APPENDIX A: STAKEHOLDER PRESENTATIONS

Overview of Maine Electric Regulations & Policies Affecting Co-generation

Co-generation Task Force Meeting
August 11, 2009
Presented by: Angela Monroe of MPUC

- **Net Energy Billing (co-generation < 660 kW).** (MPUC rule, Chapter 313). Allows netting of generation against usage, carrying excess generation credit over month-to-month for up to 12 months. No payment for excess generation credit at the end of 12 months. Now allows shared ownership with shared netting of generation against owners usage based on each owners' percent ownership.

  Applies to:
  - *Renewables* -- fuel cells, tidal, solar arrays, wind, geothermal, hydro, biomass, municipal solid waste in conjunction with recycling; or
  - "*Micro-Combined Heat and Power Systems*" -- A system that produces heat and electricity from one fuel input (no restriction on type of fuel) and
    - Generation capacity 1kW – 30kW, fuel system efficiency not less than 80% in production of heat & electricity; or
    - Generation capacity 31kW – 660 kW, fuel system efficiency not less than 65% in production of heat & electricity;
    - May work in combination with supplemental or parallel conventional heating systems;
    - Is manufactured, installed and operated in accordance with applicable government and industry standards; and
    - Is connected to the electric grid and operated in conjunction with the facilities of a T&D utility.

- **Small Generator Aggregations (generation 5 MW or less).** (MRSA 35-A § 3210-A)
  - For all fuel sources, requires standard-offer provider to purchase output at real-time price to keep payment neutral to standard offer provider. Prices are, therefore, not known ahead of time. The T&D to administer purchase & sale. There is an administrative fee for this.
  - For renewable fuel or "efficient combined heat and power system," allows T&D to administer purchase and sale with any competitive electricity provider, not just standard offer provider. Efficient combined heat and power system same definition as "micro-combined heat and power systems" without upper 660 kW limit.
    - Note: the rulemaking for the CEP purchase portion not yet done. Legislation indicates that the rulemaking may include a fee to cover the T&D utilities' cost of administration.

- **Small Power Producer or Cogenerator.** (MRSA 35-A §3305). Allows small power producers or cogenerators to "generate or distribute electricity through his private property solely for his own use, the use of his tenants or the use of, or sale to, his associates in a small power production or cogeneration facility and not for the use of or sale to others without approval or regulation by the commission."

    - "*Co-generator*" means municipality or person that generates electricity and steam or other useful forms of energy that are used for commercial, industrial, heating or cooling purposes; and that is not primarily engaged in the generation or sale of electricity other than that generated at the cogeneration facility.

    - "*Small power producer*" means a municipality or person owning or operating a power production facility that does not exceed 80 MW that depends upon renewable resources for its primary source of energy.

- **Sale and Distribution to Other Entities.** In 2000-653 (Boralex Case) the Commission found that under certain conditions, the distribution and sale of electricity by a generator (regardless of size or fuel type) is a "private," not a "public," sale and therefore does not make the generator a T&D utility or a CEP. The Commission found that factors in this determination include:

    - Whether both generator and customer are on the same or adjacent properties;
    - Whether the generator and customer have a corporate or commercial relationship that goes beyond the sale of electricity;
    - Whether the number of customers served or that could be served is limited;
    - Whether all the power sold comes from the generator as opposed to the grid;
    - Whether there are no sham transactions to create a private character;

    Note: In some cases, this might implicate provisions of MPUC Rule, Chapter 395. Chapter 395 allows private ownership of distribution facilities if the facilities serve only one customer but requires transfer to the T&D utility if more than one customer is to be served. Therefore, an entity seeking to serve more than one customer from a privately-owned distribution facility might need to seek a waiver of those provisions of Chapter 395.

In order to distribute power to a customer (or customers) without meeting the criteria of either 35-A §3305 or the Boralex decision, a generator would need to be licensed by the MPUC as a T&D utility and a CEP. The CEP license is a relatively straight-forward process. Becoming licensed as a T&D utility, however, would require a finding by the MPUC that the incumbent utility was either unable or unwilling to provide service.

- **Renewable Portfolio Standards (RPS)**. (MPUC rule, Chapter 311). For every kWh sold in Maine, 30% is required to come from an "eligible" resource (Type II resource) and starting January 1, 2008, another 1% (increasing 1% each year to the maximum of 10% by 2017) from a "new renewable" resource (Type I resource).

    - *Eligible Type II* resources must either be from an "efficient" resource or from a renewable fuel source;
        - Efficient resource must have been constructed prior to 1997;
        - Renewable resource must not exceed 100 MW and relies on fuel cells, tidal power, solar arrays, wind, geothermal, hydro, biomass, or municipal solid waste in conjunction with recycling.

    - *Eligible Type I* resources must be fueled by a renewable resource (excludes municipal solid waste and requires fish passages for hydro), not exceed more than 100 MW (except wind) and:
        - Have been added to an existing facility after September 1, 2005;
        - Have not operated for at least two consecutive years or was not recognized by the ISO-NE or NMISA as a capacity resource prior to September 1, 2005, and, after September 1, 2005, resumed operation or was recognized by the ISO-NE or NMISA or as a capacity resource; or
        - Have been refurbished after September 1, 2005 and are operating beyond their previous useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

- **Also of Note:**

    - Stand-by rates. Utilities have various rate schedules for customers that self-generate electricity but purchase electricity when their generator is unavailable;

    - Special rate contracts. Utilities often enter discount rate contracts to discourage customers from self-generating. Availability likely to decrease as stranded-costs continue to decline.

Governor's Office of Energy Independence and Security

Combined Heat and Power Stakeholder Group

August 11, 2009

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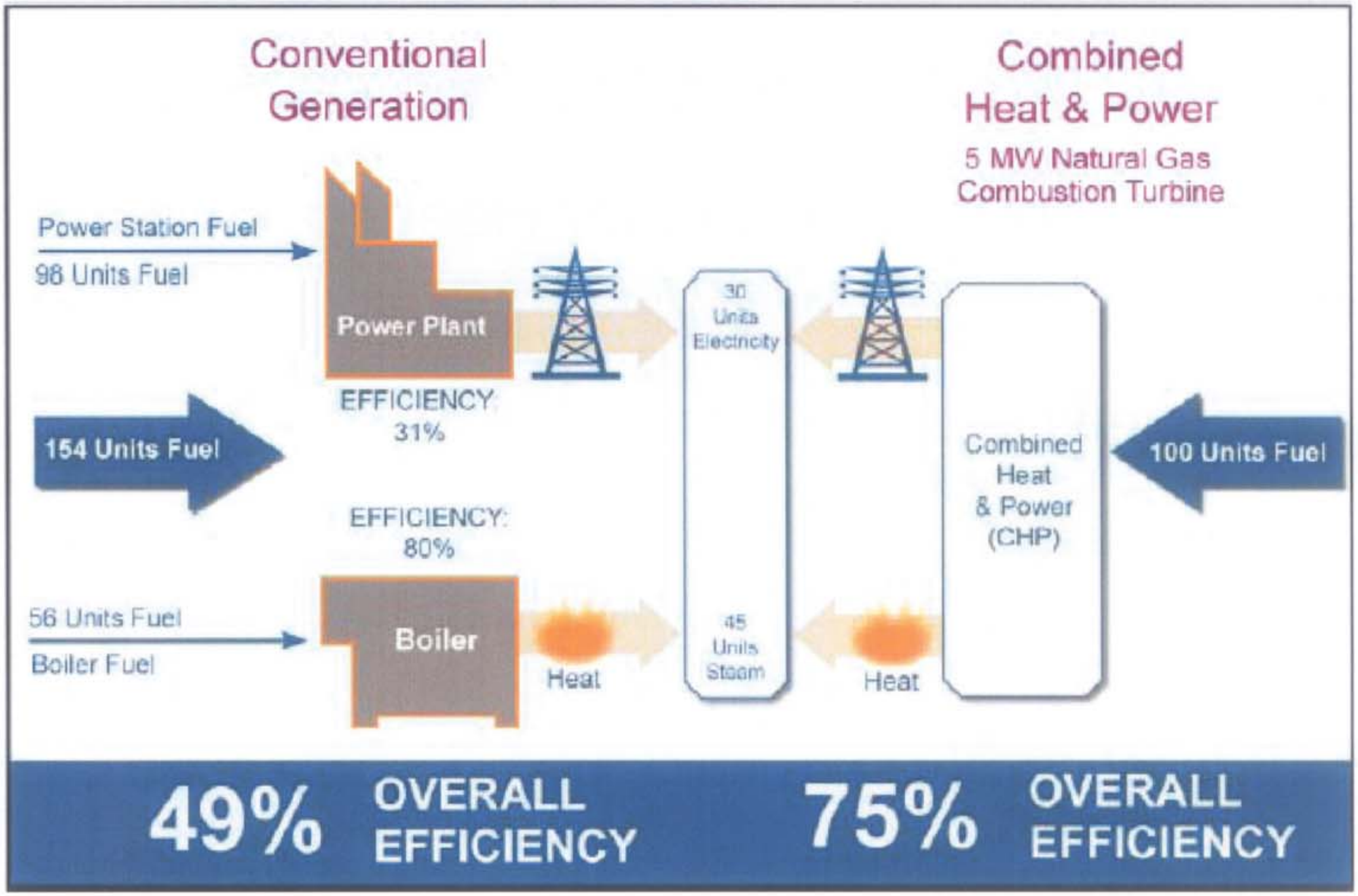
Small Scale Cogeneration

- Applications
- Technologies
- Example Projects
- Comments and Questions

Advantages of Combined Heat and Power (CHP) over Central Power Generating Station



Ref. EPA CHP Partnership

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Small Cogeneration Applications

- Small CHP or CCHP 1 MW and smaller
- Simultaneous Demand for Heating, Cooling and Power
  - Commercial Applications
  - Hospitality
  - Heath Care
  - Education
  - Industry

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Small Cogeneration Technologies

- Reciprocating Engines
- Microturbines
- Fuel Cells
- Micro CHP

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Reciprocating Engines

- Gas and Diesel Engines
- Diesel Engines limited to Emergency Standby Power due to air emissions
- Generally higher maintenance cost than gas turbines
- Available in size 10kW to over 5 MW

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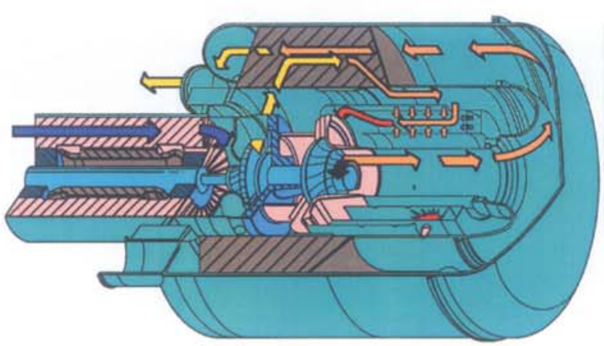
Microturbines

- Compact Gas Turbine
- NG, biogas, distillate oil, propane
- Extremely low emissions
- Modular can be ganged with absorption chiller for CCHP



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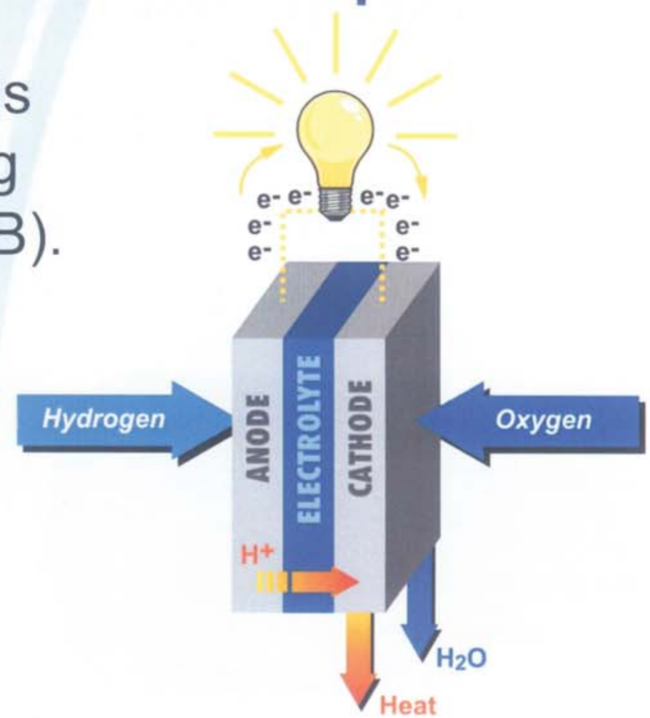
Fuel Cell

- Fuel Cells produce **electricity and heat without combustion** or moving parts. Uses hydrogen (or a hydrogen-rich fuel) and oxygen to create electricity by an **electrochemical process.**
- Meet or exceed air emission standards throughout the United States including California Air Resources Board (CARB).
- **Extremely quiet** operation



Anode: $2H_2 \rightarrow 4H^+ + 4e^-$

Cathode: $O_2 + 4H^+ + 4e^- \rightarrow H_2O$

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Fuel Cell

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Small Cogeneration Technologies

Technology	Recip Engine	Microturbine	Fuel Cell
Efficiency	70 - 80 %	65 – 75 %	55 – 85 %
Typical Capacity	.01 – 5 MW	30 – 250 kW	5 – 400 kW
Installed Cost	$1000 - $2200 / kW	$2000 - $3000 / kW	$3500 - $6500 / kW
Fuel	NG, LFG, Biogas	NG, Biogas, Fuel Oil	NG, H2, Propane
Availability	92 – 97 %	90 – 98 %	> 95 %
Noise	High	Moderate	Low
Emissions	Moderate	Low	Low

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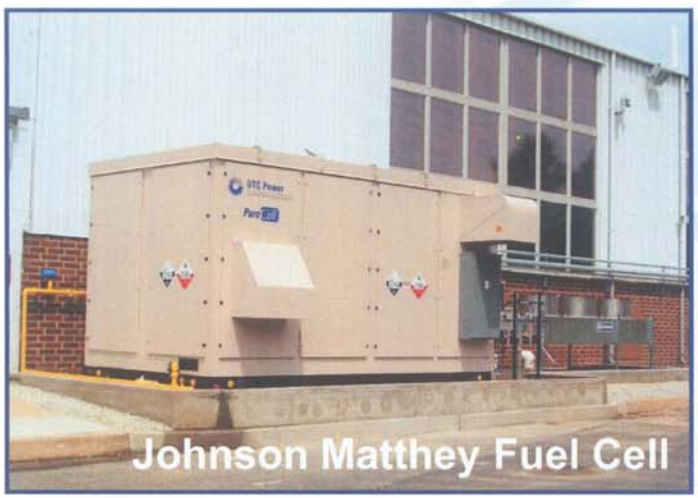
MACTEC CCHP Project Examples

- Johnson Matthey Industrial, 200 KW Fuel Cell
- St. Helena Hospital, 400 KW Fuel Cell
- Whole Foods, 200 KW Fuel Cell - several locations
- Clarkson University, three 65 KW Microturbines
- Current TV,123 Townsend Ave, Microturbines
- Ritz Carlton, San Francisco, Microturbines



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Clarkson University Microturbines

- 3 Microturbines and Absorption Chiller
- Provides 195 kW power to new LEED Silver Technology Advancement Center (TAC)
- Simultaneous chilled water and hot water for space heating/cooling and domestic hot water requirements

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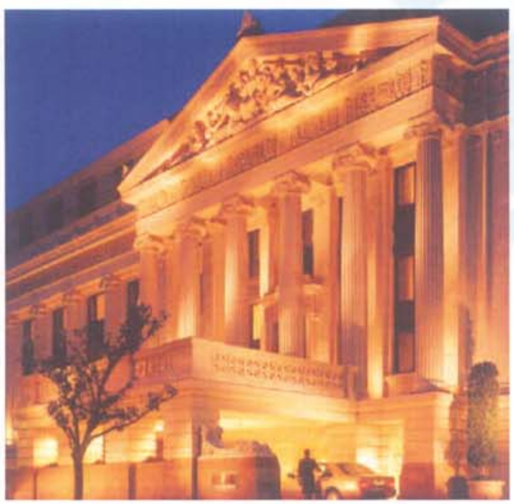
Ritz Carlton Microturbines

- 336 Room Luxury Hotel in San Francisco
- Combined Cooling, Heating and Power (CCHP)
- Four 60kW Microturbines with double effect absorption chiller
- 160 Tons of cooling



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Whole Foods Fuel Cell

- Combined Cooling, Heating and Power 46,000 sf facility
- 200 kW Fuel Cell meets 100 % of electricity and 50% heating demand

- Partially funded by State (Conn Clean Energy Fund)

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St Helena Hospital Fuel Cell

- 181 Bed Full Service Hospital
- 400 kW Fuel Cell with 1700 KBtu/Hr of Hot Water used for space heating
- Partially funded by State (CSGIP)

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Micro - CHP

- Residential Use
- Up to 5 kW
- Base load for most homes 1kW
- Propane or Natural Gas
- Integrated Inverter
- Installed Cost over $13,000

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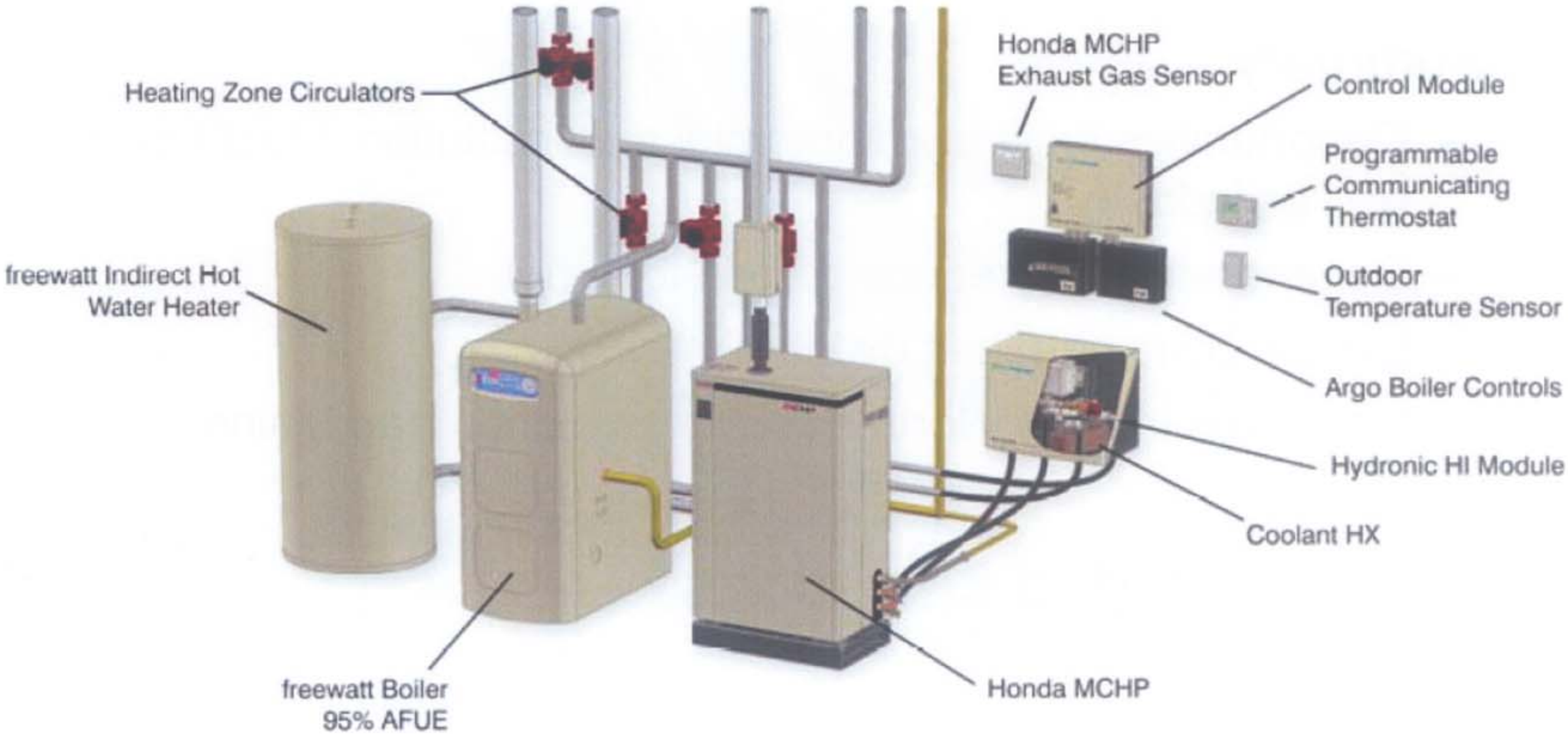
Micro – CHP Honda Freewatt



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Small Scale Cogeneration

- Summary
  - Opportunities exist at commercial and institutional facilities as well as industry
  - Cogeneration will reduce carbon footprint
  - Limited by natural gas distribution
  - Incentives in other North East states higher than Maine

- Comments and Questions

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CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP
Producing Reliable Energy & Preserving the Environment

Overview - Medium to Large CHP Technologies

OFFICE OF THE GOVERNOR
MAINE

Governor's Office of Energy Independence & Security (OEIS)

Combined Heat & Power Taskforce

August 11th, 2009

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CHP Technology Sizes

- **CHP – Combined Heat & Power:**

CHP Technologies can be divided into three size categories (CHP plants not merchant power plants).

