units, 1,640 KWe, 5,773,320 Btu/hr	106,920		106,920
250-Ton Single-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $145,375 (matl), $63,875 (inst))	28,750	17,750	$46,500
Feedwater Unit	19,340		19,340
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$213,902**
Bond @ 2% ($4,278) + Contractors fee @ 6% ($12,834) + State taxes @ 5% ($10,695)			$27,807
Alternate bid estimate			**$241,709**

Equipment (Option #3b)	Material Cost	Installation Cost	Total Cost
Four (4) Caterpillar G3516 Natural Gas-Fired Engine Generator Units, 3,280 KWe, 4,040,000 Btu/hr	312,620		312,620
100-Ton Double-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $28,750 (matl), $17,750 (inst))	28,750	17,750	$46,500
Feedwater Unit	25,800		25,800
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			$426,062
Bond @ 2% ($8,521) + Contractors fee @ 6% ($25,564) + State taxes @ 5% ($21,303)			$55,388
Alternate bid estimate			$481,450

Equipment (Option #3c)	*Material Cost*	*Installation Cost*	*Total Cost*
Three (3) Caterpillar G3516 Natural Gas-Fired Engine Generator Units, 2,480 KWe, 8,659,660 Btu/hr	154,080		154,080
250-Ton Single-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $145,375 (matl), $63,875 (inst))	145,375	63,875	$209,250
Feedwater Unit	22,840		25,800
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$427,312**
Bond @ 2% ($8,546) + Contractors fee @ 6% ($25,639) + State taxes @ 5% ($21,366)			$55,551
Alternate bid estimate			**$482,863**

Equipment (Option #3d)	Material Cost	Installation Cost	Total Cost
Six (6) Caterpillar Natural Gas-Fired Engine Generator Units, 4,920 KWe, 6,060,000 Btu/hr	461,220		461,220
250-Ton Double-Effect Indirect-Fired Absorption Chiller (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for gas absorption chiller, water cooled: $145,375 (matl), $63,875 (inst))	145,375	63,875	$209,250
Feedwater Unit	30,460		30,460
Cogeneration Unit Base (22' x 34') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	2,069	485	$2,554
Transformer Base (10' x 10') - 16" thick concrete slab (Tucson, AZ cost index = 96.7 for matl, 84.2 for inst; data interpolated based on 1997 Means Mech Cost Data for concrete slabs: $2.86/sq ft (matl), $0.77/sq ft (inst))	277	65	$342
Condensate Cooler (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; data interpolated based on 1997 Means Mech Cost Data for hot water shell and tube heat exchanger with 10 GPM condensate return and 200 deg F return outlet: $1108 (matl), $79 (inst))	1,106	65	$1,171
Duplex Condensate Return Unit/Cast Iron Receiver (Tucson, AZ cost index = 99.8 for matl, 82.0 for inst; 1997 Means Mech Cost Data: $2750 (matl), $885 (inst))	2,745	726	$3,471
122.5 Ft of Chain Link Fence, 7' High (Tucson, AZ cost index = 98.3 for matl, 81.8 for inst; data interpolated based on 1997 Means Mech Cost Data for chain link fencing: $4.35/ft (matl), $5.40/ft (inst))	524	541	$1,065
Demolition of 250-Ton Electric Centrifugal Chiller, Weight = 10,010 lb based on 1989 YORK CodePak data (Tucson, AZ cost index = 96.3; 1997 Means Mech Cost Data: $495/(2000 lb))		2,386	$2,386
Gas piping based on 35 psig inlet pressure, 17,200 CFH, 1" OD Schedule 40 steel pipe, 3007.5 ft total length (Tucson, AZ cost index = 71.7 for matl, 96.3 for inst; 1997 Means Mech Cost Data: $3.48/ft (matl), $4.95/ft (inst))	7,504	14,336	$21,840
Field office trailer rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $145/mo)	263		$263
Telephone bill usage for 8 weeks incl. long dist (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $230/mo)	417		$417
Labor for job superintendent for 8 weeks, 8 hrs/day, 5 days/wk (Tucson, AZ cost index = 81.8; 1997 Means Mech Cost Data: $27.10/hr)		7,094	$7,094
Field office supplies for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $83/mo)	151		$151
Field office lights and HVAC for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $86/mo)	156		$156
Field office equipment rental for 8 weeks (Tucson, AZ cost index = 98.3 for matl; 1997 Means Mech Cost Data: $129/mo)	234		$234
Sub-total			**$742,072**
Bond @ 2% ($14,841) + Contractors fee @ 6% ($44,524) + State taxes @ 5% ($37,104)			$96,469
Alternate bid estimate			**$838,541**

Appendix K: Energy Cost Estimates for Each Option

Option #1 - 250-Ton Capacity Natural Gas Engine-Driven Chiller

Cooling Load (Tons)	# Hours at Load	Ton-Hours	ChillerNat'l Gas Used (Btu/hr)	Chiller Natural Gas Consumption (MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas Used ($)	kW/ton if Existing Motor-Driven Centrifugal Chiller is Used
	May-Oct						
250	479	119,750	2,033,000	973.807	2.75	2,677.97	0.640
225	384	86,400	1,751,000	672.384	2.75	1,849.06	0.631
200	836	167,200	1,504,000	1,257.344	2.75	3,457.70	0.605
175	620	108,500	1,270,000	787.400	2.75	2,165.35	0.594
150	517	77,550	1,061,000	548.537	2.75	1,508.48	0.600
125	213	26,625	856,000	182.328	2.75	501.40	0.608
100	122	12,200	661,000	80.642	2.75	221.77	0.640
	Nov-Apr						
250	123	30,750	2,033,000	250.059	3.90	975.23	0.640
225	150	33,750	1,751,000	262.650	3.90	1,024.34	0.631
200	330	66,000	1,504,000	496.320	3.90	1,935.65	0.605
175	857	149,975	1,270,000	1,088.390	3.90	4,244.72	0.594
150	1225	183,750	1,061,000	1,299.725	3.90	5,068.93	0.600
125	986	123,250	856,000	844.016	3.90	3,291.66	0.608
100	482	48,200	661,000	318.602	3.90	1,242.55	0.640

kW if Existing Motor-Driven Centrifugal Is Used	kWh if Centrifugal Used	Rate for Demand ($/kW)	Cost for Demand ($)	Elec Energy Rate ($/kWh)	Cost for Elec Energy ($)	Total Elec Cost Savings ($)	"Waste" Heat From Chiller Operation (Btu/hr)
160	76,640	10.75	6,881.84	$0.0496	3,804.41	10,686.25	638,000
142	54,528	10.75	3,053.82	$0.0496	2,706.77	5,760.59	539,000
121	101,156	10.75	0	$0.0496	5,021.39	5,021.39	446,000
104	64,480	10.75	0	$0.0496	3,200.79	3,200.79	357,000
90	46,530	10.75	0	$0.0496	2,309.75	2,309.75	306,000
76	16,188	10.75	0	$0.0496	803.57	803.57	267,000
64	7,808	10.75	0	$0.0496	387.59	387.59	192,000
160	19,680	10.75	3,440.92	$0.0472	928.07	4,368.99	638,000
142	21,300	10.75	0	$0.0472	1,004.46	1,004.46	539,000
121	39,930	10.75	0	$0.0472	1,883.01	1,883.01	446,000
104	89,128	10.75	0	$0.0472	4,203.09	4,203.09	357,000
90	110,250	10.75	0	$0.0472	5,199.15	5,199.15	306,000
76	74,936	10.75	0	$0.0472	3,533.82	3,533.82	267,000
64	30,848	10.75	0	$0.0472	1,454.73	1,454.73	192,000

"Waste" Heat Energy for Thermal Use (MBtu)	Thermal Energy Required (MBtu)	Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)
305.602		638,000	817,949	391.797	1,077.44	9,085.73
206.976		539,000	691,026	265.354	729.72	4,641.26
372.856		446,000	571,795	478.021	1,314.56	2,878.25
221.34		357,000	457,692	283.769	780.37	1,815.80
158.202		306,000	392,308	202.823	557.76	1,359.04
56.871		267,000	342,308	72.912	200.51	502.68
23.424		192,000	246,154	30.031	82.58	248.41
1,345.27	5,802.87					
78.474		638,000	817,949	100.608	392.37	3,786.13
80.85		539,000	691,026	103.654	404.25	384.38
147.18		446,000	571,795	188.692	735.90	683.27
305.949		357,000	457,692	392.242	1,529.75	1,488.11
374.85		306,000	392,308	480.577	1,874.25	2,004.48
263.262		267,000	342,308	337.515	1,316.31	1,558.47
92.544		192,000	246,154	118.646	462.72	674.90
1,343.11	8,073.84					

Notes re cost: from Jeff Glick,
8/8/97
Cost of unit =
$168,000
Startup =
$4,000
Shipping =
$4,350
Exhaust heat recovery = $16,000
Tecogen does not recommend
exhaust heat
recovery if there will be low part
load operation
since exhaust velocities will be low and there
will
likely be stack corrosion.

Note: During Summer months, peak of 250 tons is experienced for 4 months,
May - August, inclusive. Peak for September and October is 225 tons.

Basis for comparison: Base case would be status quo and the energy expenses would be Columns R + AC.

Energy expenses for alternative (Option #1) would be Columns H.

