High Temperature Reciprocating Engines: A Key to Cost Effective CHP

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ABSTRACT

Reciprocating engines have been used as a simultaneous source of electrical and thermal energy for decades in combined heat and power (CHP) systems. Cooling loads can be met by powering absorption chillers with the thermal energy. However, because reciprocating engines normally operate near 212°F, the choice of absorption chillers is limited to inefficient single effect machines. If the engine operated with coolant temperatures in the 340°F range, double effect chillers could be used, and the same engine would supply about 75% more cooling capacity.

This issue is here examined from two perspectives: how much is such an improvement worth, and what are the technical barriers to achieving it? To answer the first question, the study compares (i) a base case, where heat is supplied by boilers and electricity is purchased; (ii) a standard practice CHP system, with a reciprocating engine-generator, heat recovery, a backup boiler and a single effect chiller; and (iii) a similar system operating at a higher temperature with a double effect chiller. The capital cost increment of the double effect chiller is partially compensated by a decrease in compression chiller capacity and lower operating costs result in significant life cycle savings over an eight year period.

Several technical issues must be resolved. Foremost, the engines must be converted to ebullient cooling (only steam-driven double effect chillers are commonly available). Various associated technical issues and measures are discussed below. In sum it seems likely that the cost of these measures will be substantially less than the potential savings.

Introduction and Summary of Results

Cogeneration, now known as "combined heat and power" or "CHP", is a venerable and ever-nascent technology, offering a potentially high level of resource utilization at the price of modest complexity in the energy services supply system. A traditionally attractive and popular application has been the siting of an engine generator set in a commercial facility, with the reject heat from the engine utilized for hot water and space heat in the building. Further efficiency is possible if the reject heat can also be used to power an absorption chiller, providing cooling on either a seasonal or year-round basis, as needed.

For many applications, the prime mover of choice will be a natural gas fired reciprocating engine in the 50 kW to 50 MW range, and a variety of these units are available from a wide array of manufacturers. Standard design and operating practice for these machines requires cooling water entering the engine at about 80 C (180°F), so the thermal load must be capable of cooling the circulating water to this temperature, or must be augmented by a radiator or cooling tower, rejecting useful thermal energy to a waste stream. This restriction has limited the choice of absorption chillers to single effect machines with COPs* of about 0.70. Double effect absorption chillers have COPs in the 1.20 to 1.30 range, but require input steam at over 150 C (302°F), and reject this water at about 15 C (27°F) less. Consequently, operating a double effect chiller off a reciprocating engine requires that the engine accept coolant at about 135 C (275°F) and return it at 150 C or a bit higher. That is exactly what this study proposes.

Our primary purpose is to demonstrate that this effort will produce significant economic rewards by comparing three exemplary systems. The study is carried out for a substantial commercial suburban building, with an average electric load of about 950 kW and with heating, cooling, and process loads based on national average usage. The base case system, described in Section 2, uses power from the local utility (with tariffs modeled in detail), compression chillers and gas-fired boilers for thermal demands. Section 3 describes the second system, "Standard CHP", which supplies the same loads in part from a standard cogeneration system with a gas fired reciprocating engine, thermal energy recovery and single effect absorption chillers. The system operates in a grid-connected mode, with sell-back of excess power under current tariffs. The third system, "Enhanced CHP", is presented in Section 4. It is similar, but double effect chillers replace the single effect ones, and the engine is assumed capable of operating at the requisite temperatures at no additional cost. Performance of all three systems is assessed using a detailed, probabilistic cogeneration model described in detail below.

The costs of the standard and enhanced systems relative to the base case indicate the viability of cogeneration in these applications. The returns on investment (ROI) of the additional capital needed for the cogeneration systems over an eight year economic life are compared in Table 1. The savings of the enhanced system relative to the standard system then indicate how much can be spent making the engine capable of this performance. The result, sketched in Table 1 and explained in detail below, is that for a reasonable configuration, the equipment cost of the engine can be increased by up to 18%, $12,800 per engine, to permit it to run at higher temperatures. If the improvements can be carried out for less than this, the remaining savings can potentially be captured as profit. If the engines require no investment, the capital associated with double effect chillers will show an ROI of 22% over eight years.