Small: 5 to 1,000 kWe (single or multiple units)

Medium: 1,000 to 10,000 kWe (single or multiple units)

Large: 10,000 to 50,000+ kWe (single or multiple units)

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CHP Technology - Fuel Sources

<u>Fuel Sources for **Medium** to **Large** CHP Systems</u>:

- Natural Gas
- Liquefied Natural Gas
- Bio-gas (syngas - landfill, digester, sludge, …)
- Bio-mass (woody, agricultural, opportunity fuels, …)
- Liquid Biofuels (Bio-Oil, Bio-Butanol, etc.)
- Conditioned Construction & Demolition Waste
- Coal
- Municipal Solid Waste (MSW)
- TDF – Tire Derived Fuel

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CHP Energy Conversion Technologies

- Combustion Turbines
- Combustion Engines
- Fuel Cells
- Anaerobic Digesters
- Fixed Bed Boilers
- Fluidized Bed Boilers
- Gasifiers

Combustion Turbine / Generators

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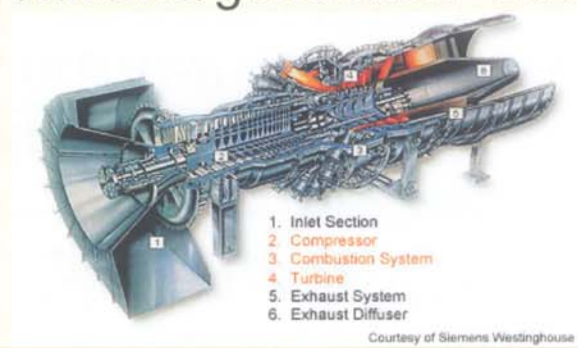
Combustion Turbines / Generators (CTG):

Combustion Turbines are much like jet aircraft engines coupled to an electric generator. C/T/G's can utilize many fuels defined for CHP technologies. High temperature exhaust gases from the turbine are captured and used to generator steam in an exhaust gas heat recovery steam generator (boiler or HRSG). This steam can be used for thermal energy needs of the host or even for additional power generation via a steam/turbine/generator. This is a called combined cycle energy model.



Combustion Turbine / Generators

- <u>Medium Size – Combustion Turbine/Generator</u>:

  This size CHP system is typical from 1,000 kW to 10,000 kW with the median size about 5,000 kW. Eastern Maine Medical Center's system is about 5,000 kW. These system can produce from 8,900 to 47,000 pph of steam with a median output of 25,000 pph. A median size hospital uses about 30,000 pph of steam.

- <u>Large Size – Combustion Turbine/Generator</u>:

  This size CHP system is typical from 10,000 kW to 50,000 kW with the median size about 25,000 kW. One of the turbines at Verso Paper Jay Mill Cogen is 50,000 kW. These systems can produce from 47,000 to 340,000 pph of steam with a median output of 180,000 pph.

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Combustion Engine / Generators

- **Medium Size – Combustion Engine/Generator:**

  This size CHP system is typical from 1,000 kW to 8,000 kW with the median size about 3,000 kW. Eastern Maine Medical Center's system is about 5,000 kW. These system can produce from 1,800 to 20,000 pph of steam with a median output of 10,000 pph.

- **Large Size – Combustion Engine / Generator:**

  Typically Engine/Generators are not used in this category and not available. There are very large engines employed for other uses like peaking merchant power plants where multiple engine/generators are combined for peaking power generation needs but not for CHP.

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Combustion Engine / Generators

- Combustion Engine / Generators (CEG):

  Combustion Engines are much like a car or tractor engine coupled to an electric generator. C/E/G's can utilize many fuels defined for CHP technologies. Thermal energy from high temperature exhaust, jacket water and lube oil coolers is recovered from the engine and used to generator steam in an exhaust gas heat recovery steam generator (boiler or HRSG). This steam can be used for thermal energy needs of the host or even for additional power generation via a steam / turbine / generator. This is a called combined cycle energy model.

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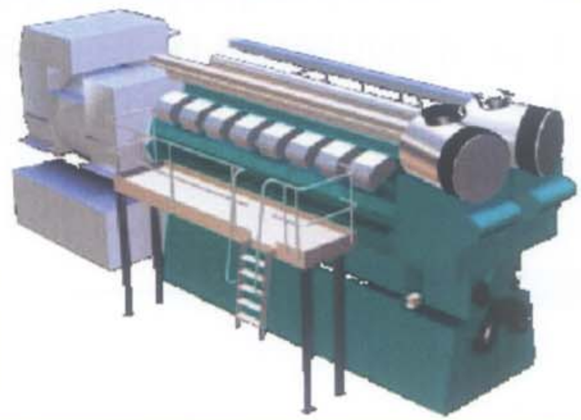
Combustion Engine / Generators

- Combustion Engine / Generators (CEG):

Combustion Engine/generators have greater flexibility than combustion turbine/generators since they have a greater turn down for matching swings in thermal loads however their thermal energy recovery is lower than combustion turbine/generators. Suitability to application is on of the core design criteria when considering CHP technologies for each end user.



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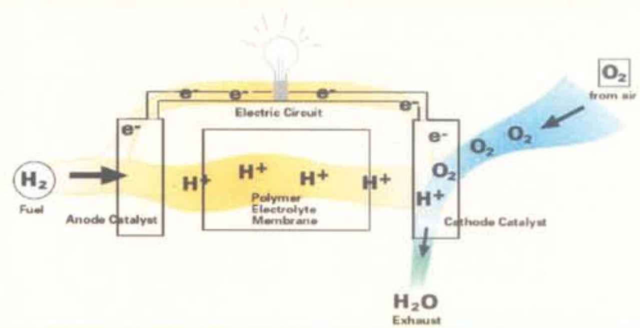
Fuel Cells

- Fuel Cells:

  Fuel cell systems produce energy different from traditional prime mover technologies. Fuel cells are similar to batteries in that both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely provided the availability of a continuous fuel source. Two electrodes (a cathode and anode) pass charged ions in an electrolyte to generate electricity and heat. A catalyst enhances this process.



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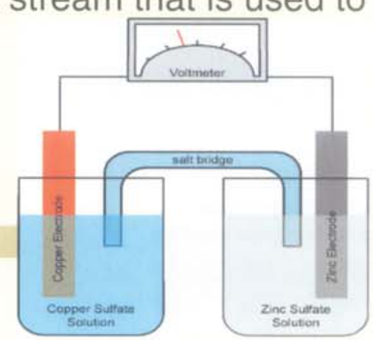
Fuel Cells - Types

There are five types of fuel cells under development.
These are: 1) phosphoric acid (PAFC), 2) proton exchange membrane (PEMFC), 3) molten carbonate (MCFC), 4) solid oxide (SOFC), and 5) alkaline (AFC). The electrolyte and operating temperatures distinguish each type. Operating temperatures range from near ambient to 1,800°F, and electrical generating efficiencies range from 30 to over 50% HHV. As a result, they can have different performance characteristics, advantages and limitations, and therefore will be suited to distributed generation applications in a variety of approaches.[1]

The different fuel cell types share certain important characteristics. First, fuel cells are not Carnot cycle (thermal energy based) engines. Instead, they use an electrochemical or battery-like process to convert the chemical energy of hydrogen into water and electricity and can achieve high electrical efficiencies. The second shared feature is that they use **hydrogen** as their fuel, which is typically derived from a hydrocarbon fuel such as **natural gas**. Third, each fuel cell system is composed of three primary subsystems: 1) the fuel cell stack that generates direct current electricity; 2) the fuel processor that converts the natural gas into a hydrogen-rich feed stream; and 3) the power conditioner that processes the electric energy into alternating current or regulated direct current. Finally, all types of fuel cells have low emissions profiles. This is because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low energy hydrogen exhaust stream that is used to provide heat to the fuel processor. [1]

[1] From EPA CHP Technologies Catalog



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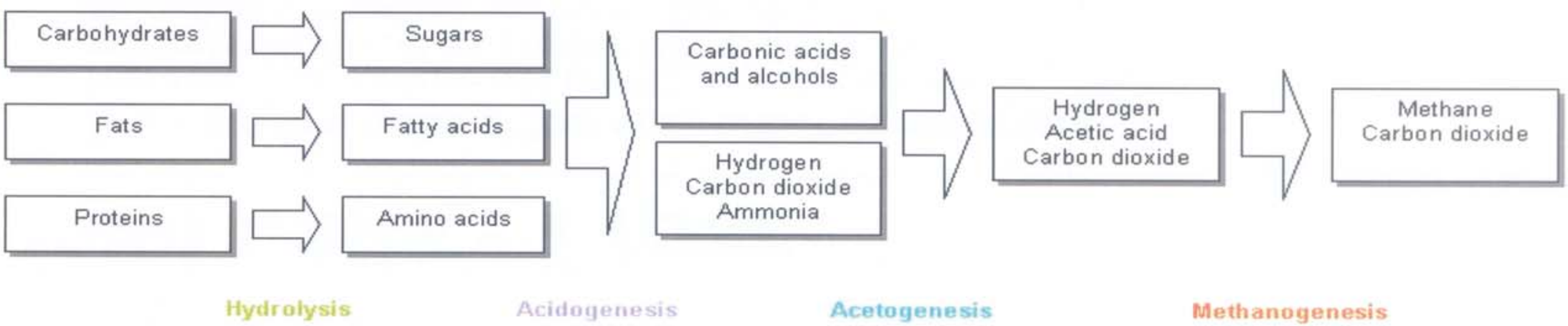
Anaerobic Digesters

Anaerobic Digesters:

Anaerobic digesters breakdown biodegradable materials in the absence of oxygen. A resultant biogas is produced containing methane gas, this gas is used to create energy. Some applications of anaerobic digesters include wastewater sludge, agricultural waste, and animal waste. The solids byproduct can be used as a fertilizer.

This source of fuel can be used in Medium Size CHP applications where the methane source is adequate to produce 1,000 kWe are greater in electrical / thermal energy.



Fixed Bed Boilers

- Fixed Bed Boilers:

  Fixed bed boilers are the most common type biomass boiler for CHP applications for large systems but are being replaced by gasification technologies in the medium size to large size systems. Fixed bed (stoker) boiler use direct fire combustion of solid fuels with excess air producing a hot flue gas to create steam which is in turn used to generate electricity with a steam turbine generator. Excess steam is then used for process thermal energy or heating based on the site specific energy balance. Many fixed bed boilers have been enhanced with over-fire air and under-fire air systems to improve complete combustion. Many lumber mills in Maine utilize medium sized systems and most paper mills have at least one large biomass boiler, typically a fixed bed system with moving grate. Some mills have large continuous fluidized bed biomass boilers.

Fluidized Bed Boilers

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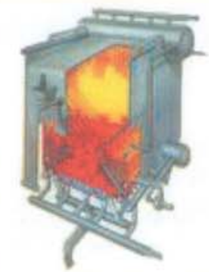
Fluidized bed boilers are employed for the high range of the medium size systems and are typical for the large size systems. Fluidized bed boilers will combust many opportunity fuels that are blended with traditional biomass.

In this method of combustion, fuel is burned in a bed of hot inert, or incombustible, particles suspended by an upward flow of combustion air that is injected from the bottom of the combustor to keep the bed in a floating or "fluidized" state. The scrubbing action of the bed material on the fuel enhances the combustion process by stripping away the CO_2 and solids residue (char) that normally forms around the fuel particles.

This process allows oxygen to reach the combustible material more readily and increases the rate and efficiency of the combustion process. One advantage of mixing in the fluidized bed is that it allows a more compact design than in conventional water tube boiler designs. Natural gas or fuel oil can also be used as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. The effective mixing of the bed makes fluidized bed boilers well-suited to burn solid refuse, wood waste, waste coals, and other nonstandard fuels.[1]

[1] EPA Biomass CHP Technology Catalog



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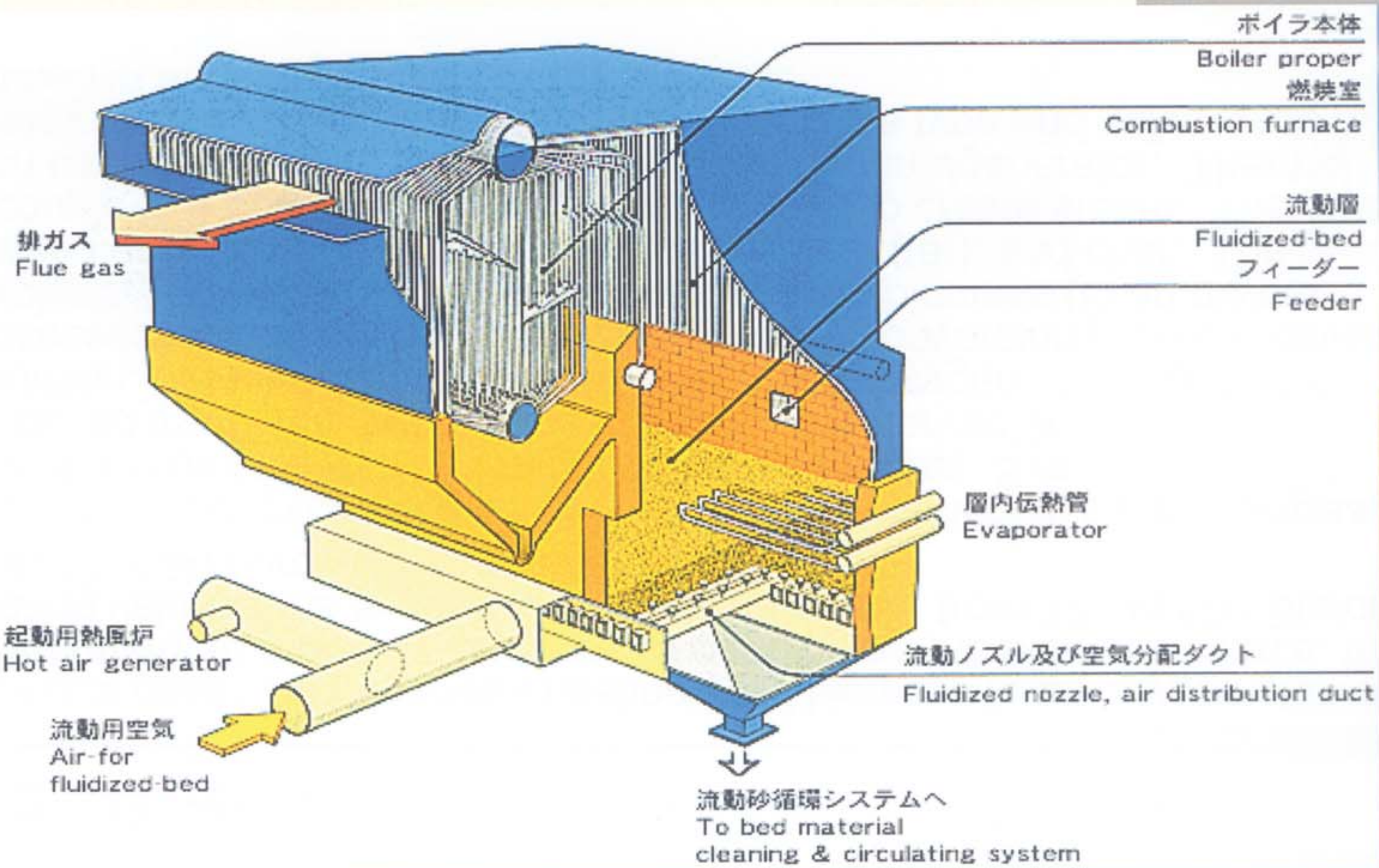
Fluidized Bed Boiler - Diagram



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Gasifiers

Biomass gasification involves heating solid biomass in an oxygen-starved environment to produce a syngas. Depending on the biomass source, the heating value of the syngas, can range anywhere from 100 to 500 Btu/cubic foot (10 to 50 percent that of natural gas).

The fuel output from the gasification process is generally called ***syngas***, though in common usage it might be called ***biogas***. Syngas can be produced through direct heating in an oxygen-starved environment, partial oxidation, or indirect heating in the absence of oxygen. Most gasification processes include several steps. The primary conversion process, called pyrolysis, is the thermal decomposition of solid biomass (in an oxygen-starved environment) to produce gases, liquids (tar), and char. The gasifier is couple to a boiler where the syngas is used to create steam. The steam is then used to create electricity with a steam/turbine/generator. Thermal energy is also utilized in the CHP model and the type and volume are defined in the site specific energy balance.

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Gasifier - Example

Nexterra Biomass Gasification for Johnson Controls at DOE's Oak Ridge National Laboratory (ORNL) in Tennessee.

CHP Emissions

(C-CHP Combined Cooling, Heating and Power)

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CHP Environmental Benefits:

Through 2007, the EPA CHP Partnership has helped install more than 335 CHP projects, representing 4,450 megawatts (MW) of capacity.
The emissions reductions are equivalent to:

A. Removing the Annual Emissions of More Than **2.0** Million Automobiles.

OR

B. Planting More Than **2.4** Million Acres of Forest.

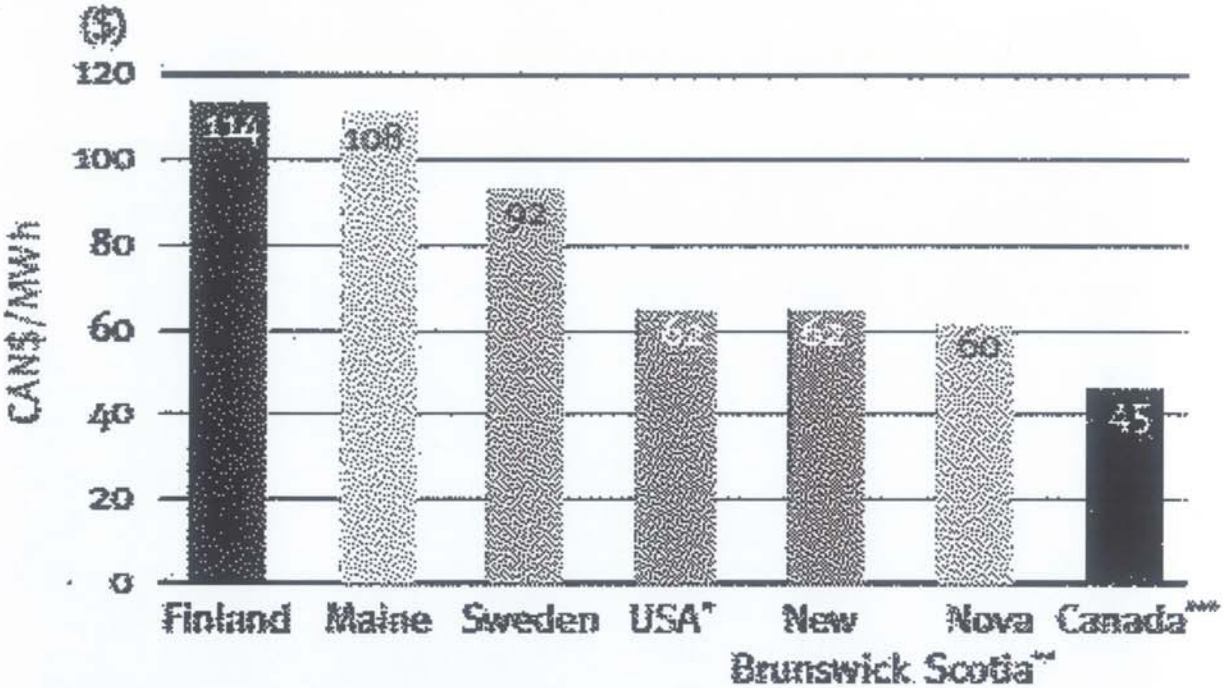
25% Less Emissions with Cogen/Tri-Gen Energy Models

Source: www.epa.gov/chp/

Biomass Electricity

- Eight existing "stand alone" biomass facilities
- About 265 MW of baseload renewable energy
- ~3.5 million green tons of annual wood use
- Support from regional RPS standards
- A number of forest industries have biomass boilers as well

Chart 13: Average Industrial Electricity Rates



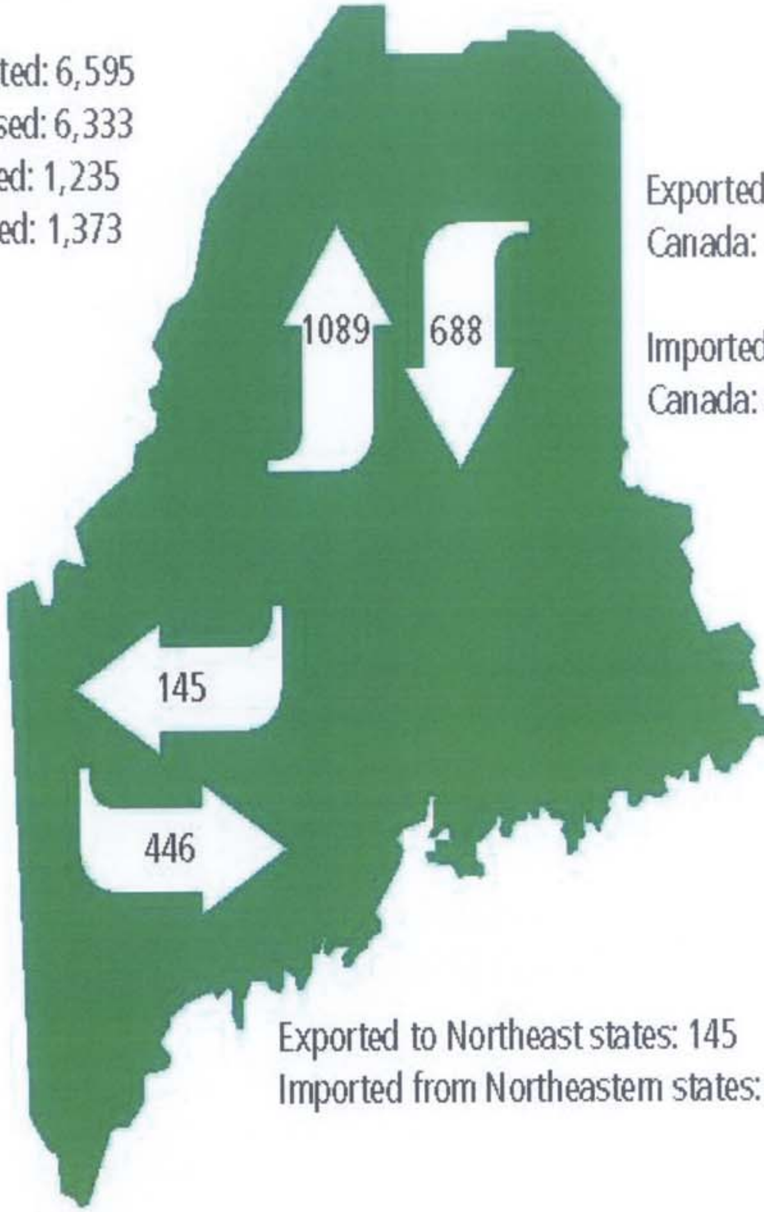
* Average of 22 "forest intensive" states
** Reflects confirmed rate offered to the Port Hawksbury paper mill
*** Average of 6 "forest intensive" provinces

Source: Competitive Energy for New Brunswick Forest Industry – Stantec Consulting

Maine 2005

All units are in 1000 cords

Harvested: 6,595
Processed: 6,333
Exported: 1,235
Imported: 1,373



Exported to Canada: 1,089

Imported from Canada: 688

Exported to Northeast states: 145
Imported from Northeastern states: 446

Eastern Maine Medical Center Combined Heat and Power Project

Presented to The Combined Heat and Power Task Force September 17, 2009

Presented by Jeff Mylen, PE, MS, Director of Construction Services, EMMC

EASTERN MAINE MEDICAL CENTER
The Right Choice, Right in the Heart of Maine

CIANBRO

Vanderweil Engineers

OAK RIDGE NATIONAL LABORATORY

Solar Turbines
A Caterpillar Company

INTERNATIONAL DISTRICT ENERGY ASSOCIATION

Eastern Maine Medical Center Combined Heat and Power Project

Highlights & Talking Points

- 1995 – 1997 EMMC started looking into turbine technology for the campus.
- 1998 (January) The ice storm reinforced the fact that hospitals need dependable electrical power.
- 2000 – 2001 EMMC started working with Vanderweil Engineers (Boston) to look at the feasibility of using turbine technology on this campus.
- 2003 Vanderweil updated their 2001 study to include the new load profile of the medical center and newer technology of the turbine.
- 2003 (fall) EMMC applied for a Department of Energy grant to help finance the turbine project.
- 2004 (May) EMMC was awarded a $3 million dollar Department of Energy award (administrated by Oak Ridge National Lab) to build and operate a CHP Plant.
- 2005 (February 4) EMMC was awarded a Certificate of Need by the State of Maine to start construction of CHP Plant.
- 2005 (July) EMMC began formal construction of the CHP Plant.
- 2006 (October 16) The CHP plant at EMMC was fully tested and online.

