The Market and Technical Potential for Combined Heat and Power in the Industrial Sector

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PREFACE

This report was prepared by ONSITE SYCOM Energy Corporation as an account of work sponsored by the Energy Information Administration. Bruce A. Hedman, Vice President of consulting services at ONSITE SYCOM was the principal investigator for the analysis. ONSITE SYCOM would like to acknowledge T. Crawford Honeycutt and Daniel H. Skelly of the Energy Information Administration for their technical guidance and support in the preparation of this report.

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The Market and Technical Potential for Combined Heat and Power in the Industrial Sector

ONSITE SYCOM Energy Corporation (OSEC) is assisting the Energy Information Administration to determine the potential for cogeneration or combined heat and power (CHP) in the industrial market. As part of this effort, OSEC has characterized typical technologies used in industrial CHP, analyzed existing CHP capacity in industrial applications, and developed estimates of additional technical potential for CHP in industry.

This report is organized into four sections as follows:

1. CHP Technology Characterization for the National Energy Modeling System
2. Existing Industrial CHP
3. Technical Potential for Industrial CHP
4. Factors Impacting Market Penetration.

1. CHP Technology Characterization for the National Energy Modeling System

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets for the midterm period through 2020. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.

A key feature of NEMS is the representation of technology and technology improvement over time. Five of the sectors--residential, commercial, transportation, electricity generation, and refining--include explicit treatment of individual technologies and their characteristics, such as initial cost, operating cost, date of availability, efficiency, and other characteristics specific to the sector.

This section provides a review and update of combined heat and power (CHP) technology choices for the industrial sector. CHP is an established technique within the industrial sector for simultaneously meeting power and process steam requirements. As will be shown in a later section 45,465 MW of CHP power capacity currently exists in the industrial sector (accounting for about 215,000 mmBtu/hr steam capacity). Two key changes in the nation's economic system are occurring that could make CHP more important economically and environmentally – the restructuring of the electric power industry may provide an enhanced economic driver and the efforts to comply with the Kyoto Protocol on global warming may provide an environmental driver for energy efficiency options such as CHP. It is critical, therefore, that NEMS include up-to-date and accurate information on CHP technology cost and performance.

The NEMS cogeneration module of the industrial model is now based on five size categories of gas turbine systems from 1,000 kW to 40,000 kW size as shown in **Table 1.1**. In this section, OSEC reviews these data and develops independent estimates for performance, equipment and installation costs, and O&M costs for gas turbine systems for input into the NEMS model.

Table 1.1. Existing CHP Cost and Performance Parameters Used in the Industrial Cogeneration Module of NEMS (1997 Costs)

CHP Cost & Performance Assumptions	System 1	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	1,000	2,500	5,000	10,000	40,000
Total Installed Cost ($/kW)	1600	1400	1200	1000	950
Capacity Factor	0.8	0.8	0.8	0.8	0.8
Overall Heat Rate (Btus/kWh) HHV	14,217	13,132	11,263	10,515	9,749
Overall Efficiency (%)	70	70	70	75	80
Derived Technical Characteristics					
Elec Generating Efficiency (3412/Heat Rate)	24.0%	26.0%	30.3%	32.4%	35.0%
Fuel input (mmBtu/hr)	14.217	32.830	56.315	105.150	389.943
Steam output (mmBtu/hr)	6.540	14.451	22.361	44.743	175.474
Steam Output/Fuel Input	46.0%	44.0%	39.7%	42.6%	45.0%
Power Steam Ratio	0.522	0.590	0.763	0.763	0.778
Net Heat Rate (Btus/kWh)	6,042	5,907	5,673	4,922	4,265
Thermal Output as Fraction of Fuel Input	0.46	0.44	0.40	0.43	0.45
Electric Output as Fraction of Fuel Input	0.24	0.26	0.30	0.32	0.35

In general, these estimates provide a reasonable reflection of combustion turbine performance characteristics for use in the model. Overall efficiency levels are within range of commercially available equipment, and the estimates accurately reflect changes in electrical efficiency and overall efficiency as one moves from the smallest size category to the largest. Installed cost estimates, however, are somewhat higher than currently found in the marketplace, particularly for larger turbines systems. Several additional observations are made on this technology data set.

- The sizes selected, especially the 1,000 and 2,500 kW sizes, may not reflect a good match between the market and the technology performance. An analysis of existing CHP shows that gas engine driven CHP systems dominate in this size range and also effectively compete with combustion turbines in applications up to 10 MW or more. OSEC has provided cost estimates for 800 kW and 3 MW engine driven systems as part of this analysis. Engine systems provide good electrical efficiency. They are best used in applications that use low-pressure steam or hot water, as the technology is limited in its ability to produce high-pressure steam.

- In addition, 80% of the capacity of industrial CHP systems is made up of large size systems of 50 MW and more. Therefore, OSEC recommends adding a 100 MW system that would better reflect use of these larger applications.

- It is not clear how the NEMS Industrial Cogeneration Module accounts for technological change in CHP technologies. There has been continual improvement in the capacities and heat rates for combustion turbines that will increase the acceptance levels for these technologies by improving the economics of their application. In addition, there is considerable development work underway to further improve the operating and environmental performance envelopes of both combustion turbines and reciprocating engines. These improvements will generally increase the power to steam ratios over time and reduce the environmental impact of these technologies. Since the NEMS module matches the technologies in the database to industrial steam-load, the shifting power to steam ratios may require a rematching of potential sites or a relaxation of the model requirement to use all power on-site. In addition, to the base case technologies, OSEC has provided projections of cost and performance characteristics for improvements in gas engine and gas turbine technologies.

- Some of the proposed *CHP Initiatives* being discussed by DOE and industry to enhance the use of CHP by U.S. industry are investment tax credits, accelerated siting and permitting, standardized electrical connections, and other measures. It would be helpful if the technology characterizations in the model were of enough detail and flexibility to allow the model to test market response to these and other initiatives.

1.1 Performance Characteristics for Commercially Available Equipment

OSEC recommends changing the original five size categories of combustion turbine CHP systems (1, 2.5, 5, 10, 40 MW) to 1, 5, 10, 25 and 40 MW. Expanding the size range at the top end and eliminating the 2.5 MW CHP system better reflects equipment availability and market acceptance of combustion turbines. OSEC has developed performance estimates (heat rate, steam output, etc.) for each of these size ranges based on published data for specific gas turbine systems. **Table 1.2** summarizes these performance characteristics. The data in the table were derived from published performance specifications contained in trade publications.[1, 2, 3] The heat rates for the listed combustion turbines (CTs) are taken from published data for typical turbines in each size class (the 1 MW size is based on the Solar 1205 kW Saturn 20 gas turbine; the 5 MW system is based on the Solar Taurus 60; the 10 MW system is based on the Solar Mars 100; the 25 MW is based on the GE LM2500; and the 40 MW is based on the GE LM6000). Available thermal energy (steam output) was calculated from published turbine data on steam produced from the selected systems. The estimates are based on an unfired heat recovery steam generator (HRSG) producing dry, saturated steam at 150 psig.

In general, the new calculated technology characteristics do not represent a dramatic change from the existing characteristics shown previously in **Table 1.1**. The revised capital costs, to be described in detail in the next section, are identical for the 1 MW size and only slightly lower for the 5 MW and 10 MW sizes. The one significant area of difference is a greater than 20% reduction in capital costs for the 40 MW size category ($700/kW versus $950/kW). In addition, the 25 MW size at $770/kW is also a significantly lower cost system compared to the existing 40 MW system. Since much of the market opportunity is in the larger sizes, these lower costs may support a greater potential for market acceptance.

Table 1.2. Revised CHP Performance Parameters Suggested for use in the Cogeneration Module of NEMS

CHP Cost & Performance Assumptions	System 1	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	1,000	5,000	10,000	25,000	40,000
Total Installed Cost (99 $/kW)	$1,600	$1,075	$965	$770	$700
Capacity Factor	0.8	0.8	0.8	0.8	0.8
Electric Heat Rate (Btu/kWh), HHV	15,600	12,375	11,750	9,950	9,220
Overall Efficiency (%)	72%	73%	74%	78%	78%
Derived Technical Characteristics					
Elec. Generating Efficiency (3412/Heat Rate)	21.9%	27.6%	29.0%	34.3%	37.0%
Fuel Input (mmBtu/hr)	15.60	61.88	117.50	248.75	368.80
Steam Output (mmBtu/hr)	7.82	28.11	52.83	108.72	151.18
Steam Output/Fuel Input	50.1%	45.4%	45.0%	43.7%	41.0%
Power Steam Ratio	0.436	0.607	0.646	0.785	0.903
Net Heat Rate (Btus/kWh)	5825	5348	5146	4514	4496
Thermal Output as Fraction of Fuel Input	0.50	0.45	0.45	0.44	0.41
Electric Output as Fraction of Fuel Input	0.22	0.28	0.29	0.34	0.37

As described earlier, the heat rates are taken from published data for popular turbines in each size class.[1, 2] All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. On the other hand, the usable energy content of fuels is typically measured on a higher heating value basis (HHV). The energy measurements in EIA publications are also measured in higher heating value. In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1030 Btu/kWh on an HHV basis and 930 Btu/kWh on an LHV basis – or about a 10% difference. Since all of the fuel data in NEMS is based on higher heating values, the manufacturers heat rates were converted to an HHV basis. Heat rates for the revised technologies are somewhat higher in all cases than the original NEMS dataset. Given the continual improvement of combustion turbines in terms of capacity and efficiency over time, we feel that the only rationale for the increase in values for this data set is that the original values were on an LHV basis.

Thermal energy was calculated from published turbine data on steam available from the selected systems.[1, 2, 3] The estimates are based on an unfired heat recovery steam generator (HRSG) producing dry, saturated steam at 150 psig. This represents a change from the original method in the NEMS industrial cogeneration database in which overall efficiency of the system is specified and the thermal energy is calculated as the difference between total efficiency and electric efficiency. The overall efficiency percentages calculated from the published steam tables are somewhat higher than the original data in the smaller size categories and somewhat lower in the larger size turbines.

The derived data in the table show electrical efficiency increases as combustion turbines become larger. As electrical efficiency increases, the absolute quantity of thermal energy available to produce steam decreases and the ratio of power to heat for the CHP system increases. A changing ratio of power to heat impacts project economics and may affect the decisions that customers make in terms of CHP acceptance, sizing, and the need to sell power.

In addition to the revised set of five CT-based CHP systems, OSEC recommends the addition of reciprocating engine systems at the low size end and a large, more efficient system at the high size end. The systems selected for inclusion are an 800 kW engine-driven CHP system, a 3,000 kW engine-driven system, and a 100 MW combined cycle plant. The performance characteristics are shown in **Table 1.3** and are derived from published data and manufacturers specifications.[1, 2, 4, 5, 6, 7] The 800 kW engine is based on the Caterpillar G3516 gas engine system; the 3000 kW engine is based on the Caterpillar G3616. Capital cost estimates for the engine systems are based on OSEC experience with both Caterpillar and Waukesha engine installations.

Table 1.3. Performance Specifications for Engine-Driven CHP and Combined Cycle Systems

CHP Cost & Performance Assumptions	Recip. Engine	Recip. Engine	Combined Cycle
Electricity Capacity (kW)	800	3000	100,000
Total Installed Cost ($/kW)	$975	$850	$690
Capacity Factor	0.8	0.8	0.9
Electrical Heat Rate (Btu/kWh), HHV	11,050	10,158	7,344
Overall Efficiency (%)	65.0%	62.0%	65.0%
Derived Technical Characteristics			
Elec Generating Efficiency (3412/Heatrate)	30.9%	33.6%	46.5%
Fuel Input (mmBtu/hr)	8.840	30.473	734.444
Steam Output (mmBtu/hr)	3.002	8.658	136.160
Steam Output/Fuel Input	33.9%	28.4%	18.5%
Power Steam Ratio	0.909	1.182	2.506
Net Heat Rate (Btus/kWh)	6359	6551	5642
Thermal Output as Fraction of Fuel Input	0.34	0.28	0.19
Electric Output as Fraction of Fuel Input	0.31	0.34	0.46

Engine systems can provide higher electrical efficiencies than combustion turbines in small sizes. Because a significant portion of the waste heat from engine systems is rejected in the jacket water at a temperature generally too low to produce high-quality steam, the ability of engine systems to produce steam is limited. Steam can be produced from the engine's exhaust heat in the same manner as from the exhaust of a CT, though the volume of exhaust per unit of electrical output is generally much lower. The jacket water for most systems is suitable only for production of hot water, however, ebullient cooling systems for larger engines are capable of producing low-pressure steam from the jacket water. Engine systems may not serve the needs of some process industries with high-pressure steam requirements, but they are a good choice for many food and manufacturing industries that do not require high-pressure steam but use large quantities of wash water and low-pressure steam. The engine systems shown are producing 15 psig steam yielding overall efficiencies of 65% or less. Systems that can use hot water can provide higher overall efficiencies.

The combined cycle plant is based on two 40 MW LM6000 combustion turbines with heat recovery and a 27 MW steam turbine. The system has an overall electric efficiency of 46.5%. This 12 point increase compared to a simple cycle CT is achieved by diverting to power generation a portion of the thermal energy that otherwise would have been available for process steam use. Consequently, the high electric efficiency of a combined cycle plant is accompanied by only about half of the process steam produced by a simple cycle CT.

1.2 Capital Costs

This section provides the details on the cost estimates for the revised CHP technology data set. An industrial sized CHP plant is a complex process with many interrelated subsystems. Construction for the larger sizes in the database can take two years or more. The detailed capital costs for the six CT-CHP systems are shown in **Table 1.4.**

The system is designed around key equipment components. The most important is the turbine-generator set. Prices typically range from $300-400 per kW except for the 1 MW size which is considerably more expensive on a unit cost basis. A heat recovery steam generator (HRSG) is used for heat recovery. The next most important subsystem is the electrical switchgear and controls. After these main components there are still a large number of smaller components such as enclosures or buildings, water treatment systems, piping, pumps, storage tanks, equipment foundations and superstructures, fire suppression systems, and emissions control and monitoring equipment. Site preparation can also be a significant cost for some projects. Labor and materials for plant construction are also a major part of overall costs. The 25 MW CT-CHP plant estimate requires 52,000 labor hours for completion costing $3 million with an additional $1.2 million in material costs. The sum of these costs is termed *total process capital* in the table. To total process capital must be added engineering, general contractor fees, permitting fees, contingency, and financing costs. In the table, these costs add an additional 20% to total process capital to provide our estimate of total capital cost.