Table 1. Summary Comparison of Three Systems

		Annual Outlays			
	Capital	Maintenance	Fuel & Electric	Total	8-yr ROI
Base Case:	-	-	$1,351,566	$1,351,566	
Standard CHP:	$675,507	$71,198	$1,043,262	$1,114,459	31%
Enhanced CHP:	$783,724	$71,165	$1,013,380	$1,084,545	30%
Standard - Enhanced:	$108,217			$29,914	22%
Capital Available for Engine Improvements at 10% over 8 years, per Engine:					$12,800

Finally, in the Section 5, the technical issues to be addressed in obtaining reliable engine operation at these temperatures are addressed. Although many items need to be considered,

* COP = coefficient of performance = cooling load met/thermal power supplied.

including coolant flow, the balance of heat from different engine components, lubricant performance at elevated temperatures, and other issues, non seem to be serious problems. It appears that any increase in the costs of implementation will be substantially outweighed by the savings resulting from the increased efficiency of double effect chillers.

The next step should be the establishment of a modest research program to put a suitable engine on a test bench, instrument it with a comprehensive set of temperature transducers, and experiment with the conversion to ebullient cooling, gradual increases in temperature, variations in coolant flow patterns, and assessment of other operating impacts. Since the double effect chiller is a mature, off the shelf item, there is no need for experimentation with that part of the configuration until enough confidence has been gained to install a demonstration system.

Base Case: Boilers and Utility Power

The fictitious facility used to evaluate the competing systems is large - 600,000 square feet. Few individual buildings are this large (EIA 1992, 28), but the analysis applies equally well to a complex such as a university or office park. This size range was chosen because the smallest double effect, steam-driven chillers currently available are in the 100 to 200 ton range, and the system must be large enough to make use of one or more of these. Monthly electric (energy and demand) and gas bills are then developed such that the facility experiences national commercial building average load intensities (OBT 1995) for non-AC electricity, cooling, heating and process heat as shown in the following table.

Table 2. Representative Facility Loads, Load Intensities and Fuel Consumption

	Load	Intensity	Conversion Efficiency	Fuel Consumption
Non-AC Electricity:	6690 MWh/yr	11.1 kWh/ft^2-yr	-	-
Cooling Load*:	8150 MBtu/yr	13.6 kBtu/ft^2-yr	10.4 Btu/Wh	780 MWh/yr
Heating Load:	13,350 MBtu/yr	22.2 kBtu/ft^2-yr	80%	166,900 Therms
Process Heat:	2630 MBtu/yr	4.4 kBtu/ft^2-yr	80%	32,900 Therms

All three systems are evaluated using a detailed operational model (Leigh, 2001), which is itself descended in part from techniques used in an earlier study of cogeneration feasibility (Andrews, e. al, 1996). The model is designed to generate actual heating, cooling, process and non-AC electric loads from electric and gas billing data. The non-AC electric load is estimated as the average power consumed during non-cooling months, then cast into a load duration curve with five equal steps. The top step (top 20% of peak load) has near-zero duration, while the energy is parceled more or less equally among the remaining steps to achieve the non-cooling annual load factor observed on the bill, here about 50%.

The cooling load is derived from the excess electric demand during the cooling season and is divided into three periods, with a peak occupying one-fifth of the cooling season and shoulder and low cooling periods occupying two-fifths each. Demand during each period is

* Throughout this report, the prefix "k" will denote 1000 and "M" will denote 1,000,000, even for Btus.

adjusted to give an overall load factor of 35% during the cooling season. Peak cooling demand is derived assuming a 90% coincidence factor with other electric loads and, as for electric loads, that there is a near-zero energy demand spike amounting to 25% of peak load superimposed on the load for each period.

Similarly, process loads (primarily hot water) are derived from gas consumption during the cooling season, but are taken as constant during the year. Heating load is treated like cooling load, with a peak period (one-fifth of the heating season) and shoulder and low periods for two-fifths of the season. Again, demand spikes amount to 25% of peak load, which is divided among the periods to produce a 45% load factor during the heating season All thermal loads are then recombined through the separate hot and chilled water distribution systems, to be supplied (in the base case) by the boilers and compression chillers.