Eastern Maine Medical Center Combined Heat and Power Project

- **<u>EMMC CHP Facts & Figures</u>**
- The generator connected to the turbine generator is 4.6 Megawatts, which is equal to supplying electricity to 46,000 one hundred watt bulbs, or approximately 400 average size homes.
- Eastern Maine Medical Center will stay connected to the Bangor Hydro Grid and still import approximately 20% of its electricity from the street on an annual basis.
- The cost of the project was approximately 8.2 million dollars. EMMC's cost was approximately 5.2 million dollars (minus the 3 million dollar award).
- The expected energy savings per year will be approximately 1 million dollars (plus) per year, yielding a pay back less than 5 years.
- The heat output of the Heat Recovery Steam Generator (boiler) is equivalent to heating approximately 300 homes.
- During the summer months, surplus steam from the plant can be used to help cool the hospital by utilizing a new 500 ton steam absorption chiller and two new cooling towers. This output is equivalent to helping cool approximately 500 homes on a hot day.

Eastern Maine Medical Center Combined Heat and Power Project

- EMMC Facility Overview
  - Critical Regional Tertiary Hospital
- Existing Utilities and Infrastructure
  - Duel fuel high pressure steam boiler plant and distribution system
  - 2300 ton electric chilled water plant
  - Two (2) 12.4 KV feeders on overhead poles from BHE with primary switchgear and site distribution
  - Two (2) 1500 KW diesel emergency gen sets & (1) 500 KW

Eastern Maine Medical Center Combined Heat and Power Project

- Existing Energy Consumption Key Figures

Electric Power	Steam
28.0 million KWH purchased annually	117,000 MLB steam produced annually
5300 KWD peak demand	42,000 PPH peak steam demand
$3.3 million annual electric cost	1,000,000 gallon of NO2 fuel consumed annually
$0.15 average cost per KWH (04-05) $0.17 cost currently without CoGen	$1.55 - $1.65 per gallon of NO2 fuel oil in 2004-2005 Higher costs presently

Eastern Maine Medical Center Combined Heat and Power Project

- CHP Project History at EMMC
- Project Implementation Approach
  - Design/Build Project Team with Cianbro Corp. & Vanderweil Engineers
  - Values and benefits of the Project team
- Explored alternative financing methods for the $8.2 million project and considered:
  - Internally financed project
  - Third party built, own and operate
  - Third party capital lease
- Applied for the DOE's Distributed Energy System Application and was successful in obtaining a $3,000,000 award and balance will be internally financed

Eastern Maine Medical Center Combined Heat and Power Project

- Why EMMC was a good application for CHP
  - High Utility Rates
  - High Process Thermal Load
  - 12 Month thermal requirement for heating or cooling
  - Match between Electric and Thermal Loads
  - 24 Hour Seven Day a Week Operation
  - High Pressure Natural Gas Availability-no compressor needed
  - Operations and Departments with Critical Load Requirements
  - Attractive ROI and Annual Operating Cost Savings

Eastern Maine Medical Center Combined Heat and Power Project

- Project Approval Process
  - Internal - Board of Director's Approval
  - External - Certificate of Need (CON) Process
  - Air Permit Application
  - City and local permits

Eastern Maine Medical Center Combined Heat and Power Project

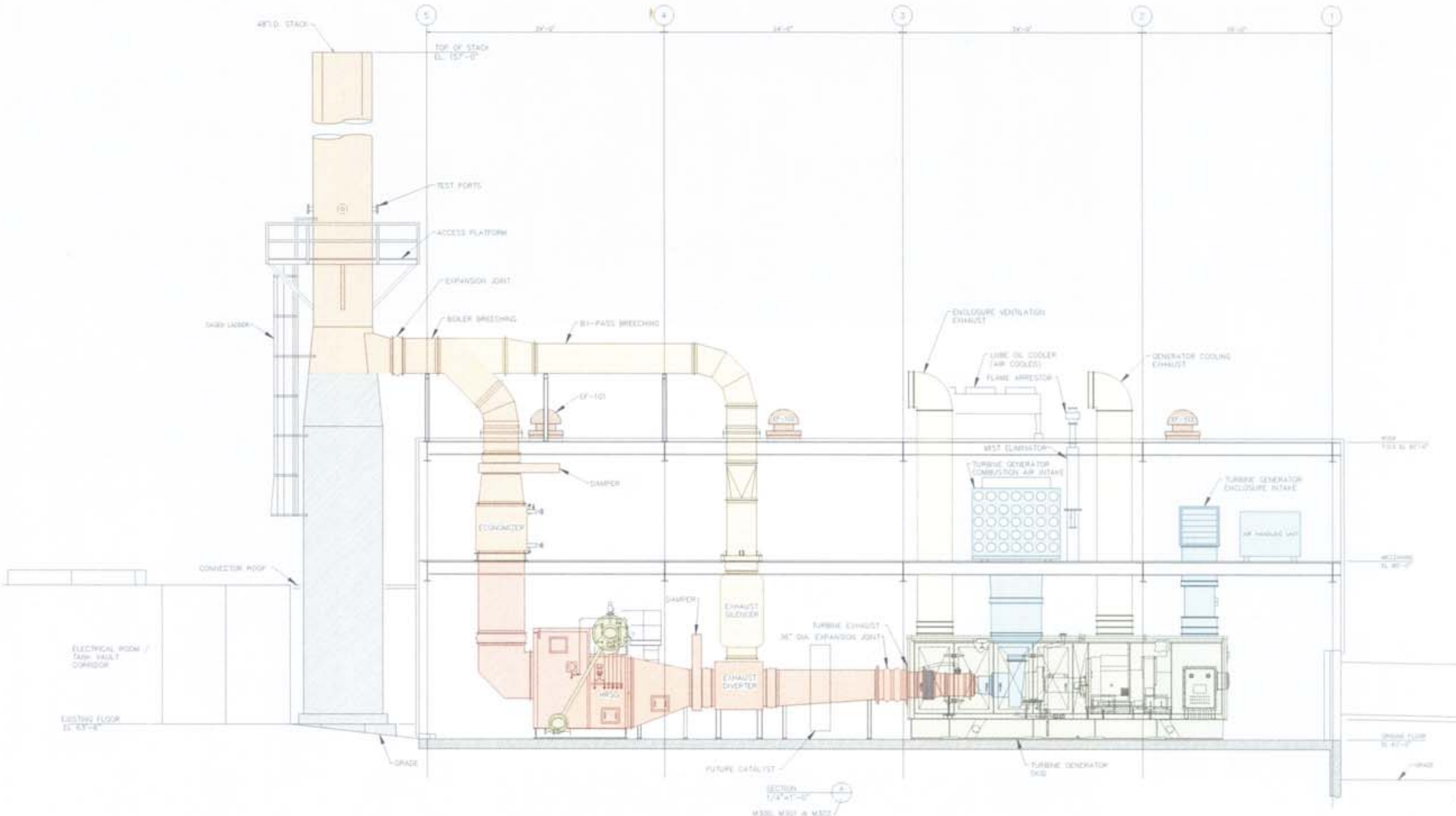
- System Configurations based on:
  - Solar Centaur 50, 4.6 Mwe @ ISO with un-fired HRSG generating 25,000 PPH steam
  - New 500 ton steam absorption chiller and ancillaries
- CHP projected key financial figures:
  - $5.2 million project net capital cost (factoring out Department of Energy Award ($3 million)
  - $700K to $800K operating cost savings (net cash flow)

Eastern Maine Medical Center Combined Heat and Power Project

Utility Interconnection Issues & Lessons Learned

- Get the electric utility involved early.
- Clearly identify how you want your control scheme to operate within the utility parameters.
- Complete comprehensive front-end analysis and resolution of utility tie connections to existing plant
- Planning, communication, and implementation between the engineer and field technicians is vital, especially for the electrical synchronizing to the utility.

Eastern Maine Medical Center Combined Heat and Power Project



Eastern Maine Medical Center Combined Heat and Power Project

Overview

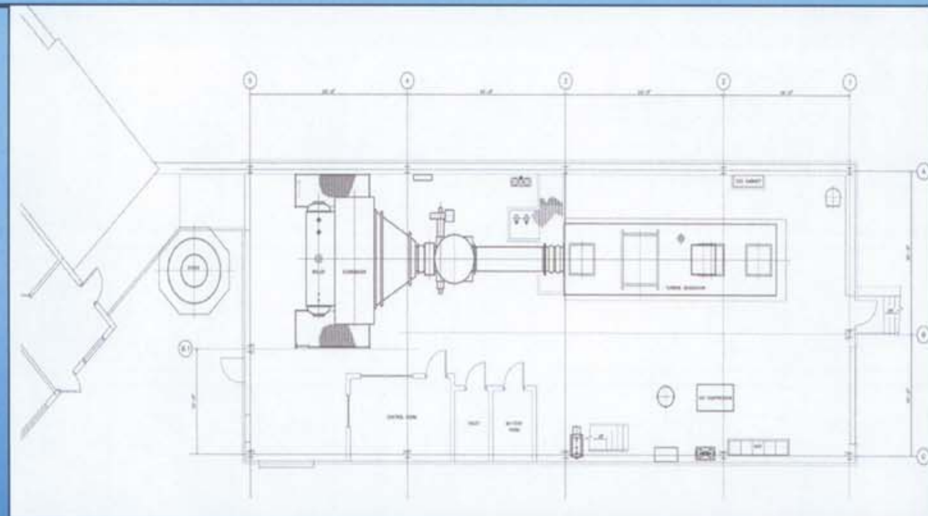
- Critical Regional Tertiary Hospital
- Duel fuel high pressure steam boiler plant and distribution system
- 2300 ton electric chilled water plant
- Two (2) 12.4 KV feeders on primary switchgear and site
- distribution
- Two (2) 1500 KW + 1- 500 KW emergency generators

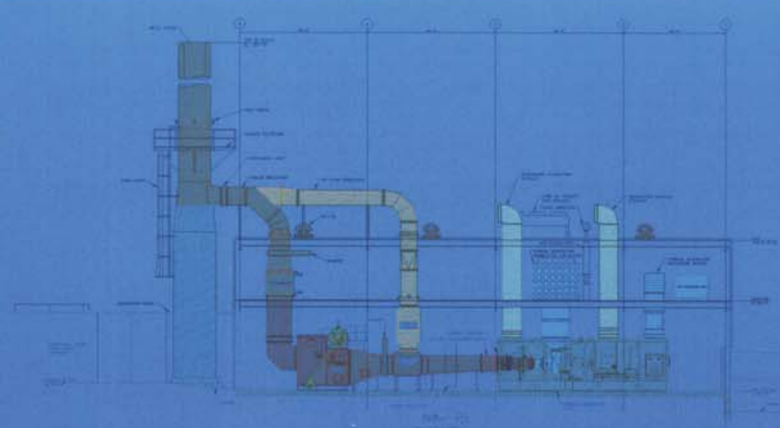
Project Overview

- High Energy Costs
- Fuel Use Diversity
- Need for additional chilled water capacity
- Need to deliver services under any climatic condition
- Utility Reliability
- Diverse thermal heating load profile
- Emissions compliance

Objectives

- Design a system that responds to a specific energy concern for healthcare – reliability
- Use an integrated, modular "power island" concept to reduce field labor costs and installation time, while increasing the opportunity for replication
- Design a system that could be replicated for similar applications with a minimal amount of balance of plant and integration costs
- Structure the CHP system using advanced information technology to aid in information dissemination





Electric Power	Steam
28 million KWH purchased annually	117,000 MLB steam produced annually
5300 KWD peak demand	42,000 PPH peak steam demand
$3.3 million annual electric cost	1,000,000 gallon of No. 2 fuel consumed annually
$0.15 average cost per KWH in 2004-2005	$1.55-$1.65 per gallon of No. 2 fuel in 2004-2005

CHP System Configuration

- Solar Centaur 50, 4.6 Mwe @ ISO Conditions
- Un-fired HRSG generating 25,000 PPH steam
- New 500 ton steam absorption chiller

Benefits

- Reduced Emissions
- Increased thermal and heating capacity and enhanced emergency backup power
- Savings will directly reduce healthcare costs
- Power availability during adverse weather conditions

Solar Turbines A Caterpillar Company | INTERNATIONAL DISTRICT ENERGY ASSOCIATION | Vanderweil Engineers | CIANBRO | OAK RIDGE NATIONAL LABORATORY | EASTERN MAINE MEDICAL CENTER

Eastern Maine Medical Center
Combined Heat and Power Project

Utilities Cost Comparison at FY2007 Demand

Projected utility Costs		With CoGen		
	$6,044,914.37	$4,681,177.12	savings	$1,363,737.25

Utilities Cost Comparison at FY2008 Demand

Projected utility Costs		With CoGen		
	$6,720,009.77	$4,774,263.72	savings	$1,945,746.05

Utilities Cost Comparison at FY2009 Demand

Projected utility Costs		With CoGen		
	$2,061,709.80	$1,600,142.97	savings	$ 461,566.83

Year to date

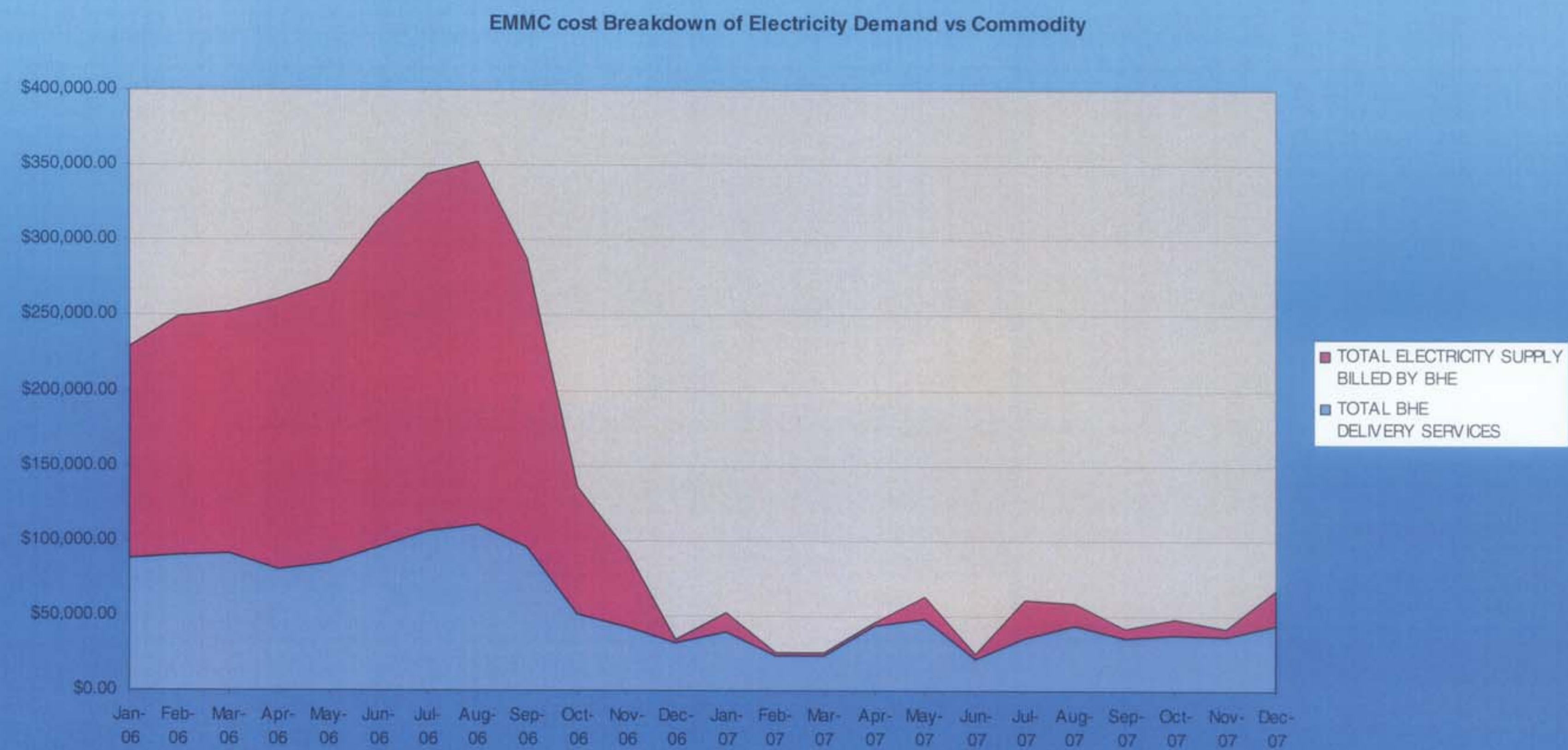
Oct 06- Jan-09

Total Savings to date

$3,771,050.13

Note: Projected costs are based on actual Bangor Hydro rate structure

Eastern Maine Medical Center Combined Heat and Power Project



Eastern Maine Medical Center Combined Heat and Power Project

Eastern Maine Medical Center Combined Heat and Power Project

Eastern Maine Medical Center Combined Heat and Power Project

- Resources to help you evaluate whether CoGen is for you:

http://www.ornl.gov/sci/engineering_science_technology/cooling_heating_power/

http://www.emmccogen.org

Any specific CoGen questions please feel free to contact me @ jmylen@emh.org

Presentation to the Combined Heat and Power Task Force
Impact of Self-Generation on Utilities and Utility Customers
September 17, 2009

For the record, I'm David Allen, and I represent CMP at the legislature. I'd like to thank the Task Force for the opportunity to present a utility perspective to the discussions we're having regarding the opportunities that combined heat and power technologies present to a wide variety of customers.

I've been asked to provide a utility's perspective in three areas, interconnections, standby charges, and the impact of lost load on other customers. In all three areas, the company's position is fairly simple and straightforward. Customer-installed generation should not be allowed to impact other customers either electrically or financially.

Interconnections are governed by federal standards at the transmission level and by MPUC standards at the distribution level. The three issues that must be addressed are safety, reliability and costs. Naturally, any generation at a customer's site must be safely installed in order to protect that customer, neighboring customers, anyone who works on the system and the system itself. Safety standards are pretty straightforward, though occasionally there are disputes about how robust safety measures should be for a given system.

System reliability is an important issue for the company and its customers, especially as more and more intermittent resources are put on the system. If a customer is taking power from the system and suddenly starts putting power out onto the system, fluctuations in voltage are bound to occur, and sometimes other customers on the same circuit are impacted. Equipment can be installed to minimize voltage fluctuations, but that equipment can be costly.

