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Clean Energy Technologies

A Preliminary Inventory of the Potential for Electricity Generation

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1. Introduction & Results

The nation's power system is facing a diverse and broad set of challenges. These range from restructuring and increased competitiveness in power production to the need for additional production and distribution capacity to meet demand growth, and demands for increased quality and reliability of power and power supply. In addition, there are growing concerns about emissions from fossil fuel powered generation units and generators are seeking methods to reduce the CO_2 emission intensity of power generation.

Although these challenges may create uncertainty within the financial and electricity supply markets, they also offer the potential to explore new opportunities to support the accelerated deployment of cleaner and cost-effective technologies to meet such challenges. The federal government and various state governments, for example, support the development of a sustainable electricity infrastructure. As part of this policy, there are a variety of programs to support the development of "cleaner" technologies such as combined heat and power (CHP, or cogeneration) and renewable energy technologies.

Energy from renewable energy sources, such as solar, wind, hydro, and biomass, are considered carbon-neutral energy technologies. The production of renewable energy creates no incremental increase in fossil fuel consumption and CO_2 emissions. Electricity and thermal energy production from all renewable resources, except biomass, produces no incremental increase in air pollutants such as nitrogen oxides, sulfur oxides, particulate matter, and carbon monoxide.

There are many more opportunities for the development of cleaner electricity and thermal energy technologies called "recycled" energy. A process using fossil fuels to produce an energy service may have residual energy waste streams that may be recycled into useful energy services. Recycled energy methods would capture energy from sources that would otherwise be unused and convert it to electricity or useful thermal energy. Recycled energy produces no or little increase in fossil fuel consumption and pollutant emissions. Examples of energy recycling methods include industrial gasification technologies to increase energy recovery, as well as less traditional CHP technologies, and the use of energy that is typically discarded from pressure release vents or from the burning and flaring of waste streams. These energy recovery technologies have the ability to reduce costs for power generation.

This report is a preliminary study of the potential contribution of this "new" generation of clean recycled energy supply technologies to the power supply of the United States. For each of the technologies this report provides a short technical description, as well as an estimate of the potential for application in the U.S., estimated investment and operation costs, as well as impact on air pollutant emission reductions. The report summarizes the potential magnitude of the benefits of these new technologies. The report does not yet provide a robust cost-benefit analysis. It is stressed that the report provides a preliminary assessment to help focus future efforts by the federal government to further investigate the opportunities offered by new clean power generation technologies, as well as initiate

policies to support further development and uptake of clean power generation technologies.

The preliminary study was funded by the U.S. Environmental Protection Agency's Office of Atmospheric Programs to evaluate the opportunities offered by less traditional new clean recycled power technologies. The specific intent is to determine whether these less "traditional" technologies have sufficient market potential to warrant the development of what might be termed a "clean energy technology initiative," or a new clean energy supply-side initiative that might complement the many energy efficiency programs now offered on the demand side. This report is a preliminary analysis of the potential contribution of a selection of clean power generation technologies. The report is not exhaustive, and neither is the number of technologies included in the report.

The study identified 19 diverse technologies. The technologies vary from small, distributed power systems on farms to large integrated gasifiers at petroleum refineries. The characteristics of the technologies and potential users vary widely. Hence, the technologies may face very different barriers and opportunities for implementation. This report does not endorse any particular technology. Instead it tries to provide an unbiased (preliminary) assessment of the potential contribution of each technology to the nation's future power supply.

The preliminary results indicate that there is a technical potential of nearly 100,000 megawatts (MW) of untapped electrical capacity. This electrical capacity is capable of producing 742 terawatt-hours (TWh) of electricity, saving an estimated 19 percent of current U.S. electricity consumption. The resulting energy savings from this alternative electricity generation, about 7.8 EJ (7.4 quadrillion Btus (Quads)) of primary energy, are anticipated to reduce carbon dioxide emissions (CO_2) by nearly 400 million metric tons along with 630,000 metric tons of nitrogen oxides (NOx) 1.8 million metric tons of sulfur dioxide (SO_2), and 9 metric tons of mercury (Hg) emissions.

Table 1 is a summary of the technical potential for electricity generation for each technology. The potentials in terms of capacity (MW), electricity production (TWh/year), and primary energy savings are given. The technologies generate electricity from energy sources that would otherwise be dissipated to the environment or abated at an environmental and financial cost. Hence the electricity generated avoids the emissions production from grid electricity. The avoided emissions are presented in Table 1.

Further research to confirm the potential energy savings and to provide a credible cost-benefit analysis are recommended to improve the estimates and to select the most promising opportunities. For example, a number of the technologies also provide thermal benefits in the form of steam or heat in addition to the generated electricity. Including these and other benefits in the assessment would undoubtedly improve the assessment of cost-effectiveness. Also, as the technologies have very different characteristics and potential barriers to implementation, further research is recommended to better characterize and evaluate opportunities for an effective and efficient policy to support further development and uptake of the clean power technologies identified in the report.

The report reports in metric units, unless specified otherwise. For comparison, British units are given as well. Note that in the following technology descriptions the capital cost represents the estimated installed turnkey cost in $/kW electric capacity. Operating costs are non-fuel operating costs in $/kWh.

Table 1. Summary of Clean Energy Technologies Potential. Emission reduction is expressed in metric tons. Primary energy is expressed as higher heating value.

Technology	Potential	Electricity Production	Primary Energy Savings		Emission Reduction			
					CO2	NOx	SOx	Hg
	MW	TWh/year	PJ/year	TBtu/year	MtCO2	metric ton	metric ton	metric ton
Back-Pressure Turbine - District Heating	290	1.6	18.7	17.7	0.94	1656	3978	0.02
Back-Pressure Turbine - Industry	2100	14.7	73.2	69.4	3.64	15266	3978	0.18
Natural Gas Pressure Recovery Turbines	3800	20.9	245.1	232.3	12.27	21705	52130	0.25
Pressure Power recovery	239	2.0	23.8	22.6	1.19	2110	5067	0.02
Organic Rankine Cycle	750	4.9	57.2	54.2	2.86	5063	12159	0.06
Flare Gas Recovery	260	2.2	25.9	24.6	1.30	2295	5512	0.03
Advanced Cogeneration - Iron & Steel	355	3.0	35.4	33.5	1.77	3134	7526	0.04
Steam Injected Gasturbine (Cheng Cycle)	1938	16.5	193.2	183.1	9.67	10384	41088	0.20
Gasturbine Process Heater	44000	365.2	4282.1	4058.8	214.37	379266	910900	4.41
Gas Turbine - Drying	1900	10.5	123.6	117.2	6.19	10947	26292	0.13
Fuels Cells in the Chlorine-Alkaline Industry	600	5.1	59.8	56.7	2.99	5296	12721	0.06
Black Liquor Gasification	6050	51.4	603.0	571.5	30.19	53406	128267	0.62
Residue Gasification - Petroleum Refining	15960	135.7	1590.7	1507.7	79.63	140885	338370	1.64
Residue Gasification - Other Industries	1080	5.5	64.6	61.2	3.23	5720	13738	0.07
EPSI - VOC Control	13500	79.2	85.2	80.7	4.07	-3953	195860	0.96
Anaerobic Digestion - Agriculture	168	1.4	16.3	15.5	0.82	993	3478	0.02
Anaerobic Digestion - Municipal Wastewater	872	7.2	83.8	79.5	4.20	5091	17835	0.09
Anaerobic Digestion- Industrial Wastewater	34	0.3	3.3	3.1	0.16	199	695	0.00
Landfill Gas Recovery	1800	14.9	175.2	166.0	8.77	10637	37264	0.18
Total	**95,696**	**742**	**7,760**	**7,355**	**388**	**670,099**	**1,816,860**	**8.95**
Reduction (share of 2002 U.S. totals)		**19.4%**			**17.3%**	**16.8%**	**19.0%**	**20.1%**