Option #2a - Natural Gas-Fired Engine-Generator with 100-Ton Capacity

Single-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't)

Cooling Load (Tons)	# Hours at Load May-Oct	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
250	479	555.36	599	332,661	10.75	5,972	$ 0.0496	16,513.28
225	384	555.36	599	332,661	10.75	5,972	$ 0.0496	16,513.28
200	836	555.36	599	332,661	10.75	5,972	$ 0.0496	16,513.28
175	620	0	599	332,661	10.75	0	$ 0.0496	16,513.28
150	517	0	599	332,661	10.75	0	$ 0.0496	16,513.28
125	213	0	599	332,661	10.75	0	$ 0.0496	16,513.28
100	122	0	601	333,771	10.75	0	$ 0.0496	16,568.42
	3171							115,648.11
	Nov-Apr							
250	123	555.36	608	337,659	10.75	5,972	$ 0.0472	15,923.27
225	150	370	608	337,659	10.75	3,979	$ 0.0472	15,923.27
200	330	370	608	337,659	10.75	3,979	$ 0.0472	15,923.27
175	857	370	608	337,659	10.75	3,979	$ 0.0472	15,923.27
150	1225	370	608	337,659	10.75	3,979	$ 0.0472	15,923.27
125	986	0	608	337,659	10.75	0.00	$ 0.0472	15,923.27
100	482	0	609	338,214	10.75	0.00	$ 0.0472	15,151.99

Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)	kW/ton for All Elec Cool	kW for All Electric Cooling
6,025,860	3,609.490	2.75	9,926.10	100	0.640	160
6,025,860	3,609.490	2.75	9,926.10	100	0.631	142
6,025,860	3,609.490	2.75	9,926.10	100	0.605	121
6,025,860	3,609.490	2.75	9,926.10	100	0.594	104
6,025,860	3,609.490	2.75	9,926.10	100	0.600	90
6,025,860	3,609.490	2.75	9,926.10	100	0.608	76
6,025,860	3,621.542	2.75	9,959.24	100	0.640	64
			69,515.83			
6,025,860	3,663.723	3.90	14,288.52	100	0.640	160
6,025,860	3,663.723	3.90	14,288.52	100	0.631	142
6,025,860	3,663.723	3.90	14,288.52	100	0.605	121
6,025,860	3,663.723	3.90	14,288.52	100	0.594	104
6,025,860	3,663.723	3.90	14,288.52	100	0.600	90
6,025,860	3,663.723	3.90	14,288.52	100	0.608	76
6,025,860	3,669.749	3.90	14,312.02	100	0.640	64

kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for 100 tons Abs	Btu/hr for 100 tons Abs Cool	MBtu for 100 tons Abs Cool	Remaining Tons of Elec Cool	kW/ton for Remaining Elec Cool	kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling
6,881.84	3,804.41	10,686.25	17.74	1,679,824	804.636	150	0.605	90.75	3903.295
3053.82	2,706.77	5,760.59	17.92	1,696,108	651.305	125	0.615	76.88	1653.255
0	5,021.39	5,021.39	18.09	1,712,391	1431.559	100	0.650	65.00	0
0	3,200.79	3,200.79	18.26	1,728,674	1071.778	75	0.713	53.48	0
0	2,309.75	2,309.75	18.09	1,712,391	885.306	50	0.681	34.05	0
0	803.57	803.57	18.09	1,712,391	364.739	25	0.799	19.98	0
0	387.59	387.59	17.74	1,679,824	204.939	0		0	0
	18,234.27								
3440.92	928.07	4,368.99	17.74	1,679,824	206.618	150	0.605	90.75	1951.65
0	1,004.46	1,004.46	17.92	1,696,108	254.416	125	0.615	76.88	0
0	1,883.01	1,883.01	18.09	1,712,391	565.089	100	0.650	65.00	0
0	4,203.09	4,203.09	18.26	1,728,674	1481,474	75	0.713	53.48	0
0	5,199.15	5,199.15	18.09	1,712,391	2097.679	50	0.681	34.05	0
0	3,533.82	3,533.82	18.09	1,712,391	1688.417	25	0.799	19.98	0
0	1,454.73	1,454.73	17.74	1,679,824	809.675	0		0	0

kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling	Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)
43,469	2,157.81	6,061.11	4,625.14	2,091,660	1,679,824
29,520	1,465.37	3,118.63	2,641.96	2,091,660	1,696,108
54,340	2,697.44	2,697.44	2,323.95	2,091,660	1,712,391
33,155	1,645.79	1,645.79	1,555.00	2,091,660	1,728,674
17,604	873.86	873.86	1,435.89	2,091,660	1,712,391
4,255	211.20	211.20	592.37	2,091,660	1,712,391
0	0.00	0.00	387.59	2,091,660	1,679,824
	9,051.47				
11,162	526.39	2,478.04	1,890.95	2,091,660	1,679,824
11,531	543.79	543.79	460.67	2,091,660	1,696,108
21,450	1,011.54	1,011.54	871.48	2,091,660	1,712,391
45,828	2,161.15	2,161.15	2,041.93	2,091,660	1,728,674
41,711	1,967.01	1,967.01	3,232.14	2,091,660	1,712,391
19,695	928.79	928.79	2,605.03	2,091,660	1,712,391
0	0.00	0.00	1,454.73	2,091,660	1,679,824

Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)	Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)
411,836	684.471		411,836	527,994	877.526
395,552	151.892		395,552	507,118	194.733
379,269	317.069		379,269	486,242	406.499
362,986	225.051		362,986	465,366	288.527
379,269	196.082		379,269	486,242	251.387
379,269	80.784		379,269	486,242	103.570
411,836	50.244		411,836	527,994	64.415
	1,705.593	5,802.874			2186.658
411,836	127.669		411,836	527,994	163.678
395,552	59.333		395,552	507,118	76.068
379,269	125.159		379,269	486,242	160.460
362,986	311.079		362,986	465,366	398.819
379,269	464.605		379,269	486,242	595.647
379,269	373.959		379,269	486,242	479.435
411,836	198.505		411,836	527,994	254.493

Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)	Total Gas Costs ($)	
2,413.20	$19,597.25	45,670	246,590.18	155,244.11	Per Engineering Controls: One (1) Caterpillar G3512 -- 600 Kwe; 2,091,660 Btu/hr; $54,560.00 Feedwater unit adds -- $13,560.00
535.52	$15,736.38				
1,117.87	$16,000.72				
793.45	$8,935.63				
691.32	$8,714.39				
284.82	$7,464.37				
177.14	$7,173.91				
6,013.31					
638.35	$10,135.77				
296.66	$6,370.66				
625.79	$7,110.59				
1,555.39	$9,210.64				
2,323.02	$11,168.48				
1,869.80	$6,109.58				
992.52	$3,287.22				
8,301.54					

Basis for comparison: Base case would be status quo and the energy expenses would be Columns K + Z + BD.
Energy expenses for alternative (Option #2) would be Columns R + AL.

Note: This basis of comparison applies for all options with engine-generator sets.

Recurring O&M Cost = $50,991

Yearly One-Time Costs =

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
0	16,934	15,797	55,950	15,458	16,724	55,542	17,998	18,115	56,639

Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
16,586	18,184	54,056	0	18,527	72,476	0	19,212	16,250	55,120

Option #2b - Natural Gas-Fired Engine-Generator with 100-Ton Capacity
Double-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't)

Cooling Load (Tons)	# Hours at Load	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
	May-Oct							
250	479	758.99	599	454,636	10.75	8,161.35	$ 0.0496	22,568.15
225	384	758.99	599	454,636	10.75	8,161.35	$ 0.0496	22,568.15
200	836	758.99	599	454,636	10.75	8,161.35	$ 0.0496	22,568.15
175	620	0	599	454,635	10.75	0.00	$ 0.0496	22,568.09
150	517	0	599	454,635	10.75	0.00	$ 0.0496	22,568.09
125	213	0	599	454,635	10.75	0.00	$ 0.0496	22,568.09
100	122	0	601	456,153	10.75	0.00	$ 0.0496	22,643.44
	Nov-Apr							
250	123	758.99	608	461,467	10.75	8,161.35	$ 0.0472	21,761.80
225	150	506.00	608	461,466	10.75	5,440.96	$ 0.0472	21,761.75
200	330	506.00	608	461,466	10.75	2,710	$ 0.0472	21,761.75
175	857	506.00	608	461,466	10.75	0.00	$ 0.0472	21,761.75
150	1225	506.00	608	461,466	10.75	0.00	$ 0.0472	21,761.75
125	986	0.00	608	461,466	10.75	0.00	$ 0,0472	21,761.75
100	482	0	609	462,225	10.75	0.00	$ 0.0472	21,797.54

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
30,729.50	7,933,260	4,752.023	2.75	$13,068.06	100
30,729.50	7,933,260	4,752.023	2.75	$13,068.06	100
30,729.50	7,933,260	4,752.023	2.75	$13,068.06	100
22,568.09	7,933,260	4,752.023	2.75	$13,068.06	100
22,568.09	7,933,260	4,752.023	2.75	$13,068.06	100
22,568.09	7,933,260	4,752.023	2.75	$13,068.06	100
22,643.44	7,933,260	4,767.889	2.75	$13,111.70	100
29,923.15	7,933,260	4,823.422	3.90	$18,811.35	100
27,202.70	7,933,260	4,823.422	3.90	$18,811.35	100
24,471.47	7,933,260	4,823.422	3.90	$18,811.35	100
21,761.75	7,933,260	4,823.422	3.90	$18,811.35	100
21,761.75	7,933,260	4,823.422	3.90	$18,811.35	100
21,761.75	7,933,260	4,823.422	3.90	$18,811.35	100
21,797.54	7,933,260	4,831.355	3.90	$18,842.29	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for 100 tons Abs	Btu/hr for 100 tons Abs Cool	MBtu for 100 tons Abs Cool	Remaining Tons of Elec Cool	kW/ton for Remaining Elec Cool
0.640	160	$6,881.84	3804.41	10,686.25	8.83	772140.5	369.855	150	0.605
0.631	142	$3,053.82	2706.77	5,760.59	8.92	779629	299.378	125	0.615
0.605	121	$0.00	5021.39	5,021.39	9.01	787117.4	658.030	100	0.650
0.594	104	$0.00	3200.79	3,200.79	9.09	794605.8	492.656	75	0.713
0.600	90	$0.00	2309.75	2,309.75	9.01	787117.4	406.940	50	0.681
0.608	76	$0.00	803.57	803.57	9.01	787117.4	167.656	25	0.799
0.640	64	$0.00	387.59	387.59	8.83	772140.5	94.201	0	
0.640	160	$3,440.92	928.07	$4,368.99	8.83	772140.5	94.973	150	0.605
0.631	142	$0.00	1004.46	$1,004.46	8.92	779629	116.944	125	0.615
0.605	121	$0.00	1883.01	$1,883.01	9.01	787117.4	259.749	100	0.650
0.594	104	$0.00	4203.09	$4,203.09	9.09	794605.8	680.977	75	0.713
0.600	90	$0.00	5199.15	$5,199.15	9.01	787117.4	964.219	50	0.681
0.608	76	$0.00	3533.82	$3,533.82	9.01	787117.4	776.098	25	0.799
0.640	64	$0.00	1454.73	$1,454.73	8.83	772140.5	372.172	0	

kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
90.75	3903.295	43469	2157.81	6061.11	$4,625.14
76.88	1653.255	29520	1465.37	3118.63	$2,641.96
65.00	0	54340	2697.44	2697.44	$2,323.95
53.48	0	33155	1645.79	1645.79	$1,555.00
34.05	0	17604	873.86	873.86	$1,435.89
19.98	0	4255	211.20	211.20	$592.37
0	0	0	0	0	$387.59
90.75	1951.65	11162	526.39	2478.04	$1,890.95
76.88	0	11531	543.79	543.79	$460.67
65.00	0	21450	1011.54	1011.54	$871.48
53.48	0	45828	2161.15	2161.15	$2,041.93
34.05	0	41711	1967.01	1967.01	$3,232.14
19.98	0	19695	928.79	928.79	$2,605.03
0	0	0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)
1,010,000	772,141	237,859	395.322	
1,010,000	779,629	230,371	88.46247	
1,010,000	787,117	222,883	186.3298	
1,010,000	794,606	215,394	133.5444	
1,010,000	787,117	222,883	115.2303	
1,010,000	787,117	222,883	47.47399	
1,010,000	772,141	237,859	29.01885	
			995.382	5802.874
1,010,000	772,141	237,859	73.736	
1,010,000	779,629	230,371	34.55565	
1,010,000	787,117	222,883	73.55126	
1,010,000	794,606	215,394	184.5928	
1,010,000	787,117	222,883	273.0312	
1,010,000	787,117	222,883	219.7622	
1,010,000	772,141	237,859	114.6483	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
237,859	304948	506.824	1393.76	$23,680.35	46,664	330,670.71
230,371	295347	113.41343	311.89	$20,615.29		
222,883	285747	238.88442	656.93	$20,642.32	Recurring O&M Cost =	
215,394	276146	171.21074	470.83	$11,525.86	YearlyOne-Time Costs=	
222,883	285747	147.73115	406.26	$11,342.18		
222,883	285747	60.864092	167.38	$10,259.78		
237,859	304948	37.203659	102.31	$10,021.65		
		1276.131				
237,859	304948	94.534	368.68	$13,371.44		
230,371	295347	44.30212	172.78	$9,024.81		
222,883	285747	94.296481	367.76	$6,899.36		
215,394	276146	236.65743	922.96	$5,915.30		
222,883	285747	350.03997	1365.16	$7,547.70		
222,883	285747	281.74646	1098.81	$6,654.24		
237,859	304948	146.98495	573.24	$4,983.22		