For the base case the only further calculations are gas and electric tariffs and conversion efficiencies. Electric and gas tariffs are treated in detail, including demand charges, ratchets, adjustments and taxes for delivery by Con Edison to Westchester (Con Ed 2001). For the base case, electricity is priced under SC-9 (General - Large) service, and gas under SC 2 (General Firm Gas Sales). All utility connections are assumed to be "High Tension", at 2400V or more. Under the impact of both deregulation and high demand for gas, Con Edison's rates have recently been quite volatile. This study used historic rates, including all after-the-fact adjustments, for May 2000 through January 2001, and projected adjustments for February through April that would bring electric prices in May 2001 close to those of May 2000. The result, including all customer, energy, and demand charges, ratchets, adjustments and taxes over a one year period is a cost of 15.8 cents per kilowatt hour. The annual load factor was 45%. The annual average overall cost of gas was $0.87 per therm ($8.70 per million Btu). The base case energy supply expenses are summarized in Table 3.

Table 3. Base Case Electric and Fuel Consumption and Expenses

	Electricity			Fuel		Total
	Energy MWh	Demand kW	Cost	Gas (therm)	Cost	E & F Costs
Jan	560	1500	$ 97,027	43,569	$ 43,491	$ 140,518
Feb	560	1500	$ 86,218	37,034	$ 32,710	$ 118,929
Mar	560	1500	$ 89,617	31,479	$ 24,319	$ 113,936
Apr	550	1500	$ 84,161	2,744	$ 2,102	$ 86,263
May	664	1700	$ 89,812	2,744	$ 1,913	$ 91,725
Jun	714	1800	$ 114,605	2,744	$ 1,970	$ 116,576
Jul	814	1900	$ 147,956	2,744	$ 2,098	$ 150,054
Aug	714	1800	$ 114,396	2,744	$ 1,993	$ 116,388
Sep	664	1700	$ 105,750	2,744	$ 2,495	$ 108,245
Oct	550	1500	$ 69,920	2,744	$ 2,759	$ 72,679
Nov	560	1500	$ 88,313	31,479	$ 26,577	$ 114,891
Dec	560	1500	$ 90,485	37,034	$ 30,877	$ 121,362
Annual:	7467	1900	$ 1,178,261	199,803	$ 173,305	$1,351,566

Space heat and process loads are met by new gas boilers operating at 80% efficiency. Cooling loads are met by a bank of six 100 ton, packaged, dry condenser chillers with a seasonal energy efficiency rating (SEER) of 10.4 Btu/kWh. The chiller cost was $77,540 per unit, (Means

1996, 281), including installation and contractor's overhead and profit (O&P) and corrected for inflation to 2001 with the Producer Price Index. Annual maintenance and repair on the chillers was taken as $2500 per unit. Losses in the distribution system were 5% for chilled water and 10% for hot water. Costs are not developed for items, such as the boilers and distribution system, that are the same in both base and cogeneration cases. The boiler(s) is assumed to have adequate capacity for the base case, and to retain the same capacity in the cogeneration cases for reliability purposes. Similarly, the six 100 ton chillers required to meet the cooling demand are not priced, nor are operational expenses calculated, in the base case. Rather, credit will be taken in the cogeneration cases for each electric chiller that need not be included because the absorption units are present. Consequently, the costs shown in Table 3 are the only costs included for the base case.

Standard CHP: Cogenerator and Single Effect Chiller

The cogeneration system serves exactly the same load as the base case system, but is based on a bank of two to five 150 kW, spark-ignited natural gas fueled reciprocating engines. The engine is modeled on one available from a West Coast supplier, but is sufficiently generic to need no detailed attribution. The characteristics are summarized in Table 4.