2. District Heating – Back-Pressure Power Recovery

District Heating is an established, mature technology, with several large steam systems having been installed in the latter half of the nineteenth century. The principle of district heat systems is that a central plant produces steam or high-pressure hot water for distribution to commercial and large residential customers. As a result of lower capital and energy costs, modern district heating systems use high-pressure hot water almost exclusively. Older systems continue to use steam, and are largely locked into this distribution method because hot water systems require a new set of distribution pipes, and cannot run the existing steam powered absorption chillers. A typical steam based system starts with some form of cogeneration of steam and electricity, with the resulting steam at 50 to 200 pounds per square inch gauge (psig) (0.4-1.4 bar). This steam then flows through the distribution system to locations up to 3 miles away. When the steam enters the building, the pressure is reduced to 10-15 psig (70-100 mbar) to minimize the stresses on the building's internal system. Once the heat has been extracted, the condensate is returned to the steam generating plant. Typically, the pressure reduction at the building is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop between 150 (1 bar) and 15 psig (100 mbar). This energy could be recovered by using a micro scale back-pressure steam turbine. Several manufactures produce these turbine sets, such as Turbosteam and Dresser-Rand (see Table 2 for a summary).

Table 2. Backpressure Steam Turbine Generator Characteristics

Turbine Name	**Capital Cost**	**Maintenance Cost[a]**	**Energy Flow[b]**	**Power Out**	**Conversion Efficiency[c]**
	($/kW)	($/kW)	(MBtu/h)	(kW)	(%)
Trigen BP-50	660	60	3.2	50	46%
Trigen BP-100	540	30	6.3	100	47%
Trigen BP-150	440	20	9.6	150	47%

Source: Turbosteam, based on 2000 data; Casten

a. Based on a maintenance cost of $3000/yr (Turbosteam, 2000 data)
b. Multiply by 1.055 to express the energy flow rate in SI units (GJ/hour).
c. The percent of theoretically recoverable power in an isentropic turbine that actually recovered as mechanical power.

Developing a high quality characterization of all existing district steam systems in the US would require a significant effort. The Energy Information Administration (EIA) of the US Department of Energy undertook one detailed survey in 1993. The 1998 Commercial Buildings Energy Consumption Survey (CBECS) (EIA, 1998), found district heat consumption by all commercial buildings to be 533 TBtu (109,000 buildings and 5,606 million ft^2 (521 Million m^2)), equivalent to 562 PJ. The majority of this consumption was by buildings in climate zones of 4,000 to 7,000 heating degree-days. Within the group, the largest estimated consumers of district heat included colleges and universities, hospitals, and industrial buildings.

Based on the two EIA surveys, the data suggest that annual district heat production in the U.S. is roughly 530 PJ (500 TBtu), the majority of which (90%) is steam-based systems.

The share of district heat applicable for the installation of micro-turbine technology is estimated at 30% (due to heat load variation and location limitations), and flow control losses are estimated at 10%. Based on these assumptions and a turbine efficiency of 46% the total potential in district heating systems is estimated at 1.5 to 1.6 TWh.

Another substantial area for energy recovery that is not yet included in these estimates is the recovery of recycled energy in the process of reducing high-pressure steam in the boiler to medium pressure steam for distribution. Although the pressure ratios are smaller, the economics is at least as favorable as at the customer site because of higher steam flows and capacity factors (Casten, 2004).

Technical potential: 290 MW

Running time: 5500 hours/year

Investment costs: 600 $/kWe ($300 to 2,000 / kWe)

Operation costs: 0.011 $/kWh

References

Casten, S. Turbosteam. 2004. Personal Communication.

Energy Information Administration, U.S. Department of Energy, 1993. *Assessment of Energy Use in Multibuilding Facilities.*

Energy Information Administration, U.S. Department of Energy, 1998. *A Look at Commercial Buildings In 1995: Characteristics, Energy Consumption, And Energy Expenditures.*

Turbosteam, 2004. http://www.turbosteam.com (accessed in Aug. 2004).

3. Industry – Back-Pressure Power Recovery

Industry consumed at least 3,635 TBtu (3.8 EJ) of fuels in 1998 to generate steam. The steam is generated at high pressures, but often the pressure is reduced to allow the steam to be used by different processes. Industrial steam distribution pressures are higher than district energy applications. Steam is generated at a few bar while pressure is reduced for distribution (high pressure distribution pressures of 800 psig (5.5 bar) are not uncommon). This steam then flows through the distribution system within the plant. The pressure is typically reduced to 50 to 200 psig (0.4 – 1.4 bar) and even as low as 10-15 psig (70-100 mbar) for small space heating applications. Once the heat has been extracted, the condensate is often returned to the steam generating plant. Typically, the pressure reduction is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop. This energy could be recovered by using a micro scale back-pressure steam turbine. Several manufactures produce these turbine sets, such as Turbosteam and Dresser-Rand (see Table 3 for a summary).

Table 3. Backpressure Steam Turbine Generator Characteristics

Turbine Name	**Capital Cost**	**Maintenance Cost[a]**	**Energy Flow[b]**	**Power Out**	**Conversion Efficiency[c,d]**
	($/kW)	($/kW)	(MBtu/h)	(kW)	(%)
BP-50	660	60	3.2	50	46%
BP-100	540	30	6.3	100	47%
BP-150	440	20	9.6	150	47%

Source: Turbosteam, based on 2000 data; Casten

a. Based on a maintenance cost of $3000/yr (Turbosteam, 2000 data).

b. Multiply by 1.055 to express the energy flow rate in SI units (GJ/hour).

c. Based on a maintenance cost of $3000/yr (Turbosteam, 2000 data)

d. The percent of theoretically recoverable power in an isentropic turbine that actually recovered as mechanical power.

e. Electricity output over total energy into the turbine (including energy that goes on to heat the building). As a result, this efficiency does not reflect losses in steam generation or distribution.

The potential for application in industry is difficult to estimate as no data is collected on the use of steam (e.g. pressure) in industrial facilities. Applications of this technology have been commercially demonstrated for campus facilities (see Section 2), pulp & paper, food, lumber, steel, petroleum, chemical, and auto manufacturing industries among others. Based on industries that typically use low-pressure process steam, the technical potential for application of this technology is estimated at 40% of total steam demand in industry (Einstein et al., 2001). We estimate that 1450 TBtu fuel (1530 PJ) is used to generate 1190 TBtu (1255 PJ) steam (82% efficiency, HHV), of which about 110 TBtu (116 PJ) is already generated through cogeneration (based on MECS 1998 data).