Total Gas Costs ($)	Per Engineering Controls:
214,851.68	One (1) Caterpillar G3516 -- 820 Kwe; 1,010,000 Btu/hr; $80,660.00 Feedwater unit adds -- $18,540.00

Recurring O&M Cost = $50,991

Yearly One-Time Costs =

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
0	16,934	15,797	55,950	15,458	16,724	55,542	17,998	18,115	56,639

Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
16,586	18,184	54,056	0	18,527	72,476	0	19,212	16,250	55,120

Option #2c - Natural Gas-Fired Engine-Generator with 250-Ton Capacity
Single-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't)

Cooling Load (Tons)	# Hours at Load	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
	May-Oct							
250	479	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
225	384	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
200	836	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
175	620	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
150	517	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
125	213	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
100	122	0.00	601	912,306	10.75	0.00	$ 0.0496	45,286.89
	Nov-Apr							
250	123	1,517.98	608	922,934	10.75	16,322.70	$ 0.0472	43,523.61
225	150	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
200	330	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
175	857	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
150	1225	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
125	986	758.99	608	922,932	10.75	8,161.33	$ 0.0472	43,523.49
100	482	0.00	609	924,450	10.75	0.00	$ 0.0472	43,595.08

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
61,459.00	15,866,520	9504.045	2.75	$26,136.13	250
61,459.00	15,866,520	9504.045	2.75	$26,136.13	225
61,459.00	15,866,520	9504.045	2.75	$26,136.13	200
53,297.53	15,866,520	9504.045	2.75	$26,136.13	175
53,297.53	15,866,520	9504.045	2.75	$26,136.13	150
53,297.53	15,866,520	9504.045	2.75	$26,136.13	125
45,286.89	15,866,520	9535.779	2.75	$26,223.39	100
59,846.31	15,866,520	9646.844	3.90	$37,622.69	250
54,416.16	15,866,520	9646.844	3.90	$37,622.69	225
54,416.16	15,866,520	9646.844	3.90	$37,622.69	200
54,416.16	15,866,520	9646.844	3.90	$37,622.69	175
54,416.16	15,866,520	9646.844	3.90	$37,622.69	150
51,684.82	15,866,520	9646.844	3.90	$37,622.69	125
43,595.08	15,866,520	9662.711	3.90	$37,684.57	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool
0.640	160	$6,881.84	3,804.41	10,686.25	17.48	4,142,286	1,984.155	0
0.631	142	$3,053.82	2,706.77	5,760.59	17.24	3,678,145	1,412.408	0
0.605	121	$0.00	5,021.39	5,021.39	17.04	3,231,542	2,701.569	0
0.594	104	$0.00	3,200.79	3,200.79	16.82	2,789,609	1,729.557	0
0.600	90	$0.00	2,309.75	2,309.75	16.33	2,321,842	1,200.392	0
0.608	76	$0.00	803.57	803.57	16.04	1,901,214	404.959	0
0.640	64	$0.00	387.59	387.59	15.82	1,499,926	182.991	0
0.640	160	$3,440.92	928.07	4,368.99	17.48	4,142,286	509.501	0
0.631	142	$0.00	1,004.46	1,004.46	17.24	3,678,145	551.722	0
0.605	121	$0.00	1,883.01	1,883.01	17.04	3,231,542	1,066.409	0
0.594	104	$0.00	4,203.09	4,203.09	16.82	2,789,609	2,390.694	0
0.600	90	$0.00	5,199.15	5,199.15	16.33	2,321,842	2,844.256	0
0.608	76	$0.00	3,533.82	3,533.82	16.04	1,901,214	1,874.597	0
0.640	64	$0.00	1,454.73	1,454.73	15.82	1,499,926	722.964	0

kW/ton for Remaining Elec Cool	kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
	0	0	0	0	0	10,686.25
	0	0	0	0	0	5,760.59
	0	0	0	0	0	5,021.39
	0	0	0	0	0	3,200.79
	0	0	0	0	0	2,309.75
	0	0	0	0	0	803.57
	0	0	0	0	0	387.59
	0	0	0	0	0	$4,368.99
	0	0	0	0	0	$1,004.46
	0	0	0	0	0	$1,883.01
	0	0	0	0	0	$4,203.09
	0	0	0	0	0	$5,199.15
	0	0	0	0	0	$3,533.82
	0	0	0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)
5,773,320	4,142,286	1,631,034	781.2653	
5,773,320	3,678,145	2,095,175	804.5471	
5,773,320	3,231,542	2,541,778	2124.926	
5,773,320	2,789,609	2,983,712	1849.901	
5,773,320	2,321,842	3,451,478	1784.414	
5,773,320	1,901,214	3,872,106	824.7586	
5,773,320	1,499,926	4,273,394	521.3541	
			7345.054	5802.874
5,773,320	4,142,286	1,631,034	200.6172	
5,773,320	3,678,145	2,095,175	314.2762	
5,773,320	3,231,542	2,541,778	838.7866	
5,773,320	2,789,609	2,983,712	2557.041	
5,773,320	2,321,842	3,451,478	4228.061	
5,773,320	1,901,214	3,872,106	3817.897	
5,773,320	1,499,926	4,273,394	2059.776	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
1,631,034	2091069	1001.6222	2754.461	$48,763.59	154,883	657,281.11
2,095,175	2686122	1031.471	2836.544	$43,920.01		
955,653	1225196	1024.264	2816.726	$43,160.99	Recurring O&M Cost =	
1,721,949	2207627	1368.729	3764.005	$34,126.20	YearlyOne-Time Costs=	
1,942,775	2490737	1287.711	3541.205	$33,012.36		
3,872,106	4964238	1057.3828	2907.803	$30,872.78		
4,273,394	5478711	668.403	1838.107	$21,289.19		
		7439.582				
1,631,034	2091069	257.202	1003.086	$27,595.69		
2,095,175	2686122	402.918	1571.381	$19,369.31		
2,541,778	3258689	1075.367	4193.933	$22,870.42		
2,437,620	3125154	2678.257	10445.2	$31,441.76		
904,540	1159666	1420.591	5540.305	$27,532.93		
1,498,881	1921642	1894.739	7389.482	$24,985.43		
4,243,085	5439853	2622.009	10225.84	$17,591.07		
		10351.083				

Total Gas Costs ($) 385,632.79	Per Engineering Controls: Two (2) Caterpillar G3516 -- 1,640 KWe total; 5,773,320 Btu/hr total; $108,480.00 Feedwater unit adds -- $19,340.00

Recurring O&M Cost = $101,982

Yearly One-Time Costs =

Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*
$0	$33,868	$31,594	$111,900	$30,916	$33,448	$111,084	$35,996	$36,230	$113,278
Year 11	*Year 12*	*Year 13*	*Year 14*	*Year 15*	*Year 16*	*Year 17*	*Year 18*	*Year 19*	*Year 20*
$33,172	$36,368	$108,112	$0	$37,054	$144,952	$0	$38,424	$32,500	$110,240

Option #2d - Natural Gas-Fired Engine-Generator with 250-Ton Capacity
Double-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't)

Cooling Load (Tons)	# Hours at Load	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
	May-Oct							
250	479	2,276.98	599	1,363,909	10.75	24484.05	$ 0.0496	67704.45
225	384	2,276.98	599	1,363,909	10.75	24484.05	$ 0.0496	67704.45
200	836	1,517.98	599	909,272	10.75	16322.70	$ 0.0496	45136.30
175	620	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67704.57
150	517	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67704.57
125	213	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67704.57
100	122	0.00	601	1,368,465	10.75	0.00	$ 0.0496	67930.63
	Nov-Apr							
250	123	2,276.98	608	1,384,401	10.75	24484.05	$ 0.0472	65285.41
225	150	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
200	330	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
175	857	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
150	1225	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
125	986	1,517.98	608	1,384,404	10.75	16322.70	$ 0.0472	65285.53
100	482	0.00	609	1,386,681	10.75	0.00	$ 0.0472	65392.91