That brings us to the issue of interconnection costs. Anytime significant generation is added to a distribution circuit, a system impact study should be done to see if the circuit can handle the generation and what protections may need to be installed. Safety equipment is added to protect people and the system as a matter of course, and that equipment must be tested periodically. In addition, special metering is usually needed and must be installed on larger facilities. All of those costs should be borne by the customer installing the generation and not shifted to other customers.

The next issue is the most contentious, and that's so-called standby charges. If someone builds a new facility and installs generation without being hooked up to the grid, there is no impact on the utility or other customers. In all other cases, whether a customer disconnects completely or continues to stay hooked to the grid, other customers are affected financially. In other words, whenever a current customer adds his own generation, other customers will end up paying more, because a large portion of a utility's costs are fixed.

In most cases, customers installing generation choose to stay hooked to the grid, and the question becomes, how much should they pay for that service. The customer would say, "I should only have to pay for T&D service when I need it." The utility would say that the customer should pay the costs of providing standby service to that customer based on the maximum demand he could place on the system at any one time. That's what the utility has to plan for.

That's because the company has to build and maintain the lines and pay all the ancillary and back office costs for that customer, including reserving space on the transmission system, whether the customer uses the system or not. If that customer does not pay those costs, then all other customers will pay them.

Here are a few examples of T&D revenue savings for hypothetical customers in different customer classes using current standby rate methodology. In each case those revenue savings become costs to other customers. In other words, the T&D savings for the generating customer are paid for by other utility customers.

Size of generator	Normal T&D revenues	Self generator T&D revenues*
5 MW	$859,633	$76,068
660 kw	$104,152	$9715
300 kw	$40,978	$3684

*All of these numbers assume that a combined heat/power plant runs 80% of the time (many run at higher numbers), and that the customer uses the grid one month each year.

The examples I've just given should give the task force and idea of how self-generation impacts other customers. How self-generation impacts the company depends greatly on what customer class the generator is in. At the residential level, the basic charge is about $9.00/month, even though the average cost to serve a residential customer is about $35/month. We collect money from residential customers based on how much power they use, so other residential customers pick up a substantial amount of that cost.

Our largest customers pay based on their **demand,** that is, the most power used in any 15 minute period in any month, and pay very little per kwh. The cost shifting by larger customers is based on how much demand they have, not how much power they use.

I stopped the examples at 5 MW, because once you get over that size, other market rules come into play.

Finally, CMP opposed one of the bills that engendered this task force, LD 1044 for a variety of reasons, but basically because of the cost shifting that would ensue. We estimated that one generator of the size mentioned in the bill would cause other customers to see rate increases to make up about $1.65 million in lost T&D revenue. In other words if one sawmill took advantage of the bill, other sawmills would see their rates increase.

In general, we oppose shifting costs from one group of customers to other customers.

I'd be happy to answer any questions you might have.

Maine IOU Rate Components and Projections of Stranded Costs as of September, 2009

Co-generation Task Force Meeting
September 17, 2009
Provided by Angela Monroe, MPUC

Rates as of 9/17/09

CMP (¢/kWh)

	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	4.38	1.33	0.96	0.06	2.70
Stranded Cost	**0.29**	**0.39**	**0.45**	**0.21**	**0.33**
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.14
Transmission	1.54	1.47	1.34	1.24	1.47
Total Delivery	**6.37**	**3.35**	**2.90**	**1.51**	**4.64**
Standard Offer	8.92	6.76	6.92	6.92	7.90
Total Rates	**15.29**	**10.11**	**9.82**	**8.43**	**12.53**

BHE (¢/kWh)

	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	5.36	2.46	1.47	0.26	3.50
Stranded Cost	**1.04**	**0.96**	**0.86**	**0.94**	**0.99**
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.13
Transmission	1.73	1.84	1.51	1.64	1.73
Total Delivery	**8.28**	**5.40**	**3.98**	**2.84**	**6.34**
Standard Offer	9.00	6.88	8.29	8.29	8.23
Total Rates	**17.28**	**12.28**	**12.27**	**11.13**	**14.58**

MPS (¢/kWh)

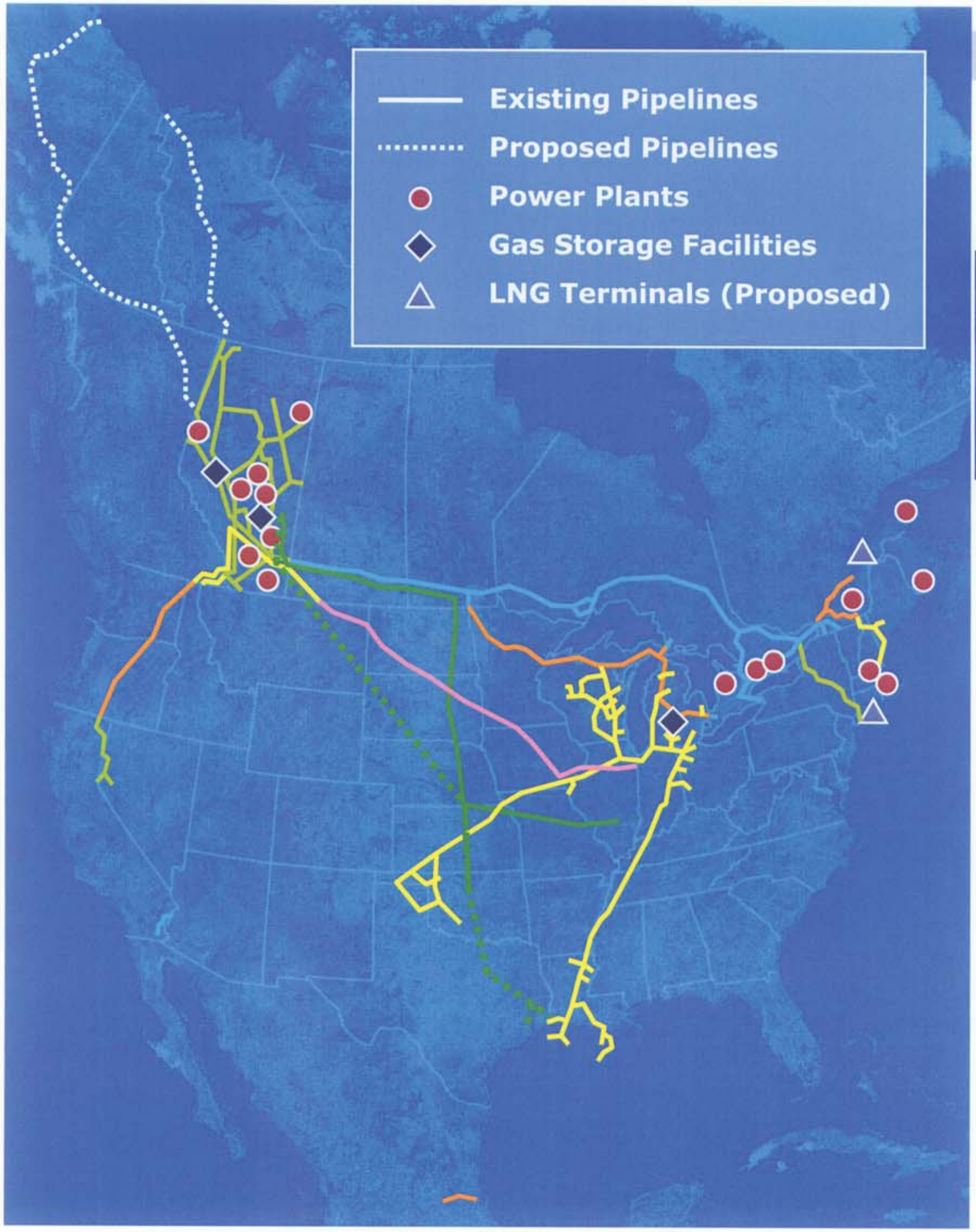
	Residential/ Small Commercial	Medium	Large (Distr. Voltage)	Large (Trans. Voltage)	Weighted Avg.
Distribution	4.77	1.96	2.25	1.14	3.15
Stranded Cost	**2.40**	**2.45**	**2.51**	**2.53**	**2.45**
Conservation & Solar Assess	0.15	0.15	0.15	0.005	0.11
Transmission	0.46	0.56	0.99	0.87	0.61
Total Delivery	**7.78**	**5.11**	**5.90**	**4.54**	**6.32**
Standard Offer	8.33	8.95	9.70	9.70	8.88
Total Rates	**16.12**	**14.06**	**15.60**	**14.24**	**15.20**

Net Stranded Cost ($M) and Projected Net SC

	Net Stranded Cost ($M) 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019-2028
CMP	$47	$28	$33	$35	$33	$32	$20	$20			
BHE	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15	$1.5
MPS	$12	$11	$11	$7	$2	$2	$2	$1			

Natural Gas "101" Transmission Pipeline

Portland Natural Gas Transmission System



Portland Natural Gas Transmission System

TransCanada Corporation (TSX/NYSE: TRP)

Portfolio of Quality Assets

- **36,500 mi. of wholly owned pipeline**
- **Interests in an additional 4,800 mi. of pipeline**
- **15 Bcf/d throughput**
- **355 Bcf of natural gas storage capacity**
- **17 power plants**
- **10,200 megawatts**
- **Crude oil pipeline project**
- **Two proposed LNG terminals**

Forward-Looking Information

This presentation may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward looking information. All forward-looking statements are based on TransCanada Pipeline ("TCPL") and Portland Natural Gas Transmission System ("PNGTS") beliefs and assumptions based on information available at the time such statements were made. The results or events predicted in this information may differ from actual results or events. Factors which could cause actual results or events to differ materially from current expectations include, among other things, the ability of TCPL and PNGTS to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, regulatory decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy industry sectors, construction and completion of capital projects, access to capital markets, interest and currency exchange rates, technological developments and the current economic conditions in North America. By its nature, such forward looking information is subject to various risks and uncertainties which could cause TCPL's and PNGTS's actual results and experience to differ materially from the anticipated results or other expectations expressed. For additional information on these and other factors, see the reports filed by TCPL with Canadian securities regulators and with the U.S. Securities and Exchange Commission. Readers are cautioned not to place undue reliance on this forward looking information, which is given as of the date it is expressed in this presentation or otherwise, and TCPL and PNGTS undertake no obligation to update publicly or revise any forward looking information, whether as a result of new information, future events or otherwise, except as required by law.

Outline

- Natural Gas Basics
  - Composition
  - Heating Value
  - Transmission
  - Delivery to Local Distribution Systems
- Transmission Pipelines Serving Maine
  - Portland Natural Gas Transmission System
  - Maritimes and Northeast
- Supply and Demand for Natural Gas
  - North America
  - Shale Gas
  - Price vs. Oil, Propane

Composition of Natural Gas

Producer Gas

Plant

HYDROCARBONS

	Chemical Formula	Normal Range of Composition %	Plant Products
Methane	CH_4	50-95	Sales Gas
Ethane	C_2H_6	3-12	.. Chemical Feedstock ..
Propane	C_3H_8	1-8	L.P.G
Iso-Butane	C_4H_{10}	0-3	
Normal Butane	C_4H_{10}	0-3	
Iso-Pentane	C_5H_{12}	0-2	Pentanes Plus, Condensate, Natural Gasoline
Normal Pentane	C_5H_{12}	0-2	
Hexane	C_6H_{14}	0-4	
Heptanes and Heavier	$C_7H_{16}+$	0-10	

NON-HYDROCARBONS

Nitrogen	N_2	0-5	Inert
Carbon Dioxide	CO_2	0-10	Waste
Hydrogen Sulphide	H_2S	0-35	Elemental Sulphur

Natural Gas Heating Value

- When hydrocarbons are combusted in the presence of oxygen they produce carbon dioxide (CO_2), water vapor (H_2O), and heat. The heat produced is called the heating value of natural gas.
- Methane (C1) has a heating value of 1,010 BTU/ft^3
- The heating value of natural gas is between 1,030-1,100 BTU/ft^3
- Heavy hydrocarbons, like Ethane (C2), Propane (C3) and higher, increase the heating value of natural gas
- Components with no heating value like CO_2 and N_2 reduce the heating value of natural gas. They are sometimes intentionally added to "hot" gas to moderate the heating value.

Transmission of Natural Gas

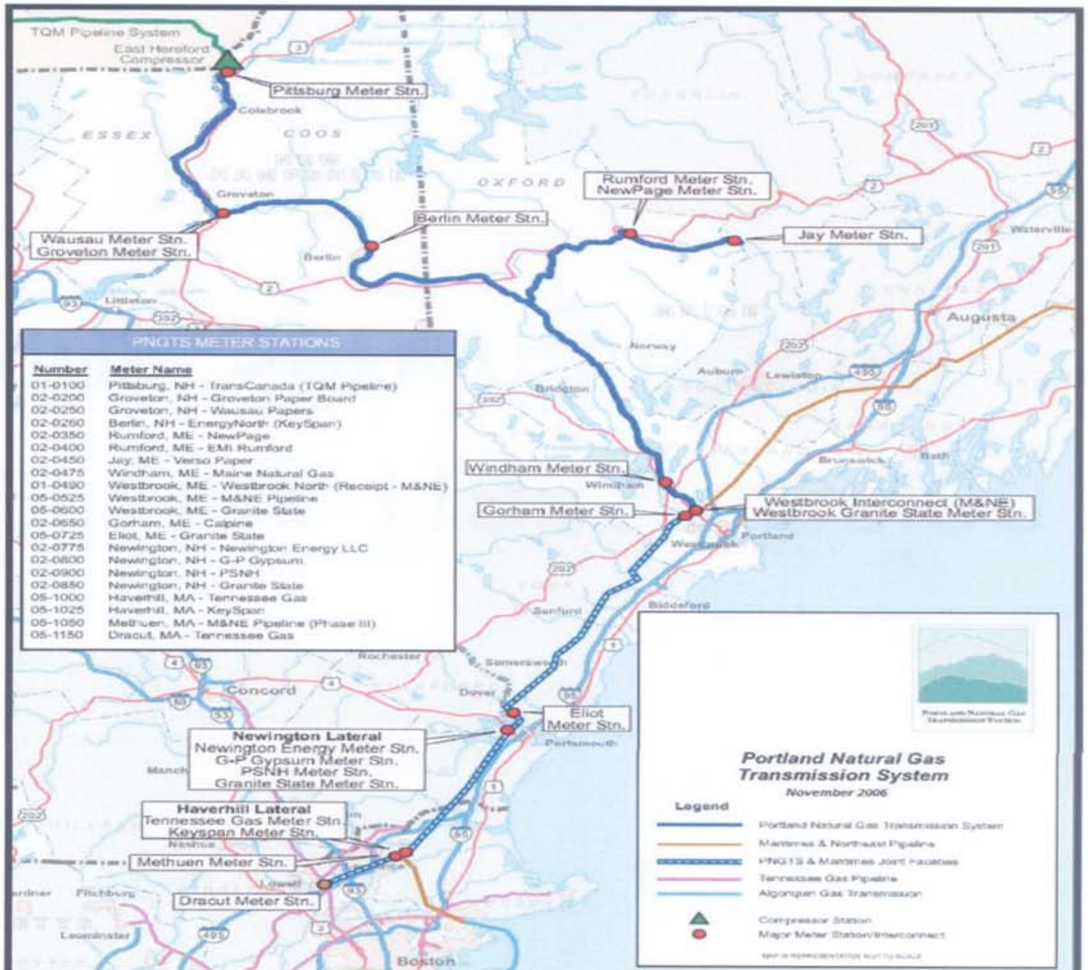
- Due to pressure drop on the pipeline, natural gas must be re-compressed; this is done at compressor stations.
- Compressor stations are typically spaced 50-80 miles apart.
- Gas ("fuel") from the flow stream is used to run the compressors (or they can be electric).
- Long distance transmission pipelines may be up to 48" in diameter, or in single and looped lines of 30" and 24" pipe.

Delivery of Natural Gas to Local Distribution Networks

- Interstate pipeline networks deliver gas to distribution companies at high pressure (700-1,440 psi).
- Before distribution within populated areas, gas pressure must be reduced to lower levels (~60 psi).
- Natural gas drops in pressure as it flows through local distribution networks. When the gas reaches the pressure regulator at customers' homes it is typically at 40-45 psi.
- The regulator further reduces the pressure to 0.25 psi for use in household appliances.
- Natural gas has no smell and must be odorized with sulfur compounds (mercaptan – "rotten egg" smell) for safety purposes before distribution.

Natural Gas Transmission Pipelines Serving Maine

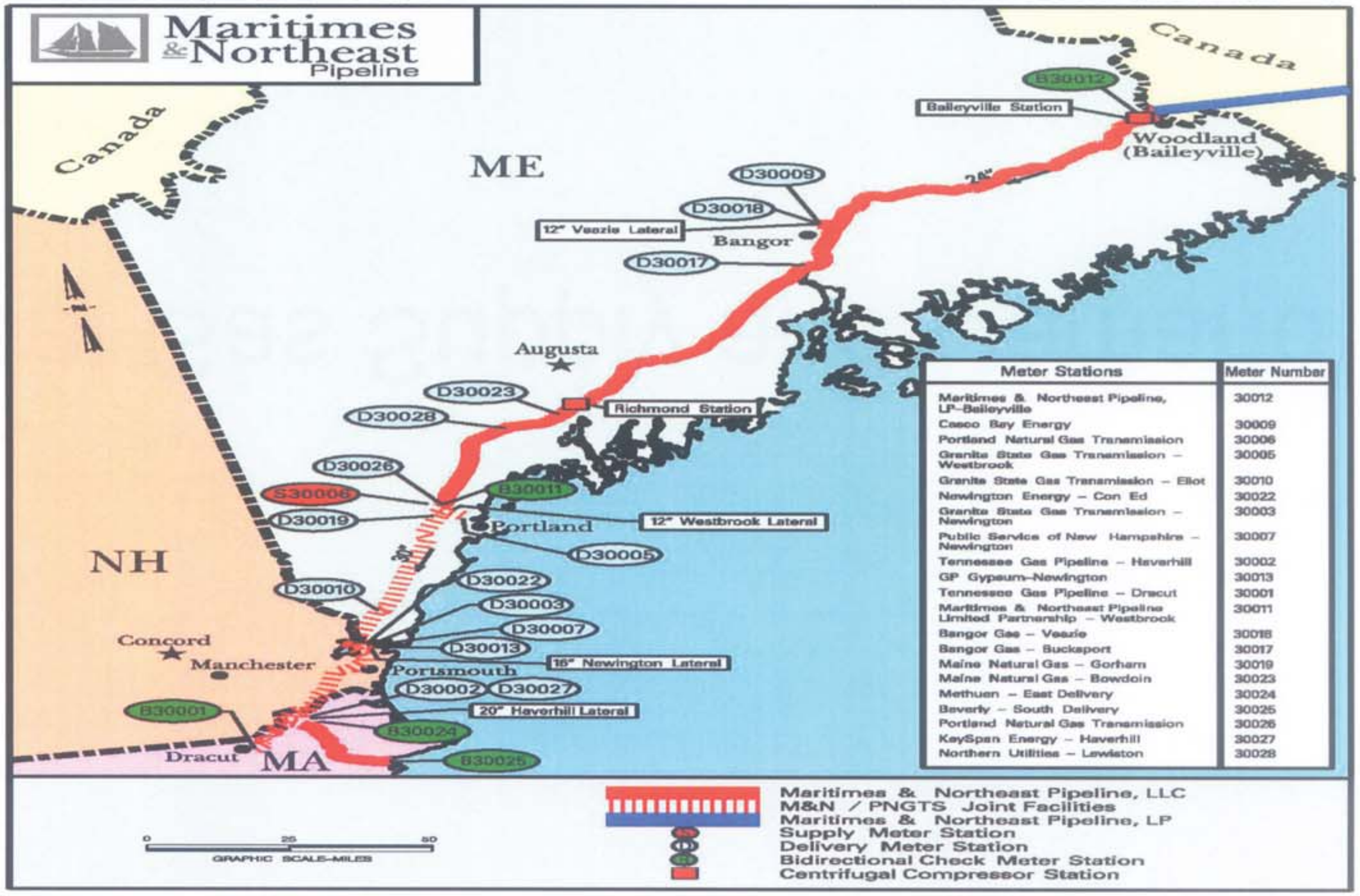
Portland Natural Gas Transmission System



Maritimes & Northeast - US

MARITIMES & NORTHEAST PIPELINE, L.L.C.
FERC Gas Tariff
First Revised Volume No. 1