Table 1.4. Capital Cost Estimates for Industrial CHP Plants Based on Combustion Turbines

Nominal Turbine Capacity MW	1	5	10	25	40	100*
Combustion Turbines	$550,000	$2,102,940	$4,319,200	$7,464,960	$14,897,920	$24,000,000
Steam Turbine Generators						$4,000,000
Heat Recovery Steam Generators	$250,000	$350,000	$590,000	$1,020,000	$2,040,000	$7,000,000
Water Treatment System	$30,000	$100,000	$150,000	$200,000	$225,000	$750,000
Electrical Equipment	$150,000	$375,000	$625,000	$990,000	$1,500,000	$5,600,000
Other Equipment	$145,000	$315,000	$575,000	$1,150,000	$1,875,000	$7,000,000
Total Equipment	$1,125,000	$3,242,940	$6,259,200	$10,824,960	$20,537,920	$48,350,000
Materials	$143,952	$356,723	$688,512	$1,190,746	$2,053,792	$3,626,250
Labor	$347,509	$908,023	$1,752,576	$3,030,989	$4,723,722	$9,670,000
Total Process Capital $	$1,616,461	$4,507,686	$8,700,288	$15,046,694	$27,315,434	$61,646,250
General Facilities Capital $	$48,483	$135,231	$261,009	$451,401	$819,463	$1,849,388
Engineering and Fees $	$48,483	$135,231	$261,009	$451,401	$819,463	$1,849,388
Process Contingency $	$48,483	$135,231	$261,009	$451,401	$819,463	$1,849,388
Project Contingency $	$171,305	$477,815	$922,231	$1,594,436	$2,895,436	$6,534,503
Total Plant Cost $	$1,933,215	$5,391,193	$10,405,544	$17,995,847	$32,669,259	$73,728,915
Actual Turbine Capacity (kW)	1,205	5,007	10,798	23,328	46,556	107,000
Total Plant Cost per net kW $	$1,604	$1,076	$964	$771	$702	$689

* Combined Cycle system

Combustion turbine costs are based on published specifications[1] and package prices.[2] The total installed cost estimation is based on the use of a proprietary cost and performance model – SOAPP-CT.25 – (for State-of-the-Art Power Plant, combustion turbine).[3] The model output was adjusted based on OSEC engineering judgment and experience and input from vendors and packagers.[8, 9]

1.3 O&M Costs

The O&M costs presented in **Table 1-5** includes operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs including routine inspections and procedures and major overhauls. O&M costs presented in **Table 1-5** are based on 8,000 operating hours expressed in terms of annual electricity generation. Fixed costs are based on an interpolation of manufacturers' estimates. The variable component of the O&M cost represents the inspections and overhaul procedures that are normally conducted by the prime mover OEM through a service agreement usually based on run hours. It is recognized, however, that there is a fixed component aspect to OEM service agreements as well. However, for purposes of clarity, the information is presented as a variable cost. Consumables primarily include an estimate for water and chemicals that are consumed in proportion to electric capacity.

Gas Turbines

O&M costs presented in **Table 1-5** are based on gas turbine manufacturer estimates for service contracts consisting of routine inspections and scheduled overhauls of the turbine generator set.[8,10] Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures.

Routine inspections are required to insure that the turbine is free of excessive vibration due to worn bearings, rotors and damaged blade tips. Inspections generally include on-site hot gas path borescope inspections and non-destructive component testing using dye penetrant and magnetic particle techniques to ensure the integrity of components. The combustion path is inspected for fuel nozzle cleanliness and wear along with the integrity of other hot gas path components.

A gas turbine overhaul is typically a complete inspection and rebuild of components to restore the gas turbine to original or current (upgraded) performance standards. A typical overhaul consists of dimensional inspections, product upgrades and testing of the turbine and compressor, rotor removal, inspection of thrust and journal bearings, blade inspection and clearances and setting packing seals.

Gas turbine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions. Although gas turbines can be cycled, maintenance costs can triple for a gas turbine that is cycled every hour versus a turbine that is operated for intervals of a 1000 hours or more. In addition, operating the turbine over the rated capacity for significant periods of time will dramatically increase the number of hot path inspections and overhauls. Gas turbines that operate for extended periods on liquid fuels will experience higher than average overhaul intervals.

Reciprocating Engines

O&M costs presented in **Table 1-5** are based on engine manufacturer estimates for service contracts consisting of routine inspections and scheduled overhauls of the engine generator set.[4,5,11] Engine service is comprised of routine inspections/adjustments and periodic replacement of engine oil, coolant and spark plugs. An oil analysis is part of most preventative maintenance programs to monitor engine wear. A top-end overhaul is generally recommended between 12,000-15,000 hours of operation that entails a cylinder head and turbocharger rebuild. A major overhaul is performed after 24,000-30,000 hours of operation and involves piston/liner replacement, crankshaft inspection, bearings and seals.

Table 1-5. O&M Cost Estimate

	Gas Turbines						Reciprocating Engine	
O&M Costs ($/kWh)	**1 MW**	**5 MW**	**10 MW**	**25 MW**	**40 MW**	**100 MW***	**800 kW**	**3000 kW**
Variable (service contract)	0.0045	0.0045	0.0045	0.0040	0.0035	0.0030	0.0100	0.0100
Variable (consumables)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0003	0.00015	0.00015
Fixed ($/kW-yr)	*40*	*10*	*7.5*	*6*	*5*	*3*	*4*	*1.5*
($/kWh)	0.0050	0.0013	0.0009	0.0008	0.0006	0.0003	0.0005	0.0002
Total O&M ($/kWh)	0.0096	0.0059	0.0055	0.0049	0.0042	0.0036	0.0107	0.0103

* Combined Cycle System

1.4 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a commonly employed emission control system for gas turbines where NOx emissions below 10 ppm are mandated by local air quality districts. Installation of such systems can be a significant cost impact especially in the smaller capacity gas turbines. For this reason the cost of SCR systems is treated separately in this report. SCR costs have dropped considerably in the last two years according a leading manufacturer due to more efficient designs and lower design costs. Operating costs have also been reduced through innovations such as using hot flue gas to pre-heat ammonia injection air to lower the power requirements. Conventional SCR must be placed between sections of the HRSG so that the catalyst is not damaged by excessive exhaust gas temperature. The cost estimate shown below does not include the cost to retrofit the HRSG since this cost is highly project and design dependent. Capital and annual costs are shown in the following table based on “Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines”, November, 1999, prepared by ONSITE SYCOM Energy Corp. for U.S. DOE.[12]

As shown in **Table 1.6**, SCR capital costs can add between $20-$82/kW to unit capital costs – representing 5-15% of the installed cost depending on the electric capacity of the project. The cost impact is greatest for smaller gas turbine projects. In a similar manner, costs to operate and maintain SCR systems can be a significant addition to the annual non-fuel operating budget, as shown in **Table 1.7**.

Table 1.6 SCR Capital Cost Summary

Gas Turbines	Electric Capacity (kW)	SCR Capital Cost ($)	SCR Capital Cost ($/kW)
System 1	1,000	N/A	N/A
System 2	5,000	$460,000	$92
System 3	10,000	$658,000*	$66
System 4	25,000	$1,200,000	$48
System 5	40,000	$1,526,000*	$38
System 6	100,000	$2,700,000*	$27

*Costs interpolated from smaller and larger engineering estimates

Table 1.7 SCR Annual Cost Summary

Gas Turbines	Electric Capacity (kW)	SCR Operating Cost ($)	SCR Maint Labor & Matl Cost ($)	SCR Electric Penalty,	SCR Ammonia, Catalyst Costs ($)	SCR Ovhd, Insurance, Taxes Costs ($)	SCR Total Annual Costs ($)	SCR Total Annual Costs assuming 6,000 hours ($/kWh)
System 1	1,000							Not economic
System 2	5,000	$15,000	$26,000	$13,000	$20,000*	$45,000	$119,000	.0040
System 3*	10,000	$15,000	$26,000	$25,000	$40,000*	$55,000	$161,000	.0027
System 4	25,000	$15,000	$26,000	$60,000	$80,000	$75,000	$256,000	.0017
System 5*	40,000	$15,000	$26,000	$100,000	$150,000*	$90,000	$381,000	.0016
System 6*	100,000	$15,000	$26,000	$250,000	$350,000*	$135,000	$776,000	.0013

*Costs interpolated from smaller and larger engineering estimates

SCR systems generally must be installed with continuous emissions monitoring system (CEMS). These systems generally cost about $250,000 per CT-HRSG train. This added cost adds significantly to the costs for smaller systems.

1.5 Advanced Technology Characteristics

The cost and performance for small power generation technologies has been continually improving. Both reciprocating engine systems and combustion turbines have increased efficiency, reduced capital cost, and reduced emissions. Over the twenty year forecast period of the NEMS model, it is reasonable to expect additional evolutionary improvement in the selected technologies. In addition, advances in emerging technologies such as fuel cells could provide for a significant industrial market opportunity in the latter part of the forecast period. There are several classes of improvements that should be considered:

- System heat rates are declining due to advances in materials and design. These have occurred over time and may accelerate with the use of ceramic materials
- Heat recovery within combustion turbines such as in a recuperated cycle or through the implementation of combined cycle operation can significantly increase electric efficiency.
- Emissions control can be improved either through the use of catalytic combustion or other means that would allow operation of these systems more economically than with the current generation of SCR technology.
- More effective packaging and integration of systems and controls can reduce the cost of the basic components and also minimize the on-site cost of installation. Particularly in the smaller system sizes, the modular approach can greatly reduce site costs.
- Streamlined siting, interconnection, and permitting procedures are another area that will reduce the cost of installing CHP plants. This area combines policy and technology in that it requires changes in government policy that will allow changes in technology and reductions in lead times.

The following improvements are projected for this area:

- Small and large gas engines will reach higher efficiencies approaching the efficiencies of diesel cycle engines.
- Small turbines will improve efficiencies as a result of improved materials that can withstand higher temperatures and recuperation that raises overall electric efficiencies from 29% to 37%.
- The larger industrial turbine efficiencies are increased using combined cycle technology to provide electric efficiencies of 50% or higher. Currently, the largest state-of-the-art combined cycle systems can achieve electric efficiencies approaching 60%.
- Package costs for engines and turbines will be reduced by 10-25%.
- Interconnect costs will be cut in half for all technologies. This change has a greater importance in the smallest sizes rather than in the medium to large industrial size categories
- Selective catalytic reduction costs cut in half or eliminated altogether through the use of catalytic combustion.
- Contractor markups will be reduced across the board to reflect a high volume competitive market
- Construction lead times will be reduced by 6 months resulting in lower carry charges for interest during construction
- Capital costs for the basic combustion turbine generator package and heat recovery generator will be reduced by 10%

Tables 1.8 and **1.9** present a comparison of current technology and expected 2020 technology for reciprocating engines and combustion turbines respectively.

Table 1-8 Current and Advanced Reciprocating Engine System Characteristics

CHP Cost & Performance Assumptions	**800 kW Recip Engine**		**3000 kW Recip Engine**	
Year	Current	2020	Current	2020
Total Installed Cost ($/kW)	$975	$690	$850	$710
O&M Costs ($/kWh)	0.0107	0.009	0.0103	0.009
Electrical Heat Rate (Btu/kWh), HHV	11,050	9,382	10,158	8,982
Overall Efficiency (%)	65.0%	66.2%	62.0%	66.0%
Derived Technical Characteristics				
Elec Generating Efficiency (3412/Heatrate)	30.9%	36.5%	33.6%	38.0%
Fuel Input (mmBtu/hr)	8.840	7.506	30.473	26.946
Steam Output (mmBtu/hr)	3.002	2.493	8.658	7.543
Steam Output/Fuel Input	33.9%	33.1%	28.4%	28.0%
Power Steam Ratio	0.909	1.095	1.182	1.357
Net Heat Rate (Btus/kWh)	6359	5487	6551	5839
Thermal Output as Fraction of Fuel Input	0.34	0.33	0.28	0.28
Electric Output as Fraction of Fuel Input	0.31	0.37	0.34	0.38

The 800 kW gas engine system is based on the Caterpillar G3516 engine system. The advanced performance was based on target specifications for a high performance system being developed by the Gas Research Institute and Caterpillar. The 3000 kW size is based on the Caterpillar G3616. The base case specifications are based on the current product performance. The advanced system is based on preliminary goals of the Advanced Reciprocating Engine System (ARES) program.[7, 13]

Table 1-8 Current and Advanced Combustion Turbine System Characteristics

CHP Cost & Performance Assumptions	**1 MW Comb Turbine**		**5 MW Comb Turbine**		**10 MW Comb Turbine**	
Year	Current	2020	Current	2020	Current	2020
Total Installed Cost ($/kW)	$1,600	$1,340	$1,075	$950	$965	$830
O&M Costs ($/kWh)	0.0096	0.008	0.0059	0.0049	0.0055	0.0046
Electrical Heat Rate (Btu/kWh), HHV	15,600	12,375	12,375	9,605	11,750	9,054
Overall Efficiency (%)	72.0%	73.0%	73.0%	74.0%	74.0%	74.0%
Derived Technical Characteristics						
Elec Generating Efficiency (3412/Heatrate)	21.9%	27.6%	27.6%	35.5%	29.0%	37.7%
Fuel Input (mmBtu/hr)	15.60	12.38	61.88	48.03	117.50	90.54
Steam Output (mmBtu/hr)	7.82	5.622	28.11	18.55	52.83	32.80
Steam Output/Fuel Input	50.1%	45.4%	45.4%	38.6%	45.0%	36.2%
Power Steam Ratio	0.436	0.607	0.607	0.920	0.646	1.041
Net Heat Rate (Btus/kWh)	5825	5348	5348	4967	5146	4954
Thermal Output as Fraction of Fuel Input	0.50	0.45	0.45	0.39	0.45	0.36
Electric Output as Fraction of Fuel Input	0.22	0.28	0.28	0.36	0.29	0.38

Table 1-8 (continued) Current and Advanced Combustion Turbine System Characteristics

CHP Cost & Performance Assumptions	25 MW Comb Turbine		40 MW Comb Turbine	
Year	Current	2020	Current	2020
Total Installed Cost ($/kW)	$770	$675	$700	$625
O&M Costs ($/kWh)	0.0049	0.0043	0.0042	0.0040
Electrical Heat Rate (Btu/kWh), HHV	9,950	8,745	9,220	8,530
Overall Efficiency (%)	78.0%	74.0%	78.0%	72.0%
Derived Technical Characteristics				
Elec Generating Efficiency (3412/Heatrate)	34.3%	39.0%	37.0%	40.0%
Fuel Input (mmBtu/hr)	248.75	218.63	368.80	341.20
Steam Output (mmBtu/hr)	108.72	76.52	151.18	109.18
Steam Output/Fuel Input	43.7%	35.0%	41.0%	32.0%
Power Steam Ratio	0.785	1.114	0.903	1.125
Net Heat Rate (Btus/kWh)	4514	4919	4514	5118
Thermal Output as Fraction of Fuel Input	0.44	0.35	0.41	0.32
Electric Output as Fraction of Fuel Input	0.34	0.39	0.37	0.40

The base case 1 MW size is based on the Solar Turbines 1205 kW Saturn 20 gas turbine; the 5 MW system is based on the Solar Taurus 60; the 10 MW system is based on the Solar Mars 100; the base case 25 MW system is based on the GE LM2500; the base case 40 MW system is based on the GE LM6000. The advanced case 1 MW system is based on a qualitative assessment of potential efficiency improvement based on recuperation. The advanced 5 MW system is based on the 4.2 MW Solar Mercury 50, a recuperated turbine system that was the successful product of the DOE Advanced Turbine System program. The advanced 10 MW system is based on the Mitsui SB60 (17.7 MW) combined cycle turbine system. Advanced 25, and 40 MW systems are based on qualitative assessments of potential improvements based on the use of ceramic components and advanced combustors.