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
92188.50	23,799,780	14,256.07	2.75	$39,204.19	250
92188.50	23,799,780	14,256.07	2.75	$39,204.19	225
61459.00	23,799,780	14,256.07	2.75	$39,204.19	200
84027.27	23,799,780	14,256.07	2.75	$39,204.19	175
84027.27	23,799,780	14,256.07	2.75	$39,204.19	150
84027.27	23,799,780	14,256.07	2.75	$39,204.19	125
67930.63	23,799,780	14,303.67	2.75	$39,335.09	100
89769.46	23,799,780	14,470.27	3.90	$56,434.04	250
81619.15	23,799,780	14,470.27	3.90	$56,434.04	225
81619.15	23,799,780	14,470.27	3.90	$56,434.04	200
81619.15	23,799,780	14,470.27	3.90	$56,434.04	175
81619.15	23,799,780	14,470.27	3.90	$56,434.04	150
81608.23	23,799,780	14,470.27	3.90	$56,434.04	125
65392.91	23,799,780	14,494.07	3.90	$56,526.86	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool
0.640	160	$6,881.84	3,804.41	10,686.25	8.87	1,938,796	928.6834	0
0.631	142	$3,053.82	2,706.77	5,760.59	8.75	1,721,605	661.0963	0
0.605	121	$0.00	5,021.39	5,021.39	8.65	1,512,602	1264.535	0
0.594	104	$0.00	3,200.79	3,200.79	8.54	1,305,673	809.5174	0
0.600	90	$0.00	2,309.75	2,309.75	8.29	1,086,826	561.8888	0
0.608	76	$0.00	803.57	803.57	8.03	877,614	186.9317	0
0.640	64	$0.00	387.59	387.59	8.15	711,950	86.85794	0
0.640	160	$1,720.46	928.07	2,648.53	8.87	1,938,796	238.4719	0
0.631	142	$0.00	1,004.46	1,004.46	8.75	1,721,605	258.2407	0
0.605	121	$0.00	1,883.01	1,883.01	8.65	1,512,602	499.1587	0
0.594	104	$0.00	4,203.09	4,203.09	8.54	1,305,673	1118.962	0
0.600	90	$0.00	5,199.15	5,199.15	8.29	1,086,826	1331.361	0
0.608	76	$0.00	3,533.82	3,533.82	8.03	877,614	865.327	0
0.640	64	$0.00	1,454.73	1,454.73	8.15	711,950	343.1601	0

kW/ton for Remaining Elec Cool	kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
	0	0	0	0	0	$10,686.25
	0	0	0	0	0	$5,760.59
	0	0	0	0	0	$5,021.39
	0	0	0	0	0	$3,200.79
	0	0	0	0	0	$2,309.75
	0	0	0	0	0	$803.57
	0	0	0	0	0	$387.59
	0	0	0	0	0	$2,648.53
	0	0	0	0	0	$1,004.46
	0	0	0	0	0	$1,883.01
	0	0	0	0	0	$4,203.09
	0	0	0	0	0	$5,199.15
	0	0	0	0	0	$3,533.82
	0	0	0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)
3,030,000	1,938,796	1,091,204	1,813.581	
3,030,000	1,721,605	1,308,395	502.424	
3,030,000	1,512,602	1,517,398	1,268.545	
3,030,000	1,305,673	1,724,327	1,069.083	
3,030,000	1,086,826	1,943,174	1,004.621	
3,030,000	877,614	2,152,386	458.458	
3,030,000	711,950	2,318,050	282.802	
			6,399.513	5802.874
3,030,000	1,938,796	1,091,204	338.273	
3,030,000	1,721,605	1,308,395	196.259	
3,030,000	1,512,602	1,517,398	500.741	
3,030,000	1,305,673	1,724,327	1,477.748	
3,030,000	1,086,826	1,943,174	2,380.389	
3,030,000	877,614	2,152,386	2,122.253	
3,030,000	711,950	2,318,050	1,117.300	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
1,091,204	1,398,979	2,325.103	6,394.03	$70,064.60	232,056	945,136.12
1,308,395	1,677,429	644.133	1,771.37	$60,516.27		
1,517,398	1,945,382	1,626.339	4,472.43	$31,748.63	Recurring O&M Cost =	
1,724,327	2,210,675	1,370.619	3,769.20	$51,793.08	YearlyOne-Time Costs=	
1,943,174	2,491,249	1,021.552	2,809.27	$49,942.10		
2,152,386	2,759,470	587.767	1,616.36	$47,243.02		
2,318,050	2,971,859	362.567	997.06	$29,980.19		
		7,938.080		$341,287.90		
1,091,204	1,398,979	433.684	1,691.37	$37,675.32		
1,308,395	1,677,429	251.614	981.30	$27,170.87		
1,517,398	1,945,382	641.976	2,503.71	$29,571.83		
1,724,327	2,210,675	1,894.549	7,388.74	$36,776.94		
1,943,174	2,491,249	3,051.780	11,901.94	$42,286.21		
2,152,386	2,759,470	2,720.837	10,611.26	$39,319.28		
2,318,050	2,971,859	1,432.436	5,586.50	$15,907.27		

Total Gas Costs ($)	Per Engineering Controls:
607,196.76	Three (3) Caterpillar G3516 --
	2,460 KWe total; 3,030,000 Btu/hr total; $232,920.00
	Feedwater unit adds -- $23,920.00

Recurring O&M Cost = $152,973.00

Yearly One-Time Costs =

Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*
0	$50,802	$47,391	$167,850	$46,374	$50,172	$166,626	$53,994	$54,345	$169,917
Year 11	***Year 12***	***Year 13***	***Year 14***	***Year 15***	***Year 16***	***Year 17***	***Year 18***	***Year 19***	***Year 20***
$49,758	$54,552	$162,168	$0	$55,581	$217,428	$0	$57,636	$48,750	$165,360

Option #3a - Natural Gas-Fired Engine-Generator with 100-Ton Capacity

Single-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't + Thermal Req't))

Cooling Load (Tons)	# Hours at Load	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
	May-Oct							
250	479	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
225	384	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
200	836	1,517.98	599	909,272	10.75	16,322.70	$ 0.0496	45,136.30
175	620	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
150	517	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
125	213	758.99	599	909,270	10.75	8,161.35	$ 0.0496	45,136.18
100	122	0.00	601	912,306	10.75	0.00	$ 0.0496	45,286.89
	Nov-Apr							
250	123	1,517.98	608	922,934	10.75	16,322.70	$ 0.0472	43,523.61
225	150	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
200	330	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
175	857	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
150	1225	1,013.00	608	922,932	10.75	10,892.67	$ 0.0472	43,523.49
125	986	758.99	608	922,932	10.75	8,161.33	$ 0.0472	43,523.49
100	482	0.00	609	924,450	10.75	0.00	$ 0.0472	43,595.08

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
61459.00	15,866,520	9504.045	2.75	$26,136.13	100
61459.00	15,866,520	9504.045	2.75	$26,136.13	100
61459.00	15,866,520	9504.045	2.75	$26,136.13	100
53297.53	15,866,520	9504.045	2.75	$26,136.13	100
53297.53	15,866,520	9504.045	2.75	$26,136.13	100
53297.53	15,866,520	9504.045	2.75	$26,136.13	100
45286.89	15,866,520	9535.779	2.75	$26,223.39	100
59846.31	15,866,520	9646.844	3.90	$37,622.69	100
54416.16	15,866,520	9646.844	3.90	$37,622.69	100
54416.16	15,866,520	9646.844	3.90	$37,622.69	100
54416.16	15,866,520	9646.844	3.90	$37,622.69	100
54416.16	15,866,520	9646.844	3.90	$37,622.69	100
51684.82	15,866,520	9646.844	3.90	$37,622.69	100
43595.08	15,866,520	9662.711	3.90	$37,684.57	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool
0.640	160	6,881.84	3804.41	10,686.25	17.74	1,679,824	804.636	150
0.631	142	3,053.82	2706.77	5,760.59	17.92	1,696,108	651.305	125
0.605	121	0.00	5021.39	5,021.39	18.09	1,712,391	1431.559	100
0.594	104	0.00	3200.79	3,200.79	18.26	1,728,674	1071.778	75
0.600	90	0.00	2309.75	2,309.75	18.09	1,712,391	885.306	50
0.608	76	0.00	803.57	803.57	18.09	1,712,391	384.739	25
0.640	64	0.00	387.59	387.59	17.74	1,679,824	204.939	0
0.640	160	3,440.92	928.07	4,368.99	17.74	1,679,824	206.618	150
0.631	142	0.00	1004.46	1,004.46	17.92	1,696,108	254.416	125
0.605	121	0.00	1883.01	1,883.01	18.09	1,712,391	565.089	100
0.594	104	0.00	4203.09	4,203.09	18.26	1,728,674	1481.474	75
0.600	90	0.00	5199.15	5,199.15	18.09	1,712,391	2097.679	50
0.608	76	0.00	3533.82	3,533.82	18.09	1,712,391	1688.417	25
0.640	64	0.00	1454.73	1,454.73	17.74	1,679,824	809.675	0

kW/ton for Remaining Elec Cool	kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
0.605	90.75	3903.295	43469	2157.81	6061.11	4,625.14
0.615	76.88	1653.255	29520	1465.37	3118.63	2,641.96
0.650	65.00	0	54340	2697.44	2697.44	2,323,95
0.713	53.48	0	33155	1645.79	1645.79	1,555.00
0.681	34.05	0	17604	873.86	873.86	1,435.89
0.799	19.98	0	4255	211.20	211.20	592.37
	0	0	0	0	0	387.59
0.605	90.75	1951.65	11162	526.39	2478.04	1,890.95
0.615	76.88	0	11531	543.79	543.79	460.67
0.650	65.00	0	21450	1011.54	1011.54	871.48
0.713	53.48	0	45828	2161.15	2161.15	2,041.93
0.681	34.05	0	41711	1967.01	1967.01	3,232.14
0.799	19.98	0	19695	928.79	928.79	2,605.03
	0	0	0	0	0	1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy Actually Used for Thermal (MBtu)	Thermal Energy Required (MBtu)
5,773,320	1,679,824	4,093,496	2,507.68	
5,773,320	1,696,108	4,077,212	0.00	
5,773,320	1,712,391	4,060,929	787.51	
5,773,320	1,728,674	4,044,646	2,507.68	
5,773,320	1,712,391	4,060,929	0.00	
5,773,320	1,712,391	4,060,929	0.00	
5,773,320	1,679,824	4,093,496	0.00	
			5,802.87	5,802.87
5,773,320	1,679,824	4,093,496	0.00	
5,773,320	1,696,108	4,077,212	0.00	
5,773,320	1,712,391	4,060,929	0.00	
5,773,320	1,728,674	4,044,646	0.00	
5,773,320	1,712,391	4,060,929	4,069.96	
5,773,320	1,712,391	4,060,929	4,004.08	
5,773,320	1,679,824	4,093,496	0.00	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
4,044,646	5,185,443	3214.9749	8,841.18	$48,789.20	147,375	641,090.96
0	0	0	0.00	$37,964.84		
941,998	1,207,689	1009.6282	2,776.48	$40,423.30	Recurring O&M Cost =	
4,044,646	5,185,443	3214.9749	8,841.18	$37,557.59	YearlyOne-Time Costs=	
0	0	0	0	$28,597.30		
0	0	0	0	$27,753.78		
		7439.578		$221,086.01		
0	0	0	0	$24,114.57		
0	0	0	0	$17,254.14		
0	0	0	0	$17,664.95		
0	0	0	0	$18,835.40		
3,322,412	4,259,503	5,217.891	20349.77	$40,375.39		
4,060,929	5,206,319	5,133.431	20020.38	$36,687.54		
0	0	0	0	$7,365.23		

Total Gas Costs ($)	Per Engineering Controls:
385,631.87	Two (2) Caterpillar G3516 -- 1,640 Kwe; 5,773,320 Btu/hr; $106,920.00 Feedwater unit adds -- $19,340.00

Recurring O&M Costs = $101,982

Yearly One-Time Costs =

Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*
$0	$33,868	$31,594	$111,900	$30,916	$33,448	$111,084	$35,996	$36,230	$113,278