Third Revised Sheet No. 5
Superseding
Second Revised Sheet No. 5



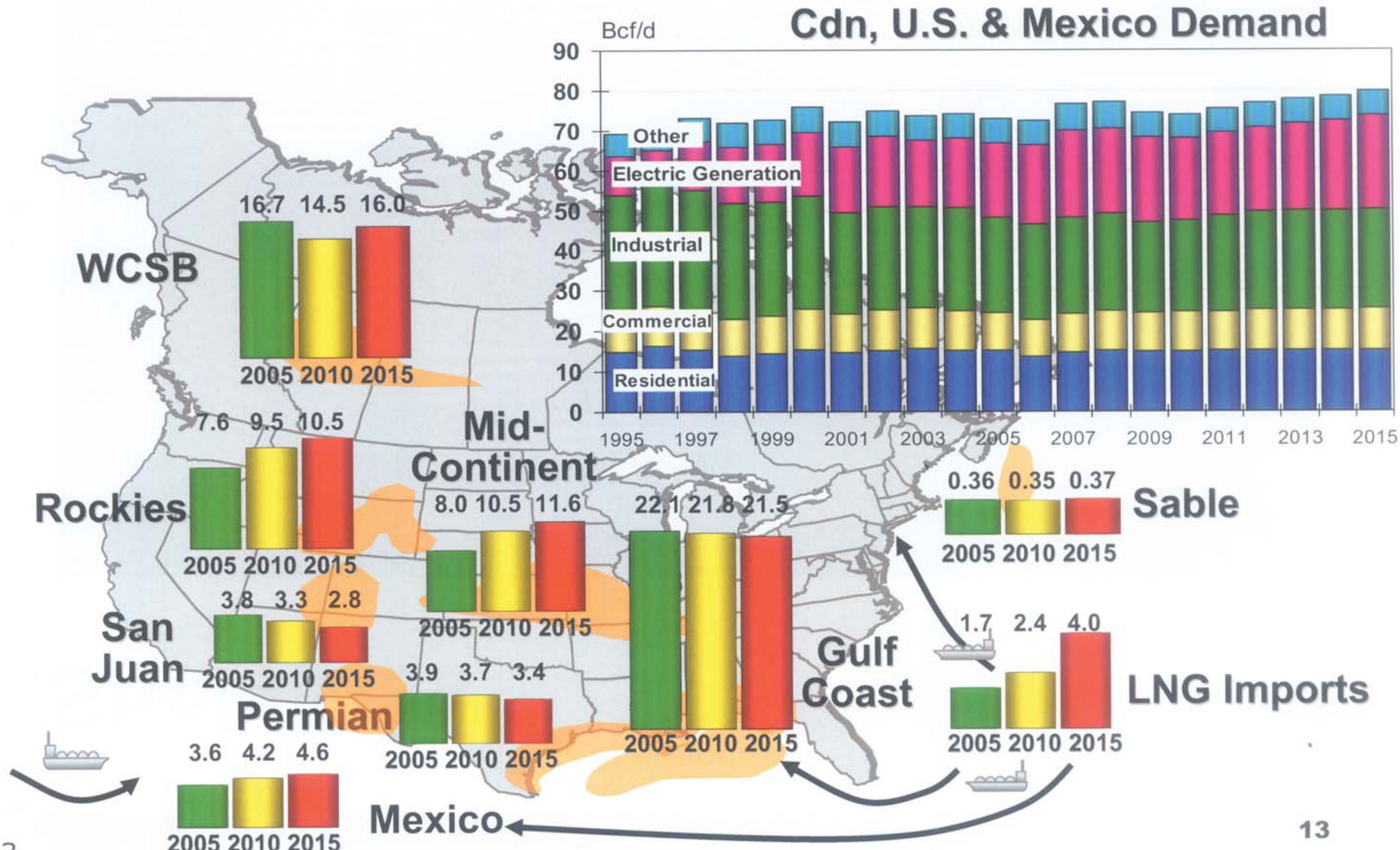
Meter Stations	Meter Number
Maritimes & Northeast Pipeline, LP-Baileyville	30012
Casco Bay Energy	30009
Portland Natural Gas Transmission	30006
Granite State Gas Transmission – Westbrook	30005
Granite State Gas Transmission – Eliot	30010
Newington Energy – Con Ed	30022
Granite State Gas Transmission – Newington	30003
Public Service of New Hampshire – Newington	30007
Tennessee Gas Pipeline – Haverhill	30002
GP Gypsum-Newington	30013
Tennessee Gas Pipeline – Dracut	30001
Maritimes & Northeast Pipeline Limited Partnership – Westbrook	30011
Bangor Gas – Veazie	30018
Bangor Gas – Bucksport	30017
Maine Natural Gas – Gorham	30019
Maine Natural Gas – Bowdoin	30023
Methuen – East Delivery	30024
Beverly – South Delivery	30025
Portland Natural Gas Transmission	30026
KeySpan Energy – Haverhill	30027
Northern Utilities – Lewiston	30028

Issued by: J. F. McHugh, Director, Rates & Regulatory Affairs
Issued on: April 30, 2008

Effective on: June 1, 2008

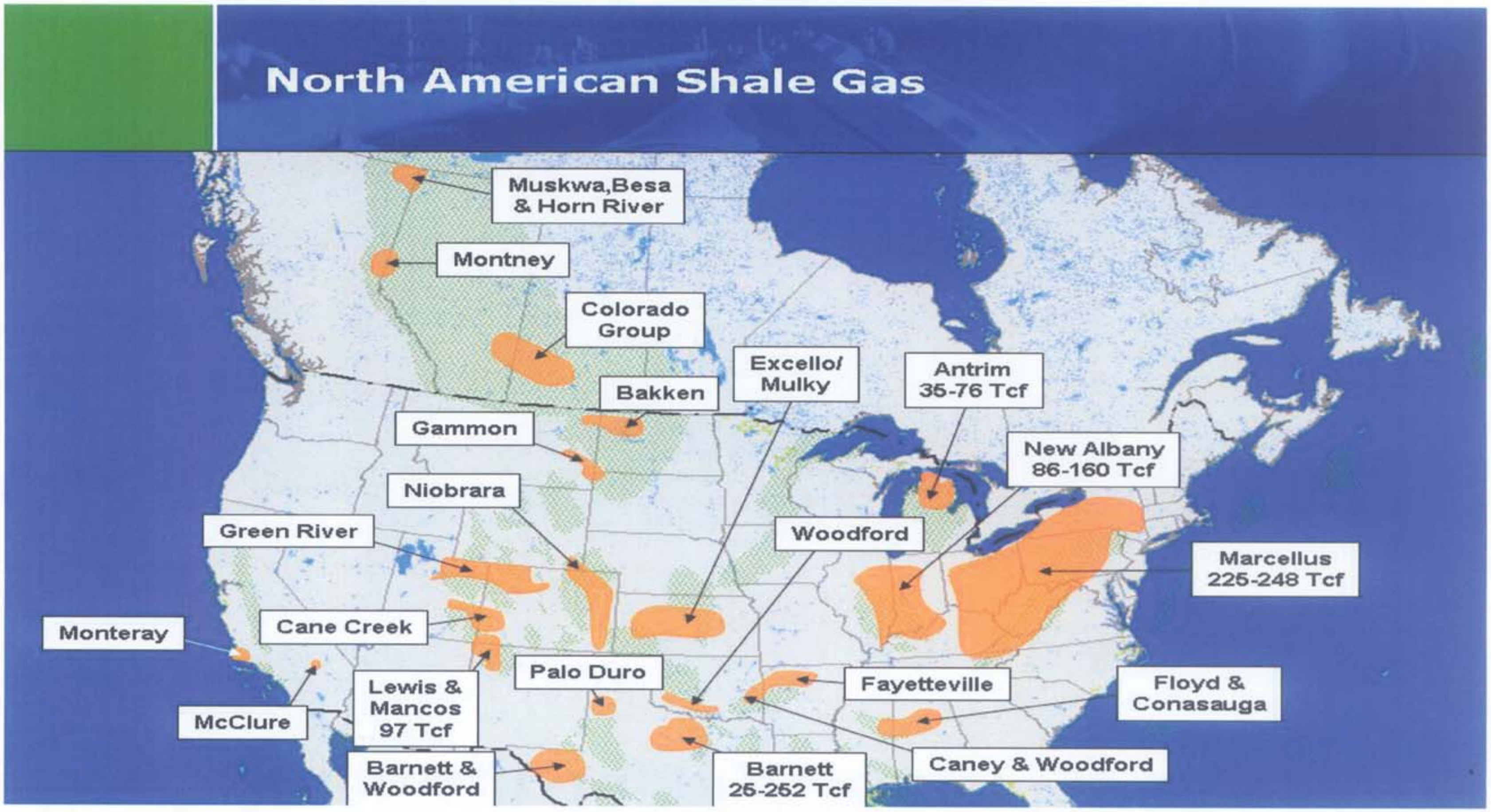
Natural Gas Supply and Demand

North American Supply/Demand (Bcf/d)

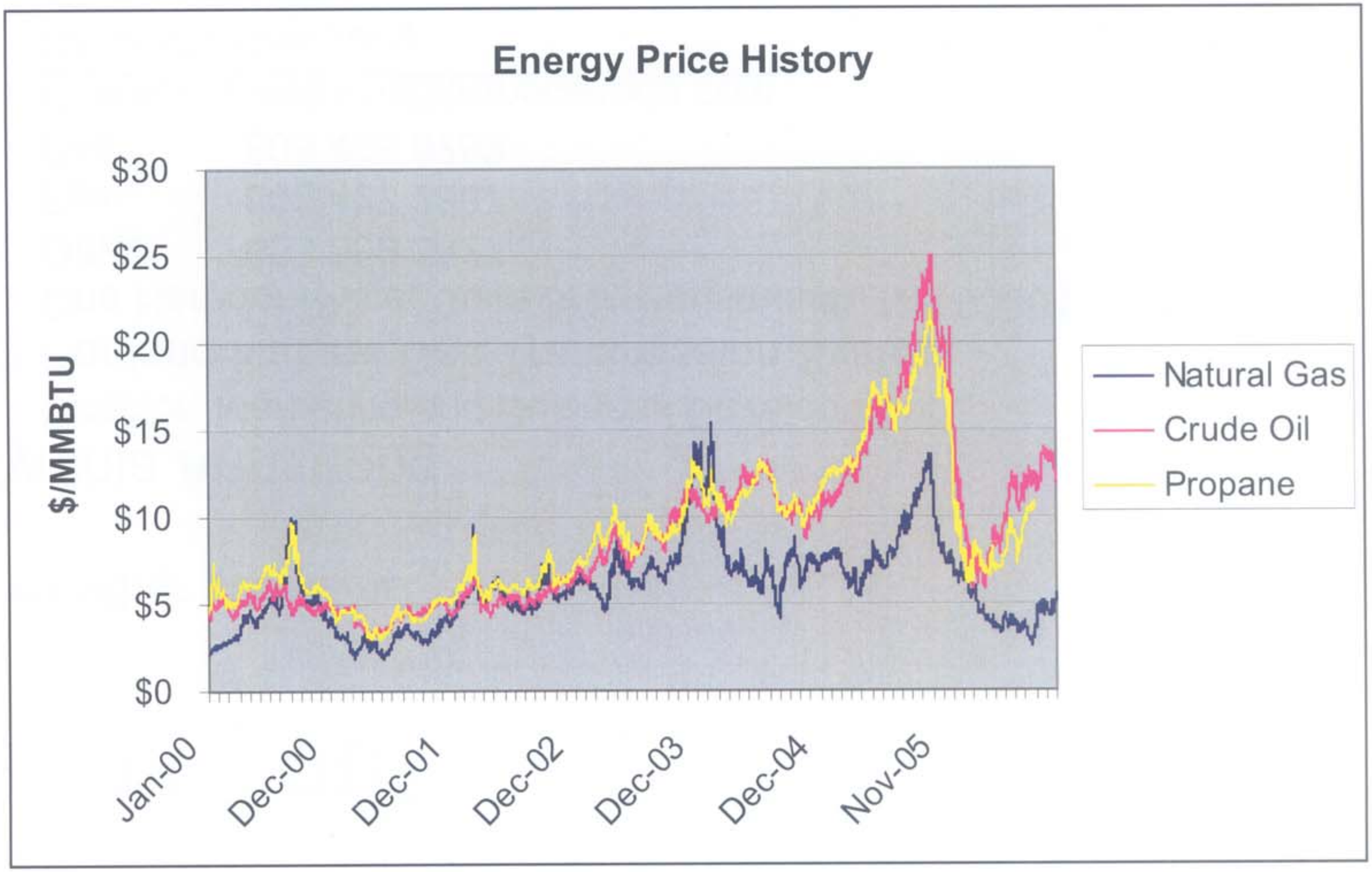


13

Shale Gas


North American Shale Gas
Muskwa,Besa & Horn River
Montney
Colorado Group
Bakken
Excello/ Mulky
Antrim 35-76 Tcf
Gammon
New Albany 86-160 Tcf
Niobrara
Green River
Woodford
Marcellus 225-248 Tcf
Monteray
Cane Creek
Palo Duro
Fayetteville
Floyd & Conasauga
Lewis & Mancos 97 Tcf
McClure
Caney & Woodford
Barnett & Woodford
Barnett 25-252 Tcf

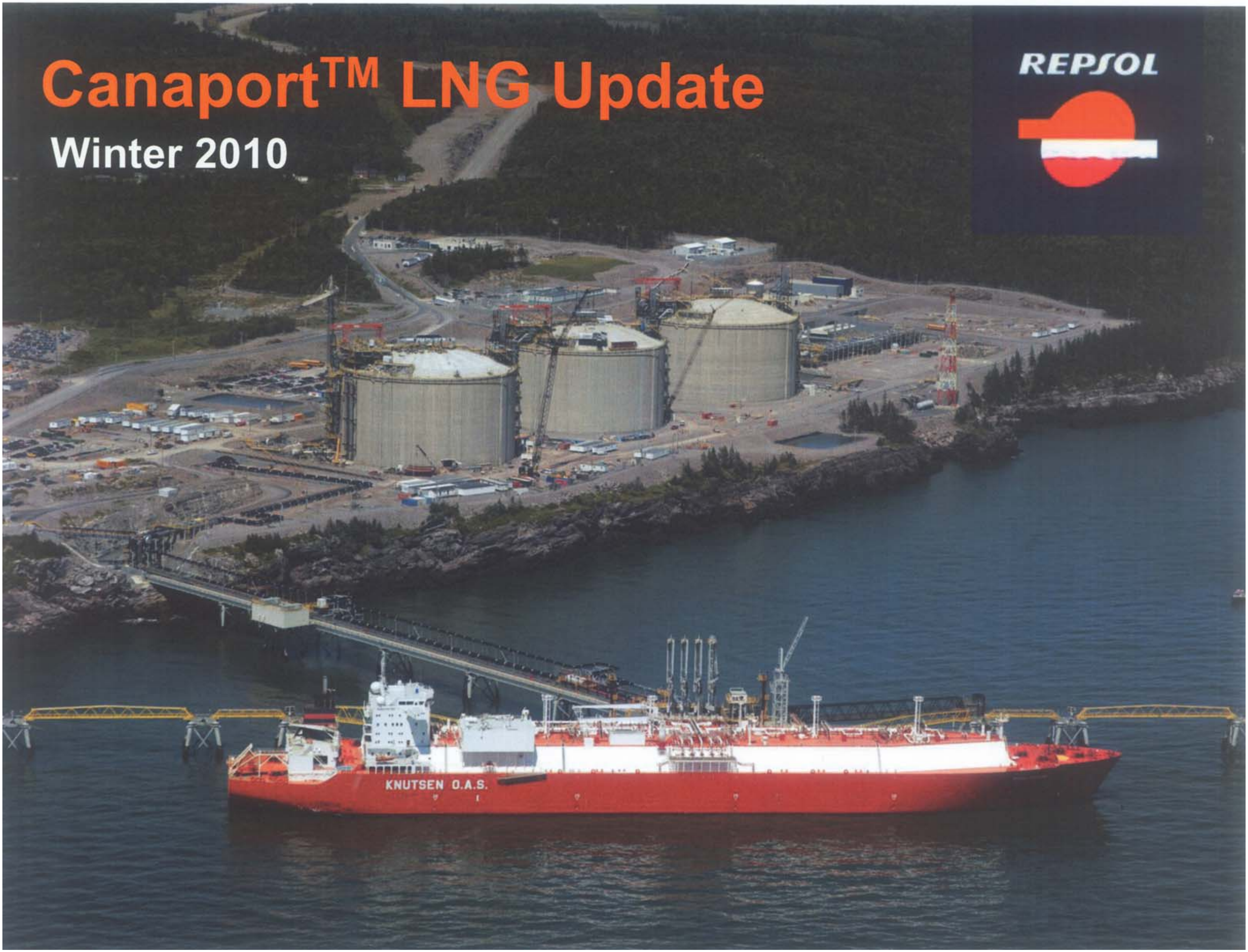
Natural Gas Price vs. Oil, Propane



Thank you!

- For further questions:

- Cynthia Armstrong
  - Director, Marketing and Business Development
  - Portland Natural Gas Transmission System
  - One Harbour Place, Suite 375, Portsmouth, NH 03801
  - Office: 603 559 5527
  - Fax: 603 427 2807
  - Cell: 603 498 0782
  - Cynthia_armstrong@transcanada.com
  - IM: cynthiarmstrong
  - www.pngts.com


Canaport™ LNG Update
Winter 2010
REPSOL
KNUTSEN O.A.S.

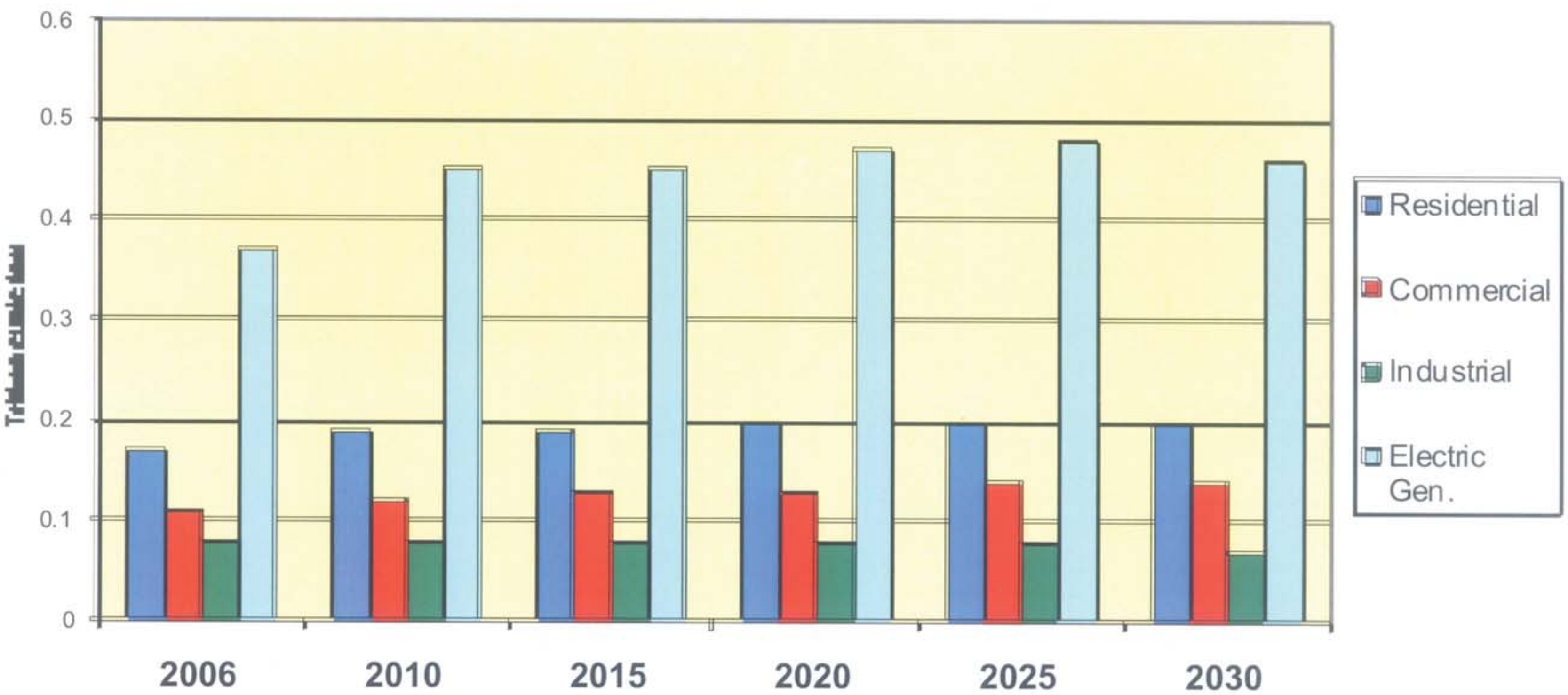
Repsol Overview

- **World-wide energy conglomerate headquartered in Madrid, Spain that has been in the energy industry for over 80 years**
- **Over 35,000 employees in more than 20 countries, with investments in more than 30 countries**
- **Total assets of ~$58 billion**
- **LNG investments:**
  - Canaport™ LNG regasification – 75% facility ownership and 100% (1 Bcfd) regas capacity ownership
  - Trinidad liquefaction – ownership interest in 3 trains ranging from 20% to 25% and ~450 MMcfd LNG purchase rights
  - Peru liquefaction (in service mid-2010) – 20% facility ownership and 100% (~500 MMcfd) LNG purchase rights
  - Leading LNG operator in the Atlantic basin via 50/50 JV with Gas Natural (Stream) - commercialized 231 cargoes in 2007; have 12 LNG tankers under long-term charter and 6 new tankers on order