2. Profile of Existing Industrial CHP

An analysis of the most recent update to the Hagler Bailly *Independent Power Data Base* (HBI) was conducted to develop a profile of existing cogeneration activity in the industrial sector. [14] OSEC has not found any single database that contains a complete listing of existing CHP and independent power facilities (i.e., coverage of small systems in the HBI database is incomplete). However, OSEC considers the HBI data as the best available and has worked with it extensively over the past two years to understand its content and to enhance its coverage and value. The profile was developed to understand the technologies and applications that comprise existing CHP capacity and to provide insight into projections of future market development. The HBI database includes information for each CHP site including technology, fuel use, electrical capacity (MW), ownership and sell-back of power to the grid. Steam capacity was calculated based on typical power to heat ratios of the technology used at each site.

CHP installations in the following industries were reviewed:

SIC	Industry
01	Agriculture - Crops
07	Agriculture - Services
11	Metal Mining
12	Coal Mining
14	Mining - nonmetallic Minerals
20	Food & Kindred Products
21	Tobacco Products
22	Textile Mill Products
23	Apparel
24	Lumber & Wood Products
25	Furniture & Fixtures
26	Paper & Allied Products
27	Printing & Publishing
28	Chemicals & Allied Products
29	Petroleum Refining and Related Industries
30	Rubber & Misc. Plastic Products
31	Leather & Leather Products
32	Stone, Clay, Glass and Concrete
33	Primary Metals
34	Fabricated Metal Products
35	Industrial & Commercial Machinery
36	Electronic & Other Electrical Equipment
37	Transportation Equipment
38	Measuring, Analyzing and Controlling Instruments
39	Miscellaneous Manufacturing Industries

As of the end of mid-1999, these industries had 1,016 CHP facilities with a total electrical capacity of 45,500 MW and an estimated cogenerated steam capacity of 225,000,000 pounds of steam/hour (225,000 million Btu/hour). Manufacturing industries (SIC 20-39) represented 44,242 MW at 980 sites (216,000 million Btu/hour steam capacity). Major conclusions from the database include:

- ☐ **Existing CHP capacity is concentrated in a few industries** - CHP facilities can be found in all manufacturing industries except Apparel Manufacturing and Leather and Tanning (SICs 21 and 31). However, SIC Groups 26, 28 and 29 (Paper and Allied Products, Chemicals and Allied Products, and Petroleum Refining and related Products) combined represent more than two thirds of the total electric and steam capacities at existing CHP installations. (**Figure 2-1** and **Table 2-1**) Note that SIC 26 has approximately the same steam capacity as SIC 28 but only half the electrical capacity, a reflection of the types of cogeneration systems employed. (**Table 2-2**) SIC 26 has relied primarily on boiler/steam turbine systems with low power to heat ratios; SIC 28 CHP capacity is primarily combustion turbine and combined cycle systems that have much higher power to heat ratios.

- ☐ **Existing CHP depends on a variety of technologies and fuels** - Natural gas is the primary fuel used for CHP (61.3 % of capacity), but coal, wood and process wastes are used extensively by many industries (16.7 %, 5.1 %, and 7.1 % respectively). (**Figure 2-1** and **Table 2-1**) Accordingly, combustion turbines are the predominant technology in use representing 62.8 % of installed CHP capacity in combined and simple cycle systems and are used by almost all industry segments. Boiler/steam turbines represent 36.4 % of installed CHP capacity and are concentrated in the paper, chemicals and primary metals industries. In terms of number of facilities, reciprocating engines are used in over 161 sites (almost 16 % of facilities), primarily in the food, chemicals and fabrication and equipment industries.

- ☐ **Large systems account for most existing CHP capacity** - There is great variation in site electrical capacity at existing industrial CHP facilities, however, 80 % of existing capacity is represented by facilities of 50 MW and greater (**Table 2-4**). Two thirds of the coal is used in systems over 100 MW size. Recip engines predominate in facilities below 1 MW, and are used extensively in facilities up to 5 MW. Combined cycle systems dominate the larger facilities. **(Table 2-5**)

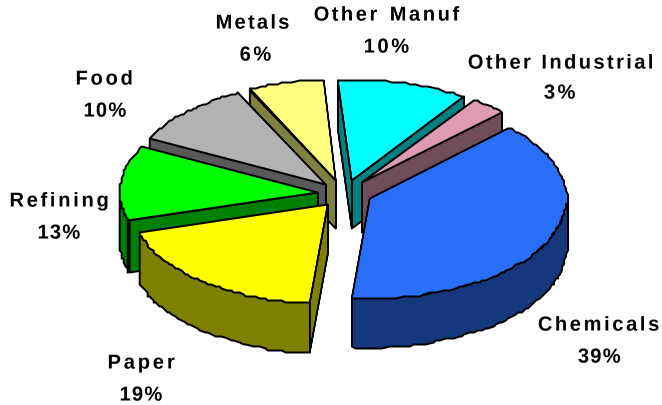
- ☐ **Most existing CHP sells some power to the grid** - As shown in **Tables 2-6** and **2-7**, over 80 % of existing CHP capacity sells at least a portion of its electricity output to the grid.

- ☐ **Third party ownership is common -** Almost 57 % of existing capacity is third party owned and/or financed (**Tables 2-8** and **2-9**). Third party financing represents a significant majority of the capacity in combined cycle systems and in systems in the food and chemicals industries.

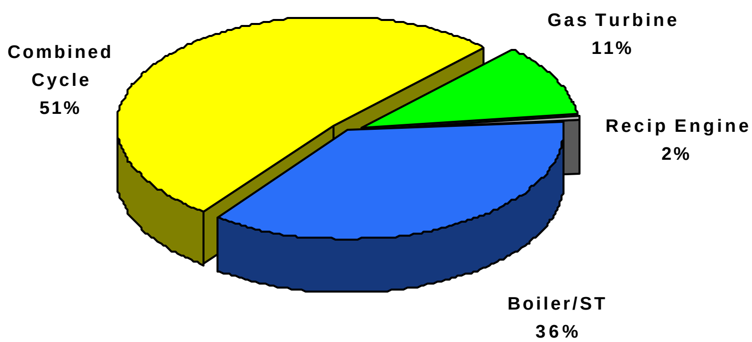
- ☐ **CHP is an important resource to a number of states - Tables 2-10** and **2-11** present existing CHP capacity by state as a function of system prime mover and fuel type. Texas has the most industrial CHP capacity followed by California, Florida, Louisiana, New Jersey and New York.

Figure 2-1   Existing Industrial CHP Capacity - 45,466 MW (1999)

- *Industrial CHP Capacity by Application*



- *Industrial CHP Capacity by Technology*



- *Industrial CHP Capacity by Fuel*

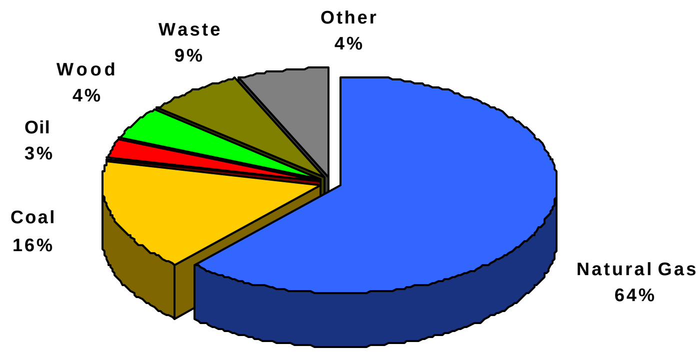


Table 2-1 CHP Fuel Type by Industry SIC

SIC	Coal	Gas	Oil	Waste	Wood	Other	Totals
1	*2* **258** *1,862*	*14* **287** *1,050*		*5* **201** *1,593*	*1* **0** *2*	*3* **1** *2*	*25* **747** *4,509*
7		*1* **4** *12*					*1* **4** *12*
10	*1* **124** *868*						*1* **124** *868*
12				*6* **232** *2,535*			*6* **232** *2,535*
14		*4* **116** *804*					*4* **116** *804*
20	*37* **983** *9,141*	*105* **3,363** *9,848*	*12* **46** *428*	*18* **154** *2,113*	*5* **47** *708*	*1* **1** *3*	*178* **4,594** *22,241*
21	*4* **129** *1,078*			*1* **2** *2*			*5* **131** *1,080*
22	*10* **332** *2,757*	*7* **275** *728*	*1* **12** *50*			*4* **32** *147*	*22* **651** *3,682*
24	*1* **44** *440*	*5* **181** *446*	*1* **1** *3*		*70* **543** *6,785*	*3* **38** *432*	*80* **806** *8,106*
25	*1* **63** *250*				*7* **5** *26*		*8* **68** *276*
26	*43* **1,543** *14,788*	*69* **2,792** *11,955*	*12* **276** *2,423*	*2* **169** *1,415*	*44* **1,618** *15,838*	*50* **2,155** *20,345*	*220* **8,553** *66,764*
27		*8* **17** *65*	*1* **3** *10*				*9* **19** *75*

SIC	Coal	Gas	Oil	Waste	Wood	Other	Totals
28	*32* **2,599** *19,607*	*127* **13,918** *34,819*	*11* **118** *720*	*12* **356** *3,047*	*4* **86** *648*	*26* **615** *5,503*	*212* **17,692** *64,344*
29	*2* **183** *1,298*	*40* **3,398** *9,224*	*5* **633** *1,496*	*21* **1,284** *6,094*		*5* **120** *1,126*	*73* **5,618** *19,238*
30	*4* **249** *1,996*	*8* **533** *1,257*			*2* **0** *5*	*1* **4** *60*	*15* **787** *3,318*
32	*1* **170** *1,190*	*14* **528** *1,525*	*1* **1** *5*			*3* **74** *740*	*19* **774** *3,460*
33	*2* **842** *5,895*	*15* **1,246** *3,598*	*1* **0** *0*	*14* **782** *6,282*		*1* **3** *45*	*33* **2,873** *15,820*
34		*22* ***77*** *693*	*2* ***2*** *8*				*24* ***78*** *701*
35	*3* **31** *460*	*12* **98** *948*	*2* **4** *15*	*1* **8** *113*	*1* **10** *150*		*19* **149** *1,686*
36		*4* **179** *373*	*2* **1** *6*				*6* **180** *379*
37	*2* **53** *530*	*12* **674** *1,489*	*3* **81** *234*				*17* **808** *2,253*
38		*2* **51** *173*	*2* **8** *121*				*4* **59** *294*
39	*2* **29** *303*	*15* **203** *762*	*7* **57** *208*	*4* **61** *532*	*3* **23** *263*	*4* **29** *127*	*35* **402** *2,195*
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7,631**	**27,939**	**1,243**	**3,250**	**2,332**	**3,070**	**45,466**
Totals	*62,463*	*79,769*	*5,727*	*23,726*	*24,425*	*28,530*	*224,640*

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**
Steam Capacity, PPHx1,000	147,600

Table 2-2 Existing CHP by Prime Mover and SIC Industry

SIC	Steam	CC	CT	Recip.	Other	Totals
1	*7* **458** *3,454*	*6* **275** *1,000*		*12* **14** *55*		*25* **747** *4,509*
7		*1* **4** *12*				*1* **4** *12*
10	*1* **124** *868*					*1* **124** *868*
12	*4* **213** *1,715*		*2* **20** *820*			*6* **232** *2,535*
14	*1* **8** *120*	*1* **55** *440*	*2* **53** *244*			*4* **116** *804*
20	*77* **1,279** *13,367*	*24* **2,740** *6,045*	*34* **497** *2,519*	*41* **78** *306*	*2* **1** *4*	*178* **4,594** *22,241*
21	*5* **131** *1,080*					*5* **131** *1,080*
22	*12* **339** *2,870*	*3* **260** *600*	*2* **5** *24*	*3* **21** *84*	*2* **26** *104*	*22* **651** *3,682*
24	*74* **625** *7,657*	*2* **175** *400*	*2* **6** *44*	*2* **1** *5*		*80* **806** *8,106*
25	*8* **68** *276*					*8* **68** *276*
26	*173* **6,049** *58,271*	*23* **1,664** *4,105*	*21* **837** *4,377*	*3* **3** *11*		*220* **8,553** *66,764*
27	*1* **3** *10*		*2* **5** *20*	*6* **12** *45*		*9* **19** *75*
28	*76* **4,096** *32,931*	*52* **11,683** *24,146*	*63* **1,838** *6,968*	*17* **34** *136*	*4* **41** *163*	*212* **17,692** *64,344*
29	*19* **747** *6,848*	*21* **3,486** *7,468*	*30* **1,380** *4,901*	*2* **5** *18*	*1* **1** *3*	*73* **5,618** *19,238*
30	*8* **264** *2,226*	*3* **515** *1,047*	*1* **4** *29*	*3* **4** *16*		*15* **787** *3,318*
32	*5* **248** *1,990*	*3* **420** *1,005*	*5* **101** *448*	*6* **4** *17*		*19* **774** *3,460*
33	*20* **1,722** *13,375*	*4* **1,144** *2,403*	*2* **4** *33*	*7* **2** *9*		*33* **2,873** *15,820*
34	*2* **10** *152*	*1* **56** *500*		*21* **12** *49*		*24* **78** *701*
35	*5* **48** *723*	*2* **92** *920*		*12* **10** *43*		*19* **149** *1,686*
36		*1* **173** *350*		*5* **7** *29*		*6* **180** *379*
37	*2* **53** *530*	*6* **719** *1,574*	*4* **28** *116*	*5* **9** *33*		*17* **808** *2,253*
38	*1* **8** *120*	*1* **50** *170*		*2* **1** *4*		*4* **59** *294*
39	*9* **99** *1,057*	*3* **147** *465*	*9* **137** *600*	*14* **18** *73*		*35* **402** *2,195*
Totals **Totals** *Totals*	*510* **16,591** *149,640*	*157* **23,660** *52,650*	*179* **4,912** *21,143*	*161* **233** *933*	*9* **69** *274*	*1,016* **45,466** *224,640*

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**
Steam Capacity, PPHx1,000	147,600