Year 11	*Year 12*	*Year 13*	*Year 14*	*Year 15*	*Year 16*	*Year 17*	*Year 18*	*Year 19*	*Year 20*
$33,172	$36,368	$108,112	$0	$37,054	$144,952	$0	$38,424	$32,500	$110,240

Option #3b - Natural Gas-Fired Engine-Generator with 100-Ton Capacity

Double-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't + Thermal Req't))

Cooling Load (Tons)	# Hours at Load May-Oct	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
250	479	3,035.97	599	1,818,545	10.75	32,645.40	$ 0.0496	90272.61
225	384	3,035.97	599	1,818,545	10.75	32,645.40	$ 0.0496	90272.61
200	836	2,277.00	599	1,363,923	10.75	24,484.31	$ 0.0496	67705.17
175	620	2,277.00	599	1,818,546	10.75	24,484.31	$ 0.0496	90272.66
150	517	2,277.00	599	1,818,546	10.75	24,484.31	$ 0.0496	90272.66
125	213	2,277.00	599	1,818,546	10.75	24,484.31	$ 0.0496	90272.66
100	122	0.00	601	1,824,618	10.75	0.00	$ 0.0496	90574.08
	3171							
	Nov-Apr							
250	123	3,035.97	608	1,845,870	10.75	32,645.42	$ 0.0472	87047.28
225	150	2,095.00	608	1,845,870	10.75	22,527.28	$ 0.0472	87047.28
200	330	2,025.00	608	1,845,870	10.75	21,774.58	$ 0.0472	87047.28
175	857	2,025.00	608	1,845,870	10.75	21,774.58	$ 0.0472	87047.28
150	1225	2,025.00	608	1,845,870	10.75	21,774.58	$ 0.0472	87047.28
125	986	2,025.00	608	1,845,870	10.75	21,774.58	$ 0.0472	87047.28
100	482	0.0	609	1,848,906	10.75	0.00	$ 0.0472	87190.44

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
122,918.01	31,733,040	19008.091	2.75	$52,272.25	100
122,918.01	31,733,040	19008.091	2.75	$52,272.25	100
92,189.48	31,733,040	19008.091	2.75	$52,272.25	100
114,756.97	31,733,040	19008.091	2.75	$52,272.25	100
114,756.97	31,733,040	19008.091	2.75	$52,272.25	100
114,756.97	31,733,040	19008.091	2.75	$52,272.25	100
90,574.08	31,733,040	19071.557	2.75	$52,446.78	100
119,692.70	31,733,040	19293.688	3.90	$75,245.38	100
109,574.56	31,733,040	19293.688	3.90	$75,245.38	100
108,821.86	31,733,040	19293.688	3.90	$75,245.38	100
108,821.86	31,733,040	19293.688	3.90	$75,245.38	100
108,821.86	31,733,040	19293.688	3.90	$75,245.38	100
108,821.86	31,733,040	19293.688	3.90	$75,245.38	100
87,190.44	31,733,040	19325.421	3.90	$75,369.14	100

kW/ton for All Elec Cool	kW for All Electric Cooling		kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool	kW/ton for Remaining Elec Cool
0.640	160		$6,881.84	3804.41	10,686.25	8.83	772140.5	369.855	150	0.605
0.631	142		$3,053.82	2706.77	5,760.59	8.92	779629	299.378	125	0.615
0.605	121		$0.00	5021.39	5,021.39	9.01	787117.4	658.030	100	0.650
0.594	104		$0.00	3200.79	3,200.79	9.09	794605.8	492.656	75	0.713
0.600	90		$0.00	2309.75	2,309.75	9.01	787117.4	406.940	50	0.681
0.608	76		$0.00	803.57	803.57	9.01	787117.4	167.656	25	0.799
0.640	64		$0.00	387.59	387.59	8.83	772140.5	94.201	0	
0.640	160		$1,720.46	928.07	$2,648.53	8.83	772140.5	94.973	150	0.605
0.631	142	75	$806.47	1004.46	$1,810.93	8.92	779629	116.944	125	0.615
0.605	121		$0.00	1883.01	$1,883.01	9.01	787117.4	259.749	100	0.650
0.594	104		$0.00	4203.09	$4,203.09	9.09	794605.8	680.977	75	0.713
0.600	90		$0.00	5199.15	$5,199.15	9.01	787117.4	964.219	50	0.681
0.608	76		$0.00	3533.82	$3,533.82	9.01	787117.4	776.098	25	0.799
0.640	64		$0.00	1454.73	$1,454.73	8.83	772140.5	372.172	0	

kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling		kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
90.75	3903.295		43469	2157.81	6061.11	$4,625.14
76.88	1653.255		29520	1465.37	3118.63	$2,641.96
65.00	0		54340	2697.44	2697.44	$2,323.95
53.48	0		33155	1645.79	1645.79	$1,555.00
34.05	0		17604	873.86	873.86	$1,435.89
19.98	0		4255	211.20	211.20	$592.37
0	0		0	0	0	$387.59
90.75	1951.65		11162	526.39	2478.04	$170.49
76.88	0	-8.12	11531	543.79	543.79	$1,267.14
65.00	0		21450	1011.54	1011.54	$871.48
53.48	0		45828	2161.15	2161.15	$2,041.93
34.05	0		41711	1967.01	1967.01	$3,232.14
19.98	0		19695	928.79	928.79	$2,605.03
0	0		0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy Actually Used for Thermal (MBtu)	Thermal Energy Required (MBtu)
4,040,000	772,140.5	3,267,859	0	
4,040,000	779,629.0	3,260,371	1251.982	
4,040,000	787,117.4	3,252,883	2535.419	
4,040,000	794,605.8	3,245,394	2012.144	
4,040,000	787,117.4	3,252,883	0	
4,040,000	787,117.4	3,252,883	0	
4,040,000	772,140.5	3,267,859	0	
			5799.546	5802.874
4,040,000	772,140.5	3,267,859	0	
4,040,000	779,629.0	3,260,371	489.0557	
4,040,000	787,117.4	3,252,883	1073.451	
4,040,000	794,605.8	3,245,394	2781.303	
4,040,000	787,117.4	3,252,883	3725.591	
4,040,000	787,117.4	3,252,883	0	
4,040,000	772,140.5	3,267,859	0	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total En-Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
0	0	0	0	$75,270.90	310,453	1,239,367.00
3,260,371	4179963	1605.1057	4414.041	$77,701.76		
3,032,798	3888202	3250.5372	8938.977	$51,180.15	Recurring O&M Cost =	
3,245,394	4160762	2579.6723	7094.099	$71,133.82	YearlyOne-Time Costs=	
0	0	0	0	$63,920.62		
0	0	0	0	$63,077.09		
0	0	0	0	$38,514.88		
		7435.315		$440,799.22		
0	0	0	0	$44,617.80		
3,260,371	4179963	626.994	2445.278	$38,041.59		
3,252,883	4170362	1376.220	5367.256	$39,815.21		
3,245,394	4160762	3565.773	13906.51	$49,524.92		
3,041,299	3899101	4776.399	18627.96	$55,436.57		
0	0	0	0	$36,181.50		
0	0	0	0	$13,276.03		

Total Gas Costs ($)	Per Engineering Controls:
832,127.61	Four (4) Caterpillar G-3516 -- 3,280 Kwe total; 4,040,000 Btu/hr total; $312,620.00 Feedwater unit adds -- $25,800.00

Recurring O&M Costs = $203,964

Yearly One-Time Costs =

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
$0	$67,736	$63,188	$223,800	$61,832	$66,896	$222,168	$71,992	$72,460	$226,556

Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
$66,344	$72,736	$216,224	$0	$74,108	$289,904	$0	$76,848	$65,000	$220,480

Option #3c - Natural Gas-Fired Engine-Generator with 250-Ton Capacity
Single-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't + Thermal Req't))

Cooling Load (Tons)	# Hours at Load	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
	May-Oct							
250	479	2,276.98	599	1,363,909	10.75	24484.05	$ 0.0496	67,704.45
225	384	2,276.98	599	1,363,909	10.75	24484.05	$ 0.0496	67,704.45
200	836	1,517.98	599	909,272	10.75	16322.70	$ 0.0496	45,136.30
175	620	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67,704.57
150	517	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67,704.57
125	213	1,517.98	599	1,363,911	10.75	16322.70	$ 0.0496	67,704.57
100	122	0.00	601	1,368,465	10.75	0.00	$ 0.0496	67,930.63
	Nov-Apr							
250	123	2,276.98	608	1,384,401	10.75	24484.05	$ 0.0472	65285.41
225	150	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
200	330	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
175	857	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
150	1225	1,519.00	608	1,384,404	10.75	16333.62	$ 0.0472	65285.53
125	986	1,517.98	608	1,384,404	10.75	16322.70	$ 0.0472	65285.53
100	482	0.00	609	1,386,681	10.75	0.00	$ 0.0472	65392.91

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
92,188.50	23,799,780	14,256.068	2.75	$39,204.19	250
92,188.50	23,799,780	14,256.068	2.75	$39,204.19	225
61,459.00	23,799,780	14,256.068	2.75	$39,204.19	200
84,027.27	23,799,780	14,256.068	2.75	$39,204.19	175
84,027.27	23,799,780	14,256.068	2.75	$39,204.19	150
84,027.27	23,799,780	14,256.068	2.75	$39,204.19	125
67,930.63	23,799,780	14,303.668	2.75	$39,335.09	100
89,769.46	23,799,780	14,470.266	3.90	$56,434.04	250
81,619.15	23,799,780	14,470.266	3.90	$56,434.04	225
81,619.15	23,799,780	14,470.266	3.90	$56,434.04	200
81,619.15	23,799,780	14,470.266	3.90	$56,434.04	175
81,619.15	23,799,780	14,470.266	3.90	$56,434.04	150
81,608.23	23,799,780	14,470.266	3.90	$56,434.04	125
65,392.91	23,799,780	14,494.066	3.90	$56,526.86	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool
0.640	160	$6,881.84	3,804.41	10,686.25	17.48	4,142,286	1,984.155	0
0.631	142	$3,053.82	2,706.77	5,760.59	17.24	3,678,145	1,412.408	0
0.605	121	$0.00	5,021.39	5,021.39	17.04	3,231,542	2,701.569	0
0.594	104	$0.00	3,200.79	3,200.79	16.82	2,789,609	1,729.557	0
0.600	90	$0.00	2,309.75	2,309.75	16.33	2,321,842	1,200.392	0
0.608	76	$0.00	803.57	803.57	16.04	1,901,214	404.959	0
0.640	64	$0.00	387.59	387.59	15.82	1,499,926	182.991	0
0.640	160	$1,720.46	928.07	$2,648.53	17.48	4,142,286	509.501	0
0.631	142	$0.00	1004.46	$1,004.46	17.24	3,678,145	551.722	0
0.605	121	$0.00	1883.01	$1,883.01	17.04	3,231,542	1,066.409	0
0.594	104	$0.00	4203.09	$4,203.09	16.82	2,789,609	2,390.694	0
0.600	90	$0.00	5199.15	$5,199.15	16.33	2,321,842	2,844.256	0
0.608	76	$0.00	3533.82	$3,533.82	16.04	1,901,214	1,874.597	0
0.640	64	$0.00	1454.73	$1,454.73	15.82	1,499,926	722.964	0