Table 4. Characteristics of Cogeneration Prime Mover

Electrical Capacity:	150 kW	
Heat Rate:	11,000 Btu/Wh,31% (HHV)	9920 Btu/Wh, 34% (LHV)
Peak Thermal Output:	704 kBtu/hr	
Thermal efficiency:	43% (HHV)	47% (LHV)
Availability:	95% (each unit)	
Equipment Cost:	$71,000	$473/kW
Installation Cost:	$82,500	$550/kW
Maintenance & Repair:	$0.010/kWh + $25/kW-yr	

More efficient engines are available, at higher equipment costs, but optimization on this variable would have been off the point of this study. Installation costs are extremely uncertain; the number used here was used by a large California developer for feasibility studies. The result lies comfortably within the range for combined equipment plus installation costs found by a Gas Research Institute study (Mulloney 1988) of $805-$3750/kW (escalated to 2001 dollars). The average installed cost found in that study, $1800/kW (2001 dollars) is somewhat higher than ours, but small machines were included in the sample.

The engines are modeled using the characteristics in Table 4. Engine outages are treated probabilistically, with system output and availability, and therefore residual demand and energy charges, depending on the convolution of individual machine availability. Electric and thermal loads are assumed statistically independent of each other, and are divided among twelve bins representing the four electric demand levels times three heating demand levels in the heating season, twelve similar bins in the cooling season, and four bins for the different electric demands during the shoulder season, when process loads are assumed constant. In each of these bins, generation tracks the larger of the electric or thermal demand, discarding unused thermal energy and selling excess electric energy back to the grid. Another strategy, tracking electric demand and making up thermal load with boilers, is discussed below. Two final strategies, tracking thermal load and exchanging more power with the grid, or tracking the smaller of thermal or electric demand, are less effective and are not examined here.

Electric demands are lowered because compression chillers are displaced by absorption chillers driven by hot water from the engines, as described below. Boilers meet heating loads that are beyond the capacity of the installed engines, purchasing gas in parallel with the engines on the same SC-2 tariff used for the base case. Due to the presence of the engines, however, electricity must be purchased on the SC-10 (Supplementary Service) tariff (Con Edison, 2001), which has a far more complex structure than does SC-9. It includes both contract and as-used demand charges, with twelve month seasonal ratchets superposed on an underlying two or three block structure of escalating charges with seasonal variations. The demand structures are different (and additive) for supply, transmission and distribution. Energy charges are similarly complex, and are topped off by the usual collection of adjustments and taxes. The overall impact is to make the projection of the expected electric bill of a self generation project a daunting task. And the bills will be higher, on a unit energy basis, due in part to the lower load factor of supplemental power. In one typical case, the load factor was 15% and the overall cost of electric power, reduced to an energy basis, was $0.29 per kilowatt hour, about double the unit cost of electric service in the base case.

Power is also sold back to the utility under the provisions of Con Edison's SC-11 (Buy Back Service) tariff. Owners of large independent generators normally sell their power on the open market, through (for New York State) the Independent System Operator (ISO). However, a self generator with a system sized to meet its own loads, like the one examined here, will produce a fluctuating and unpredictable output that will be very hard to sell. The SC 11 tariff is only available to "Qualifying Facilities" under Federal and New York State law, which essentially requires either a biomass fuel or cogeneration with a specified minimum utilization of thermal energy. The system under study here met the minimum utilization requirements easily in all cases.

The SC-11 tariff is supposed to recognize that even fluctuating output is of some value to the aggregate system, but has in fact been structured so that the actual payments are quite small or even negative. The payment can be negative because of the inclusion of contract demand charges, to be paid to Con Edison by the independent generator to recompense Con Ed for the expenses associated with maintaining the distribution and transmission system over which the energy will be delivered. In a typical case, these demand charges amounted to $12,219 per year while payment (by Con Ed) for the delivered energy was only $4110, resulting in a net loss of $0.11 per kilowatt hour to the facility for keeping the possibility of energy sales available. The real problem with this is that the facility already paid to maintain exactly the same transformers and wires (which don't care which direction the power flows in) under the demand charges of SC-10! Although a rational operator would give up on energy sales and utilize a dispatch scheme that tracks only electrical demand, making up thermal load with boilers, the amounts of money are too small to affect the outcome of the other questions being examined here, so the maximum load tracking strategy is retained and the results are included in order to make this situation more widely known. All of the electric power and fuel expenses are summarized in Table 5.