Table 2-3   Existing Industrial CHP - Prime Mover by Fuel Type

	Coal	Gas	Oil	Waste	Wood	Other	Totals
Steam Boiler	*147* **7631**	*58* **1234**	*22* **365**	*64* **2308**	*137* **2332**	*82* **2720**	*510* **16591**
Combined Cycle		*144* **22611**	*3* **285**	*9* **737**		*1* **27**	*157* **23660**
Combution Turbine		*156* **3948**	*7* **507**	*8* **199**		*8* **258**	*179* **4912**
Reciproca-ting Engine		*123* **140**	*31* **87**	*3* **6**		*4* **1**	*161* **233**
Other		*3* **5**				*6* **64**	*9* **69**
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7631**	**27939**	**1243**	**3250**	**2332**	**3070**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-4 Existing Industrial CHP by Size Range and Fuel Type

Size Range	Coal	Gas	Oil	Waste	Wood	Other	Totals
0 - 999 kW	*5* **2**	*90* **32**	*18* **9**	*3* **2**	*28* **13**	*8* **3**	*152* **60**
1 - 4.9 MW	*20* **54**	*112* **317**	*23* **53**	*15* **39**	*25* **71**	*13* **40**	*208* **574**
5.0 - 9.9 MW	*29* **188**	*50* **351**	*6* **45**	*11* **75**	*25* **177**	*6* **38**	*127* **872**
!0.0 - 14.9 MW	*13* **155**	*19* **219**	*3* **32**	*7* **81**	*11* **133**	*7* **79**	*60* **699**
15.0 - 19.9 MW	*11* **189**	*12* **195**	*2* **33**	*5* **86**	*12* **195**	*6* **108**	*48* **806**
20.0- -29.9 MW	*14* **336**	*24* **565**	*3* **70**	*9* **203**	*9* **195**	*20* **484**	*79* **1854**
30.0 - 49.9 MW	*13* **484**	*51* **2057**	*3* **130**	*11* **409**	*13* **519**	*20* **759**	*111* **4357**
50.0 - 74.9 MW	*11* **686**	*28* **1667**	*2* **105**	*11* **609**	*9* **545**	*12* **742**	*73* **4355**
75.0 - 99.9 MW	*6* **509**	*20* **1672**		*4* **359**	*2* **172**	*8* **671**	*40* **3383**
100.0 - 199.9 MW	*20* **3074**	*50* **7521**	*2* **345**	*8* **1388**	*3* **313**	*1* **148**	*84* **12789**
200.0 - 499.9 MW	*4* **1222**	*21* **7304**	*1* **422**				*26* **8948**
500.0 - 999.9 MW	*1* **732**	*4* **2314**					*5* **3046**
I,000+ MW		*3* **3724**					*3* **3724**
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7631**	**27939**	**1243**	**3250**	**2332**	**3070**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-5 Existing Industrial CHP: Size Range by Prime Mover

Size Range	Steam	CC	CT	Recip.	Other	Totals
0 - 999 kW	*43* **19**		*4* **2**	*101* **36**	*4* **2**	*152* **60**
1 - 4.9 MW	*97* **271**	*2* **9**	*56* **187**	*50* **100**	*3* **8**	*208* **574**
5.0 - 9.9 MW	*86* **575**	*6* **41**	*29* **217**	*6* **40**		*127* **872**
!0.0 - 14.9 MW	*46* **535**	*4* **52**	*8* **90**	*2* **22**		*60* **699**
15.0 - 19.9 MW	*36* **611**	*1* **16**	*10* **164**	*1* **15**		*48* **806**
20.0- -29.9 MW	*48* **1105**	*14* **364**	*15* **340**	*1* **20**	*1* **24**	*79* **1854**
30.0 - 49.9 MW	*57* **2165**	*19* **774**	*34* **1383**		*1* **35**	*111* **4357**
50.0 - 74.9 MW	*40* **2426**	*24* **1389**	*9* **541**			*73* **4355**
75.0 - 99.9 MW	*18* **1517**	*15* **1276**	*7* **590**			*40* **3383**
100.0 - 199.9 MW	*33* **4905**	*46* **7187**	*5* **697**			*84* **12789**
200.0 - 499.9 MW	*4* **1222**	*20* **7024**	*2* **702**			*26* **8948**
500.0 - 999.9 MW	*2* **1241**	*3* **1805**				*5* **3046**
I,000+ MW		*3* **3724**				*3* **3724**
Totals **Totals**	*510* **16591**	*157* **23660**	*179* **4912**	*161* **233**	*9* **69**	*1016* **45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-6 Sales to Utilities by Prime Mover

	No	Yes	Totals
Steam Boiler	*263* **5187**	*247* **11404**	*510* **16591**
Combined Cycle	*16* **1119**	*141* **22541**	*157* **23660**
Combution Turbine	*86* **1517**	*93* **3395**	*179* **4912**
Reciproca-ting Engine	*109* **156**	*52* **77**	*161* **233**
Other	*5* **38**	*4* **31**	*9* **69**
Totals **Totals**	*479* **8018**	*537* **37448**	*1016* **45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-7 Sales to Utilities by SIC

SIC	No	Yes	Totals
1	*8* **7**	*17* **740**	*25* **747**
7		*1* **4**	*1* **4**
10		*1* **124**	*1* **124**
12	*2* **20**	*4* **213**	*6* **232**
14	*1* **8**	*3* **108**	*4* **116**
20	*95* **536**	*83* **4059**	*178* **4594**
21		*5* **131**	*5* **131**
22	*9* **39**	*13* **611**	*22* **651**
24	*26* **142**	*54* **664**	*80* **806**
25	*6* **4**	*2* **64**	*8* **68**
26	*126* **3174**	*94* **5378**	*220* **8553**
27	*6* **11**	*3* **8**	*9* **19**

SIC	No	Yes	Totals
28	*79* **1837**	*133* **15855**	*212* **17692**
29	*30* **813**	*43* **4805**	*73* **5618**
30	*7* **61**	*8* **726**	*15* **787**
32	*8* **59**	*11* **715**	*19* **774**
33	*16* **1092**	*17* **1780**	*33* **2873**
34	*14* **19**	*10* **59**	*24* **78**
35	*14* **49**	*5* **101**	*19* **149**
36	*5* **7**	*1* **173**	*6* **180**
37	*8* **70**	*9* **738**	*17* **808**
38	*3* **9**	*1* **50**	*4* **59**
39	*16* **61**	*19* **342**	*35* **402**
Totals **Totals**	*479* **8018**	*537* **37448**	*1016* **45466**

Table 2-8 Ownership by Prime Mover

	3rd Party	Self	Totals
Steam Boiler	*112* **6415**	*398* **10176**	*510* **16591**
Combined Cycle	*113* **18146**	*44* **5514**	*157* **23660**
Combustion Turbine	*41* **1366**	*138* **3546**	*179* **4912**
Reciproca-ting Engine	*80* **85**	*81* **148**	*161* **233**
Other	*3* **2**	*6* **67**	*9* **69**
Totals **Totals**	*349* **26014**	*667* **19452**	*1016* **45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-9 CHP Facility Ownership by SIC

SIC	3rd Party	Self	Totals
1	*20* **729**	*5* **19**	*25* **747**
7		*1* **4**	*1* **4**
10		*1* **124**	*1* **124**
12	*4* **213**	*2* **20**	*6* **232**
14	*1* **55**	*3* **61**	*4* **116**
20	*64* **3629**	*114* **966**	*178* **4594**
21		*5* **131**	*5* **131**
22	*12* **586**	*10* **64**	*22* **651**
24	*31* **526**	*49* **280**	*80* **806**
25	*1* **63**	*7* **5**	*8* **68**
26	*36* **2889**	*184* **5664**	*220* **8553**
27	*3* **5**	*6* **14**	*9* **19**
28	*68* **10361**	*144* **7331**	*212* **17692**
29	*26* **3398**	*47* **2220**	*73* **5618**
30	*10* **727**	*5* **60**	*15* **787**
32	*12* **555**	*7* **219**	*19* **774**
33	*10* **1377**	*23* **1495**	*33* **2873**
34	*13* **58**	*11* **20**	*24* **78**
35	*6* **10**	*13* **139**	*19* **149**
36	*2* **176**	*4* **4**	*6* **180**
37	*7* **265**	*10* **544**	*17* **808**
38	*1* **50**	*3* **9**	*4* **59**
39	*22* **344**	*13* **58**	*35* **402**
Totals **Totals**	*349* **26014**	*667* **19452**	*1016* **45466**

Table 2-10 State Profile of Existing CHP by Prime Movers

State	Steam	CC	CT	Recip.	Other	Totals
AK	*2*		*4*	*3*		*9*
	28		**51**	**16**		**95**
AL	*14*	*2*	*1*			*17*
	556	**125**	**40**			**720**
AR	*6*		*2*			*8*
	126		**38**			**164**
AZ	*2*	*1*		*2*		*5*
	82	**50**		**7**		**139**
CA	*33*	*25*	*43*	*52*	*1*	*154*
	581	**1710**	**1024**	**46**	**0**	**3362**
CO	*2*	*4*	*4*			*10*
	43	**429**	**47**			**519**
CT	*8*	*2*	*1*	*5*		*16*
	236	**82**	**5**	**4**		**327**
DE	*4*					*4*
	89					**89**
FL	*25*	*7*	*10*			*42*
	1494	**712**	**293**			**2499**
GA	*17*	*1*	*1*	*2*	*1*	*22*
	490	**300**	**2**	**2**	**2**	**796**
GU	*1*		*1*			*2*
	0		**50**			**50**
HI	*7*	*1*	*1*	*3*		*12*
	240	**180**	**9**	**1**		**430**
IA	*8*					*8*
	135					**135**
ID	*10*		*3*			*13*
	120		**23**			**143**
IL	*13*	*2*	*10*	*8*	*2*	*35*
	314	**55**	**176**	**13**	**6**	**564**
IN	*8*		*1*	*1*		*10*
	1123		**18**	**4**		**1145**
KS	*3*		*1*	*1*		*5*
	8		**40**	**10**		**58**
KY	*1*					*1*
	4					**4**
LA	*18*	*8*	*12*	*2*		*40*
	1094	**1421**	**732**	**1**		**3248**
MA	*13*	*7*	*4*	*4*		*28*
	76	**941**	**32**	**5**		**1053**
MD	*4*	*1*				*5*
	232	**240**				**472**

ME	*18* **745**					*18* **745**
MI	*23* **289**	*4* **1542**	*8* **59**	*6* **4**		*41* **1894**
MN	*13* **250**	*1* **262**	*1* **1**			*15* **513**
MO	*4* **44**	*1* **4**				*5* **48**
MS	*13* **345**		*3* **28**			*16* **373**
MT	*4* **68**					*4* **68**
NC	*29* **1064**	*2* **185**	*2* **8**			*33* **1258**
ND	*3* **24**					*3* **24**
NE	*1* **7**			*1* **0**		*2* **7**
NH	*3* **5**		*1* **1**	*1* **12**		*5* **18**
NJ	*11* **592**	*19* **2406**	*8* **46**	*18* **13**	*1* **1**	*57* **3057**
NM	*1* **33**		*1* **3**			*2* **37**
NV		*4* **310**		*1* **1**		*5* **311**
NY	*12* **366**	*21* **3003**	*8* **129**	*24* **29**	*1* **0**	*66* **3528**
OH	*12* **260**		*1* **7**	*4* **5**		*17* **271**
OK	*4* **456**	*2* **220**				*6* **676**
OR	*15* **109**	*2* **499**	*1* **49**			*18* **657**
PA	*35* **1261**	*4* **194**	*4* **109**	*9* **15**		*52* **1580**
PR			*3* **9**	*1* **20**		*4* **29**
RI		*1* **67**				*1* **67**
SC	*7* **374**	*2* **500**		*1* **7**		*10* **881**
TN	*16* **338**		*1* **24**		*2* **59**	*19* **421**

TX	*26*	*27*	*29*	*5*	*1*	*88*
	719	**7157**	**1467**	**4**	**1**	**9349**
UT	*3*		*1*			*4*
	5		**15**			**21**
VA	*25*	*2*	*2*	*4*		*33*
	1400	**476**	**20**	**12**		**1907**
VT	*2*		*1*	*1*		*4*
	21		**8**	**0**		**28**
WA	*8*	*4*	*3*			*15*
	194	**590**	**165**			**949**
WI	*20*		*1*	*1*		*22*
	409		**180**	**1**		**590**
WV	*2*					*2*
	139					**139**
WY	*1*		*1*	*1*		*3*
	7		**3**	**0**		**10**
Totals	*510*	*157*	*179*	*161*	*9*	*1016*
Totals	**16591**	**23660**	**4912**	**233**	**69**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-11   State Profile of Existing CHP by Fuel Type

State	Coal	Gas	Oil	Waste	Wood	Other	Totals
AK	*1* **25**	*3* **43**	*4* **24**		*1* **3**		*9* **95**
AL	*1* **65**	*3* **165**		*2* **12**	*5* **159**	*6* **319**	*17* **720**
AR		*2* **38**		*1* **10**	*2* **23**	*3* **94**	*8* **164**
AZ	*1* **60**	*3* **76**	*1* **3**				*5* **139**
CA	*4* **198**	*116* **2545**	*2* **3**	*10* **301**	*15* **194**	*7* **123**	*154* **3362**
CO	*1* **40**	*8* **476**		*1* **3**			*10* **519**
CT	*1* **181**	*8* **93**	*5* **42**	*1* **11**	*1* **0**		*16* **327**
DE	*2* **36**			*1* **48**		*1* **5**	*4* **89**
FL	*3* **810**	*15* **904**		*3* **50**	*2* **200**	*19* **535**	*42* **2499**
GA	*4* **98**	*5* **321**	*1* **1**		*6* **69**	*6* **307**	*22* **796**
GU			*1* **50**			*1* **0**	*2* **50**
HI	*1* **180**	*1* **0**	*4* **182**	*6* **68**			*12* **430**
IA	*5* **121**	*1* **2**			*2* **13**		*8* **135**
ID	*2* **9**	*2* **20**			*8* **111**	*1* **3**	*13* **143**
IL	*10* **280**	*19* **206**	*2* **21**	*1* **28**		*3* **29**	*35* **564**
IN	*4* **745**	*2* **23**	*1* **4**	*3* **373**			*10* **1145**
KS		*5* **58**					*5* **58**
KY					*1* **4**		*1* **4**
LA		*26* **2264**	*1* **422**	*6* **221**	*2* **116**	*5* **225**	*40* **3248**
MA	*3* **32**	*14* **919**	*11* **103**				*28* **1053**
MD		*2* **250**		*1* **169**	*1* **50**	*1* **3**	*5* **472**