kW/ton for Remaining Elec Cool	kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
	0	0	0	0	0	10,686.25
	0	0	0	0	0	5,760.59
	0	0	0	0	0	5,021.39
	0	0	0	0	0	3,200.79
	0	0	0	0	0	2,309.75
	0	0	0	0	0	803.57
	0	0	0	0	0	387.59
	0	0	0	0	0	$2,648.53
	0	0	0	0	0	$1,004.46
	0	0	0	0	0	$1,883.01
	0	0	0	0	0	$4,203.09
	0	0	0	0	0	$5,199.15
	0	0	0	0	0	$3,533.82
	0	0	0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)
8,659,980	4,142,286	4,517,694	2,163.975	
8,659,980	3,678,145	4,981,835	1,913.025	
8,659,980	3,231,542	5,428,438	4,538.174	
8,659,980	2,789,609	5,870,372	3,639.630	
8,659,980	2,321,842	6,338,138	3,276.818	
8,659,980	1,901,214	6,758,766	1,439.617	
8,659,980	1,499,926	7,160,054	873.527	
			15,531.62	5,802.87
8,659,980	4,142,286	4,517,694	555.6764	
8,659,980	3,678,145	4,981,835	747.2752	
8,659,980	3,231,542	5,428,438	1791.384	
8,659,980	2,789,609	5,870,372	5030.908	
8,659,980	2,321,842	6,338,138	7764.22	
8,659,980	1,901,214	6,758,766	6664.143	
8,659,980	1,499,926	7,160,054	3451.146	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
1,749,426	2,242,854	1074.327	2954.399	$66,624.97	232,056	945,136.12
2,138,086	2,741,135	1052.596	2894.639	$61,639.54		
949,969	1,217,909	1018.172	2799.973	$30,076.17	Recurring O&M Cost =	
1,356,030	1,738,500	1077.87	2964.143	$50,988.02	YearlyOne-Time Costs=	
1,585,720	2,032,975	1051.048	2890.382	$50,023.22		
3,829,188	4,909,216	1045.663	2875.573	$48,502.23		
7,160,054	9,179,557	1119.9059	3079.741	$32,062.88		
		7439.582		$339,917.03		
4517694	5,791,915	712.40559	2778.382	$38,762.33		
4981834.8	6,386,968	958.04515	3736.376	$29,925.95		
5428437.6	6,959,535	2296.6467	8956.922	$36,025.05		
1,330,222	1,705,413	1461.539	5700.002	$35,088.20		
1,244,261	1,595,207	1954.128	7621.099	$38,005.37		
1,221,240	1,565,693	1543.773	6020.715	$34,728.73		
2,305,282	2,955,490	1424.546	5555.729	$15,876.50		

Total Gas Costs ($)	Per Engineering Controls:
	Three (3) Caterpillar G-3516 --
	2,460 KWe total; 8,659,980 Btu/hr total; $154,080.00
608,863.22	Feedwater unit adds -- $22,840.00

Recurring O&M Costs = $152,973

Yearly One-Time Costs =

Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*
$0	$50,802	$47,391	$167,850	$46,374	$50,172	$166,626	$53,994	$54,345	$169,917
Year 11	*Year 12*	*Year 13*	*Year 14*	*Year 15*	*Year 16*	*Year 17*	*Year 18*	*Year 19*	*Year 20*
$49,758	$54,552	$162,168	$0	$55,581	$217,428	$0	$57,636	$48,750	$165,360

Option #3d - Natural Gas-Fired Engine-Generator with 250-Ton Capacity
Double-Effect Indirect-Fired Absorption Chiller (Waste Heat ~ Chiller Req't + Thermal Req't))

Cooling Load (Tons)	# Hours at Load May-Oct	Power Produced (kW)	Total Hours	Electrical Energy Produced (kWh)	UtilityCost ($/kW)	Avoided kW Utility Cost ($)	UtilityCost ($/kWh)	Avoided kWhUtility Cost ($)
250	479	4,553.95	599	2,727,817	10.75	48,968.10	$ 0.0496	135,408.91
225	384	4,553.95	599	2,727,817	10.75	48,968.10	$ 0.0496	135,408.91
200	836	3,794.96	599	2,273,181	10.75	40,806.75	$ 0.0496	112,840.76
175	620	3,794.96	599	2,727,816	10.75	40,806.75	$ 0.0496	135,408.85
150	517	3,036.00	599	2,727,816	10.75	32,645.74	$ 0.0496	135,408.85
125	213	3,036.00	599	2,727,816	10.75	32,645.74	$ 0.0496	135,408.85
100	122	0.0	601	2,736,924	10.75	0.00	$ 0.0496	135,860.97
	Nov-Apr							
250	123	4,553.95	608	2,768,803	10.75	48,968.10	$ 0.0472	130,570.83
225	150	3,038.0	608	2,768,802	10.75	32,667.25	$ 0.0472	130,570.77
200	330	3,038.0	608	2,768,802	10.75	32,667.25	$ 0.0472	130,570.77
175	857	3,038.0	608	2,768,802	10.75	32,667.25	$ 0.0472	130,570.77
150	1225	3,038.0	608	2,768,802	10.75	32,667.25	$ 0.0472	130,570.77
125	986	3,036.0	608	2,768,802	10.75	32,645.74	$ 0.0472	130,570.77
100	482	0.0	609	2,773,356	10.75	0.00	$ 0.0472	130,785.52

Total Electrical Cost Savings From Generator Power Produced	Natural Gas to Produce Electricity (Btu/hr)	Natural Gas Consumption to Generate Electric Power(MBtu)	Natural Gas Rate ($/MBtu)	Cost of Nat'l Gas ($)	Cooling Produced From Waste Heat (Tons)
184,377.01	47,599,560	28,512.136	2.75	$78,408.38	250
184,377.01	47,599,560	28,512.136	2.75	$78,408.38	225
153,647.51	47,599,560	28,512.136	2.75	$78,408.38	200
176,215.60	47,599,560	28,512.136	2.75	$78,408.38	175
168,054.59	47,599,560	28,512.136	2.75	$78,408.38	150
168,054.59	47,599,560	28,512.136	2.75	$78,408.38	125
135,860.97	47,599,560	28,607.336	2.75	$78,670.17	100
179,538.93	47,599,560	28,940.532	3.90	$112,868.08	250
163,238.02	47,599,560	28,940.532	3.90	$112,868.08	225
163,238.02	47,599,560	28,940.532	3.90	$112,868.08	200
163,238.02	47,599,560	28,940.532	3.90	$112,868.08	175
163,238.02	47,599,560	28,940.532	3.90	$112,868.08	150
163,216.51	47,599,560	28,940.532	3.90	$112,868.08	125
130,785.52	47,599,560	28,988.132	3.90	$113,053.71	100

kW/ton for All Elec Cool	kW for All Electric Cooling	kW Cost for All Elec Cooling	kWh Cost for All Elec Cooling	Total Cost for All Elec Cooling	#/ton-hr for Abs Tons	Btu/hr for Abs Tons	MBtu for Abs Tons	Remaining Tons of Elec Cool
0.640	160	$6,881.84	3,804.41	10,686.25	8.87	1,938,796	928.683	0
0.631	142	$3,053.82	2,706.77	5,760.59	8.75	1,721,605	661.096	0
0.605	121	$0.00	5,021.39	5,021.39	8.65	1,512,602	1,264.535	0
0.594	104	$0.00	3,200.79	3,200.79	8.54	1,305,673	809.517	0
0.600	90	$0.00	2,309.75	2,309.75	8.29	1,086,826	561.889	0
0.608	76	$0.00	803.57	803.57	8.03	877,614	186.932	0
0.640	64	$0.00	387.59	387.59	8.15	711,950	86.858	0
0.640	160	$1,720.46	928.07	2,648.53	8.87	1,938,796	238.472	0
0.631	142	$0.00	1,004.46	1,004.46	8.75	1,721,605	258.241	0
0.605	121	$0.00	1,883.01	1,883.01	8.65	1,512,602	499.159	0
0.594	104	$0.00	4,203.09	4,203.09	8.54	1,305,673	1,118.962	0
0.600	90	$0.00	5,199.15	5,199.15	8.29	1,086,826	1,331.361	0
0.608	76	$0.00	3,533.82	3,533.82	8.03	877,614	865.327	0
0.640	64	$0.00	1,454.73	1,454.73	8.15	711,950	343.160	0

kW for Remaining Elec Cool	Cost for kW for Remaining Electric Cooling	kWh for Remaining Elec Cool	Cost for kWh for Remaining Electric Cooling	Total Electric Costs WhenElectricProvides Remaining Cooling	Total Electric Cost Savings w/ Absorption Cooling
0	0	0	0	0	$10,686.25
0	0	0	0	0	$5,760.59
0	0	0	0	0	$5,021.39
0	0	0	0	0	$3,200.79
0	0	0	0	0	$2,309.75
0	0	0	0	0	$803.57
0	0	0	0	0	$387.59
0	0	0	0	0	$2,648.53
0	0	0	0	0	$1,004.46
0	0	0	0	0	$1,883.01
0	0	0	0	0	$4,203.09
0	0	0	0	0	$5,199.15
0	0	0	0	0	$3,533.82
0	0	0	0	0	$1,454.73

Total "Waste" Heat From Power Production (Btu/hr)	"Waste" Heat For Chiller Operation (Btu/hr)	Residual "Waste" Heat for Thermal Use (Btu/hr)	Residual "Waste"Heat Energy For Thermal Use (MBtu)	Thermal Energy Required (MBtu)
6,060,000	1,938,796	4,121,204	1,974.057	
6,060,000	1,721,605	4,338,395	1,665.944	
6,060,000	1,512,602	4,547,398	3,801.625	
6,060,000	1,305,673	4,754,327	2,947.683	
6,060,000	1,086,826	4,973,174	2,571.131	
6,060,000	877,614	5,182,386	1,103.848	
6,060,000	711,950	5,348,050	652.462	
			14716.749	5802.874
6,060,000	1,938,796	4,121,204	506.9081	
6,060,000	1,721,605	4,338,395	650.7593	
6,060,000	1,512,602	4,547,398	1500.641	
6,060,000	1,305,673	4,754,327	4074.458	
6,060,000	1,086,826	4,973,174	6092.139	
6,060,000	877,614	5,182,386	5109.833	
6,060,000	711,950	5,348,050	2577.76	
				8073.845