Projected New England Gas Demand Growth

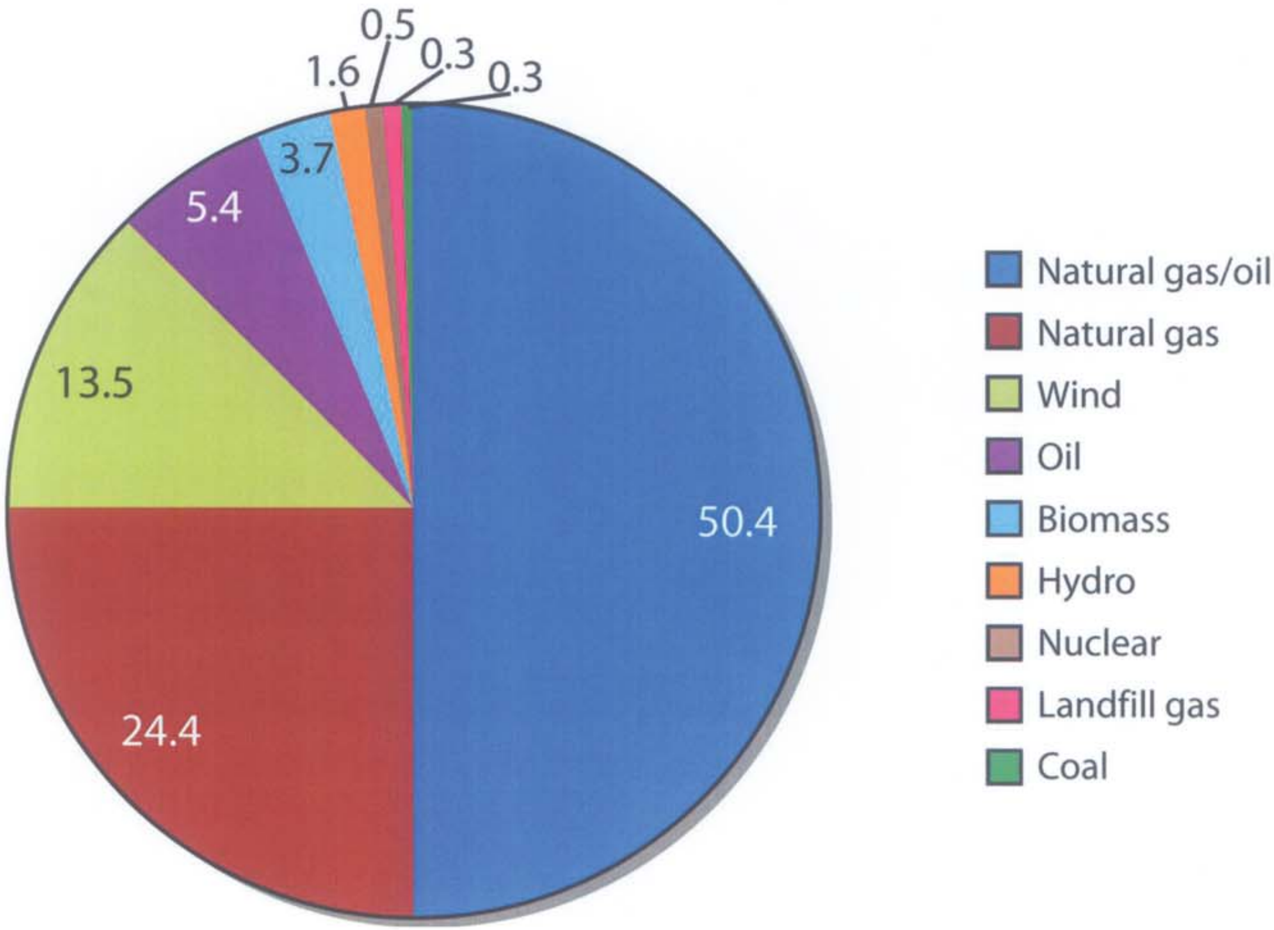
Over the next 25 years, the 2nd greatest rate of regional growth in the U.S. Natural gas demand is projected to grow by 22% from 2006 to 2025, from approx. 740 Bcf to 900 Bcf annually

Second Largest Growth in US



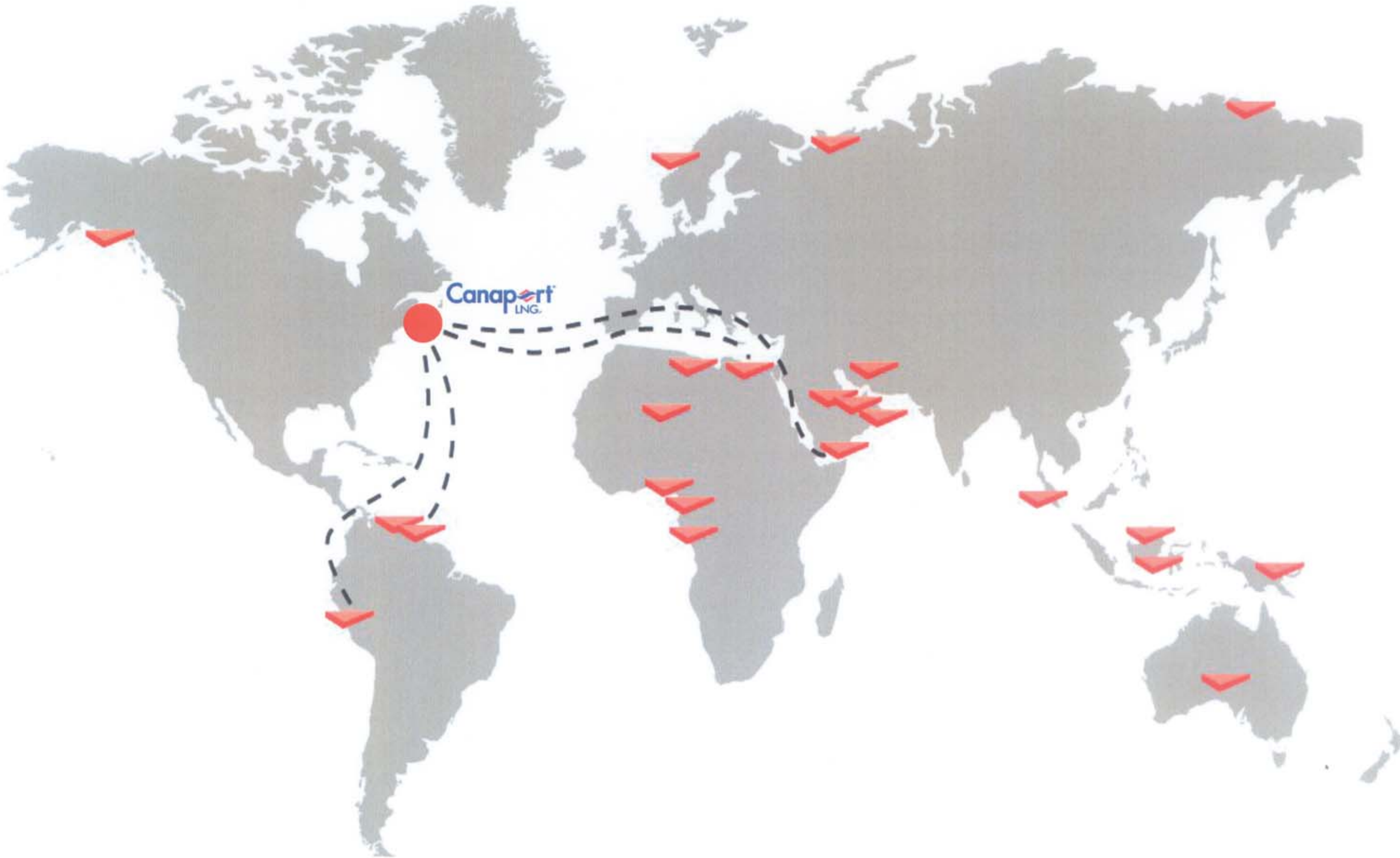
Source: U.S. Energy Information Administration, "2008 Annual Energy Outlook"

Power Generation by Fuel Type

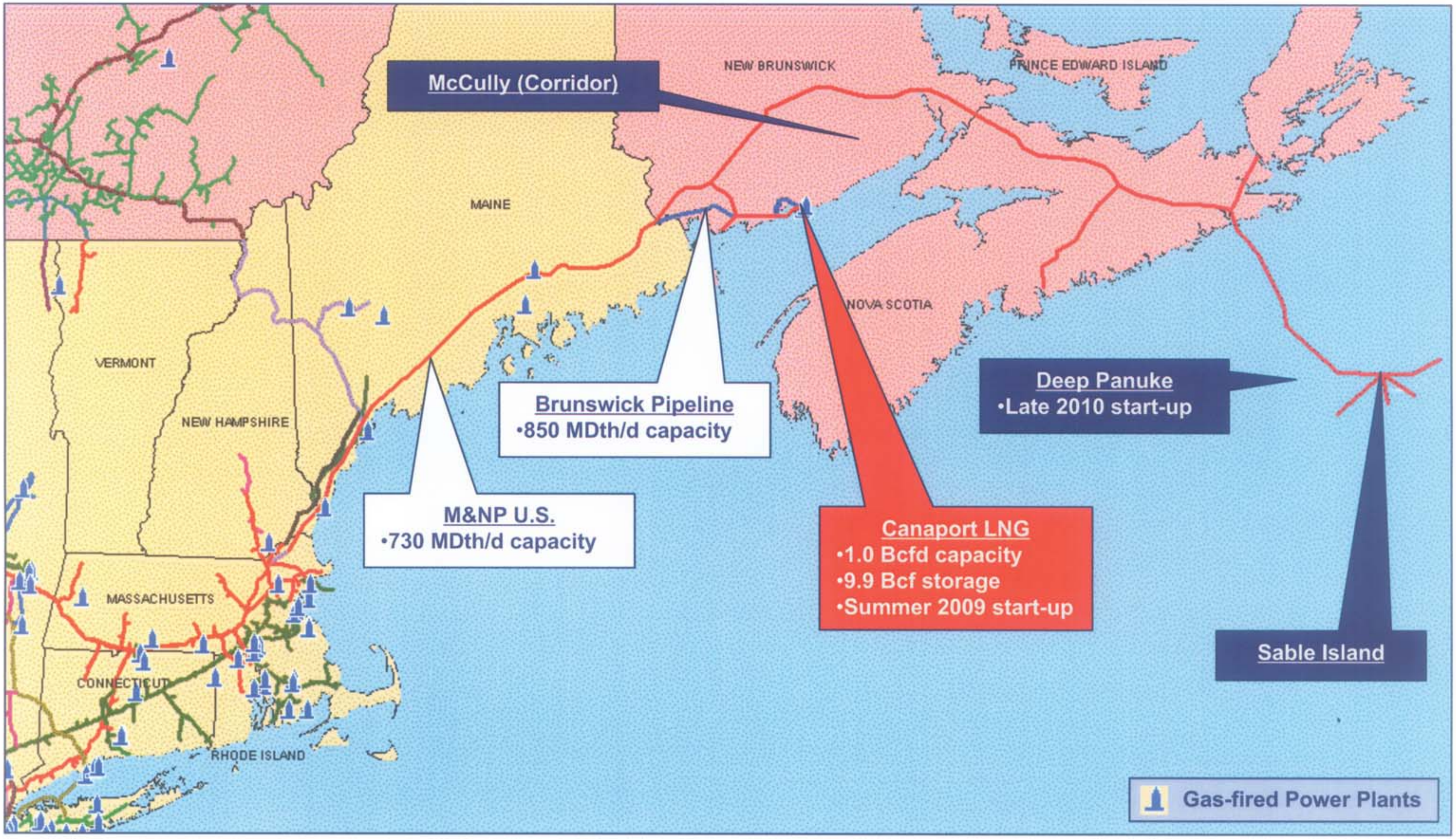


Source: ISO New England

Canaport LNG Global Sources



Gas Supply Diversification



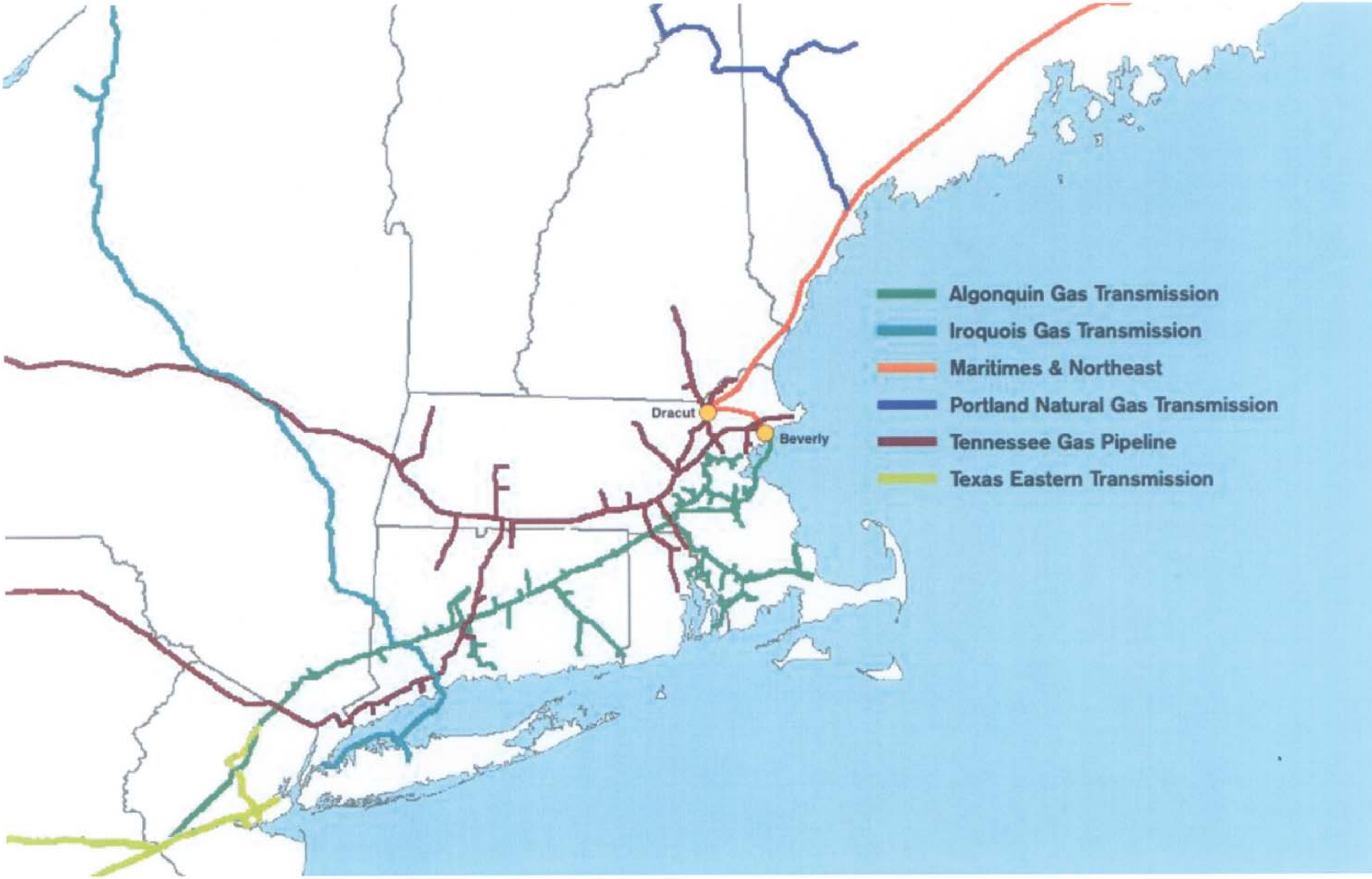
Canaport LNG Benefits

- Provides new source of safe, clean, and efficient gas supply to growing Northeast U.S. energy market
- Back-feeds the capacity constrained Northeast U.S. pipeline grid and minimizes new facility additions
- Attracts LNG suppliers to the high value gas markets in Northeast U.S. and Maritimes Canada
- Supplements declining Western and Maritimes Canada gas production
- Provides reliable back-up supply source when disruptions or restrictions occur due to weather events or other unscheduled outages
- Adds LNG storage that is readily accessible to the Northeast U.S. and Maritimes Canada markets

Q-FLEX MV Mesaimeer Arrives at Canaport LNG

REPSOL

A Safe, Clean, Reliable Source of Natural Gas



APPENDIX B: CATALOG OF CHP TECHNOLOGIES, US EPA COMBINED HEAT & POWER PARTNERSHIP, DEC. 2008

See http://www.epa.gov/chp/index.html for the entire report.

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Catalog of CHP Technologies

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

December 2008

Introduction to CHP Technologies

Introduction

Interest in combined heat and power (CHP) technologies has grown among energy customers, regulators, legislators, and developers over the past decade as consumers and providers seek to reduce energy costs while improving service and reliability. CHP is a specific form of distributed generation (DG), which refers to the strategic placement of electric power generating units at or near customer facilities to supply onsite energy needs. CHP enhances the advantages of DG by the simultaneous production of useful thermal and power output, thereby increasing the overall efficiency.

CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

EPA offers this catalog of CHP technologies as an online educational resource for regulatory, policy, permitting, and other interested CHP stakeholders. EPA recognizes that some energy projects will not be suitable for CHP; however, EPA hopes that this catalog will assist readers in identifying opportunities for CHP in applications where thermal-only or electric-only generation are currently being considered.

The remainder of this introductory summary is divided into sections. The first section provides a brief overview of how CHP systems work and the key concepts of efficiency and power-to-heat ratios. The second section summarizes the cost and performance characteristics of five CHP technologies in use and under development.

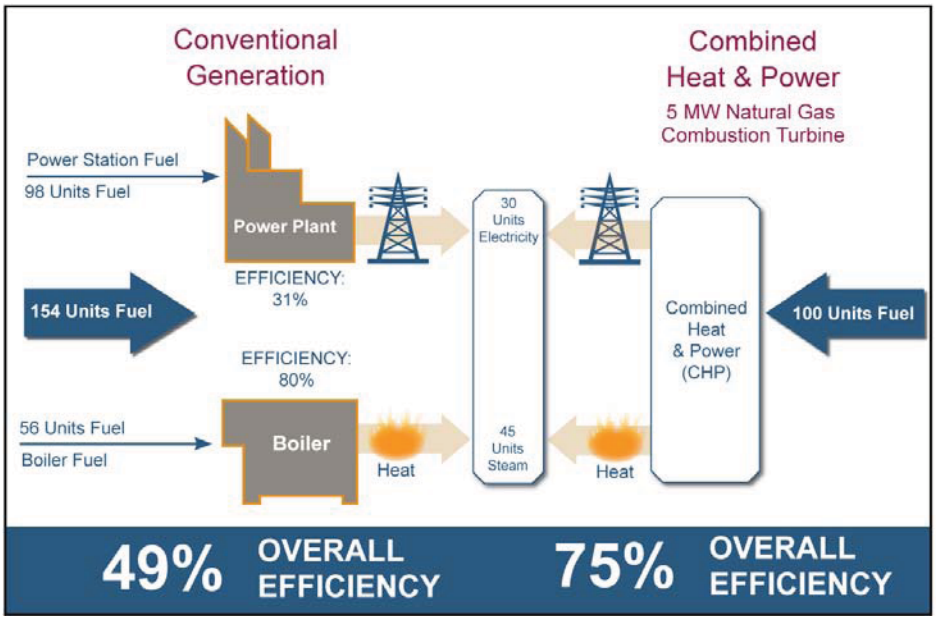
Overview of Combined Heat and Power

What is Combined Heat and Power?

CHP is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components—prime mover (heat engine), generator, heat recovery, and electrical interconnection—configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers for CHP systems include reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells. These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

Figure 1 shows the efficiency advantage of CHP compared with conventional central station power generation and onsite boilers. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. CHP systems utilize less fuel than separate heat and power generation, resulting for same level of output, resulting in fewer emissions.

Figure 1: CHP versus Separate Heat and Power (SHP) Production



Note: Assumes national averages for grid electricity and incorporates electricity transmission losses.

Expressing CHP Efficiency

Many of the benefits of CHP stem from the relatively high efficiency of CHP systems compared to other systems. Because CHP systems simultaneously produce electricity and useful thermal energy, CHP efficiency is measured and expressed in a number of different ways.[1] Table I summarizes the key elements of efficiency as applied to CHP systems.

[1] Measures of efficiency are denoted either as lower heating value (LHV) or higher heating value (HHV). HHV includes the heat of condensation of the water vapor in the products. Unless otherwise noted, all efficiency measures in this section are reported on an HHV basis.

Table I: Measuring the Efficiency of CHP Systems			
System	**Component**	**Efficiency Measure**	**Description**
Separate heat and power (SHP)	Thermal Efficiency (Boiler)	$EFF_Q = \frac{\text{Net Useful Thermal Output}}{\text{Energy Input}}$	Net useful thermal output for the fuel consumed.
	Electric-only generation	$EFF_P = \frac{\text{Power Output}}{\text{Energy Input}}$	Electricity Purchased From Central Stations via Transmission Grid.
	Overall Efficiency of separate heat and power (SHP)	$EFF_{SHP} = \frac{P + Q}{P/EFF_{Power} + Q/EFF_{Thermal}}$	Sum of net power (P) and useful thermal energy output (Q) divided by the sum of fuel consumed to produce each.
Combined heat and power (CHP)	Total CHP System Efficiency	$EFF_{Total} = (P + Q)/F$	Sum of the net power and net useful thermal output divided by the total fuel (F) consumed.
	FERC Efficiency Standard	$EFF_{FERC} = \frac{(P + Q/2)}{F}$	Developed for the Public Utilities Regulatory Act of 1978, the FERC methodology attempts to recognize the quality of electrical output relative to thermal output.
	Effective Electrical Efficiency (or Fuel Utilization Efficiency, FUE):	$FUE = \frac{P}{F - Q/EFF_{Thermal}}$	Ratio of net power output to net fuel consumption, where net fuel consumption excludes the portion of fuel used for producing useful heat output. Fuel used to produce useful heat is calculated assuming typical boiler efficiency, usually 80 percent.
	Percent Fuel Savings	$S = 1 - \frac{F}{P/EFF_P + Q/EFF_Q}$	Fuel savings compares the fuel used by the CHP system to a separate heat and power system. Positive values represent fuel savings while negative values indicate that the CHP system is using more fuel than SHP.