ME	*1* **85**		*2* **175**		*10* **298**	*5* **187**	*18* **745**
MI	*9* **147**	*23* **1644**			*7* **76**	*2* **28**	*41* **1894**
MN	*8* **164**	*2* **263**			*2* **45**	*3* **41**	*15* **513**
MO	*2* **43**	*1* **4**			*2* **1**		*5* **48**
MS		*3* **28**		*1* **5**	*8* **150**	*4* **190**	*16* **373**
MT	*1* **2**			*1* **55**	*1* **1**	*1* **10**	*4* **68**
NC	*20* **814**	*3* **189**	*1* **7**	*1* **19**	*3* **57**	*5* **172**	*33* **1258**
ND	*2* **19**			*1* **5**			*3* **24**
NE	*1* **7**	*1* **0**					*2* **7**
NH		*1* **1**	*1* **12**		*3* **5**		*5* **18**
NJ	*2* **487**	*46* **2420**	*6* **56**	*2* **94**		*1* **1**	*57* **3057**
NM		*2* **37**					*2* **37**
NV		*5* **311**					*5* **311**
NY	*2* **190**	*48* **3147**	*8* **51**	*4* **83**	*4* **56**		*66* **3528**
OH	*8* **186**	*5* **12**		*2* **53**	*2* **22**		*17* **271**
OK	*1* **320**	*3* **334**		*1* **17**	*1* **5**		*6* **676**
OR	*1* **8**	*3* **548**			*12* **89**	*2* **13**	*18* **657**
PA	*12* **368**	*14* **321**	*6* **14**	*16* **799**	*2* **33**	*2* **44**	*52* **1580**
PR			*4* **29**				*4* **29**
RI		*1* **67**					*1* **67**
SC	*1* **72**	*3* **507**	*1* **43**		*2* **43**	*3* **217**	*10* **881**

TN	*7*				*8*	*4*	*19*
	223				**110**	**87**	**421**
TX		*64*		*13*	*4*	*7*	*88*
		8146		**800**	**121**	**282**	**9349**
UT		*1*		*1*	*2*		*4*
		15		**1**	**5**		**21**
VA	*16*	*4*	*1*	*5*	*6*	*1*	*33*
	1280	**482**	**3**	**27**	**97**	**19**	**1907**
VT		*1*			*2*	*1*	*4*
		8			**21**	**0**	**28**
WA		*7*			*5*	*3*	*15*
		755			**105**	**89**	**949**
WI	*8*	*7*			*4*	*3*	*22*
	200	**295**			**47**	**48**	**590**
WV	*2*						*2*
	139						**139**
WY		*1*			*1*	*1*	*3*
		3			**7**	**0**	**10**
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7631**	**27939**	**1243**	**3250**	**2332**	**3070**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

3. Technical Potential for Industrial CHP

This section summarizes the analysis of CHP technical potential in the manufacturing sector of the U.S. economy. This analysis is based on existing industrial facilities and estimates of their current power and steam consumption. The estimated potential is a snapshot of the technical potential for CHP at these facilities at the end of 1999 and does not include an analysis of sector growth over the time period of the EIA forecast. The technical market potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit existing customer energy needs. No consideration of economics is included in the analysis. The analysis also considers only traditional steam/electric power CHP. No estimate was made for mechanical drive applications or for uses of thermal energy other than steam.

3.1 Technical Approach

OSEC integrated the output of three separate databases to derive the remaining industrial CHP potential. A schematic of the approach and the databases is shown in **Figure 3.1**.

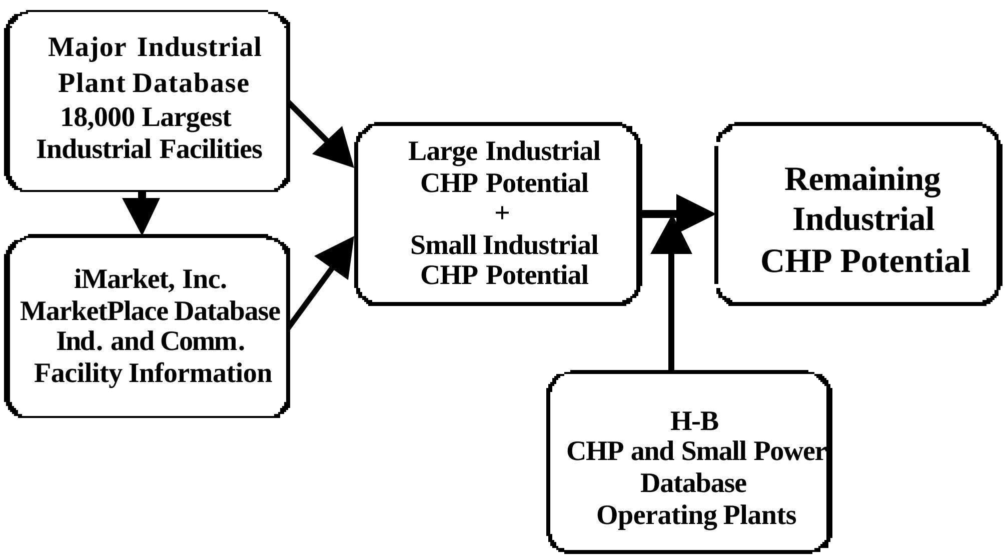


Figure 3.1. Methodology for Estimating Total Remaining CHP Potential in the Industrial Sector

Major Industrial Plant Database (MIPD)[15]

The MIPD is a very detailed description of over 18,000 of the largest industrial facilities in the U.S. Using this database, OSEC was able to aggregate the electrical capacity and steam utilization for each site and sort them into bins reflecting size and power-to-steam (P/S) ratios for each 2-digit SIC (20-39). It is also possible to get average hours of operation for each 2-digit SIC. Plants were sorted into three P/S bins as follows:

- **P/S < 0.4 –** These plants have a high steam load and CHP sizing would require either sizing to the steam load and exporting power or sizing to the site-power load and meeting only part of the on-site steam requirements. For this analysis, we have sized to the steam load, thereby requiring export of power from the site.

- **0.4 < P/S < 1.5 –** P/H ratios between 0.4 and 1.5 are sized to the steam load and provide only partial support for the on-site electric power needs

- **P/S > 1.5 –** Sites with a P/H ratio of greater than 1.5 are not included in the CHP potential because their on-site steam load is too small compared to their electrical requirements to warrant economic consideration of CHP.

Technical CHP potential was assigned to these P/S bins by assigning a specific technology P/S ratio for each bin. The excess steam category (P/S < 0.4) CHP potential was allocated to steam and power using a typical simple cycle combustion turbine system as defined in Section 1 of this report. The P/S chosen was 0.6. The potential for the balanced steam and power bin (P/S between 0.4 and 1.5) was assigned using a P/S ratio of 1.0 – reflective of a higher electric efficiency generation technology such as a recuperated cycle or combined cycle gas turbine.

MarketPlace Database[16]

The MIPD covers approximately 18,000 of the estimated 250,000 manufacturing facilities in the U.S. It is estimated by IHS Energy Group that the 18,000 represents about 80% of total energy consumption in the manufacturing sector as a whole – though this percentage varies by SIC. To estimate CHP potential at the small end of the market, the iMarket, Inc. *MarketPlace Database* was utilized to identify the number of sites by SIC code that have average electric loads between 100 kW and 1 MW. Unlike the MIPD, this database has limited site operating data. The database presorts facilities into discrete power use size bins; however, there is no direct steam consumption data, so there is no way to directly sort by P/S. SIC categories that are known to have adequate steam loads were selected based on power and steam data profiles contained in DOE's 1994 Manufacturing Energy Consumption Survey.[17] The 100-1,000kW size range represents a single bin in the database. CHP power and steam potential were allocated to this bin using the performance characteristics of reciprocating engine systems, that is a P/S of 0.8.

The MIPD and *MarketPlace* analyses are summed together to provide an estimate of the gross CHP potential within the manufacturing sector for facilities of 100 kW demand and above.

Database of Operating CHP and Small Power Plants

The MIPD has limited data on CHP by facility and OSEC determined that these data were incomplete. The *MarketPlace* database does not provide any information on existing CHP. Therefore, we utilized the Hagler-Bailly database of CHP and small power plants to identify the number of operating CHP plants in the manufacturing sector.

The detailed results of this analysis were presented in the previous section. For each of the 2-digit SIC categories (20-39) we subtracted the operating CHP from the total potential to arrive at the remaining technical CHP potential by 2-digit SIC and by size range.

3.2 Estimate of Remaining Power and Steam Potential for CHP by SIC

This section summarizes the results of the analysis based on the methodology described above. **Table 3.1** summarizes CHP potential in terms of electric capacities (MW) by 2-digit SIC. Specific notes on the columns are as follows:

- ***Small Plants 100-1,000kW total*** represents the number of facilities in *MarketPlace* database in the 100-1,000 kW size category times an assumed average size per facility of 400 kW.

- ***CHP Potential > 1MW, P/S< 0.4*** represents the CHP MW potential for facilities larger than 1 MW with power to steam ratios less than 0.4. It is assumed that the steam load is met with a simple-cycle combustion turbine technology that has a P/S of 0.6. Therefore, in this category, the estimated capacity includes a portion of power that must be exported from the site.

- ***CHP Potential > 1MW, 0.4<P/S<1.5*** represents an analogous computation for facilities with P/S between 0.4 and 1.5. For this column, however, it is assumed that the CHP generating technology is a recuperated cycle combustion turbine with a P/S of 1.0. The CHP capacity is sized to the facility steam load with only a partial contribution to the facility electric requirements.

- ***CHP Total Potential*** represents the sum of each of the three potential calculations described above.

- ***Existing CHP*** by 2-digit SIC is taken from the enhanced Hagler Bailly *Independent Power Database* as described previously in Section 2.

- ***Remaining CHP Potential*** is the difference between the total CHP and the existing CHP. The number represents the amount of CHP that can still be installed to existing industrial facilities.

- ***CHP Saturation of Total Potential*** is the percentage of total CHP technical potential in existing industrial facilities that is already operating (existing.)

We estimate that the technical potential for CHP at existing manufacturing facilities is approximately 132,000 MW. In Section 2 of this report we showed that approximately 44,000 MW of CHP capacity is already in place at existing manufacturing facilities, leaving a remaining CHP potential of just over 88,000 MW for the manufacturing sector (existing CHP represents a 33 % saturation of the total CHP potential for manufacturing as a whole). Much of the remaining potential is found in those industries that have traditionally relied on CHP -- paper, chemicals, food, primary metals and refining. Paper in particular has the largest amount of remaining CHP potential, accounting for 26,000 MW of the total 88,000. However, significant remaining potential exists in industries such as textiles, rubber and plastics, metals fabrication and equipment -- industries that have not aggressively implemented CHP to-date.

Table 3.2 presents CHP potential in terms of steam load, including calculated annual steam loads corresponding to both the total potential and existing CHP capacity presented in **Table 3.1**. Steam loads in trillion Btus (Tbtu) were calculated from CHP potential capacity estimates (in MW) and average operating hours derived for each SIC from the MIPD.

- ***Total Steam Load*** is an estimate in Tbtu of overall steam consumption by each 2-digit SIC. The data in the table are estimates for 1997 from EIA's internal cogeneration analysis and are based on the 1994 MECS and NEMS industrial and refining models.

- ***Existing CHP Steam*** is based on the steam capacity derived from the enhanced *Independent Power Database* presented in Section 2 and the average operating hours of each SIC derived from the MIPD.

- ***Existing CHP Steam Saturation*** is the percentage of total steam load that is satisfied by steam produced by existing CHP systems.

- ***Remaining CHP Steam*** is derived from the remaining CHP potential, the average operating hours for each SIC, and the P/S ratios assumed for each category of CHP potential as outlined for **Table 3.1**. As indicated above, the P/S assumed for the two MIPD categories are 0.6 and 1.0 respectively. The less than 1 MW analysis based on the *MarketPlace* database assumed a P/S of 0.8 that is more characteristic of a reciprocating engine CHP system.

- ***Total Potential CHP Steam Saturation*** represents the percentage of total steam load for each SIC that would be met by full implementation of the total CHP technical potential (sum of existing plus remaining CHP potential).

Based on this analysis, existing CHP systems produce almost 24 % of the total manufacturing steam demand. We estimate that approximately 68 % of total manufacturing steam demand could be satisfied by CHP if the full technical potential was realized at existing plants. This potential saturation number is less than 100 %, reflecting the fact that many steam loads are not conducive to CHP implementation (i.e., P/S < 1.5) and also reflecting a margin of error introduced into the calculation itself through the use of average operating hours, average P/S ratios for categories of CHP systems, and the fact that the total steam loads are themselves estimates derived from calculated data.

Table 3.3 presents CHP technical potential (MW electric capacity) by size categories for primary SIC industries. For each CHP installation size category (< 1 MW, 1-4 MW, 4-20 MW, 20-50 MW, > 50 MW), the table contains the following:

- ***Total Potential*** represents the total CHP technical potential at existing plants for each SIC for systems in the specified size categories. Total technical potential is given in MW of electric capacity.

- ***Existing CHP*** represents the installed CHP capacity in MW for each SIC in the specified size categories.

- ***Remaining Potential*** is the difference between the total CHP potential and the existing CHP capacity for each SIC and size category.

Major conclusions from review of the analysis results include:

- **Significant CHP potential remains at existing industrial facilities -** Existing CHP capacity (MW) represents about one third of the total CHP potential at existing industrial facilities. Certain industries such as Chemicals and Petroleum Refining have saturation rates that are much higher (65% and 45% respectively). Total remaining potential is estimated to be in the range of 75,000 to 100,000 MW (the analysis developed a specific estimate of 88,000 MW based on a limited technology match - the range of 75,000 to 100,000 MW reflects the wide range of technologies that could be utilized and the varying power to heat ratios of those technologies).

- **Much of the remaining CHP potential is with industries that have traditionally employed CHP** - Two thirds of the remaining CHP potential is in five industries (Food, Paper, Chemicals, Refining, Primary Metals) that currently have significant levels of CHP saturation (i.e., > 25 %).

- **CHP development to-date has focused on large systems** - Over 90 % of existing CHP capacity in the industrial market is represented by systems of 20 MW or greater. Existing CHP capacity represents over 45 % of total CHP potential in this size range.

- **Large systems represent a significant share of remaining CHP potential** - Fifty five percent of the remaining CHP potential is in system sizes of 20 MW or greater.

- **Small systems represent a large untapped market for CHP** - Forty five percent of the remaining CHP potential (over 39,000 MW) is in system sizes of less than 20 MW. Thirty two percent of the remaining potential is in system sizes of 4 MW or less. Market saturation in these size categories is currently very low (7 % for systems less than 20 MW, 1 % for systems less than 4 MW).