Based on the production of 13.5 kWh/MBtu steam (12.8 kWh/GJ; Casten and O'Brien, 2003), and the above steam production, the technical potential for power generation is estimated at 14.7 TWh, using an additional 94 TBtu (99 PJ) of fuel to make up for enthalpy losses in the steam.

The actual power generation on a site will vary depending on steam pressures for steam generation and actual use in the process. It is hard to make a more accurate estimate without further data on steam pressures in industrial steam systems.

Technical potential:	2100 MW
Running time:	7000 hours/year (mix of two-shift plants and continuous operations)
Investment costs:	600 $/kWe ($300 to 2,000 / kWe)
Operation costs:	0.011 $/kWh

References

Casten, S. Turbosteam. 2004. Personal Communication.

Casten, S. and T. O'Brien. 2003. Free Electricity from Steam Turbine-Generators: A System-level Economic Analysis. *Cogeneration and Competitive Power Journal*, Vol. 18., No. 1, Winter 2003, pp. 7-25.

Einstein, D., E. Worrell and M. Khrushch. 2001. Steam Systems in Industry: Energy Use and Energy Efficiency Improvement Potentials. *Proc. 2001 ACEEE Summer Study on Energy Efficiency in Industry – Volume 1*, Tarrytown, NY, July 24-27th, 2001, pp. 535-548.

Turbosteam, 2004. http://www.turbosteam.com.

4. Natural gas Pressure Recovery Turbines

In 1999, the U.S. consumed roughly $610 \cdot 10^9$ m^3 (22 Tcf) of natural gas (EIA, 2000). The transport of natural gas in the U.S. accounts for roughly 3.4% of U.S. natural gas consumption. While it is necessary to transport natural gas at high pressures, end-users require gas delivery at only a fraction of main pipeline pressure. Pressure is generally reduced with a regulator, a valve that controls outlet pressure. Expansion turbines can replace regulators. These turbines offer a way to capture some of the energy contained in high-pressure gas by harnessing the energy released as gas expands to low pressure, thus generating electricity. Expansion turbines use the pressure drop when natural gas from high-pressure pipelines is decompressed for local networks to generate power. Expansion turbines (also known as generator loaded expanders) actually serve as a form of power recovery, utilizing otherwise unused pressure in the natural gas grid. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. The drop in pressure in the expansion cycle causes a drop in temperature. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below –15°C (5°F). In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. Expansion necessitates heating the gas just before or after expansion. The heating is generally performed with either a combined heat and power (CHP) unit, or a nearby source of waste heat. We focus on locations with sufficient low-temperature waste heat available to preheat the gas, such as power stations (sites where much natural gas is consumed). Also, industrial sites such as steel mills have opportunities to recycle energy economically because of easier electrical connections and heat rejection (Casten, 2004). Modern expansion turbines are found at various sites in Europe and Japan.

Lehman and Worrell (2001) studied the potential in the U.S. and found that expansion turbines have the potential to generate a theoretical maximum of 21 TWh in industrial and utility settings, recovering 11% of natural gas transport energy as electricity.

Technical potential: 3.8 GW

Running time: 5500 hours/year

Investment costs: $2000/kWe

Operation costs: 0.009 $/kWh

References

Energy Information Administration, 2000. "Natural Gas Annual 1999," Energy Information Administration, Washington, D.C.

Lehman B. and E. Worrell. 2001. "Electricity Production from Natural Gas Pressure Recovery Using Expansion Turbines," *Proc. 2001 ACEEE Summer Study on Energy Efficiency in Industry – Volume 2*, Tarrytown, NY, July 24-27th, 2001, pp. 43-54.

5. Pressure Power Recovery

Various processes run at elevated pressures, enabling the opportunity for power recovery from the pressure in the flue gas. The major current application for power recovery in the petroleum refining industry is the fluid catalytic cracker (FCC). However, power recovery can also be applied to hydrocrackers (petroleum refining), dual-pressure nitric acid plants (chemical industry) and pressurized blast furnaces (iron and steel industry).

Gas holders are another simple and cost effective technology. The volume of gas on site changes rapidly several times per hour. Boilers and steam turbines cannot change production levels rapidly enough to capture the surges, requiring the gas to be flared. Gas holders are big bags supported by a large steel cylinder and can absorb the rapid gas volume changes, then average out boiler fired gas and eliminate flares.

Refining. Power recovery applications for FCC are characterized by high volumes of high temperature gases at relatively low pressures, while operating continuously over long periods of time between maintenance stops (> 32,000 hours). The turbine is used to drive the FCC compressor or for to generate (additional) power (Worrell and Galitsky, 2005). There is wide and long-term experience with power recovery turbines for FCC applications. Various designs are marketed, and newer designs tend to be more efficient in power recovery. Many refineries in the US and around the world have installed recovery turbines. Valero has recently upgraded the turbo expanders at its Houston and Corpus Christi (Texas) and Wilmington (California) refineries. Valero's Houston Refinery replaced an older power recovery turbine to enable increased blower capacity to allow an expansion of the FCC. At the Houston refinery the rerating of the FCC power recovery train led to power savings of 22 MW (Valero, 2003), and will export additional power (up to 4 MW) to the grid.

Power recovery turbines can also be applied at hydrocrackers. Power can be recovered from the pressure difference between the reactor and fractionation stages of the process. In 1993 the Total refinery in Vlissingen, The Netherlands, installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker (45,653 barrel/calendar day). The cracker operates at 160 bar. The power recovery turbine produces about 7.3 GWh/year.

Based on the installation at Valero we estimate the total potential for power export in all U.S. refineries at 170 MW. Our analysis indicates that 50% of the potential FCC capacity can install power recovery turbines cost-effectively. This will produce 722 GWh of power annually (8500 hours/year). Based on the installed hydrocracker capacity of $1.47 \cdot 10^6$ barrels/day, we estimate the additional potential for power recovery for hydrocrackers at 29 MW, producing 247 GWh/year.

Chemicals. Nitric acid is produced through the controlled combustion of ammonia. The modern process variant is the dual-pressure process, allowing power recovery between the two reactors. Also, the single-stage high-pressure process allows for power recovery. The recovered power can be used to power the compressors or for power generation. The

U.S. chemical industry produces about 7 million metric tons (Mt) of nitric acid per year at multiple locations. Expanders can also be used in the production of ethylene oxide. The expanders are often used to drive the compressor. Hence, we assume that no additional power is generated, although the expander may reduce the need for a steam turbine or electrically driven compressor, potentially reducing electricity use onsite of the chemical plant.

Iron & Steel. Top pressure recovery turbines are used to recover the pressure in the blast furnace.[1] Although the pressure difference is low, the large gas volumes make the recovery economically feasible. The pressure difference is used to produce 15-40 kWh/t hot metal (Stelco, 1993). Turbines are installed at blast furnaces worldwide, especially in areas where electricity prices are relatively high (e.g. Western Europe, Japan). The standard turbine has a wet gas cleanup system. The top gas pressure in the U.S. is generally too low for economic power recovery. A few large blast furnaces (representing about 11 Mt of production) have sufficiently high pressure (Worrell et al., 1999). We estimate the technical potential at 325 GWh, or about 40 MW capacity.