Table 5. Electric and Fuel Expenses for Standard CHP

	Electric Purchases			Electric Sales			Fuel	
	Energy	Demand	Cost	Energy	Demand	Credit	Gas	Cost
	MWh	kW		MWh	kW		(therm)	
Jan	152	930	$ 31,225	11.8	270	$ (1,018)	86,130	$ 26,102
Feb	152	930	$ 59,723	11.8	270	$ (466)	65,549	$ 37,454
Mar	152	930	$ 77,992	11.0	252	$ (897)	45,640	$ 40,367
Apr	152	930	$ 59,902	0.0	0	$ (466)	44,433	$ 37,998
May	152	1130	$ 57,128	0.0	0	$ (1,018)	44,433	$ 35,560
Jun	174	1230	$ 28,406	10.3	237	$ (1,018)	61,785	$ 39,841
Jul	302	1330	$ 33,808	2.3	52	$ (431)	61,785	$ 38,378
Aug	174	1230	$ 34,326	10.3	237	$ (389)	61,785	$ 54,384
Sep	152	1130	$ 36,965	0.0	0	$ (389)	44,433	$ 85,637
Oct	152	930	$ 32,859	0.0	0	$ (389)	44,433	$ 57,629
Nov	152	930	$ 33,719	11.0	252	$ (431)	45,640	$ 35,104
Dec	152	930	$ 31,630	11.8	270	$ (1,018)	65,549	$ 29,192
Annual:	2018	1330	$ 517,683	80	270	$ (7,932)	671,595	$517,647

If the facility were to purchase enough generation capacity to meet all facility loads internally under normal circumstances, it would then have to choose whether to sever the link to Con Edison altogether, or retain the link in order to make sales or to purchase back-up coverage in the event of an outage. Back up power is provided under the SC-3 tariff, and would cost this facility up to $70,000 per year based on a contract demand system. A facility on SC-3 whose load factor (i.e. use of the system) exceeds 10% is forced to switch to SC-10 (Supplementary Service). Purchasing enough generation capacity to make the SC-3 tariff appropriate is not generally cost effective.

In this "Standard CHP" part of the study, some of the cooling load is met by the introduction of one or two 200 ton single effect absorption chillers. (A case with no chiller was also examined.) These are generic, hot water driven units with characteristics displayed in Table 6. Equipment and installation costs are from an estimating manual (Means 1996, 271) (corrected for inflation to 2001 with the Producer Price Index), and are consistent with recent conversations with manufacturer's representatives. The COP of 0.65 is for ARI design point operation; part-load is better, but that was not modeled here. The compression chillers incorporated their own air-cooled condensers, but the absorption chillers require wet cooling towers. These are normally described in terms of the tonnage of compression chillers they would serve, and must be resized to match the much lower COP of the absorption chillers. Cooling tower cost are from the same estimating manual (Means 1996, 293).

Annual performance is obtained by summing the monthly figures and incorporating maintenance expenses, with the results summarized in Table 7. The savings in electric and fuel dominate the annual expenses. The second part of the table summarizes the additional capital expenses associated with the standard CHP system, and the credit for not having to construct compression chiller capacity due to the presence of the absorption chillers. Finally, the bottom part of the table shows that the projected economic performance of this system is very good indeed, with a simple payback of less than three years and a very attractive return on investment

(ROI) over an hypothesized eight year economic horizon. (The system should be useful much longer than eight years!) This is a constant dollar ROI, to which expected inflation should be added before comparing it to other investments.

Table 6. Single Effect Chiller System Characteristics

Capacity:	200 tons	COP:	0.65
Operating Conditions:	ARI Standard: 54/44F chilled water, 85 F cooling water		
Hot Water supply:	15 psig, 250 F		
Equipment:	$136,200	Installation:	$40,900
Maintenance and Repair:	$4900/year		
Cooling Tower Capacity:	6.1 MBtu/hr		
Installed Cost:	$39,500		
Maintenance and Repair:	$1000/year		