Avoided Boiler Btu/hr	Avoided Boiler Gas UseBtu/hr	Avoided Natural Gas Consumption (MBtu)	Avoided Nat'l Gas Cost ($)	Total Energy Cost Savings($)	Total Demand Savings($)	Total Elec Energy Savings($)
1,825,000	2339744	1,120.737	3082.027	$119,736.91	468,780	1,876,397
1,825,000	2339744	898.462	2470.769	$114,199.99		
1,825,000	2339744	1,956.026	5379.071	$85,639.59	Recurring O&M Cost =	
1,825,000	2339744	1,450.641	3989.263	$104,997.27	YearlyOne-Time Costs=	
1,825,000	2339744	1,209.647	3326.53	$95,282.50		
1,825,000	2339744	498.365	1370.505	$91,820.29		
1,954,501	2505771	305.704	840.686	$58,419.07		
12,904,501		7,439.582		$670,095.63		
2,000,000	2564103	315.38462	1230	$70,549.38		
2,000,000	2564103	384.61538	1500	$52,874.40		
1,296,500	1662179	548.51923	2139.225	$54,392.18		
2,000,000	2564103	2197.4359	8570	$63,143.03		
2,000,000	2564103	3141.0256	12250	$67,819.10		
2,000,000	2564103	2528.2051	9860	$63,742.26		
2,000,000	2564103	1235.8974	4820	$24,006.53		

Total Gas Costs ($)	Per Engineering Controls:
1,278,555	Six (6) Caterpillar G-3516 -- 4,920 KWe total; 6,060,000 Btu/hr total; $461,220.00 Feedwater unit adds -- $30,460.00

Recurring O&M Costs = $305,946

Yearly One-Time Costs =

Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*
$0	$101,604	$94,782	$335,700	$92,748	$100,344	$333,252	$107,988	$108,690	$339,834
Year 11	*Year 12*	*Year 13*	*Year 14*	*Year 15*	*Year 16*	*Year 17*	*Year 18*	*Year 19*	*Year 20*
$99,516	$109,104	$324,336	$0	$111,162	$434,856	$0	$115,272	$97,500	$330,720

Appendix L: Calculated Paybacks and Savings-to-Investment Ratio for Option 1

```
Life Cycle Cost Analysis      Study: Option #1
Energy Conservation Investment Program (ECIP)             LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA         Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #1
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T.Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$260,963
B. SIOH	$14,353
C. Design Cost	$15,658
D. Total Cost (1A+1B+1C)	$290,974
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$290,974

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	792	Mwatt-	$36,441	14.47	$527,296
Elec. Deman					$13,377	13.47	$180,188
Natural Gas	$3.4	/Mbtus	-5,502	Mbtus	-$18,706	17.32	-$323,993
TOTAL			-2,799	Mbtus	$31,111		$383,491

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
ANNUAL TOTAL	$0			$0
ONE TIME TOTAL	$0			$0
TOTAL	$0			$0

4. First Year Dollar Savings	$31,111
5. Simple Payback Period (Years)	9.35
6. Total Net Discounted Savings	$383,491
7. Savings to Investment Ratio	1.32
If < 1, Project does not qualify	
8. Adjusted Internal Rate of Return	5.55%

Appendix M: Calculated Paybacks and Savings-to-Investment Ratio for Option 2a

```
Life Cycle Cost Analysis      Study: Option #2a
Energy Conservation Investment Program (ECIP)              LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA         Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2a
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$176,011
B. SIOH	$9,681
C. Design Cost	$10,561
D. Total Cost (1A+1B+1C)	$196,252
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$196,252

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	5,361	Mwatt-	$246,590	14.47	$3,568,160
Elec. Deman					$45,670	13.47	$615,175
Natural Gas	$3.4	/Mbtus	-45,660	Mbtus	-$155,244	17.32	-$2,688,826
TOTAL			-27,369	Mbtus	$137,016		$1,494,509

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$50,991	Annual	13.47	-$686,849
ANNUAL TOTAL	-$50,991			-$686,849
Maintenance	-$16,934	2	.92	-$15,626
Maintenance	-$15,797	3	.89	-$14,003
Maintenance	-$55,950	4	.85	-$47,643
Maintenance	-$15,458	5	.82	-$12,644
Maintenance	-$16,724	6	.79	-$13,141
Maintenance	-$55,542	7	.75	-$41,924
Maintenance	-$17,998	8	.73	-$13,050
Maintenance	-$18,115	9	.7	-$12,618
Maintenance	-$56,639	10	.67	-$37,897
Maintenance	-$16,586	11	.64	-$10,661
Maintenance	-$18,184	12	.62	-$11,227
Maintenance	-$54,056	13	.59	-$32,062
Maintenance	-$18,527	15	.55	-$10,140
Maintenance	-$72,476	16	.53	-$38,105
Maintenance	-$19,212	18	.49	-$9,321
Maintenance	-$16,250	19	.47	-$7,573
Maintenance	-$55,120	20	.45	-$24,677
ONE TIME TOTAL	-$539,568			-$352,314
TOTAL	-$590,559			-$1,039,163

Life Cycle Cost Analysis Study: DAVMON2.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2a
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $59,047
5. Simple Payback Period (Years) 2.87
6. Total Net Discounted Savings $455,346
7. Savings to Investment Ratio 2.32
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 8.57%

Appendix N: Calculated Paybacks and Savings-to-Investment Ratio for Option 2b

```
    Life Cycle Cost Analysis       Study: Option #2b
Energy Conservation Investment Program (ECIP)               LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA         Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2b
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$211,132
B. SIOH	$11,612
C. Design Cost	$12,668
D. Total Cost (1A+1B+1C)	$235,412
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$235,412

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	7,188	Mwatt-	$330,671	14.47	$4,784,803
Elec. Deman					$46,664	13.47	$628,564
Natural Gas	$3.4	/Mbtus	-63,192	Mbtus	-$214,852	17.32	-$3,721,231
TOTAL			-38,664	Mbtus	$162,483		$1,692,136

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$50,991	Annual	13.47	-$686,849
ANNUAL TOTAL	-$50,991			-$686,849
Maintenance	-$16,934	2	.92	-$15,626
Maintenance	-$15,797	3	.89	-$14,003
Maintenance	-$55,950	4	.85	-$47,643
Maintenance	-$15,458	5	.82	-$12,644
Maintenance	-$16,724	6	.79	-$13,141
Maintenance	-$55,542	7	.75	-$41,924
Maintenance	-$17,998	8	.73	-$13,050
Maintenance	-$18,115	9	.7	-$12,618
Maintenance	-$56,639	10	.67	-$37,897
Maintenance	-$16,586	11	.64	-$10,661
Maintenance	-$18,184	12	.62	-$11,227
Maintenance	-$54,056	13	.59	-$32,062
Maintenance	-$18,527	15	.55	-$10,140
Maintenance	-$72,476	16	.53	-$38,105
Maintenance	-$19,212	18	.49	-$9,321
Maintenance	-$16,250	19	.47	-$7,573
Maintenance	-$55,120	20	.45	-$24,677
ONE TIME TOTAL	-$539,568			-$352,314
TOTAL	-$590,559			-$1,039,163

Life Cycle Cost Analysis Study: DAVMON3.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2b
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $84,513
5. Simple Payback Period (Years) 2.51
6. Total Net Discounted Savings $652,973
7. Savings to Investment Ratio 2.77
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 9.55%

Appendix O: Calculated Paybacks and Savings-to-Investment Ratio for Option 2c

```
    Life Cycle Cost Analysis       Study: Option #2c
Energy Conservation Investment Program (ECIP)               LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA        Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2c
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment	
A. Construction Cost	$427,380
B. SIOH	$23,506
C. Design Cost	$25,643
D. Total Cost (1A+1B+1C)	$476,529
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$476,529

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	14,289	Mwatt-	$657,281	14.47	$9,510,858
Elec. Deman					$154,883	13.47	$2,086,274
Natural Gas	$3.4	/Mbtus	-113,421	Mbtus	-$385,633	17.32	-$6,679,160
TOTAL			-64,666	Mbtus	$426,531		$4,917,973

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$101,982	Annual	13.47	-$1,373,698
ANNUAL TOTAL	-$101,982			-$1,373,698
Maintenance	-$33,868	2	.92	-$31,253
Maintenance	-$31,594	3	.89	-$28,006
Maintenance	-$111,900	4	.85	-$95,286
Maintenance	-$30,916	5	.82	-$25,289
Maintenance	-$33,448	6	.79	-$26,282
Maintenance	-$111,084	7	.75	-$83,849
Maintenance	-$35,996	8	.73	-$26,100
Maintenance	-$36,230	9	.7	-$25,235
Maintenance	-$113,278	10	.67	-$75,795
Maintenance	-$33,172	11	.64	-$21,321
Maintenance	-$36,368	12	.62	-$22,455
Maintenance	-$108,112	13	.59	-$64,123
Maintenance	-$37,054	15	.55	-$20,280
Maintenance	-$144,952	16	.53	-$76,210
Maintenance	-$38,424	18	.49	-$18,642
Maintenance	-$32,500	19	.47	-$15,147
Maintenance	-$110,240	20	.45	-$49,354
ONE TIME TOTAL	-$1,079,1			-$704,628
TOTAL	-$1,181,1			-$2,078,325

Life Cycle Cost Analysis Study: DAVMON4.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2c
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings	$270,593
5. Simple Payback Period (Years)	1.65
6. Total Net Discounted Savings	$2,839,647
7. Savings to Investment Ratio	5.96
If < 1, Project does not qualify	
8. Adjusted Internal Rate of Return	13.82%

Appendix P: Calculated Paybacks and Savings-to-Investment Ratio for Option 2d

```
Life Cycle Cost Analysis      Study: Option #2d
Energy Conservation Investment Program (ECIP)             LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA        Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2d
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$573,172
B. SIOH	$31,524
C. Design Cost	$34,390
D. Total Cost (1A+1B+1C)	$639,087
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$639,087

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	20,546	Mwatt-	$945,136	14.47	$13,676,120
Elec. Deman					$232,056	13.47	$3,125,795
Natural Gas	$3.4	/Mbtus	-178,587	Mbtus	-$607,197	17.32	-$10,516,65
TOTAL			-108,480	Mbtus	$569,995		$6,285,267

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$152,973	Annual	13.47	-$2,060,546
ANNUAL TOTAL	-$152,973			-$2,060,546
Maintenance	-$50,802	2	.92	-$46,879
Maintenance	-$47,391	3	.89	-$42,009
Maintenance	-$167,840	4	.85	-$142,920
Maintenance	-$46,374	5	.82	-$37,933
Maintenance	-$50,172	6	.79	-$39,424
Maintenance	-$166,626	7	.75	-$125,773
Maintenance	-$53,994	8	.73	-$39,151
Maintenance	-$54,345	9	.7	-$37,853
Maintenance	-$169,917	10	.67	-$113,692
Maintenance	-$49,758	11	.64	-$31,982
Maintenance	-$54,552	12	.62	-$33,682
Maintenance	-$162,168	13	.59	-$96,185
Maintenance	-$55,581	15	.55	-$30,420
Maintenance	-$217,428	16	.53	-$114,315
Maintenance	-$57,636	18	.49	-$27,963
Maintenance	-$48,750	19	.47	-$22,720
Maintenance	-$165,360	20	.45	-$74,031
ONE TIME TOTAL	-$1,618,6			-$1,056,933
TOTAL	-$1,771,6			-$3,117,479

Life Cycle Cost Analysis Study: DAVMON5.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #2d
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $336,088
5. Simple Payback Period (Years) 1.75
6. Total Net Discounted Savings $3,167,788
7. Savings to Investment Ratio 4.96
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 12.77%

Appendix Q: Calculated Paybacks and Savings-to-Investment Ratio for Option 3a