Technical potential: 239 MW

Running time: 8500 hours/year

Investment costs: 1500 $/kWe (estimate)

Operation costs: 0.01 $/kWh (estimate)

References

Stelco, 1993. Present and Future Use of Energy in the Canadian Steel Industry, Ottawa, Canada: CANMET.

Valero, 2003. Valero Energy Corporation Tour Guide Book Houston Refinery. Distributed at the Texas Technology Showcase 2003, Houston, March 17-19, 2003.

Worrell, E., N. Martin, L. Price. 1999. Energy Efficiency and Carbon Emissions Reduction Opportunities in the U.S. Iron and Steel Sector. Berkeley, CA: Lawrence Berkeley National Laboratory, July 1999 (LBNL-41724).

Worrell, E. and C. Galitsky. 2005. Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR® Guide for Energy and Plant Managers. Berkeley, CA: Lawrence Berkeley National Laboratory.

[1] Top pressure recovery turbines (dry type) use a dry gas clean up system that raises the turbine inlet temperature, increasing the power recovery by about 25-30% (Stelco, 1993). However, the system is more expensive, estimated at 28 US$/t hot metal. Due to the high costs, we assume that this system will not be implemented on existing blast furnaces in the U.S. in the near term.

6. Organic Rankine Cycle

Organic Rankine Cycle (ORC) is the same process as a steam turbine system with the driving fluid being an organic fluid instead of steam. The standard Rankine Cycle requires superheated steam above 600°C. ORC can work with lower temperature fluids in the range of 100°C to 400°C. Lower temperature operation uses lower quality heat, often residual, that would otherwise be wasted to generate electricity. The efficiency is around 10-20% depending on the temperature of the fluid. Fluids used in ORC are CFCs, Freon, isopentane and ammonia. The range for heat recovery capacities of ORC turbines is 400 to 1500 kW. A proposed large ORC project in The Netherlands had a simple payback of 6.5 years and capital costs of about $950 per kW.

One estimate of current EU market adoption of ORC is 2 – 5 MWe with an expected market potential of 500 MW in 2010 in the EU (for the original 12 member states only). A study in Germany estimated the technical potential of ORC at approximately 500 MWe in German refineries, chemical, iron and steel, non-metallic minerals industries. Based on fuel use by these industries in Europe (EU-12), Germany and the U.S. we estimate the technical potential at 3000 MW. Based on a penetration rate of 25%, the total potential in the U.S. is estimated at 750 MW.

Technical potential: 750 MW

Running time: 6500 hours/year

Investment costs: $2000/kWe

Operation costs: 0.01 $/kWh (estimate)

References

Blok, K., J. de Beer and C. Geuzendam. 1999. Nederlandse R&D-opties voor verbetering van de energie-efficiëntie (Dutch R&D Options for Improvement of the Energy Efficiency, in Dutch), Dept. of Science, Technology & Society, Utrecht University, The Netherlands.

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7. Flare Gas Recovery

In oil and gas production methane-containing gases are vented and flared throughout the production cycle. In natural gas production methane is vented and leaking from storage facilities and pipelines. In oil production, methane is vented from oil tanks and may leak from refineries. Furthermore, oil refineries flare methane and hydrocarbon containing gases. Flares are used for both background and upset (emergency) use. In all cases the methane can be recovered and used for local power production. The recovery and use for power generation will not only offset power generation but also reduce methane emissions, a potent greenhouse gas, leading to double benefits. Companies like BP have shown that it is possible to reduce the leaks and recover methane from oil and gas production facilities at a profit.

The US EPA estimates total methane emissions at 2834 million Nm^3 (100,048 Million ft^3) from natural gas systems and 82 million Nm^3 (2,885 Million ft^3) from refineries in 2000 (EPA, 2002). Using a calorific value of 37.1 MJ/Nm^3 (995 Btu/ft^3), this gives a total CH_4-energy content of 108 PJ (102 TBtu). Methane emissions from natural gas systems are due to leakage from storage and in pipelines. Emissions from oil systems are mainly vents from oil tanks. For this analysis we assume that 25% of the emissions are recoverable for power generation. Furthermore, we assume that the gas recovered from natural gas systems is combusted in micro-turbines with an efficiency of 28% (LHV).

Flare gas recovery (or zero flaring) is a strategy evolving from the need to improve environmental performance. Generally, conventional flaring practice has been to operate at some flow greater than the manufacturer's minimum flow rate to avoid damage to the flare (Miles, 2001). Typically, flared gas consists of background flaring (including planned intermittent and planned continuous flaring) and upset-blowdown flaring. In offshore flaring, background flaring can be as much as 50% of all flared gases (Miles, 2001). In refineries, background flaring will generally be less than 50%, depending on practices in the individual refinery. Reduction of flaring can be achieved by improved recovery systems, including installing recovery compressors. This technology is commercially available. For example, an Arkansas refinery recently installed a new flare gas recovery system to reduce emissions. New compressors and liquid-seals have been installed, and the two flare gas recovery systems have reduced flaring to near-zero levels (Fisher and Brennan, 2002). A plant-wide assessment of the Equilon refinery in Martinez (now fully owned by Shell) highlighted the potential for flare gas recovery. The refinery will install new recovery compressors to reduce flaring.

Flared gas contains on average 25% methane and 35% VOCs. Standard engineering assessments suggest nearly all is combustible. Based on typical emissions of ChevronTexaco refinery in Richmond, CA total amount of HC flared is 0.0038 kg HC/bbl-processed. Based on national input of 5,514 Million bbl, the total amount of combustibles in flared gas is estimated at $20.9 \cdot 10^3$ metric tons. For ease of calculation we assume an average heating value of 41.9 GJ/ton. Hence total amount of recoverable fuels would be 878 TJ (0.83 TBtu) (2000). Refinery flare gas is combusted in a standard industrial cogeneration unit with an efficiency of 36% (LHV).

Technical potential: 260 MW

Running time: 8500 hours/year (98% availability)

Investment costs: 1400 $/kWe

Operation costs: 0.015 $/kWh

References

EPA. 2002. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2000. Washington, DC: U.S. Environmental Protection Agency

Fisher, P.W. and D. Brennan. 2002. Minimize Flaring with Flare Gas Recovery. *Hydrocarbon Processing* 6 **81** pp.83-85 (June 2002).

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Miles, J., 2001. Zero Flaring can Achieve Operational Environmental Benefits. *Oil & Gas Journal*, July 23rd, 2001 pp.72-75.

8. Advanced Cogeneration – Iron & Steel Industry

All plants and sites that need electricity and heat (i.e. steam) in the steel industry are excellent candidates for cogeneration. Conventional cogeneration uses a steam boiler and steam turbine (back pressure turbine) to generate electricity. Steam systems generally have a low efficiency and high investment costs. Current steam turbine systems use the waste fuels, e.g. at Inland Steel and US Steel Gary Works. Modern cogeneration units are gas turbine based, using either a simple cycle system (gas turbine with waste heat recovery boiler), or a combined cycle integrating a gas turbine with a steam cycle for larger systems.