Table 3.1. Total CHP Potential, Existing CHP, and Remaining Potential by 2-Digit SIC (Megawatts)

SIC	SIC Description	Small Plants 100-1,000kW total	CHP Potential > 1MW, P/S< 0.4	CHP Potential >1MW, 0.4<P/S<1.5	CHP Total Potential	Existing CHP	Remaining CHP Potential*	Existing CHP Saturation of Total MW Potential
		---- Total MW Capacity ----						
20	Food and Kindred Products	2,683	6,652	3,345	12,680	4,594	8,086	36.2%
21	Tobacco and Allied Products*	16	24	63	103	131	0	100.0%
22	Textile Mill Products	766	1,854	1,157	3,777	651	3,126	17.2%
23	Apparel Manufacturing	n.a.	77	86	163	0	163	0.0%
24	Lumber and Wood Products	595	1,220	726	2,542	806	1,736	31.7%
25	Furniture	n.a.	108	294	401	68	333	16.9%
26	Paper and Allied Products	1,168	28,774	4,810	34,751	8,553	26,198	24.6%
27	Printing and Publishing	n.a.	258	146	404	19	385	4.7%
28	Chemicals and Allied Products	1,780	17,957	7,395	27,132	17,692	9,440	65.2%
29	Petroleum and Coal Products	154	8,067	4,186	12,407	5,618	6,789	45.3%
30	Rubber and Misc. Plastics	2,772	839	802	4,413	787	3,626	17.8%
31	Leather and Tanning	n.a.	89	9	98	0	98	0.0%
32	Stone, Clay, Glass, Concrete	n.a.	2,348	351	2,698	774	1,924	28.6%
33	Primary Metals Industries	294	4,744	4,776	9,814	2,873	6,941	29.3%
34	Fabricated Metal Products	4,050	920	756	5,726	78	5,648	1.4%
35	Industrial Machinery and Equip.	4,787	403	1,195	6,385	149	6,236	2.3%
36	Electrical and Electron. Equip.	n.a.	327	660	987	180	807	18.2%
37	Transportation Equipment	1,169	1,242	3,001	5,412	808	4,604	14.9%
38	Instruments and Related Prod.	972	344	246	1,562	59	1,503	3.8%
39	Miscellaneous Manufacturing	784	270	73	1,128	402	726	35.6%
	Total	21,990	76,518	34,075	132,583	44,242	88,341	33.4%

* Existing CHP is greater than estimated CHP potential

Table 3.2 CHP Steam Potential and Steam Saturation

SIC	SIC Description	CHP Total Potential, MW	Existing CHP, MW	Remaining CHP Potential, MW	Total Steam Load, Tbtu	Existing CHP Steam, Tbtu	Existing CHP Steam Saturation	Remaining CHP Steam, Tbtu	Total Potential CHP Steam Saturation
20	Food and Kindred Products	12,680	4,594	8,086	549	127	23.1%	219	63.0%
26	Paper and Allied Products	34,751	8,553	26,198	1627	434	26.7%	769	73.9%
28	Chemicals and Allied Products	27,132	17,692	9,440	1332	450	33.8%	495	70.9%
29	Petroleum and Coal Products	12,407	5,618	6,789	1000	135	13.5%	291	42.6%
33	Primary Metals Industries	9,814	2,873	6,941	186	79	42.5%	144	119.7%
-	Other Manufacturing	35,799	4,912	30,887	1132	151	13.4%	649	70.7%
	Total	132,583	44,242	88,341	5,827	1,375	23.6%	2,566	67.6%

* Total potential CHP steam saturation of >100 % for SIC 33 reflects that steam loads calculated in the MIPD and *MarketPlace* databases are greater than the EIA estimates of total SIC 33 steam load in 1997

Table 3.3 CHP Potential by Size of CHP System

SIC	Industry	< 1 MW Total Potential (MW)	< 1 MW Existing Capacity (MW)	< 1 MW Remaining Potential (MW)	1 - 4 MW Total Potential MW	1 - 4 MW Existing Potential MW	1 - 4 MW Remaining Potential MW	4 - 20 MW Total Potential MW	4 - 20 MW Existing Potential MW	4 - 20 MW Remaining Potential MW
20	Food	2,683	14	2,669	1,777	89	1,688	2,734	598	2,136
26	Paper	1,167	3	1,164	570	53	518	1,324	635	688
28	Chemicals	1,780	8	1,772	515	77	437	2,353	443	1,910
29	Petroleum	154	1	153	95	17	78	393	181	212
33	Primary Metals	294	0	294	261	4	257	741	27	714
-	Other Manuf.	15,912	34	15,878	3,221	129	3,092	6,234	558	5,676
TOTALS		21,990	60	21,930	6,439	369	6,070	13,779	2,442	11,337

SIC	Industry	20 - 50 MW Total Potential MW	20 - 50 MW Existing Potential MW	20 - 50 MW Remaining Potential MW	> 50 MW Total Potential MW	> 50 MW Existing Potential MW	> 50 MW Remaining Potential MW	Totals MW	Totals Net Remaining Potential
20	Food	1,922	655	1,267	3,564	3,239	325	12,680	8,086
26	Paper	2,152	2,083	70	29,537	5,779	23,758	34,751	26,198
28	Chemicals	3,125	1,487	1,637	19,360	15,676	3,684	27,132	9,440
29	Petroleum	934	621	313	10,831	4,799	6,032	12,407	6,789
33	Primary Metals	948	48	900	7,570	2,794	4,776	9,814	6,941
-	Other Manuf.	4,718	1,118	3,601	5,714	3,074	2,640	35,799	30,887
TOTALS		13,799	6,011	7,788	76,576	35,361	41,215	132,583	88,340

4. Factors Impacting Market Penetration

Decentralized combined heat and power systems located at industrial and municipal sites were the foundation of the early electric power industry in the United States. However, as generating technologies advanced, the power industry began to build larger and larger central station facilities to take advantage of increasing economies of scale. CHP became a limited practice utilized by a handful of industries -- paper, chemicals, refining and steel -- with certain characteristics -- high and relatively constant steam and electric demands, access to byproduct or waste fuels. These systems were typically sized to meet the base-load thermal demand and produced electricity as a "byproduct." A large percentage of these systems consisted of boiler/steam turbines that burned low cost/low quality fuels. The very low power to heat ratio of these systems ensured that electricity generated would not exceed plant demand and resulted in very high overall fuel utilization.

By the 1970s, a mature, regulated electric utility industry controlled the electricity market in the U.S. Utilities more often then not discouraged customer CHP by imposing high back-up and standby rates and by refusing to purchase excess power from on-site generators. Along with utility resistance, a host of regulatory barriers at the state and federal level served to further discourage broader CHP development.

In 1978 Congress passed the Public Utilities Regulatory Policies Act (PURPA), partly to encourage energy efficiency in response to the second oil crisis. A portion of PURPA was meant to encourage energy efficient cogeneration (CHP) and small power production from renewables by requiring servicing utilities to interconnect with "qualified facilities" (QFs), to provide such facilities with reasonable standby and back-up charges, and to purchase excess electricity from these facilities at the utilities avoided cost. PURPA also exempted QFs from regulatory oversight under the Public Utilities Holding Company Act and from constraints on natural gas use imposed by the Fuel Use Act.

PURPA had the expected effect on CHP. Installed CHP capacity increased from about 12,000 MW in 1980 to over 52,000 MW in 1999. But PURPA also had unforeseen results. PURPA was enacted coincidentally with the availability of larger, more efficient, lower cost combustion turbines and combined cycle systems with high power to heat ratios. The power purchase provisions of PURPA coupled with the availability of this new technology resulted in the development of a number of very large merchant plants leveraged towards high electricity production. For the first time since the inception of the industry, non-utility participation was being allowed in the power market. This triggered the development of third party CHP developers who had greater interest in electric markets than thermal markets, and ultimately started the progression towards wholesale generation and open access.

In the 1980s and early 1990s CHP was a requirement for participation in the electric market and third party developers actively sought industrial facilities to serve as thermal hosts. As a result, CHP penetration in sites greater than 20 MW now approaches 45%

and over half of existing CHP capacity -- 29,000 MW -- is concentrated in a relative small number of plants over 100 MW in size -- 120 facilities.

The environment changed again in the mid 1990s with the advent of the wholesale market for electricity. Independent power producers could now sell directly to the market without the need for QF status and CHP development slowed. In the transition to a fully restructured market, CHP is once again disadvantaged in many ways, particularly in small applications. Access to power markets is restricted, utilities are again imposing high back-up rates and offering low buyback rates, and users are delaying purchase decisions with an expectation of low retail prices in the future.

Whether this is a temporary situation or a long term trend is unclear. Most analysts agree that CHP optimized to meet in-plant needs can be a very competitive energy option in a fully restructured market and that a variety of institutional and market hurdles are currently limiting CHP growth in the transition. Factors that could lead to more aggressive market penetration in the future include:

- Technology Improvements - Over 45% of the remaining potential in the industrial market is in systems below 20 MW. Projects in this size range are currently marginal in many areas. Equipment and development costs are high and users perceive CHP to be a high risk, non-core investment. New technologies are entering the market that promise to significantly improve CHP economics for small to medium facilities due to reduced capital costs, higher efficiencies, and inherently low emissions

- Streamlined Project Implementation - Along with technology improvements, many analysts expect project implementation to become easier as well. This includes faster project implementation, lower interconnection costs due to standardization of technology and contracts, and lower installation costs due to a more competitive and stable environment for CHP.

- Third Party Financing and/or Ownership - Energy users use a variety of methods to determine if a particular investment is economically desirable. Simple payback is often used for preliminary evaluation of projects, and many users will not pursue an energy-related investment unless it has a payback of 2-3 years or less. Leasing arrangements and third party financing eliminate the need for the user to provide the initial investment, and are becoming more prevalent in CHP transactions -- over 57% of existing industrial CHP capacity has some third party involvement in the transaction. Third party transactions typically have much lower economic hurdle rates as well. Third party financers often have a better understanding of the technology, have different risk aversion profiles, and will base project decisions on more flexible internal rate of return expectations.

- Electric Industry Restructuring - Restructuring is proceeding unevenly across the nation, but many states are considering provisions to ensure that on-site generation is not unfairly disadvantaged in a restructured environment. As an example, several states including California, New York and Texas are looking into the structure, level and equity of existing standby/back-up rates. Others including Texas, New Jersey, Massachusetts, Michigan, Illinois and California are exempting CHP either totally or partially from stranded cost recovery charges.

- Recognizing the Value of Ancillary Services - Users are beginning to realize that electric service is more than just the commodity cost. Services such as power quality, reliability, flexibility and independence are beginning to be recognized as having value and can impact project economics if properly monetized. Similarly, the value that on-site CHP can provide to the T&D system is beginning to be recognized, and may eventually be quantified and shared between the utility and the user.

- Recognizing Environmental Benefits of CHP - It is becoming widely accepted that CHP offers inherent environmental benefits because of it's increased efficiency. Future market penetration could be increased by efforts underway to advance adoption of output-based emissions standards that promote deployment of efficient technologies such as CHP and to streamline the environmental permitting process for efficient CHP installations.

- CHP Competes with Retail Rates - CHP optimized to meet plant thermal and power needs competes with retail electricity rates. Project economics are heavily dependent on the structure and level of the applicable rate structure including demand and time of use charges.

- CHP Initiatives - Financial incentives for CHP (e.g., investment tax credits) provided by either the federal or state governments are being discussed by various parties to promote CHP's efficiency and emissions benefits. The rationale for these incentives is that increased penetration of efficient CHP results in broad public benefits that accrue to the public at large.

- Increased Marketing Efforts - The competitive market has created a large number of energy service providers that will be aggressively marketing energy service options including CHP. With higher marketing efforts, market penetration rates will increase for a given level of economic value. As marketing efforts and government programs are implemented, customer confidence in the technology will increase, reducing the very high risk premium that has been placed on CHP projects.

The enactment of PURPA was a watershed event that substantially changed the landscape for cogeneration in the U.S. and accelerated the penetration of large systems into the industrial market. Electric industry restructuring, the need for additional capacity to meet growing demand and maintain system integrity, advances in smaller generation technology, and concerns over climate change may collectively represent another watershed event that initiates a new cycle of accelerated growth for CHP. The evolution of the factors outlined above will determine how rapidly this new cycle grows and how sustained a market it becomes.

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Appendix : CHP Technology Characterization

Combined heat and power (CHP) technologies produce electricity or mechanical power and recover waste heat for process use. Conventional centralized power systems average less than 33% delivered efficiency for electricity in the U.S.; CHP systems can deliver energy with efficiencies exceeding 80%[1], while significantly reducing emissions per delivered MWh. CHP systems can provide cost savings for industrial and commercial users and substantial emissions reductions. This report describes the leading CHP technologies, their efficiency, size, cost to install and maintain, fuels and emission characteristics.

The technologies included in this report include diesel engines, natural gas engines, steam turbines, gas turbines, and combined cycle units. These CHP technologies are commercially available for on-site generation and combined heat and power applications. The power industry is witnessing dramatic changes with utility restructuring and increased customer choice. As a result of these changes, CHP is expected to gain wider acceptance in the market.

Selecting a CHP technology for a specific application depends on many factors, including the amount of power needed, the duty cycle, space constraints, thermal needs, emission regulations, fuel availability, utility prices and interconnection issues. Table A-1 summarizes the characteristics of each CHP technology. The table shows that CHP covers a wide capacity range from 50 kW reciprocating engines to 300 MW gas turbines. Estimated costs per installed kW range from $500-$1400/kW.

[1] T. Casten, *CHP – Policy Implications for Climate Change and Electric Deregulation,* May 1998, p2.

Table A-1. Comparison of CHP Technologies

		Recip Engine	Steam Turbine	Combustion Turbine	Combined Cycle	
Electric Efficiency (LHV)		25-45%	15-25%	25-40%	40 - 50%	
Size (MW)		0.05-5	Any	1-100	25 - 300	
Footprint (sqft/kW)		0.2-0.3	<0.1	0.02-0.6	0.6	
CHP installed cost ($/kW)		800-1500	800-1000	700-900	600-800	
O&M Cost ($/kWh)		0.007-0.015	0.004	0.002-0.008	0.002-0.008	
Availability		92-97%	Near 100%	90-98%	90-98%	
Hours between overhauls		24,000-60,000	>50,000	30,000-50,000	30,000-50,000	
Start-up Time		10 sec	1 hr-1 day	10 min –1 hr	10 min –1 hr	
Fuel pressure (psi)		1-45	n/a	120-500 (may require compressor)	120-500 (may require compressor)	
Fuels		natural gas, biogas, propane	all	natural gas, biogas, propane, distillate oil	natural gas, biogas, propane, distillate oil	
Noise		moderate to high (requires building enclosure)	moderate to high (requires building enclosure)	moderate (enclosure supplied with unit)	moderate (enclosure supplied with unit)	
NO_x Emissions(lb/MWh)		2.2-28	1.8	0.3-4	0.3-4	
Uses for Heat Recovery		hot water, LP steam, district heating	LP-HP steam, district heating	direct heat, hot water, LP-HP steam, district heating	direct heat, hot water, LP-HP steam, district heating	
CHP Thermal Output (Btu/kWh)		1,000-5,000	5,000-25,000	3,400-12,000	2,000-8,000	
Useable Temp for CHP (F)		300-500	n/a	500-1,100	500-1,100	

1. Reciprocating Engines

Introduction

Among the most widely used and most efficient prime movers are reciprocating (or internal combustion) engines. Electric efficiencies of 25-50% make reciprocating engines an economic CHP option in many applications. Several types of reciprocating engines are commercially available, however, two designs are of most significance to stationary power applications and include four cycle- spark-ignited (Otto cycle) and compression-ignited (diesel cycle) engines. They can range in size from small fractional portable gasoline engines to large 50,000 HP diesels for ship propulsion. In addition to CHP applications, diesel engines are widely used to provide standby or emergency power to hospitals, and commercial and industrial facilities for critical power requirements.