```
Life Cycle Cost Analysis       Study: Option #3a
Energy Conservation Investment Program (ECIP)            LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA          Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3a
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$241,710
B. SIOH	$13,294
C. Design Cost	$14,503
D. Total Cost (1A+1B+1C)	$269,507
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$269,507

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	13,937	Mwatt-	$641,091	14.47	$9,276,586
Elec. Deman					$147,375	13.47	$1,985,141
Natural Gas	$3.4	/Mbtus	-113,421	Mbtus	-$385,632	17.32	-$6,679,142
TOTAL			-65,867	Mbtus	$402,834		$4,582,585

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$101,982	Annual	13.47	-$1,373,698
ANNUAL TOTAL	-$101,982			-$1,373,698
Maintenance	-$33,868	2	.92	-$31,253
Maintenance	-$31,594	3	.89	-$28,006
Maintenance	-$111,900	4	.85	-$95,286
Maintenance	-$30,916	5	.82	-$25,289
Maintenance	-$33,448	6	.79	-$26,282
Maintenance	-$111,084	7	.75	-$83,849
Maintenance	-$35,996	8	.73	-$26,100
Maintenance	-$36,230	9	.7	-$25,235
Maintenance	-$113,278	10	.67	-$75,795
Maintenance	-$33,172	11	.64	-$21,321
Maintenance	-$36,368	12	.62	-$22,455
Maintenance	-$108,112	13	.59	-$64,123
Maintenance	-$37,054	15	.55	-$20,280
Maintenance	-$144,952	16	.53	-$76,210
Maintenance	-$38,424	18	.49	-$18,642
Maintenance	-$32,500	19	.47	-$15,147
Maintenance	-$110,240	20	.45	-$49,354
ONE TIME TOTAL	-$1,079,1			-$704,628
TOTAL	-$1,181,1			-$2,078,325

Life Cycle Cost Analysis Study: DAVMON6.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3a
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $246,895
5. Simple Payback Period (Years) 1.01
6. Total Net Discounted Savings $2,504,260
7. Savings to Investment Ratio 9.29
 If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 16.37%

Appendix R: Calculated Paybacks and Savings-to-Investment Ratio for Option 3b

Life Cycle Cost Analysis Study: Option #3b
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3b
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

ECIP Summary Report

1. Investment

A. Construction Cost	$481,450
B. SIOH	$26,480
C. Design Cost	$28,887
D. Total Cost (1A+1B+1C)	$536,817
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$536,817

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	26,943	Mwatt-	$1,239,367	14.47	$17,933,640
Elec. Deman					$310,453	13.47	$4,181,802
Natural Gas	$3.4	/Mbtus	-244,743	Mbtus	-$832,128	17.32	-$14,412,45
TOTAL			-152,811	Mbtus	$717,692		$7,702,992

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$203,964	Annual	13.47	-$2,747,395
ANNUAL TOTAL	-$203,964			-$2,747,395
Maintenance	-$67,736	2	.92	-$62,505
Maintenance	-$63,188	3	.89	-$56,012
Maintenance	-$223,800	4	.85	-$190,571
Maintenance	-$61,832	5	.82	-$50,578
Maintenance	-$66,896	6	.79	-$52,565
Maintenance	-$222,168	7	.75	-$167,697
Maintenance	-$71,992	8	.73	-$52,201
Maintenance	-$72,460	9	.7	-$50,471
Maintenance	-$226,556	10	.67	-$151,589
Maintenance	-$66,344	11	.64	-$42,643
Maintenance	-$72,736	12	.62	-$44,910
Maintenance	-$216,224	13	.59	-$128,246
Maintenance	-$74,108	15	.55	-$40,561
Maintenance	-$289,904	16	.53	-$152,420
Maintenance	-$76,848	18	.49	-$37,284
Maintenance	-$65,000	19	.47	-$30,294
Maintenance	-$220,480	20	.45	-$98,709
ONE TIME TOTAL	-$2,158,2			-$1,409,255
TOTAL	-$2,362,2			-$4,156,651

Life Cycle Cost Analysis Study: DAVMON7.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3b
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $405,815
5. Simple Payback Period (Years) 1.21
6. Total Net Discounted Savings $3,546,342
7. Savings to Investment Ratio 6.61
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 14.41%

Appendix S: Calculated Paybacks and Savings-to-Investment Ratio for Option 3c

```
Life Cycle Cost Analysis       Study: Option #3c
Energy Conservation Investment Program (ECIP)             LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA          Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3c
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$482,863
B. SIOH	$26,557
C. Design Cost	$28,972
D. Total Cost (1A+1B+1C)	$538,392
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$538,392

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	20,546	Mwatt-	$945,136	14.47	$13,676,120
Elec. Deman					$232,056	13.47	$3,125,795
Natural Gas	$3.4	/Mbtus	-179,077	Mbtus	-$608,863	17.32	-$10,545,51
TOTAL			-108,970	Mbtus	$568,329		$6,256,406

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$152,973	Annual	13.47	-$2,060,546
ANNUAL TOTAL	-$152,973			-$2,060,546
Maintenance	-$50,802	2	.92	-$46,879
Maintenance	-$47,391	3	.89	-$42,009
Maintenance	-$167,850	4	.85	-$142,928
Maintenance	-$46,374	5	.82	-$37,933
Maintenance	-$50,172	6	.79	-$39,424
Maintenance	-$166,626	7	.75	-$125,773
Maintenance	-$53,994	8	.73	-$39,151
Maintenance	-$54,345	9	.7	-$37,853
Maintenance	-$169,917	10	.67	-$113,692
Maintenance	-$49,758	11	.64	-$31,982
Maintenance	-$54,552	12	.62	-$33,682
Maintenance	-$162,168	13	.59	-$96,185
Maintenance	-$55,581	15	.55	-$30,420
Maintenance	-$217,428	16	.53	-$114,315
Maintenance	-$57,636	18	.49	-$27,963
Maintenance	-$48,750	19	.47	-$22,720
Maintenance	-$165,360	20	.45	-$74,031
ONE TIME TOTAL	-$1,618,7			-$1,056,941
TOTAL	-$1,771,6			-$3,117,488

Life Cycle Cost Analysis   Study: DAVMON8.LC
Energy Conservation Investment Program (ECIP)   LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA   Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3c
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $334,421
5. Simple Payback Period (Years) 1.49
6. Total Net Discounted Savings $3,138,918
7. Savings to Investment Ratio 5.83
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 13.69%

Appendix T: Calculated Paybacks and Savings-to-Investment Ratio for Option 3d

```
Life Cycle Cost Analysis      Study: Option #3d
Energy Conservation Investment Program (ECIP)              LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA         Census Region:  4
Project NO. & Title:  250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3d
Analysis Date: 10/01/97 Economic Life:  20  years
Prepared by: William T Brown III
```

ECIP Summary Report

1. Investment

A. Construction Cost	$838,542
B. SIOH	$46,120
C. Design Cost	$50,313
D. Total Cost (1A+1B+1C)	$934,974
E. Salvage Value of Existing Equip.	$0
F. Public Utility Company Rebate	$0
G. Total Investment (1D-1E-1F)	$934,974

2. Energy Savings (+) / Costs (-)
Date of NISTIR 85-3273-X used for Discount Factors Oct 1995

Fuel	Price	Price Units	Usage Savings	Usage Units	Annual Savings	Discount Factor	Discounted Savings
Electricity	$46.	/Mwatt	40,791	Mwatt-	$1,876,397	14.47	$27,151,460
Elec. Deman					$468,780	13.47	$6,314,467
Natural Gas	$3.4	/Mbtus	-376,046	Mbtus	-$1,278,55	17.32	-$22,144,57
TOTAL			-236,860	Mbtus	$1,066,622		$11,321,360

3. Non Energy Savings (+) / Costs (-)

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost
Baseline Maint	-$305,946	Annual	13.47	-$4,121,093
ANNUAL TOTAL	-$305,946			-$4,121,093
Maintenance	-$101,604	2	.92	-$93,758
Maintenance	-$94,782	3	.89	-$84,018
Maintenance	-$335,700	4	.85	-$285,857
Maintenance	-$92,748	5	.82	-$75,867
Maintenance	-$100,344	6	.79	-$78,847
Maintenance	-$333,252	7	.75	-$251,546
Maintenance	-$107,988	8	.73	-$78,301
Maintenance	-$108,690	9	.7	-$75,706
Maintenance	-$339,834	10	.67	-$227,384
Maintenance	-$99,516	11	.64	-$63,964
Maintenance	-$109,104	12	.62	-$67,365
Maintenance	-$324,336	13	.59	-$192,369
Maintenance	-$111,162	15	.55	-$60,841
Maintenance	-$434,856	16	.53	-$228,630
Maintenance	-$115,272	18	.49	-$55,926
Maintenance	-$97,500	19	.47	-$45,440
Maintenance	-$330,720	20	.45	-$148,063
ONE TIME TOTAL	-$3,237,4			-$2,113,883
TOTAL	-$3,543,3			-$6,234,975

Life Cycle Cost Analysis Study: DAVMON9.LC
Energy Conservation Investment Program (ECIP) LCCID FY96
Installation & Location: Davis-Monthan AFB
Region data: ARIZONA Census Region: 4
Project NO. & Title: 250-Ton Chiller Replacement
Fiscal Year: 97 Discrete Portion: Option #3d
Analysis Date: 10/01/97 Economic Life: 20 years
Prepared by: William T Brown III

Item	Savings/ Cost	Year	Discount Factor	Discounted Savings/Cost

4. First Year Dollar Savings $598,806
5. Simple Payback Period (Years) 1.43
6. Total Net Discounted Savings $5,086,382
7. Savings to Investment Ratio 5.44
   If < 1, Project does not qualify
8. Adjusted Internal Rate of Return 13.3%

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