Integrated steel plants produce significant levels of off-gases (coke oven gas, blast furnace gas, and basic oxygen furnace-gas). Specially adapted turbines can burn these low calorific value gases at electrical generation efficiencies of 45% (LHV) but internal compressor loads reduce these efficiencies to 33% (Mitsubishi, 1993). Mitsubishi Heavy Industries has developed such a turbine and it is now used in several integrated steel plants around the world, e.g. Kawasaki Chiba Works (Japan) (Takano et al., 1989) and Corus (IJmuiden, The Netherlands) (Anon., 1997). These systems have low NOx emissions (20 ppm) (Mitsubishi, 1993).

Our research indicates that steel production facilities that have ready access to coke oven gas (55% of integrated plants in the U.S.) can re-power their generating systems with a combination off-gas turbine/steam turbine system. Currently, almost 7 TWh of electricity is generated by the iron and steel industry, of which 72% by steam turbines (AISI, 1997; EIA, 1997). Use of combined cycles would result in an increase in electricity generation of 3.0 TWh. Investments for the turbine systems are $1090/kWe (Anon.,1997).

Technical potential: 355 MW

Running time: 8500 hours/year

Investment costs: 1090 $/kWe

Operation costs: 0.004$/kWh

References

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9. Cheng Cycle or Steam Injected Gas Turbine

This type of turbine uses the exhaust heat from a combustion turbine to turn water into high pressure steam. This steam is then fed back into the combustion chamber to mix with the combustion gas. This technology is also known as a steam injected gas turbine (STIG). The advantages of this system are (Willis and Scott 2000):

- Added mass flow of steam through turbine increases power by about 33%;
- Simplifies the machinery involved by eliminating the additional turbine and equipment used in combined cycle gas turbine;
- Steam is cool compared to combustion gasses helping to cool the turbine interior;
- Reaches full output more quickly than combined-cycle unit;
- Applicable for DER applications due to smaller equipment size.

Additional advantages are that the amounts of power and thermal energy produced by a turbine can be adjusted to meet current power and thermal energy (steam) loads. If steam loads are reduced then the steam can be used for power generation, increasing output and efficiency (Ganapathy 2003).

Drawbacks include the additional complexity of the turbine's design. Additional attention to the details of the turbine's design and materials are needed during the design phase. This may result in a higher capital cost for the turbine compared to traditional models.

Combined cycles (combining a gas turbine and a back-pressure steam turbine) offer flexibility for power and steam production at larger sites, and potentially at smaller sites as well. STIG can absorb excess steam, e.g. due to seasonal reduced heating needs, to boost power production by injecting the steam in the turbine. The size of typical STIGs starts around 5 MWe. STIGs are found in various industries and applications, especially in Japan and Europe, as well as in the U.S. International Power Technology (CA), for example, installed a STIG at Sunkist Growers in Ontario (CA) in 1985.

According to the Onsite Sycom study of 2000, the total remaining potential for "normal" cogeneration in sectors with large variations in steam demand is roughly 31,000 MW in industry, and 8690 MW in large commercial buildings (over 5 MWe) (Onsite 2000, Onsite 2000b). Our research suggests that perhaps 50% of the sites can have a STIG. For this analysis, we further assume that 50% of the time the unit can operate in STIG mode (i.e. steam is not used for other purposes).

A STIG produces about 25-33% extra power than a standard turbine. In the calculations we assume 25% additional power generation for a STIG. The net additional power generation (compared to a standard CHP unit) for STIGs is estimated at 1938 MW for industry and 543 MW for commercial buildings (on top of the CHP potential with traditional CHP units). The total technical potential of STIG-based CHP is provided below. However, in the calculations of the energy and emission benefits we only account for the *additional* power production from the STIG compared to traditional CHP units.

Technical potential:	7750 MW for industry 2172 MW for commercial buildings	
Running time:	Industry	8500 hours/yr.
	Commercial buildings	4000 hours/yr.

Investment costs: $1000 per kW (Goldstein et al. 2003)

Operation costs: $0.006 per kWh (Goldstein et al. 2003)

References

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10. Gasturbine Process heater

Modern turbine designs allow higher inlet and outlet temperatures. The makes it possible to use the flue gas of the turbine to heat a reactor in the chemical and petroleum refining industries. One option is the so-called *"re-powering"* option. In this option, the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen, and can thus be used as combustion air for the furnaces. The gas turbine can deliver up to 20% of the furnace heat. The re-powering option is used by a few plants around the world. Another option, with a larger CHP potential and associated energy savings, is *"high-temperature CHP."* In this case, the flue gases of a CHP plant are used to heat the input of a furnace. Zollar (2002) discusses various applications in the chemical and refinery industries. The study found a total potential of 44 GW. The major candidate processes are atmospheric distillation, coking and hydrotreating in petroleum refineries and ethylene and ammonia manufacture in the chemical industry. The simple payback period is estimated at 3 to 5 years, depending on the electricity costs. The additional investments compared to a traditional furnace were estimated at 630 $/kW (1997) (Worrell et al., 1997; Onsite, 2000). Excessive costs for adaptation of an existing furnace are additional to the given investment costs. This cycle has nearly 100% efficiency since the fuel is either converted into power or waste heat, all of which is used in the boiler. This greatly influences power generation costs and reduces sensitivity to fuel price (Casten, 2004).

Technical potential:	44,000 MW
Running time:	8300 hours/year (95% availability)
Investment costs:	$630/kWe (for large gas turbines)
Operation costs:	$0.004/kWh

References

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11. Gas Turbine – Drying

CHP Integration allows increased use of CHP in industry by using the heat in more efficient ways. This can be done by using the heat as a process input for drying. The fluegas of a turbine can often be used directly in a drier. This option has been used successfully for the drying of minerals as well as food products. Although NOx emissions of gas turbines vary widely, tests in The Netherlands have shown that, depending on the type of gas turbine selected, the flue gases do not negatively affect the drying air and product quality(Buijze, 1998). To allow continuous operation, bypass of the gas turbines makes it possible to maintain the turbine and run the drying process (Buijze, 1998). A cement plant in Rozenburg, The Netherlands, uses a standard industrial gas turbine to generate power and to dry the blast furnace slags used in cement making. The Kambalda nickel mine in Australia uses four gas turbines of 42 MW each to dry nickel concentrate. The mine currently produces around 300,000 tons per year, saving 0.9 GJ/ton (0.77 MBtu/short ton) of concentrate. Another project in The Netherlands demonstrated the use of the flue gases from a gas turbine to dry protein rich cattle feed by-product. The excess flue gas is mixed with air and used directly for the drying process. The project was expected to result in savings of 12% of total onsite fuel consumption with a simple payback period of 2.5 years (under conditions in the Netherlands in 1995) (NOVEM, 1995).

The key assumptions for the calculation of the potential are:
Amount of minerals to be dried: $60 \cdot 10^6$ metric tons (slags, phosphate ore, potash, and others). CHP-capacity is estimated to be around 130 kWh/ton, total capacity around 7.8 TWh. We then assume that 50% of this capacity can apply gas turbine driers. Technical potential is 3.9 TWh. Installed capacity (two shifts) is 0.7 GW

Capacity in food and related industries: estimated energy use is around 210 PJ (200 TBtu) used for drying, equivalent to 6.7 GW of capacity. Assuming 35% efficiency for gas turbine and 50% for heat use, the power generation capacity is 4.7 GW. We assume that 25% of this capacity can apply gas turbines, or 1.2 GW. Assuming two shift operation and 95% availability will result in the production of 6.7 TWh.