Technology Description

The essential mechanical parts of Otto-cycle and diesel engines are the same. Both use a cylindrical combustion chamber in which a close fitting piston travels the length of the cylinder. The piston is connected to a crankshaft which transforms the linear motion of the piston within the cylinder into the rotary motion of the crankshaft. Most engines have multiple cylinders that power a single crankshaft. Both Otto-cycle and diesel four stroke engines complete a power cycle in four strokes of the piston within the cylinder. Strokes include: 1) introduction of air (or air-fuel mixture) into the cylinder, 2) compression with combustion of fuel, 3) acceleration of the piston by the force of combustion (power stroke) and 4) expulsion of combustion products from the cylinder.

The primary difference between Otto and diesel cycles is the method of fuel combustion. An Otto cycle uses a spark plug to ignite a pre-mixed fuel-air mixture introduced to the cylinder. A diesel engine compresses the air introduced in the cylinder to a high pressure, raising its temperature to the ignition temperature of the fuel which is injected at high pressure.

A variation of the diesel is the dual fuel engine. Up to 80-90% of the diesel fuel is substituted with gasoline or natural gas while maintaining power output and achieving substantial emission reductions.

Large modern diesel engines can attain electric efficiencies near 50% and operate on a variety of fuels including diesel fuel, heavy fuel oil or crude oil. Diesel engines maintain higher part load efficiencies than an Otto cycle because of leaner fuel-air ratios at reduced load.

Design Characteristics

The features that have made reciprocating engines a leading prime mover for CHP include:

Economical size range:	Reciprocating engines are available in sizes that match the electric demand of many end-users (institutional, commercial and industrial).
Fast start-up:	Fast start-up allows timely resumption of the system following a maintenance procedure. In peaking or emergency power applications, reciprocating engines can quickly supply electricity on demand.
Black-start capability:	In the event of a electric utility outage, reciprocating engines can be started with minimal auxiliary power requirements, generally only batteries are required.
Excellent availability:	Reciprocating engines have typically demonstrated availability in excess of 95%.
Good part load operation:	In electric load following applications, the high part load efficiency of reciprocating engines maintain economical operation.
Reliable and long life:	Reciprocating engines, particularly diesel and industrial block engines have provided many years of satisfactory service given proper maintenance.

Performance Characteristics

Efficiency

Reciprocating engines have electric efficiencies of 25-50% (LHV) and are among the most efficient of any commercially available prime mover. The smaller stoichiometric engines that require 3-way catalyst after-treatment operate at the lower end of the efficiency scale while the larger diesel and lean burn natural gas engines operate at the higher end of the efficiency range.

Capital Cost

CHP projects using reciprocating engines are typically installed between $800-$1500/kW. The high end of this range is typical for small capacity projects that are sensitive to other costs associated with constructing a facility, such as fuel supply, engine enclosures, engineering costs, and permitting fees.

Availability

Reciprocating engines have proven performance and reliability. With proper maintenance and a good preventative maintenance program, availability is over 95%. Improper maintenance can have major impacts on availability and reliability.

Maintenance

Engine maintenance is comprised of routine inspections/adjustments and periodic replacement of engine oil, coolant and spark plugs every 500-2,000 hours. An oil analysis is an excellent method to determine the condition of engine wear. The time interval for overhauls is recommended by the manufacturer but is generally between 12,000-15,000 hours of operation for a top-end overhaul and 24,000-30,000 for a major overhaul. A top-end overhaul entails a cylinder head and turbo-charger rebuild. A major overhaul involves piston/ring replacement and crankshaft bearings and seals. Typical maintenance costs including an allowance for overhauls is 0.01 - 0.015$/kWhr.

Heat Recovery

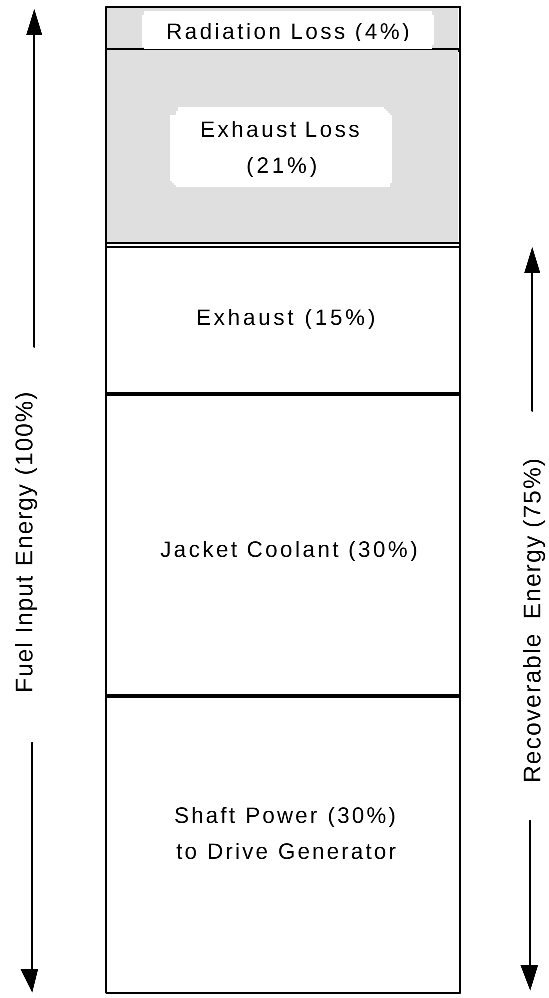
Energy in the fuel is released during combustion and is converted to shaft work and heat. Shaft work drives the generator while heat is liberated from the engine through coolant, exhaust gas and surface radiation. Approximately 60-70% of the total energy input is converted to heat that can be recovered from the engine exhaust and jacket coolant, while smaller amounts are also available from the lube oil cooler and the turbocharger's intercooler and aftercooler (if so equipped). Steam or hot water can be generated from recovered heat that is typically used for space heating, reheat, domestic hot water and absorption cooling.

Heat in the engine jacket coolant accounts for up to 30% of the energy input and is capable of producing 200°F hot water. Some engines, such as those with high pressure or ebullient cooling systems, can operate with water jacket temperatures up to 265°.

Engine exhaust heat is 10-30% of the fuel input energy. Exhaust temperatures of 850°-1200°F are typical. Only a portion of the exhaust heat can be recovered since exhaust gas temperatures are generally kept above condensation thresholds. Most heat recovery units are designed for a 300°-350°F exhaust outlet temperature to avoid the corrosive effects of condensation in the exhaust piping. Exhaust heat is typically used to generate hot water to about 230°F or low-pressure steam (15 psig).

By recovering heat in the jacket water and exhaust, approximately 70-80% of the fuel's energy can be effectively utilized as shown in Figure A-1.1 for a typical spark-ignited engine.

Figure A-1.1 Energy Balance for a Reciprocating Engine



Closed-Loop Hot Water Cooling Systems

The most common method of recovering engine heat is the closed-loop cooling system as shown in Figure A-1.2. These systems are designed to cool the engine by forced circulation of a coolant through engine passages and an external heat exchanger. An ancillary heat exchanger transfers engine heat to a cooling tower or radiator when there is excess heat generated. Closed-loop water cooling systems can operate at coolant temperatures between 190°-250°F.

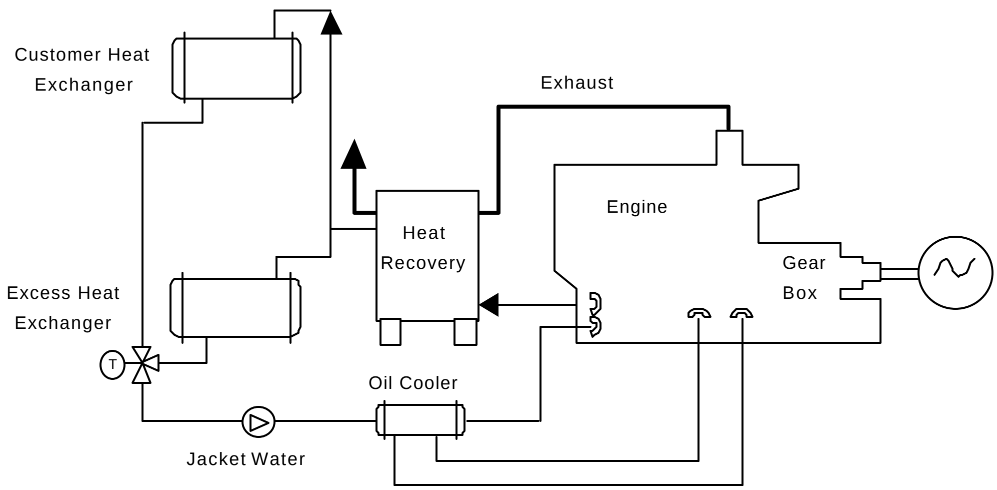


Figure A-1.2. Closed-Loop Heat Recovery System

Ebullient Cooling Systems

Ebullient cooling systems cool the engine by natural circulation of a boiling coolant through the engine. This type of cooling system is typically used in conjunction with exhaust heat recovery for production of low-pressure steam. Cooling water is introduced at the bottom of the engine where the transferred heat begins to boil the coolant generating two-phase flow. The formation of bubbles lowers the density of the coolant, causing a natural circulation to the top of the engine.

The coolant at the engine outlet is maintained at saturated steam conditions and is usually limited to 250°F and a maximum of 15 psig. Inlet cooling water is also near saturation conditions and is generally 2°- 3°F below the outlet temperature. The uniform temperature throughout the coolant circuit extends engine life, contributes to improved combustion efficiencies and reduces friction in the engine.

Emissions

The two primary methods of lowering emissions in Otto cycle engines is lean burn (combustion control) and rich burn with a catalytic after-treatment.

Lean burn engine technology was developed during the 1980's in response to the need for cleaner burning engines. Most lean burn engines use turbocharging to supply excess air to the engine and produce lean fuel-air ratios. Lean burn engines consume 50-100% excess air (above stoichiometric) to reduce temperatures in the combustion chamber and limit creation of nitrogen oxides (NO_x,) carbon dioxide (CO) and non-methane hydrocarbons (NMHC.) The typical NO_x emission rate for lean burn engines is between 0.5–2.0 grams/hphr. Emission levels can be reduced to less than 0.15gm/hphr with selective catalytic reduction (SCR) where ammonia is injected into the exhaust gas in the presence of a catalyst. SCR adds a significant cost burden to the installation cost and increases the O&M on the engine. This approach is typically used on large capacity engines.

Catalytic converters are used with rich burn (i.e. stoichiometric) Otto cycles. A reducing catalyst converts NO_x to N_2 and oxidizes some of the CO to CO_2. A catalytic converter can contain both reducing and oxidizing catalytic material in a single bed. Electronic fuel–air ratio controls are typically needed to hold individual emission rates to within a very close tolerance. Also referred to as a three-way catalyst, hydrocarbon, NO_x and CO are simultaneously controlled. Typical NO_x emission rates for rich burn engines are approximately 9 grams/hphr. Catalytic converters have proven to be the most effective after treatment of exhaust gas with control efficiencies of 90-99%+, reducing NO_x emissions to 0.15gm/hphr. A stoichiometric engine with a catalytic convertor operates with an efficiency of approximately 30%. Maintenance costs can increase by 25% for catalyst replacement.

Diesel engines operate at much higher air-fuel ratios than Otto cycle engines. The high excess air (lean condition) causes relatively low exhaust temperatures such that conventional catalytic converters for NO_x reduction are not effective. Lean NO_x catalytic converters are currently under development. Some diesel applications employ SCR to reduce emissions.

A major emission impact of a diesel engine is particulates. Particulate traps physically capture fine particulate matter generated by the combustion of diesel fuel and are typically 90% effective. Some filters are coated with a catalyst that must be regenerated for proper operation and long life.

Applications

Reciprocating engines are typically used in CHP applications where there is a substantial hot water or low pressure steam demand. When cooling is required, the thermal output of a reciprocating engine can be used in a single-effect absorption chiller. Reciprocating engines are available in a broad size range of approximately 50kW to 5,000kW suitable for a wide variety of commercial, institutional and small industrial facilities. Reciprocating engines are frequently used in load following applications where engine power output is regulated based on the electric demand of the facility. Thermal output varies accordingly. Thermal balance is achieved through supplemental heat sources such as boilers.

Technology Advancements

Advances in electronics, controls and remote monitoring capability should increase the reliability and availability of engines. Maintenance intervals are being extended through development of longer life spark plugs, improved air and fuel filters, synthetic lubricating oil and larger engine oil sumps.

Reciprocating engines have been commercially available for decades. A global network of manufacturers, dealers and distributors is well established.

2. Steam Turbines

Introduction

Steam turbines are one of the most versatile and oldest prime mover technologies used to drive a generator or mechanical machinery. Steam turbines are widely used for CHP applications in the U.S. and Europe where special designs have been developed to maximize efficient steam utilization.

Most of the electricity in the United States is generated by conventional steam turbine power plants. The capacity of steam turbines can range from a fractional horsepower to more than 1,300 MW for large utility power plants.

A steam turbine is captive to a separate heat source and does not directly convert a fuel source to electric energy. Steam turbines require a source of high pressure steam that is produced in a boiler or heat recovery steam generator (HRSG). Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste.

Steam turbines offer a wide array of designs and complexity to match the desired application and/or performance specifications. In utility applications, maximizing efficiency of the power plant is crucial for economic reasons. Steam turbines for utility service may have several pressure casings and elaborate design features. For industrial applications, steam turbines are generally of single casing design, single or multi-staged and less complicated for reliability and cost reasons. CHP can be adapted to both utility and industrial steam turbine designs.

Technology Description

The thermodynamic cycle for the steam turbine is the Rankine cycle. The cycle is the basis for conventional power generating stations and consists of a heat source (boiler) that converts water to high pressure steam. The steam flows through the turbine to produce power. The steam exiting the turbine is condensed and returned to the boiler to repeat the process.

A steam turbine consists of a stationary set of blades (called nozzles) and a moving set of adjacent blades (called buckets or rotor blades) installed within a casing. The two sets of blades work together such that the steam turns the shaft of the turbine and the connected load. A steam turbine converts pressure energy into velocity energy as it passes through the blades.

The primary type of turbine used for central power generation is the *condensing* turbine. Steam exhausts from the turbine at sub-atmospheric pressures, maximizing the heat extracted from the steam to produce useful work.