Table 7. Economic Summary for Standard CHP with Four Engines and One Chiller

Comparison of Annual Expenses:			
	Baseline System	Cogeneration System	Savings
Electric & Fuel:	$ 1,351,566	$ 1,043,262	$ 308,304
Cogen Maintenance:	0	$70,292	$ (70,292)
Absorption O&M:	0	$4,905	$ (4,905)
Tower O&M:	0	$1,000	$ (1,000)
Comp AC Credit:	0	($5,000)	$ 5,000
Total=	$ 1,351,566	$ 1,114,459	$ 237,107
Additional Capital for Cogeneration System:			
Cogenerator:	$614,000	Comp AC credit:	($155,080)
Absorption Chillers:	$177,100		
Cooling Towers:	$39,487		
		Total=	$675,507
Financial Analysis:			
Simple payback=	2.8	years	
Over	3	8	years
Constant $ ROI=	2.6%	31%	

The analysis in Table 7 is for a configuration with four engines, having a nominal capacity of 600 kW and an expected capacity of 570 kW when outages are factored in. Although the invested capital and annual savings varied widely, systems having from three to six engines and one chiller had almost the same payback and ROI, with four engines optimal by a margin that is smaller than the uncertainties that result from plausible variations in input parameters.

A system with four engines and no chiller was similarly slightly better, with an ROI greater than the one in Table 7 by less than a percent. A system with four engines and two absorption chillers had an eight year ROI of 26%, which is still a very good investment, and which carries substantial value that does not show up in a simple assessment like this, such as further reductions in emissions and greater insulation from future electric price shocks. Since the point of this study is to examine the value of improved chiller performance, and since the difference between the performance of the various systems is much less than the uncertainties, the one chiller configuration is used for analysis.

Enhanced CHP With Double Effect Chiller

This part of the study makes a bold leap of faith and assumes the engines can be ebulliently cooled (that is, the coolant is boiling inside the engine, with the heat being carried away as steam) at a working pressure of about 115 psig. The heat rate and other operating characteristics are assumed unchanged. This makes it possible to use double effect chillers, producing almost twice the chilling capacity from the same reject heat or, conversely, permitting operation of the absorption chillers at times when single effect chillers would not have sufficient thermal power to meet load. Ebullient cooling is necessary because no double effect chillers are available designed to operate on pressurized hot water. (The generator tubing configuration is the primary difference between steam and hot water firing.) If a significant market developed there are no technical obstacles to developing a hot water driven double effect chiller, but this study is based on currently available technology, and the cost of a new absorber technology would be higher, and uncertain.

The characteristics of the double effect chillers are summarized in Table 8. Again, they are a generic product, with characteristics (at this level of detail) driven by the basic physical chemistry of the process. The equipment costs represent the 80% premium over single effect machines, and installation costs a 25% premium, as specified by the estimating manual (Means 1996, 271). The cooling towers are downsized from the standard CHP case to match the increased COP of the double effect chillers. Maintenance figures are sufficiently small and uncertain to be left unchanged. In all other respects, operation of the system is the same as it was in the case of standard CHP. The monthly electric bills are identical to the previous case, and the fuel bills differ only in a 26% decline in fuel use during June, July and August, since summer loads could now be met completely by cogenerated thermal energy. A comparison of the double effect system to the base case, in Table 9, shows that it is also very attractive, with almost the same economic performance as the standard CHP system.

Finally, Table 10 compares the standard and enhanced systems for the same four engine, one chiller configuration. The annual savings are summed over the eight year economic life of the project at a 10% per year constant dollar discount rate; the capital required to pay for the double effect chillers is subtracted from the result to arrive at the capital that could be spent upgrading the engines for high temperature operation and still break even. In the bottom row, this available capital is presented as a fraction of the total equipment (not installation) costs for the four engines.

Table 8. Double Effect Chiller System Characteristics

Capacity:	200 tons	COP:	1.2
Operating Conditions:	ARI Standard: 54/44F chilled water, 85 F cooling water		
Steam Supply:	115 psig, 350 F		
Equipment:	$245,160	Installation:	$51,125
Maintenance and Repair:	$4900/year		
Cooling Tower Capacity:	4.4 MBtu/hr		
Installed Cost:	$28,520		
Maintenance and Repair:	$1000/year		