<u>Key:</u>
P = Net power output from CHP system
Q = Net useful thermal energy from CHP system
F = Total fuel input to CHP system
EFF_P = Efficiency of displaced electric generation
EFF_Q = Efficiency of displaced thermal generation

As illustrated in Table I the efficiency of electricity generation in power-only systems is determined by the relationship between net electrical output and the amount of fuel used for the power generation. **Heat rate**, the term often used to express efficiency in such power generation systems, is represented in terms of Btus of fuel consumed per kWh of electricity generated. However, CHP plants produce useable heat as well as electricity. In CHP systems, the **total CHP efficiency** seeks to capture the energy content of both electricity and usable steam and is the net electrical output plus the net useful thermal output of the CHP system divided by the fuel consumed in the production of electricity and steam. While total CHP efficiency provides a measure for capturing the energy content of electricity and steam produced it does not adequately reflect the fact that electricity and steam have different qualities. The quality and value of electrical output is higher relative to heat output and is evidenced by the fact that electricity can be transmitted over long distances and can be converted to other forms of energy. To account for these differences in quality, the Public Utilities Regulatory Policies Act of 1978 (PURPA) discounts half of the thermal energy in its calculation of the efficiency standard (Eff_{FERC}). The EFF_{FERC} is represented as the ratio of net electric output plus half of the net thermal output to the total fuel used in the CHP system. Opinions vary as to whether the standard was arbitrarily set, but the FERC methodology does recognize the value of different forms of energy. The following equation calculates the FERC efficiency value for CHP applications.

$$EFF_{FERC} = \frac{P + Q/2}{F}$$

Where: P = Net power output from CHP system F = Total fuel input to CHP system Q = Net thermal energy from CHP system

Another definition of CHP efficiency is **effective electrical efficiency**, also known as **fuel utilization effectiveness (FUE)**. This measure expresses CHP efficiency as the ratio of net electrical output to net fuel consumption, where net fuel consumption excludes the portion of fuel that goes to producing useful heat output. The fuel used to produce useful heat is calculated assuming typical boiler efficiency, generally 80 percent. The effective electrical efficiency measure for CHP captures the value of both the electrical and thermal outputs of CHP plants. The following equation calculates FEU.

$$FUE = \frac{P}{F - Q/EFF_Q}$$

Where: Eff_Q = Efficiency of displaced thermal generation

FUE captures the value of both the electrical and thermal outputs of CHP plants and it specifically measures the efficiency of generating power through the incremental fuel consumption of the CHP system.

EPA considers fuel savings as the appropriate term to use when discussing CHP benefits relative to separate heat and power (SHP) operations. Fuel savings compares the fuel used by the CHP system to a separate heat and power system (i.e. boiler and electric-only generation). The following equation determines percent fuel savings (S).

$$S = 1 - \left[\frac{F}{P/Eff_P + Q/Eff_Q} \right]$$

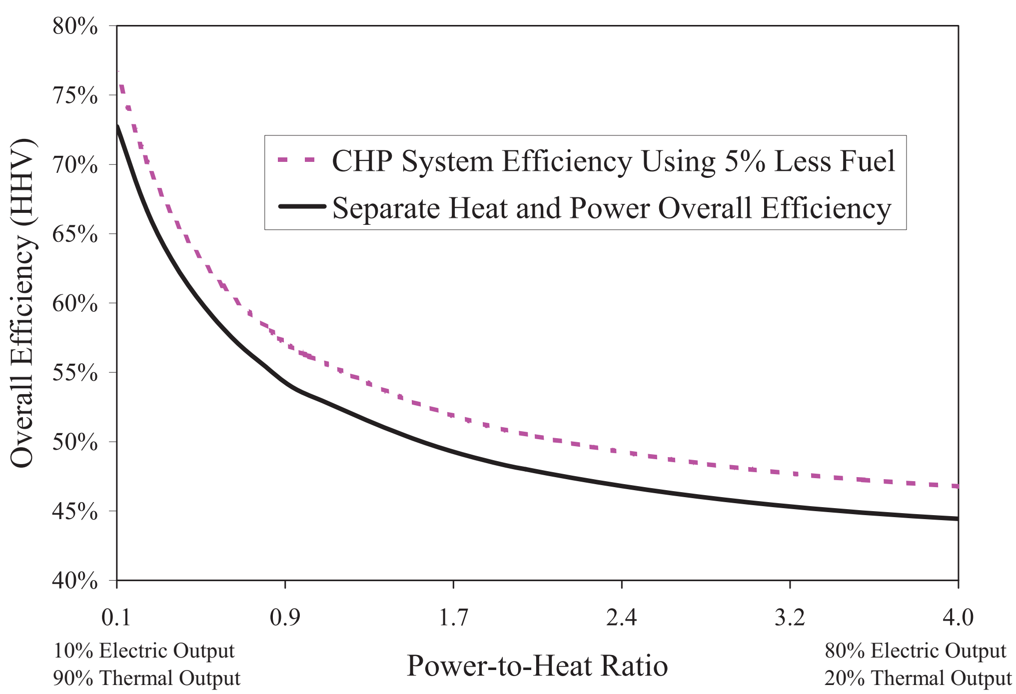
Where:
Eff_P = Efficiency of displaced electric generation
Eff_Q = Efficiency of displaced thermal-only facility

In the fuel saving equation given above, the numerator in the bracket term denotes the fuel used in the production of electricity and steam in a CHP system. The denominator describes the sum of the fuel used in the production of electricity (P/Eff_P) and thermal energy (Q/Eff_Q) in separate heat-and-power operations. Positive values represent fuel savings while negative values indicate that the CHP system in question is using more fuel than separate heat and power generation.

Another important concept related to CHP efficiency is the **power-to-heat ratio**. The power-to-heat ratio indicates the proportion of power (electrical or mechanical energy) to heat energy (steam or hot water) produced in the CHP system. Because the efficiencies of power generation and steam generation are likely to be considerably different, the power-to-heat ratio has an important bearing on how the total CHP system efficiency might compare to that of a separate power-and-heat system. Figure 2 illustrates this point. The illustrative curves display how the overall efficiency might change under alternate power-to-heat ratios for a separate power-and-heat system and a CHP system (for illustrative purposes, the CHP system is assumed to use 5 percent less fuel than its separate heat-and-power counterpart for the same level of electrical and thermal output).

Figure 2: Equivalent Separate Heat and Power Efficiency

Assumes 40 percent efficient electric and 80 percent efficient thermal generation



Overview of CHP Technologies

This catalog is comprised of five chapters that characterize each of the different CHP technologies (gas turbine, reciprocating engines, steam turbines, microturbines, and fuel cells) in detail. The chapters supply information on the applications of the technology, detailed descriptions of its functionality and design characteristics, performance characteristics, emissions, and emissions control options. The following sections provide snapshots of the five technologies, and a comparison of key cost and performance characteristics across the range of technologies that highlights the distinctiveness of each. Tables II and III provide a summary of the key cost and performance characteristics of the CHP technologies discussed in the catalog.

<table>
<tr><th colspan="4">Table II: Summary of CHP Technologies</th></tr>
<tr><th>CHP system</th><th>Advantages</th><th>Disadvantages</th><th>Available sizes</th></tr>
<tr><td>Gas turbine</td><td>High reliability.
Low emissions.
High grade heat available.
No cooling required.</td><td>Require high pressure gas or in-house gas compressor.
Poor efficiency at low loading.
Output falls as ambient temperature rises.</td><td>500 kW to 250 MW</td></tr>
<tr><td>Microturbine</td><td>Small number of moving parts.
Compact size and light weight.
Low emissions.
No cooling required.</td><td>High costs.
Relatively low mechanical efficiency.
Limited to lower temperature cogeneration applications.</td><td>30 kW to 250 kW</td></tr>
<tr><td>Spark ignition (SI) reciprocating engine</td><td rowspan="3">High power efficiency with part-load operational flexibility.
Fast start-up.
Relatively low investment cost.
Can be used in island mode and have good load following capability.
Can be overhauled on site with normal operators.
Operate on low-pressure gas.</td><td rowspan="3">High maintenance costs.
Limited to lower temperature cogeneration applications.
Relatively high air emissions.
Must be cooled even if recovered heat is not used.
High levels of low frequency noise.</td><td>< 5 MW in DG applications</td></tr>
<tr><td rowspan="2">Compression ignition (CI) reciprocating engine (dual fuel pilot ignition)</td><td>High speed (1,200 RPM) ≤4MW</td></tr>
<tr><td>Low speed (102-514 RPM) 4-75 MW</td></tr>
<tr><td>Steam turbine</td><td>High overall efficiency.
Any type of fuel may be used.
Ability to meet more than one site heat grade requirement.
Long working life and high reliability.
Power to heat ratio can be varied.</td><td>Slow start up.
Low power to heat ratio.</td><td>50 kW to 250 MW</td></tr>
<tr><td>Fuel Cells</td><td>Low emissions and low noise.
High efficiency over load range.
Modular design.</td><td>High costs.
Low durability and power density.
Fuels requiring processing unless pure hydrogen is used.</td><td>5 kW to 2 MW</td></tr>
</table>

Table III: Summary Table of Typical Cost and Performance Characteristics by CHP Technology*					
Technology	**Steam Turbine**[1]	**Recip. Engine**	**Gas Turbine**	**Microturbine**	**Fuel Cell**
Power efficiency (HHV)	15-38%	22-40%	22-36%	18-27%	30-63%
Overall efficiency (HHV)	80%	70-80%	70-75%	65-75%	55-80%
Effective electrical efficiency	75%	70-80%	50-70%	50-70%	55-80%
Typical capacity (MW_e)	0.5-250	0..01-5	0.5-250	0.03-0.25	0.005-2
Typical power to heat ratio	0.1-0.3	0.5-1	0.5-2	0.4-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/$kW_e$)	430-1,100	1,100-2,200	970-1,300 (5-40 MW)	2,400-3,000	5,000-6,500
O&M costs ($/$kWh_e$)	<0.005	0.009-0.022	0.004-0.011	0.012-0.025	0.032-0.038
Availability	near 100%	92-97%	90-98%	90-98%	>95%
Hours to overhauls	>50,000	25,000-50,000	25,000-50,000	20,000-40,000	32,000-64,000
Start-up time	1 hr - 1 day	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuel pressure (psig)	n/a	1-45	100-500 (compressor)	50-80 (compressor)	0.5-45
Fuels	all	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
Noise	high	high	moderate	moderate	low
Uses for thermal output	LP-HP steam	hot water, LP steam	heat, hot water, LP-HP steam	heat, hot water, LP steam	hot water, LP-HP steam
Power Density (kW/m^2)	>100	35-50	20-500	5-70	5-20
NO_x (lb/MMBtu) (not including SCR)	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.013 rich burn 3-way cat. 0.17 lean burn	0.036-0.05	0.015-0.036	0.0025-.0040
$lb/MWh_{TotalOutput}$ (not including SCR)	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.06 rich burn 3-way cat. 0.8 lean burn	0.17-0.25	0.08-0.20	0.011-0.016

* Data are illustrative values for typically available systems; All costs are in 2007$

[1]For steam turbine, not entire boiler package

Technology

The first chapter of the catalog focuses on gas turbines as a CHP technology. Gas turbines are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas, synthetic gas, landfill gas, and fuel oils. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycle systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 900 degree Fahrenheit (ºF). Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid. Simple-cycle CHP applications are common in smaller installations, typically less than 40 MW.

The second chapter of the catalog focuses on microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available models range in sizes from 30 kW to 250 kW.

The third chapter in the catalog describes the various types of reciprocating engines used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI; however, propane, gasoline and landfill gas can also be used. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

The fourth chapter of the catalog is dedicated to steam turbines that generate electricity from the heat (steam) produced in a boiler. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas, solid waste, coal, wood, wood waste, and agricultural by-products. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

Chapter five in the catalog deals with an emerging technology that has the potential to serve power and thermal needs cleanly and efficiently. Fuel cells use an electrochemical or battery-like process to convert the chemical energy of hydrogen into water and electricity. In CHP applications, heat is generally recovered in the form of hot water or low-pressure steam (<30 psig) and the quality of heat is dependent on the type of fuel cell and its operating temperature. Fuel cells use hydrogen, which can be obtained from natural gas, coal gas, methanol, and other hydrocarbon fuels. There are currently five types of fuel cells under development. These include (1) phosphoric acid (PAFC), (2) proton exchange membrane (PEMFC), (3) molten carbonate (MCFC), (4) solid oxide (SOFC), and (5) alkaline (AFC). PAFC systems are commercially available in two sizes, 200 kW and 400 kW, and two MCFC systems are commercially available, 300 kW and 1200 kW. Due to the high installed cost of fuel cell systems, the most prominent DG applications of fuel cell systems are CHP-related.

Installed Cost[1]

The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost.

Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines (5-40 MW) ranges from $970/kW to $1,300/kW, while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from $2,400/kW to $3,000/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of $1,100/kW to $2,200/kW, and steam turbines have total installed costs ranging from $350/kW to $700/kW. Fuel cells are currently the most expensive among the five CHP technologies with total installed costs ranging between $5,000/kW and $6,500/kW.

O&M Cost

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from $0.004/kWh to $0.011/kWh for typical gas turbines, from $0.009/kWh to $0.022/kWh for commercially available gas engine gensets and are typically less than $0.005/kWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines are $0.015/kWh to $0.030/kWh. For fuel cells O&M costs range between $0.032/kWh and $0.038/kWh.

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[1] All $ are 2007$.

Start-up Time

Start-up times for the five CHP technologies described in this catalog can vary significantly depending on the technology and fuel used. Gas turbines have relatively short start up time, though heat recovery considerations may constraint start up times. Microturbines require several minutes for start-up but require a power storage unit (typically a battery UPS) for start-up if the microturbine system is operating independently of the grid. Reciprocating engines have fast start-up capability, which allows for timely resumption of the system following a maintenance procedure. In peaking or emergency power applications, reciprocating engines can most quickly supply electricity on demand. Steam turbines, on the other hand, require long warm-up periods in order to obtain reliable service and prevent excessive thermal expansion, stress and wear. Fuel cells also have relatively long start-up times (especially for MCFC and SOFC). The longer start-up times for steam turbines and fuel cells make them more applicable to baseload needs.

Availability

Availability indicates the amount of time a unit can be used for electricity and/or steam production. Availability generally depends on the operational conditions of the unit. Frequent starts and stops of gas turbines can increase the likelihood of mechanical failure, though steady operation with clean fuels can permit gas turbines to operate for about a year without a shutdown. The estimated availability for gas turbines operating on clean gaseous fuels such as natural gas is over 95 percent.

Manufacturers of microturbines have targeted availabilities between 98 and 99 percent. Natural gas engine availabilities generally vary with engine type, speed, and fuel quality. Typically demonstrated availabilities for natural gas engine gensets in CHP applications is approximately 95 percent. Steam turbines have high availability rates—usually greater than 99 percent with longer than one year between shutdowns for maintenance and inspections. However, for purposes of CHP application it should be noted that this high availability rate is only applicable to the steam turbine itself and not to the boiler or HRSG that is supplying the steam. Some demonstrated and commercially available fuel cells have achieved greater than 90 percent availability.

Thermal Output

The ability to produce useful thermal energy from exhaust gases is the primary advantage of CHP technologies. Gas turbines produce a high quality (high temperature) thermal output suitable for most CHP applications. High-pressure steam can be generated or the exhaust can be used directly for process heating and drying. Microturbines produce exhaust output at temperatures in the 400ºF to 600ºF range, suitable for supplying a variety of building thermal needs. Reciprocating engines can produce hot water and low-pressure steam. Steam turbines are capable of operating over a broad range of steam pressures. They are custom designed to deliver the thermal requirements of CHP applications through use of backpressure or extraction steam at the appropriately needed pressure and temperature. Waste heat from fuel cells can be used primarily for domestic hot water and space heating applications.

Efficiency

Total CHP efficiency is a composite measure of the CHP fuel conversion capability and is expressed as the ratio of net output to fuel consumed. As explained earlier, for any technology the total CHP efficiency will vary depending on size and power-to-heat ratio. Combustion turbines achieve higher efficiencies at greater size and with higher power-to-heat ratios. The total CHP efficiency for gas turbines between 1 MW and 40 MW, and with power-to-heat ratios between 0.5 and 1.0, range from 70 percent to 75 percent. Unlike gas turbines, microturbines typically achieve 65 percent to 75 percent total CHP efficiency for a range of power-to-heat ratios. Commercially available natural gas spark engines ranging between 100 kW to 5 MW are likely to have total CHP efficiency in the 75 percent to 80 percent range. The total CHP efficiency of such engines will decrease with unit-size, and also with higher power-to-heat ratios. Although performance of steam turbines may differ substantially based on the fuel used, they are likely to achieve near 80 percent total CHP efficiency across a range of sizes and power-to–heat ratios. Fuel cell technologies may achieve total CHP efficiency in the 65 percent to 75 percent range.

Emissions

In addition to cost savings, CHP technologies offer significantly lower emissions rates compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly, emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.17 to 0.25 lbs/MWh[2] with no post-combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.23 lbs/MWh and 0.28 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2. Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 4ppmy and 9 ppmv or 0.08 lbs/MWh and 0.20 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.06 lbs/MWh and 0.54 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from small "rich burn" reciprocating engines with integral 3-way catalyst exhaust treatment can be as low as 0.06

[2] The NOx emissions reported in this section in lb/MWh are based on the total electric and thermal energy provided by the CHP system in MWh.

lbs/MWh. Larger lean burn engines have values of around 0.8 lbs/MWh without any exhaust treatment; however, these engines can utilize SCR for NOx reduction.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbines depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x range between 0.3 lbs/MMBtu and 1.24 lbs/MMBtu for coal, 0.2 lbs/MMBtu and 0.5 lbs/MMBtu for wood, and 0.1 lbs/MMBtu and 0.2 lbs/MMBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/MMBtu and 0.7 lbs/MMBtu for coal, approximately 0.06 lbs/MMBtu for wood, and 0.08 lbs/MMBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent.

SO_2 emissions from steam turbines depend largely on the sulfur content of the fuel used in the combustion process. SO_2 comprises about 95 percent of the emitted sulfur and the remaining 5 percent is emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

Fuel cell systems have inherently low emissions profiles because the primary power generation process does not involve combustion. The fuel processing subsystem is the only significant source of emissions as it converts fuel into hydrogen and a low energy hydrogen exhaust stream. The hydrogen exhaust stream is combusted in the fuel processor to provide heat, achieving emissions signatures of less than 0.019 lbs/MWh of CO, less than 0.016 lbs/MWh of NO_x and negligible SO_x without any after-treatment for emissions. Fuel cells are not expected to require any emissions control devices to meet current and projected regulations.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel-based CHP technologies. The amount of CO_2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/MMBtu; oil is 48 lbs of carbon/MMBtu and ash-free coal is 66 lbs of carbon/MMBtu.