Technical potential: 1.9 GW

Running time: 5548 Hours/year (2 shifts, 7 days/week, 95% availability)

Investment costs: $970/kWe (Onsite, 2000), assuming 10 MW turbine on average.

Operation costs: 0.0055 $/kWh

References

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12. Fuels Cells in the Chlorine-Alkaline Industry

Fuel cells generate direct current electricity and heat by combining fuel and oxygen in an electrochemical reaction. This technology avoids the intermediate combustion step and boiling water associated with Rankine cycle technologies, or efficiency losses associated with gas turbine technologies. Fuel to electricity conversion efficiencies can theoretically reach 80-83% for low temperature fuel cell stacks and 73-78% for high temperature stacks. In practice, efficiencies of 50-60% are achieved with hydrogen fuel cells while efficiencies of 42-65% are achievable with natural gas as a fuel (Martin et al., 2000). The main fuel cell types for industrial CHP applications are phosphoric acid (PAFC), molten carbonate (MCFC) and solid oxide (SOFC). Proton exchange membrane (PEM) fuel cells are less suitable for cogeneration as they only produce hot water as byproduct. PAFC efficiencies are limited and the corrosive nature of the process reduces the economic attractiveness of the technology. Hence, MCFC and SOFC offer the most potential for industrial applications.

Although PAFC is the most sold fuel cell system, MCFC and SOFC offer the most potential. Currently, several industrial facilities use MCFCs in Japan (Kirin brewery) and Germany (Michelin rubber processing) (Hoogers, 2003). These demonstration systems still cost around $11,000/kW. Stand-alone SOFCs have achieved an efficiency of 47%, and in combination with a gas turbine in a pressurized system, efficiencies of 53% (LHV) have been achieved (Hoogers, 2003). Unfortunately, the production costs of SOFCs are still high. Dow Chemical and GM will collaborate in the installation of a large-scale proton exchange membrane fuel cell (PEMFC) system (up to 35 MW), using hydrogen produced as a byproduct from chlorine production at Freeport, Texas. The Freeport facility of Dow Chemical is one the largest sites in the country producing about 1.9 Mt of chlorine annually.

The U.S. produces about 12 Mt of chlorine. Based on the typical hydrogen production rate of the chlorine-alkaline electrolysis process, the total hydrogen production is estimated at 37 PJ (35 TBtu). Assuming an efficiency of 52% (Kreutz and Ogden, 2000) total power generation is estimated at 5.3 TWh.

Technical potential:	0.6 GW
Running time:	8500 hours/year (95% availability)
Investment costs:	$1500/kWe. Current costs are around $3000/kWe (Goldstein et al., 2003), but are expected to come down as the volume produced increases.
Operation costs:	0.008 $/kWh

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13. Black Liquor Gasification

In standard integrated Kraft mills, the spent liquor produced from de-lignifying wood chips (called black liquor) is normally burned in a large recovery boiler in which the black liquor combustion is used to recover the chemicals used in the delignification process. Because of the relatively high water content of the black liquor fuel, the efficiency of existing recovery boilers is limited. Gasification allows not only the efficient use of black liquor, but also of other biomass fuels such as bark and felling rests to generate a synthesis gas that after cleaning is combusted in a gas turbine or combined cycle with a high electrical efficiency. This increases the electricity production within the pulp mill. The technology is called black liquor gasification-combined cycle (BLGCC). The black liquor gasifier technology will produce a surplus of energy from the pulp process and opens the possibility to generate several different energy products for external use, i.e. electricity, heat and fuels. Gasifiers can use air or pure oxygen to provide the oxygen needed for the chemical conversions. We assume a (more expensive) oxygen-blown gasifier. The richer synthesis gas produced in an oxygen-blown gasifier allows easier combustion in a gas turbine. Furthermore, the process provides a natural separation of sulfur from sodium is provided that allows for advanced pulping, making it possible to enhance pulp productivity (Larson et al., 2000).

While increased fuel inputs are required for gasification systems, and increased electricity inputs are required (especially for gas compression in the combined cycle system), power efficiencies are much higher, thereby allowing for significant primary energy savings. Based on an electricity production capacity of 1740-1860 kWh/ton, and the performance of a typical Kraft-plant in the Southeastern United States, a plant will be able to export 220-335 kWh/t pulp (Larson et al., 2003). At the 2002 production level of chemical pulp, the U.S. pulp and paper industry could produce around 89.6 TWh of electricity, or double that of the current Tomlinson boiler system, or 50.2 TWh additional to the current power production in the pulp and paper industry.

Technical potential:	6050 MW
Running time:	8500 hours/year (98% availability)
Investment costs:	1070 $/kWe
Operation costs:	0.006$/kWh

References

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14. Residue Gasification – Petroleum Refining

Because of the growing demand for lighter products and increased use of conversion processes to process a 'heavier' crude, refineries will have to manage an increasing stream of heavy bottoms and residues. Gasification of the heavy fractions and coke to produce synthesis gas can help to efficiently remove these by-products. The state-of-the-art gasification processes combine the heavy by-products with oxygen at high temperature in an entrained bed gasifier. The synthesis gas can be used as feedstock for chemical processes, hydrogen production and generation of power in an Integrated Gasifier Combined Cycle (IGCC). Entrained bed IGCC technology was originally developed for refinery applications, but is also used for the gasification of coal. Hence, the major gasification technology developers were oil companies like Shell and Texaco. The technology was first applied by European refineries due to the characteristics of the operations in Europe (e.g., coke was often used onsite). IGCC is used by the Shell refinery in Pernis (The Netherlands) to treat residues from the hydrocracker and other residues to generate 110 MWe of power and 285 metric tons of hydrogen for the refinery. Also, the IPA Falconara refinery (Italy) uses IGCC to treat visbreaker residue to produce 241 MWe of power (Cabooter, 2001). Interest among U.S. refiners has increased, and 3 U.S. refineries currently operate gasifiers, i.e., Motiva (Delaware City, DE), Frontier (El Dorado, KS) and Farmland (Coffeyville, KS). New installations have been announced or are under construction for the Sannazzaro refinery (Agip, Italy), Lake Charles, (Citgo, Louisiana) and Bulwer Island (BP, Australia).

With increasing production of lighter products the coke production at refineries is expected to increase to 105,000 tons/day in 2010 (Gray and Tomlinson, 2000). The net power production of a refinery based IGCC plant is estimated at 38-45%. Marano (2003) estimates net power production at 3,664 kWh/t petroleum coke at an efficiency of 38.2%. The efficiency of an IGCC using heavy fuel oil is expected to be around 40% (Marano, 2003). Based on the 1999 coke production total power production can be 135.7 TWh/year, or 51 TWh over the baseline.