Steam turbines used for CHP can be classified into two main types:

The *non-condensing turbine* (also referred to as a back-pressure turbine) exhausts steam at a pressure suitable for a downstream process requirement. The term refers to turbines that exhaust steam at atmospheric pressures and above. The discharge pressure is established by the specific CHP application.

The *extraction turbine* has opening(s) in its casing for extraction of steam either for process or feedwater heating. The extraction pressure may or may not be automatically regulated depending on the turbine design. Regulated extraction permits more steam to flow through the turbine to generate additional electricity during periods of low thermal demand by the CHP system. In utility type steam turbines, there may be several extraction points each at a different pressure.

Design Characteristics

Custom design:	Steam turbines can be designed to match CHP design pressure and temperature requirements. The steam turbine can be designed to maximize electric efficiency while providing the desired thermal output.
High thermal quality:	Steam turbines are capable of operating over the broadest available steam pressure range from subatmospheric to supercritical and can be custom designed to deliver the thermal requirements of the CHP application.
Fuel flexibility:	Steam turbines offer the best fuel flexibility using a variety of fuel sources including nuclear, coal, oil, natural gas, wood and waste products.

Performance Characteristics

Efficiency

Modern large condensing steam turbine plants have efficiencies approaching 40-45%, however, efficiencies of smaller industrial or backpressure turbines can range from 15-35%.

Capital Cost

Boiler/ steam turbines installation costs are between $800-$1000/kW or greater depending on environmental requirements. The incremental cost of adding a steam turbine to an existing boiler system or to a combined cycle plant is approximately $400-$800/kW.

Availability

A steam turbine is generally considered to have 99%+ availability with longer than a year between shutdowns for maintenance and inspections. This high level of availability applies only for the steam turbine and does not include the heat source.

Maintenance

A maintenance issue with steam turbines is solids carry over from the boiler that deposit on turbine nozzles and degrades power output. The oil lubrication system must be clean and at the correct operating temperature and level to maintain proper performance. Other items include inspecting auxiliaries such as lubricating-oil pumps, coolers and oil strainers and check safety devices such as the operation of overspeed trips. Steam turbine maintenance costs are typically less than $0.004 per kWh.

Heat Recovery

Heat recovery methods from a steam turbine use exhaust or extraction steam. Heat recovery from a steam turbine is somewhat misleading since waste heat is generally associated with the heat source, in this case a boiler either with an economizer or air preheater.

A steam turbine can be defined as a heat recovery device. Producing electricity in a steam turbine from the exhaust heat of a gas turbine (combined cycle) is a form of heat recovery.

The amount and quality of the recovered heat is a function of the entering steam conditions and the design of the steam turbine. Exhaust steam from the turbine can be used directly in a process or for district heating. Or it can be converted to other forms of thermal energy including hot water or chilled water. Steam discharged or extracted from a steam turbine can be used in a single or double-effect absorption chiller. A steam turbine can also be used as a mechanical drive for a centrifugal chiller.

Emissions

Emissions associated with a steam turbine are dependent on the source of the steam. Steam turbines can be used with a boiler firing a large variety of fuel sources or it can be used with a gas turbine in a combined cycle. Boiler emissions can vary depending on environmental regulations. Large boilers can use SCR to reduce NO_x emissions to single digit levels.

Applications

Steam Turbines for Industrial and CHP Applications

In industrial applications, steam turbines may drive an electric generator or equipment such as boiler feedwater pumps, process pumps, air compressors and refrigeration chillers. Turbines as industrial drivers are almost always a single casing machine, either single stage or multistage, condensing or non-condensing depending on steam conditions and the value of the steam. Steam turbines can operate at a single speed to drive an electric generator or operate over a speed range to drive a refrigeration compressor.

For non-condensing applications, steam is exhausted from the turbine at a pressure and temperature sufficient for the CHP heating application. Back pressure turbines can operate over a wide pressure range depending on the process requirements and exhaust steam at typically between 5 psig to 150 psig. Back pressure turbines are less efficient than condensing turbines, however, they are less expensive and do not require a surface condenser.

Technology Advancements

Steam turbines have been commercially available for decades. Advancements will more likely occur in gas turbine technology.

3. Combustion Turbines and Combined Cycles

Introduction

Over the last two decades, the combustion or gas turbine has seen tremendous development and market expansion. Whereas gas turbines represented only 20% of the power generation market twenty years ago, they now claim approximately 40% of new capacity additions. Gas turbines have been long used by utilities for peaking capacity, however, with changes in the power industry and increased efficiency, the gas turbine is now being used for base load power. Much of this growth can be accredited to large (>50 MW) combined cycle plants that exhibit low capital cost (less than $550/kW) and high thermal efficiency. Manufacturers are offering new and larger capacity machines that operate at higher efficiencies. Some forecasts predict that gas turbines may furnish more than 80% of all new U.S. generation capacity in coming decades.[2]

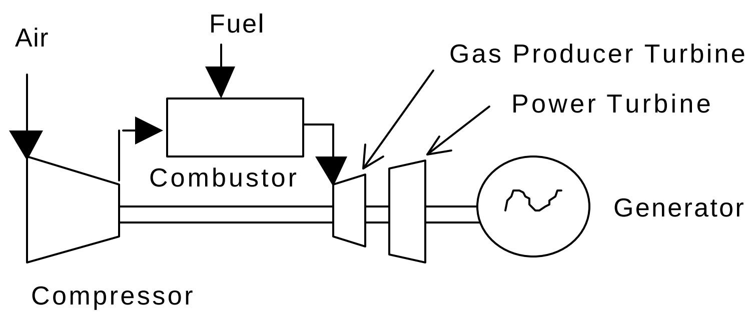
Gas turbine development accelerated in the 1930’s as a means of propulsion for jet aircraft. It was not until the early 1980’s that the efficiency and reliability of gas turbines had progressed sufficiently to be widely adopted for stationary power applications. Gas turbines range in size from 30 kW (microturbines) to 250 MW (industrial frames).

[2] U.S. DOE Energy Information Administration

Technology Description

The thermodynamic cycle associated with the majority of gas turbine systems is the Brayton cycle, that passes atmospheric air, the working fluid, through the turbine only once. The thermodynamic steps of the Brayton cycle include compression of atmospheric air, introduction and ignition of fuel, and expansion of the heated combustion gases through the gas producing and power turbines. The developed power is used to drive the compressor and the electric generator. Primary components of a gas turbine are shown in Figure A-3.1.

Figure A-3.1. Components of a Gas



Aeroderivative gas turbines for stationary power are adapted from their jet engine counterpart. These turbines are light weight and thermally efficient, however, are limited in capacity. The largest aeroderivitives are approximately 40 MW in capacity today. Many aeroderivative gas turbines for stationary use operate with compression ratios up to 30:1 requiring an external fuel gas compressor. With advanced system developments, aeroderivitives are approaching 45% simple cycle efficiencies.

Industrial or frame gas turbines are available between 1 MW to 250 MW. They are more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation. However, they are less efficient and much heavier than the aeroderivative. Industrial gas turbines generally have more modest compression ratios up to 16:1 and often do not require an external compressor. Industrial gas turbines are approaching simple cycle efficiencies of approximately 40% and in combined cycles are approaching 60%.

Small industrial gas turbines are being successfully used in industry for on-site power generation and as mechanical drivers. Turbine sizes are typically between 1–10 MW for these applications. Small gas turbines drive compressors along natural gas pipelines for cross country transport. In the petroleum industry they drive gas compressors to maintain well pressures. In the steel industry they drive air compressors used for blast furnaces. With the coming competitive electricity market, many experts believe that installation of small industrial gas turbines will proliferate as a cost effective alternative to grid power.

Design Characteristics

Quality thermal output:	Gas turbines produce a high quality thermal output suitable for most CHP applications.
Cost effectiveness:	Gas turbines are among the lowest cost power generation technologies on a $/kW basis, especially in combined cycle.
Fuel flexibility:	Gas turbines operate on natural gas, synthetic gas and fuel oils. Plants are often designed to operate on gaseous fuel with a stored liquid fuel for backup.
Reliable and long life:	Modern gas turbines have proven to be reliable power generation devices, given proper maintenance.
Economical size range:	Gas turbines are available in sizes that match the electric demand of many end-users (institutional, commercial and industrial).

Performance Characteristics

Efficiency

The thermal efficiency of the Brayton cycle is a function of pressure ratio, ambient air temperature, turbine inlet temperature, the efficiency of the compressor and turbine elements and any performance enhancements (i.e. recuperation, reheat, or combined cycle). Efficiency generally increases for higher power outputs and aeroderivative designs. Simple cycle efficiencies can vary between 25-40% lower heating value (LHV). Next generation combined cycles are being advertised with electric efficiencies approaching 60%.

Capital Cost

The capital cost of a gas turbine power plant on a kW basis ($/kW) can vary significantly depending on the capacity of the facility. Typical estimates vary between $300-$900/kW. The lower end applies to large industrial frame turbines in combined cycle.

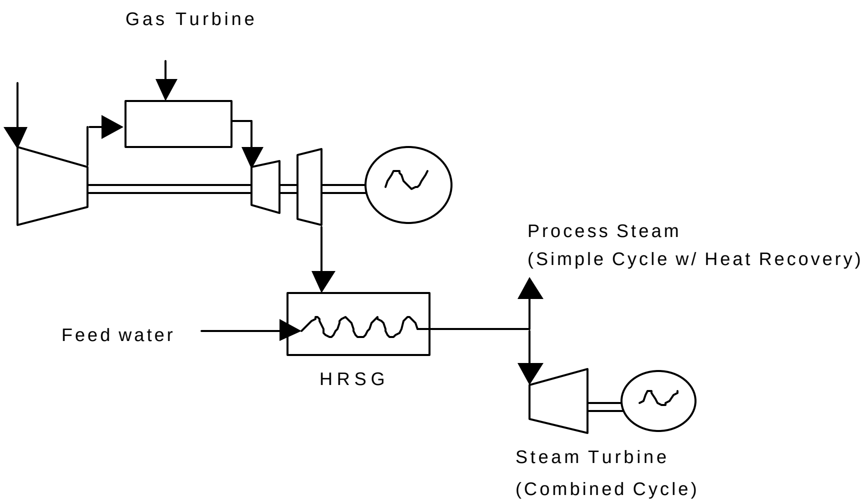
Availability

Estimated availability of gas turbines operating on clean gaseous fuels like natural gas is in excess of 95%. Use of distillate fuels and other fuels with contaminants require more frequent shutdowns for preventative maintenance that reduce availability.

Maintenance

Although gas turbines can be cycled, maintenance costs can triple for a turbine that is cycled every hour versus a turbine that is operated for intervals of 1000 hours. Operating the turbine over the rated design capacity for significant time periods will also dramatically increase the number of hot path inspections and overhauls. Maintenance costs of a turbine operating on fuel oil can be approximately three times that as compared to natural gas. Typical maintenance costs for a gas turbine fired by natural gas is 0.003-0.005 $/kWh.

Figure A-3.2 Heat Recovery from a Gas Turbine System



Heat Recovery

The simple cycle gas turbine is the least efficient arrangement since there is no recovery of heat in the exhaust gas. Hot exhaust gas can be used directly in a process or by adding a heat recovery steam generator (HRSG), exhaust heat can generate steam or hot water. An important advantage of CHP using gas turbines is the high quality waste heat available in the exhaust gas. The high temperature exhaust gas is suitable for generating high-pressure steam that is used frequently for industrial processes.

For larger gas turbine installations, combined cycles become economical, achieving approximately 60% electric generation efficiencies using the most advanced utility-class gas turbines. The heat recovery options available from a steam turbine used in the combined cycle can be implemented to further improve the overall system efficiency (as discussed previously.)

Since gas turbine exhaust is oxygen rich, it can support additional combustion through supplementary firing. A duct burner is usually fitted within the HRSG to increase the exhaust gas temperature at efficiencies of 90% and greater.

Combined Cycle Power Plants

The trend in power plant design is the combined cycle that incorporates a steam turbine in a bottoming cycle with a gas turbine. Steam generated in the heat recovery steam generator (HRSG) of the gas turbine is used to drive a steam turbine to yield additional electricity and improve cycle efficiency. The steam turbine is usually an extraction-condensing type and can be designed for CHP applications.

Emissions

The dominant NO_x control technologies for gas turbines include water/steam injection and lean pre-mix (combustion control) and selective catalytic reduction (post combustion control). Without any controls, gas turbines produce levels of NO_x between 75-200 ppmv. By injecting water or steam into the combustor, NO_x emissions can be reduced to approximately 42 ppmv with water and 25 ppmv with steam. NO_x emissions from distillate-fired turbines can be reduced to about 42-75 ppmv. Water or steam injection requires very purified water to minimize the effects of water-induced corrosion of turbine components.

Lean pre-mix (dry low NO_x) is a combustion modification where a lean mixture of natural gas and air are pre-mixed prior to entering the combustion section of the gas turbine. Pre-mixing avoids "hot spots" in the combustor where NO_x forms. Turbine manufacturers have achieved NO_x emissions of 9-42 ppmv using this technology. This technology is still being developed and early designs have caused turbine damage due to "flashback". Elevated noise levels have also been encountered.

Selective catalytic reduction (SCR) is a post combustion treatment of the turbine's exhaust gas in which ammonia is reacted with NO_x in the presence of a catalyst to produce nitrogen and water. SCR is approximately 80-90% effective in the reduction of upstream NO_x emission levels. Assuming a turbine has NO_x emissions of 25 ppm, SCR can further reduce emissions to 3-5 ppm. SCR is used in series with water/steam injection or lean pre-mix to produce single-digit emission levels. SCR requires an upstream heat recovery device to temper the temperature of the exhaust gas in contact with the catalyst. SCR requires on-site storage of ammonia, a hazardous chemical. In addition ammonia can "slip" through the process unreacted that contributes to air pollution. SCR systems are expensive and significantly impact the economic feasibility of smaller gas turbine projects.

Applications

Gas turbines are a cost effective CHP alternative for commercial and industrial end-users with a base load electric demand greater than about 5 MW. Although gas turbines can operate satisfactorily at part load, they perform best at full power in base load operation. Gas turbines are frequently used in district steam heating systems since their high quality thermal output can be used for most medium pressure steam systems.

Gas turbines for CHP can be in either a simple cycle or a combined cycle configuration. Simple cycle applications are most prevalent in smaller installations typically less than 25 MW. Waste heat is recovered in a HRSG to generate high or low pressure steam or hot water. The thermal product can be used directly or converted to chilled water with single or double effect absorption chillers.

Technology Advancements

Advancements in blade design, cooling techniques and combustion modifications including lean premix (dry low NOx) and catalytic combustion are under development to achieve higher thermal efficiencies and single digit emission levels without post combustion treatment. Gas turbine manufacturers have been commercializing their products for decades. A global network of manufacturers, dealers and distributors is well established.