Table 9. Economic Summary for Enhanced CHP with Four Engines and One Chiller

Comparison of Annual Expenses:			
	Baseline System	Cogeneration System	Savings
Electric & Fuel:	$ 1,351,566	$ 1,013,380	$ 338,186
Cogen Maintenance:		$70,259	$ (70,259)
Absorption O&M:	0	$4,905	$ (4,905)
Tower O&M:	0	$1,000	$ (1,000)
Comp AC Credit:		($5,000)	$ 5,000
Total=	$ 1,351,566	$ 1,084,545	$ 267,022
Additional Capital for Cogeneration System:			
Cogenerator:	$614,000	Comp AC credit:	($155,080)
Absorption Chillers:	$296,285		
Cooling Towers:	$28,519		
		Total=	$783,724
Financial Analysis:			
Simple payback=	2.9	years	
Over	3	8	years
Constant $ ROI=	1.1%	30%	

Table 10. Comparison of Standard and Enhanced CHP

Annual savings of Advanced CHP over Standard CHP:	$29,915
Capital increment of Advanced CHP over Standard CHP:	$108,216
Capital Available for Engine Improvements at 10% over 8 years:	$51,377
Same as Fraction of Engine Equipment Costs:	18%

This result depends strongly on the number of engines. With fewer engines, more fuel is burned in the boilers, so the double effect chillers offer more savings, and this is amplified by spreading the savings over fewer engines. With more engines, the single effect chillers are at less of a disadvantage, since there is lots of thermal energy available, and the (smaller) amount of excess capital must be divided among more engines. For two, three and five engines, the corresponding fractions of engine equipment costs are 43%, 29%, and 0.3%. These results indicate that a significant sum is available for the engine upgrades discussed in the next section

Engineering Challenges in High Temperature Reciprocating Engines

This section briefly summarizes the major issues in getting reciprocating engines to operate at about 340 F and 115 psig with ebullient cooling. Ebullient cooling by itself is not uncommon for reciprocating engines and has several advantages, including greater temperature uniformity within the engine and elimination of the water circulation pump (Segaser, 1977, 6). (The engine must be located below the chiller's generator if pumps are to be eliminated from the system.) The system must be balanced carefully, as absorption chillers work best with steam that is just above saturation. Desuperheating is an inefficient use of costly heat exchangers in the generator. And there are various sources of thermal energy within the engine that must be considered separately: the water jacket, the oil cooler, the exhaust manifold and, in larger engines, the pistons, which must be separately cooled with water under considerable pressure (Baumeister 1979, 9-105). It may be possible, for example, to use the piston cooling path as a preheater for water which would then be flashed and completely vaporized in the jacket and exhaust manifold.

Although some manufacturers derate engines under ebullient cooling, neither the efficiency nor the emissions of the engine are substantially affected by the increased temperature, since they are largely determined by the internal combustion processes, which are not affected by the modest (from the flame's perspective) increase in wall temperature. However, many other issues require assessment, including:

- Complying with high pressure codes,
- Lubricant performance and longevity,
- Exhaust valve temperature and metallurgy,
- Impact of increased coolant pressure on gaskets and seals,
- Thermal release paths into the engine body at elevated temperatures,
- Optimal coolant flow pathways,
- Impact on operating limits and strategies.

None of these areas seem to pose serious barriers to high temperature engine operation, but some (especially lubrication) may raise operating costs. Higher pressures should not be a serious problem: head gaskets withstand the hundreds of pounds per square inch produced by combustion; raising coolant pressure from a few psig to something over 100 psig should not be hard to manage. Balancing the contributions of various heat sources (jacket, oil, manifold, etc.) by careful routing of coolant will be key. Gaskets capable of withstanding the higher pressures will be required. Lubricants claiming adequate performance are available, but performance must be verified. The higher temperatures will produce greater thermal stress. One way to mitigate the effects of this will be to decrease ramp rates. Since rapid response is one of the reciprocating engine's assets, this is not a trivial compromise, but the only way to determine adequate limits will be through testing.

Although an experimental engineering effort is clearly required to establish responses to these issues, none of them seem likely to raise capital or operating costs by amounts comparable to the savings found in the previous section. In short, it appears that the value of raising engine operating temperatures in this application should turn out significantly greater than the costs. A development effort aimed at a high temperature engine would be a wise investment.

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