Technical potential: 15,960 MW

Running time: 8500 hours/year (98% availability)

Investment costs: 1780 $/kWe

Operation costs: 0.001$/kWh

References

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Marano, J.J. 2003. Refinery Technology Profiles: Gasification and Supporting Technologies. Report for U.S. Department of Energy, Washington, DC

15. Residue Gasification – Other Industries

Various industries produce low-grade fuels as a by-product of the production process. Currently, these low-grade fuels are combusted in boilers to generate steam or heat, or disposed of through landfilling. Often, this results in relatively less efficient use. Gasification offers opportunities to increase the efficiency of using low-grade fuels. In gasification, the hydrocarbon feedstock is heated in an environment with limited oxygen. The hydrocarbons react to form synthesis gas, a mixture of mainly carbon monoxide and hydrogen. The synthesis gas can be used in more efficient applications like gas turbine-based power generation or as a chemical feedstock. The technology not only allows the efficient use of by-products and wastes, it also allows low-cost gas cleanup (when compared to flue gas treatment). Various industries are pursuing the development of gasification technology, and are at different stages of development. Furthermore, gasification technology can also lead to more efficient and cleaner use of coal, biomass and wastes for power generation. Besides the pulp and paper and petroleum refining industries other industries with sufficient production of by-products that can be gasified are found in the food industry (e.g. bagasse in the sugar industry, nutshells, rice husk). The technology can also be used to process municipal solid waste with a higher efficiency than offered by incineration (e.g. the Thermoselect process developed in Switzerland produces over 700 kWh/t waste), and is seeing commercial application in Japan.

In this description we focus on wastes from the food industry. A bagasse gasifier was installed in 1995 at the HC&S sugar mill on Maui (HI) producing a syngas with a low calorific value (Turn, 1997). The U.S. produces annually about 32 Mt of sugarcane (2001), of which about 30% is bagasse. The bagasse is currently combusted in boilers and used for cogeneration. Gasification will increase the net power export by 110 kWh/t cane (Larson et al., 2001). The technical potential for the cane sugar industry alone is estimated at 3.5 TWh. There are no estimates of the available amount of waste (e.g. nutshells, rice husk) in the other food industry that can be used for gasification. We suggest for this analysis that the technical potential in other industries is equivalent to 2 TWh.

Technical potential: 1,080 MW

Running time: 5100 hours/year (average 7 months/year)

Investment costs: 1600 $/kWe

Operation costs: 0.008$/kWh

References

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16. VOC Control (EPSI)

In many plants VOCs are generated. VOCs contribute to ozone formation and VOC controls are installed by virtually at any source of VOC emissions. In small-scale systems carbon filters can be used to capture VOCs. In large-scale systems, generally regenerative thermal oxidizers (RTO) are used. In a RTO the VOC-containing flue gas (e.g. from a paint booth) is mixed with natural gas to a combustible mixture. The mixture is combusted in the RTO and the VOCs are destroyed.

Environmental and Power Systems International (EPSI) has developed an alternative pollution control technology for handling VOC emissions. The technology has the ability to generate electricity and useful thermal heat with a gas turbine, using the VOC-containing gases enriched with natural gas. The EPSI system is an alternative VOC abatement technology to RTOs with the following advantages over standard RTOs (GTI 2003):

- Shorter initial cold start-up time (5 minutes versus 1 to 8 hours);
- Recoverable heat for use by end-user (RTOs use their heat in the VOC abatement process);
- Electrical power generation;
- Higher combustion temperature (which in combination with high residence time, assures more complete destruction of VOC);
- Smaller equipment footprint;
- Lower major overhaul cost.

Technical potential:	13,500 MW. 60 TWh to 100 TWh (at 30% to 50% market share in 20 years respectively), or 10,000 – 17,000 MW total capacity.
Running time:	5870 hours/year (67% capacity factor)
Investment costs:	Marginal cost of $360 to $4,000 /kW for a 525kWe system compared to a regenerative thermal oxidizer (RTO) VOC abatement system. The lower marginal cost estimate is derived by using a RTO system cost from a RTO end-user and the higher marginal cost estimate is obtained if the RTO manufacturer's system cost is used (GTI 2003). The EPSI cost is from the manufacturer.
Operation costs:	0.01 $/kWh

References

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17. Anaerobic Digestion - Agriculture

Biogas systems are a waste management technique that can provide multiple benefits:

- removal of manure waste;
- reduction of odor;
- reducing disposal truck traffic and costs;
- reduction in spreading disposal costs;
- pathogen control and destruction, and;
- protection of groundwater.

Furthermore biogas digester systems can generate electricity and thermal energy to serve heating and cooling needs while providing financial profits. The byproducts of the digester system also include high-quality compost that can be used for crop fertilizer. Biogas systems are most suitable for farms that handle a large amount of manure as a liquid slurry or semi-solid with little or no bedding added. The type of digester should be matched to the type, design, and manure characteristics of the farm. There are five types of manure collection systems characterized by the solids content: raw, liquid, slurry, semi-solid, or solid (often left in pasture and not suitable). There are three types of digester systems: covered lagoon (used to treat and produce biogas from liquid manure), complete mix digester (heated engineered tanks for scraped and flushed manure), and plug flow (treat scraped *dairy* manure in 11% to 13% solids range). Swine manure does not have enough fiber to treat in plug flow digester. The products of anaerobic digestion are biogas and effluent. The effluent needs to be stored in a suitable sized tank. Recovered gas is 60-80% methane with heating value of 22-30 MJ (600-800 Btu/ft^3) (AgSTAR Handbook). This gas can be used to generate electricity or serve heating and cooling loads.

In January 2003 there were 40 anaerobic digesters operating in the U.S. with another 45 planned or under construction (AgSTAR Digest 2003). AgSTAR estimates that over 2,000 livestock facilities across the United States could cost effectively install biogas recovery systems (AgSTAR Handbook). Based on the average energy production from the 17 farms reporting electricity production from biogas in the AgSTAR Handbook survey an average estimate per farm of 700,000 kWh per year was obtained. This produces an estimate of 1.4 TWh per year for anaerobic digestion from livestock on farms. Digester system cost will vary depending upon the size and layout of the farm, type of animal, type of manure treatment and bedding used, and type of digester system installed, and the end-use application of the biogas (electrical generation or heat production only). Barriers to the adoption of biogas recovery systems include: poor technical and economic perception of digester systems based on initial system failures, and the lack of technical information and expertise.

Technical potential: 168 MW (AgSTAR Handbook)

Running time: 8300 hours/year

Investment costs: $2000 (plug flow digester, AgSTAR Handbook)

Operation costs: $0.03/kWh (AgSTAR Handbook)

References

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18. Anaerobic Digestion - Municipal Wastewater

Wastewater treatment plants release biogas through the decomposition of organic matter. The biogas (mostly methane) can be captured and used to provide energy services either by direct heating or through the generation of electricity. Anaerobic digestion destroys pathogens and this method is used to generate biogas in many treatment plants. Typically the biogas is burned to produce heat to maintain the temperature of the digester process. Excess gas is then flared (Oregon State Energy Office 2004). This process destroys pathogens resulting in cleaner water and more benign solids.

The Madison Municipal Solid Waste District treats 42 million gallons of water every day at the Nine Springs Wastewater Treatment Facility. They have installed two 475 kW generators for $2 million. The savings are $370,000 per year in electricity and $75,000 in gas purchases before O&M costs are considered (Wisconsin's Focus on Energy 2002).

Of all the sites in the U.S. currently capturing biogas released at treatment plants and using it for electricity production there are only three sites that power a fuel cell to make electricity (Oregon State Energy Office 2004). One example of a wastewater treatment fuel cell biogas system is located in Portland Oregon. The facility handles 82 million gallons of wastewater per day. This one 200 kW capacity fuel cell will: cost $1.3 million, produce 1,400,000 kWh per year, saving $60,000 per year (Oregon State Energy Office 2004).

There are 16,400 public wastewater treatment facilities in the US. There are another 23,700 "other" treatment facilities, which includes commercial or industrial facilities that treat their own water (see section 19). These public sites each release about 9.5 10^6 liter/day (2.5 Mgal/day) on average of treated wastewater to the environment (USGS 1995). The non-public treatment facilities will be analyzed in section 19 (see below).

The technical potential is estimated assuming 100% of the public plants generate electricity from biogas and they have the same rate of electrical generation that the Madison facility demonstrated (6.0 kW per million liter/day of waste treated), generating 7.6 TWh per year. This assumes 94% availability (as achieved in Oregon) and that the size of the treatment plant is linearly scalable with the amount of power capacity available from the biogas.

Technical potential: 872 MW

Running time: 8200 hours/year

Investment costs: $2,000 per kW or $120,000 for an average wastewater plant

Operation costs: 0.01 $/kWh (est. from industrial biogas)

References

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19. Anaerobic Digestion - Industrial Wastewater

Industrial wastewater is typically treated by aerobic systems that remove contaminants prior to discharging the water. These aerobic systems have a number of disadvantages including high electricity use by the aeration blowers, production of large amounts of sludge, and reduction of dissolved oxygen in the wastewater which is detrimental to fish and other aquatic life. The decomposition of organic materials without oxygen results in the production of carbon dioxide and methane from the presence of anaerobic bacteria. This gas is called biogas and contains 50% methane (CH_4) and a powerful greenhouse gas (21 times more potent of a greenhouse gas than CO_2). This process is called anaerobic digestion and takes place in an airtight chamber called a digester. Biogas systems are a waste management technique with numerous benefits including: lower water treatment cost, reduction in odor, reduction in material handling and wastewater treatment costs, and protection of local environmental groundwater and other resources. In addition the biogas can be used as a supplemental energy source for thermal energy loads and the generation of electricity.

Any type of biological waste from plant or animals is a potential source of biogas. Some example industries include: pharmaceutical fermentation, pulp and paper wastewaters, fuel ethanol facility, brewery and yeast fermentation wastewater, coal conversion wastewater. Anaerobic digester biogas is comprised of methane (50%-80%), carbon dioxide (20%-50%), and trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen, and hydrogen sulfide. The most widely used technology for anaerobic wastewater treatment is the Upflow Anaerobic Sludge Blanket (UASB) reactor, which was developed in 1980 in The Netherlands. Industrial wastewater is directed up through the UASB reactor, passing through a “blanket” that traps the sludge. Anaerobic bacteria break down the organic compounds in the sludge, producing methane in the process. This type of anaerobic wastewater treatment is currently used predominantly in the paper and food industries, but some industries such as chemical and pharmaceuticals have also used this technology and its use is growing for municipal wastewater treatment. Globally, there are approximately 1500 anaerobic wastewater treatment plants (80 percent are UASBs), of which approximately 150 are in the U.S. (Martin et al. 2000).

The UASB technology is used around the world and the two leading UASB companies, Paques and Biothane, have installed several hundred facilities. Evaluations of anaerobic wastewater treatment facilities in the UK, Netherlands, Canada and U.S. show a wide range of costs and energy savings, with payback periods ranging from 1.4 years to 3.7 years (Martin et al., 2000). Currently, there are approximately 125 anaerobic wastewater treatment facilities in the U.S. There is great potential to increase the number of anaerobic wastewater treatment plants; some countries have 3 to 5 plants per million people, which implies that 750 to 1250 total plants could be installed in the U.S. For our analysis, we estimate that an additional 400 plants could be built by 2015. These plants can be used by a variety of industrial facilities, including papermaking, food processing, chemicals, pharmaceuticals, and distilleries. The market potential varies for these industries from 30 to 40 percent for the paper industry to 100 percent for processing of

sugar, starch, and alcohol based on the size of the mills, types of mills, and their water consumption (Martin et al., 2000).

As of 1995, the last year the government kept track of these data, there were 23,700 non-public wastewater treatment facilities in the U.S. These include commercial and industrial facilities. Release information for these facilities is not available so the average capacity of the units is difficult to determine. A recent study (Martin et al., 2000) estimated the feasible potential for power production by 2015 at 150 GWh, based on a penetration rate of 33%. We assume a 60% penetration rate by 2025. The technical potential is equal to about 450 GWh.

Technical potential: 34 MW

Running time: 8000 Hours/year

Investment costs: $640/kWe (Martin et al., 2000)

Operation costs: 0.0055 $/kWh

Payback period: 0.5 – 1.5 years (Martin et al., 2000)

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20. Landfill Gas

The decomposition of organic materials without oxygen in landfills results in the production of carbon dioxide and methane from the presence of anaerobic bacteria. In a non-controlled landfill, this would generate methane, a powerful greenhouse gas. Therefore, the landfill gas is often collected and flared, in which case the energy is not utilized. However, the gas can also be used for energy generation. The more common uses are: fuel gas for industrial boilers and electricity generation.

At many landfills, however, the gas is not recovered or flared. There are numerous barriers to economically utilizing landfill gas (EIA 1996): fluctuating gas prices, technology prices and performance risks, transportation costs of energy (when transported), air permits and changing regulations, as well as obtaining power contracts

The average size of LFG system is 3 MW with over 95% availability (EIA, 1996). There are 340 landfills, out of 6000, that currently capture landfill gas and turn it into energy. EPA estimates that there over 600 additional sites that could cost effectively capture methane and convert it into energy resources (EPA, LMOP 2004). Using this data 1800 MW of capacity could be obtained by fully utilizing the landfill gas in the U.S.

Direct end use of the gas for process heat and boiler fuel is the most economic use of landfill gas for sites within 1-2 miles (2-3 km). However, these projects accounted for only about 20% of the total energy recovery projects at landfills due in part to the lack of nearby customers for the fuel (Renewable Energy Annual, 1996). Over 70% of the landfill gas energy recovery projects generate electricity and 50% (of the total) use reciprocating engines (Thorneloe et al, 2004). Electricity generation may be provided from reciprocating engines, gas turbines, and fuel cells. Engines are most economical for smaller projects from 1-3 MW and gas turbines for projects over 3 MW.

It's important to match the energy supply source with a nearby demand to increase the financial benefits from the project. The running time will be affected by the choice among the five options for recovering landfill gas and the type, location, and consistency of the demand. The estimated availability is 95% or 8,300 hours per year.

Technical potential: 1800 MW

Running time: 8300 hours/year

Investment costs: $1200/kWe

Operation costs: 0.016 $/kWh

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