Fuel Savings Equations

Absolute Fuel Savings:

$$F_{CHP} = F_{SHP} * (1-S) \text{ and } E_{SHP} = E_{CHP} * (1-S)$$

$$\text{Fuel Savings} = F_{SHP} - F_{CHP} = \frac{F_{CHP}}{1-S} - F_{CHP}$$

Where F_{CHP} = CHP fuel use
F_{SHP} = SHP fuel use
S = % fuel savings compared to SHP
E_{CHP} = CHP efficiency
E_{SHP} = SHP efficiency

$$= F_{CHP}\left[\frac{1}{1-S} - 1\right] = F_{CHP}\left[\frac{1}{1-S} - \frac{1-S}{1-S}\right] = F_{CHP}\left[\frac{1-1+S}{1-S}\right]$$

$$\text{Fuel Savings} = F_{CHP}\left[\frac{S}{1-S}\right] = F_{SHP} - F_{SHP} * (1-S) = F_{SHP} * S$$

Percentage Fuel Savings:

Equivalent separate heat and power (SHP) efficiency

$$Eff_{SHP} = \frac{\text{SHP Output}}{\text{SHP Fuel Input}} = \frac{P+Q}{P/Eff_P + Q/Eff_Q}$$

Where P = power output
Q = useful thermal output
Eff_P = power generation efficiency
Eff_Q = thermal generation efficiency

divide numerator and denominator by (P+Q)

$$Eff_{SHP} = \frac{1}{\frac{\%P}{Eff_P} + \frac{\%Q}{Eff_Q}}$$

Where percent P = P/(P+Q)
Percent Q =

CHP efficiency

$$Eff_{CHP} = \frac{P+Q}{F_{CHP}} = \frac{Eff_{SHP}}{(1-S)}$$

Substitute in equation for EFF_{SHP} and isolate S

$$\frac{P+Q}{F} = \frac{\frac{P+Q}{P/EFF_P + Q/EFF_Q}}{(1-S)}$$

$$(1-S)*\frac{P+Q}{F}=\frac{P+Q}{P/EFF_P+Q/EFF_Q}$$

Divide out (P+Q) and multiply by F

$$1-S=\frac{F}{\left(\frac{P}{Eff_P}+\frac{Q}{Eff_Q}\right)}$$

Percent fuel savings calculated from power and thermal output, CHP fuel input, and efficiency of displaced separate heat and power.

$$\boxed{S=1-\frac{F}{\frac{P}{Eff_P}+\frac{Q}{Eff_Q}}}$$

<u>Calculation of percentage power or percent thermal output from power to heat ratio:</u>

$$\text{Power to Heat Ratio}=X=P/Q=\%P/\%Q$$

$$P+Q=1$$

$$P=X*Q \qquad Q=\frac{P}{X}$$

$$P=X*(1-P) \qquad Q=\frac{1-Q}{X}$$

$$P=X-X*P \qquad Q*X=1-Q$$

$$P+X*P=X \qquad Q*(X+1)=1$$

$$P*(1+X)=X$$

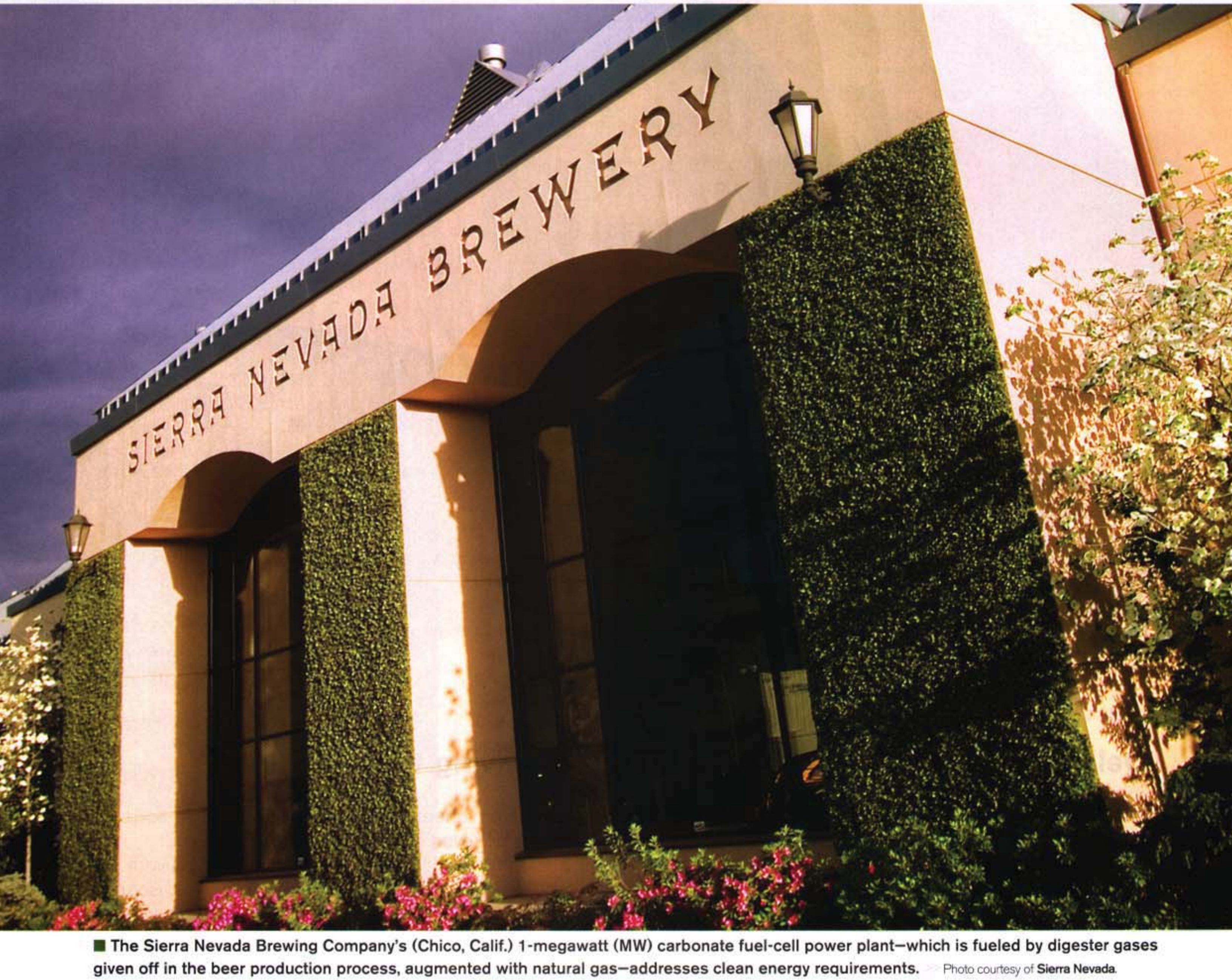
$$P=\frac{X}{1+X} \qquad Q=\frac{1}{X+1}$$

APPENDIX C: SIERRA NEVADA BREWERY FUEL CELL EXAMPLE

Pristine Power, Premium Beer

State-of-the-art brewing company meets its distributed generation needs using Ultra-Clean fuel cells and beer process byproducts.

By **Andy Skok**

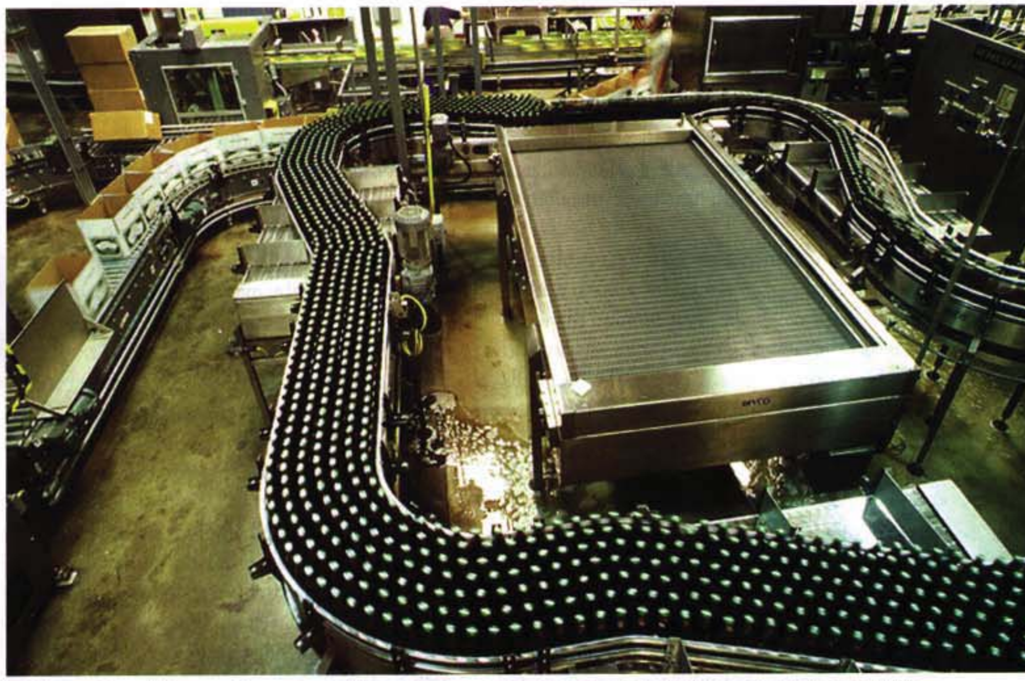


■ **The Sierra Nevada Brewing Company's (Chico, Calif.) 1-megawatt (MW) carbonate fuel-cell power plant—which is fueled by digester gases given off in the beer production process, augmented with natural gas—addresses clean energy requirements.** Photo courtesy of **Sierra Nevada**.

Brewing high-quality beer requires a high-quality, reliable source of power. A brewing company that regards earth-friendly production processes with the same degree of importance as the brewing of its premium beers wants to produce that power cleanly and efficiently. How can a brewer use all its natural resources wisely and realize new efficiencies in the process? With an onsite stationary fuel-cell power plant that provides reliable power, fuel flexibility, and produces the highest possible electricity from the available biogas.

The Sierra Nevada Brewing Company in Chico, Calif., has installed a 1-megawatt (MW) carbonate fuel-cell power plant to address its clean energy requirements. The system is fueled by digester gases given off in the beer production process, augmented with natural gas. The power plant provides virtually 100 percent of Sierra Nevada's baseload electrical requirements, using a non-combustion hydrogen reforming process that produces almost no pollutant emissions and dramatically reduced greenhouse gases compared with traditional fossil-fuel power plants. The result is high-quality, utility-grade electric power, usable heat from cogeneration, and ultra-clean emissions. In addition, overall energy efficiency for the new power system is twice that of power supplied from the electrical grid.

The new fuel cell is part of a large commitment to environmental responsibility by Sierra Nevada, which has incorporated heat recovery, byproduct recycling, and computerized energy reduction equipment into its state-of-the art beer-making processes. But Sierra quickly discovered that its fuel cells, more than just another addition to its environmental efforts, became the "heart" of an energy-cycle system of clean power, cogeneration and wastewater recycling.



■ Sierra Nevada's world-renowned beers are produced with high-quality electricity and high-value heat from the brewery's own fuel-cell power plants. >> Photo courtesy of Sierra Nevada.

THE FUEL CELL POWER PLANT

There are many types of fuel cells, from experimental mobile systems in Detroit's show cars to the ultra high-tech system found on the Space Shuttle. But one type—large stationary carbonate fuel cells like the one at Sierra Nevada—already has a history of proven results in distributed generation systems around the world. When Sierra Nevada founder Ken Grossman went looking for a fuel cell in 2004, products like the DFC300, a 250-kilowatt (kW) fuel-cell plant produced by FuelCell Energy, Inc., was an obvious choice. The fuel flexibility offered by the company's Direct FuelCell (DFC) power plants was an important part of the decision criteria.

Configured in size for such applications, the DFC300 is a high-temperature, high-efficiency carbonate fuel cell. The installation of four DFC300s offered Sierra Nevada the ability to provide virtually all of its baseload electrical power. DFC power plant operate on biofuels—gases from food processing, landfills, and wastewater treatment—in addition to natural gas, ethanol, diesel and coal gas. Sierra Nevada's four DFC300s use a combination of digester gas and natural gas to complete the hydrogen reforming process. Natural gas is provided through a standard distribution network. This ability to maximize electricity production from readily available onsite fuel resources is an important advantage. Other types of fuel cells require external fuel processing to obtain a supply of hydrogen.

The DFC power plant uses a modular design containing separately configured units for power generation (i.e., fuel cell modules), Electrical Balance of Plant (EBOP) including power conditioning and grid interconnect, and Mechanical Balance of Plant (MBOP) including fuel supply and conditioning, and heat recovery. Each module is arranged on its own skid to provide efficient transport to the installation site, installation flexibility, and ease of access for plant maintenance.

The MBOP incorporates a fuel and water treatment module and de-oxidizing reactors to treat the natural gas. The Heat Recovery Unit/Anode Gas Oxidizer (HRU/AGO) module then takes the treated fuel and cold water and produces a heated fuel/water mixture for delivery to the fuel-cell module, which consists of fuel cells arranged into stacks that produce DC power. The EBOP converts DC to AC for use in conjunction with the existing utility grid. This module contains the inverter, control system, operator interface, transformers and all grid interconnection hardware.

In addition to reducing overall fuel requirements and carbon dioxide emissions, the system eliminates air pollutants equivalent to removing 500 gasoline-powered cars from California roadways each year.

GREEN IS JUST THE START

This type of fuel cell initially gained popularity for its ultra-clean emissions signature, and recent installations have only served to heighten that advantage. The DFC300 is certified to meet the stringent distributed generation emissions standards established by the California Air Resources Board (CARB), which qualifies the fuel cell as an Ultra-Clean technology, and also exempts it from air-pollution control and air-quality district permitting requirements. The certification also qualifies the fuel cell for preferential rate treatment by the California Public Utilities Commission (CPUC), which includes the elimination of additional exit fees and standby charges. Combined with additional incentives from CPUC's Self-Generation Incentive Program (SGIP), the fuel-cell system demonstrated its ability to save Sierra Nevada money, not only with its efficient operation, but also with fast-track installation and rate benefits.

For an environmentally-conscious brewer in a state devoted to green solutions, such advantages can be priceless, because beyond the regulations lie the actual clean-air benefits at and around the brewery site. Because the fuel cells make their energy through a non-combustion process, they produce virtually zero emissions of nitrogen oxides (NOx), sulfur oxides (SOx), and particulate matter.

Thus, in addition to reducing overall fuel requirements and carbon dioxide emissions, the system eliminates air pollutants equivalent to removing 500 gasoline-powered cars from California roadways each year. These advantages, and Sierra Nevada's commitment to generating clean power, were highlighted by Governor Arnold Schwarzenegger in his speech at the dedication of Sierra Nevada's fuel cell plant in July 2005: "Like any business, Sierra Nevada was looking for stable, affordable, reliable power, and they wanted to limit the environmental impact of their operation," Schwarzenegger said. "They found the answer in a hydrogen fuel cell system that generates power onsite."

As Sierra Nevada joined the ranks of institutions noted for providing clean, distributed generation of electrical power, it began to realize that making the most of clean natural gas was only the beginning. The fuel cells quickly became the heart of a power cycle that maximizes their benefits, further reducing emissions and increasing the brewer's efficiency. The secret is twofold: Using the waste heat from the fuel cells to produce steam for the brewing process, and using a key byproduct of that process called Anaerobic Digester Gas (ADG) to fuel the DFC power plant. The DFC power plant converts the limited supply of ADG gas into the most electricity possible by a distributed generation technology, thereby maximizing the resource.

■ **The installation of four DFC300 high temperature, high-efficiency carbonate fuel cells provide the brewery virtually all of its baseload electrical power.** >> Photo courtesy of **Sierra Nevada**

COLD BEER STARTS WITH HOT STEAM

Because of their high operating temperatures, carbonate fuel cells are an excellent source of heat energy, and that heat energy is typically recovered to boost the cell's overall energy production efficiency. At Sierra Nevada, the 650-degree waste-heat from the fuel cells are harvested as 125-PSI steam, used not only for heating and boiler needs throughout the facility, but also to help power the brewing process itself by boiling the beer. The brewery's world-renowned beers are produced with high-quality electricity and high-value heat from its own fuel-cell power plants.

This cogeneration of useful energy from the waste heat associated with the conversion process is a key differentiator for large stationary fuel cell applications. Sierra Nevada's 1 MW fuel cell installation provides over 1.5 million BTUs of waste heat each year, which, when put to good use, can significantly boost the plant's overall efficiency and save money.

CLEANER POWER FROM CLEANING HOUSE

Beer brewing produces a variety of byproducts, including large amounts of wastewater. As part of the water-treatment process, anaerobic digesters use natural biological processes to generate methane from this wastewater. The brewery site's filtration system then purifies this methane gas and feeds it to the fuel-cell power plants, further reducing the plant's need for pipeline fuel.

The DFC300 can operate with this natural fuel just as efficiently as with natural gas. Two of the plant's four DFC300s can now operate on ADG, natural gas, or any combination of the two fuels. Using this system, the fuel cells can provide up to 400 kW of electricity exclusively from ADG, reducing the brewery's fuel costs by up to 40 percent each year, and maximizing electricity production from the available biogas. Not only does this multi-fuel ability reduce reliance on the power grid, it further reduces the net levels of carbon released into the atmosphere, and saves money. And regardless of the fuel used, the fuel-cell plants are classified as an Ultra-Clean installation under California law.

A RESPONSIBLE NEIGHBOR

By producing power onsite at the facility, Sierra Nevada reduces the need for power from the local utility, allowing the grid to operate in a less congested, and therefore more efficient, manner. This benefit came into clear focus during the California heat wave of 2006, when the utility asked the brewery to reduce its energy use to the baseload amount supplied by the fuel cells to avoid leaving nearby Chico residents with no power to support critical air-conditioning needs in the 110-degree Fahrenheit heat—a potentially life threatening scenario. The brewery was able to maintain normal operations thanks to the fuel cells, and the citizens of Chico continued to have electricity without the need to resort to emergency diesel generators.

POWER, PROFITS AND PROFILE

The overall process, as described by Grossman, is a "hand in glove" cycle of benefits. Sierra uses high-efficiency fuel cells to maximize electricity production from available fuels, taps the cogenerated heat to brew its high-quality beers, then recycles once-wasted byproducts to create additional fuel, which the versatile DFC power plants use to maximize electricity production and begin the process again. For a company like Sierra Nevada, whose dedication to environmental stewardship plans include everything from water conservation to carbon dioxide recycling, this cycle pays benefits with every turn.

And there is a second cycle of benefits: money savings, plant efficiency and corporate image. The fuel cells produce electricity at high efficiency, and cogeneration reduces the need for fuel, increasing profit. The ADG produced reduces fuel demand, further increasing profit. And the environmentally-friendly corporate image of Sierra Nevada receives a big lift from beer drinkers, increasing potential sales—and boosting profit. Far from an added expense or regulatory hassle, multi-fuel Ultra-Clean fuel-cell power plants can provide energy savings, cost savings and a green, friendly corporate image—an image Sierra's customers can savor with each sip of their premium beer. SF

Andy Skok is a senior marketing executive for FuelCell Energy in Danbury, Conn., where he has more than 28 years of experience in various management positions. Skok received his undergraduate degree in materials engineering from Wilkes University and attended Yale University's Chemical Engineering Graduate School. He has published numerous technical articles, and actively participates on many national and international committees.

APPENDIX D: SMALL AND LARGE SYSTEM TRIGENERATION ENERGY MODELS

Self-Gen, Inc.
Scarborough, Maine

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	0.19	0.55	0.24	0.60	76%
SO2 (tons/year)	0.00	1.08	0.00	1.07	100%
CO2 (tons/year)	733	1,041	282	590	45%
Carbon (metric tons/year)	181	257	70	146	45%
Fuel Consumption (MMBtu/year)	12,562	17,459	4,828	9,725	44%
Acres of Forest Equivalent				122	
Number of Cars Removed				97	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 590 tons per year

This is equal to 146 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 122 acres of forest

OR

This reduction is equal to removing the carbon emissions of 97 cars

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

CHP Technology:	Recip Engine - Rich Burn	
Fuel:	Natural Gas	
Unit Capacity:	150	kW
Number of Units:	1	
Total CHP Capacity:	150	kW
Operation:	8,760	hours per year
Heat Rate:	9,560	Btu/kWh HHV
CHP Fuel Consumption:	12,562	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**12,562**	**MMBtu/year**
Total CHP Generation:	**1,314**	**MWh/year**
Useful CHP Thermal Output:	3,863	MMBtu/year for thermal applications (non-cooling)
	3,003	MMBtu/year for electric applications (cooling and electric heating)
	6,866	**MMBtu/year Total**
Displaced On-Site Production for		Existing Gas Boiler
Thermal (non-cooling) Applications:	0.10	lb/MMBtu NOx
	0.00%	sulfur content
Displaced Electric Service (cooling and electric heating):	30	tons of cooling capacity from CHP system
CHP:	Single-Effect Absorption Chiller	
Replaces:	0.94 kW/ton (COP=3.75) Best available, rotary screw compressor, air-cooled, <150 tons capacity	
	3.74	COP
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	1,314	MWh/year CHP generation
	165	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	129	MWh/year Transmission Losses
	1,607	**MWh/year Total**

Self-Gen, Inc.
Scarborough, Maine

Town Hall - Tri-Generation
Basic Emmissions Data

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Annual Analysis for CHP				
	CHP System: Recip Engine - Rich Burn			Total Emissions from CHP System
NOx (tons/year)	0.19	-		0.19
SO2 (tons/year)	0.00	-		0.00
CO2 (tons/year)	733	-		733
Carbon (metric tons/year)	181	-		181
Fuel Consumption (MMBtu/year)	12,562	-		12,562

Annual Analysis for Displaced Production for Thermal (non-cooling) Applications				
				Total Displaced Emissions from Thermal Production
NOx (tons/year)				0.24
SO2 (tons/year)				0.00
CO2 (tons/year)				282
Carbon (metric tons/year)				70
Fuel Consumption (MMBtu/year)				4,828

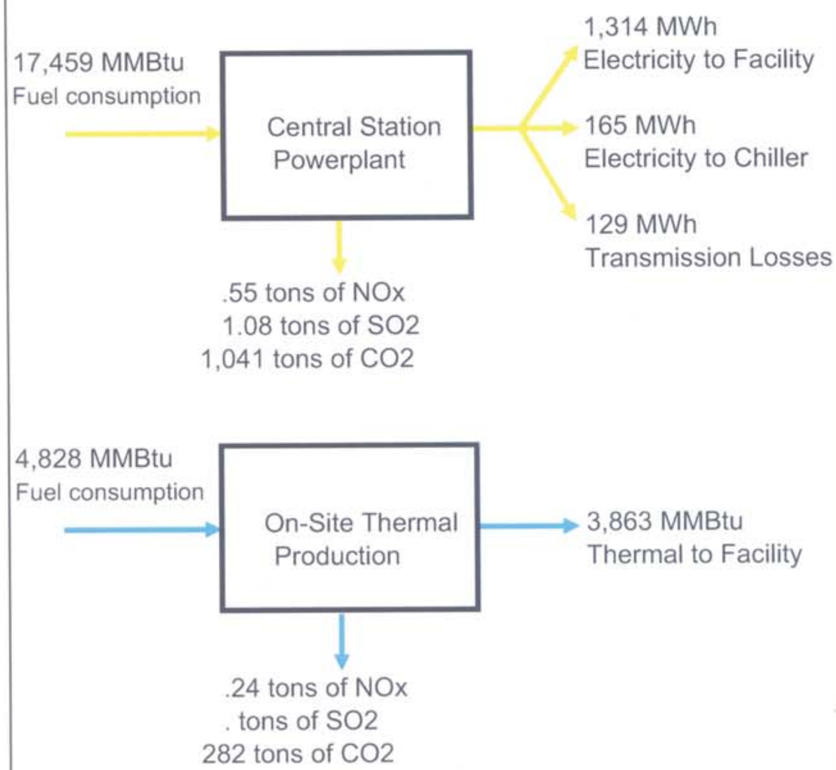
Annual Analysis for Displaced Electricity Production					
	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	0.45	0.06	-	0.04	0.55
SO2 (tons/year)	0.88	0.11	-	0.09	1.08
CO2 (tons/year)	851	106.67	-	83.28	1,041
Carbon (metric tons/year)	210	26	-	21	257
Fuel Consumption (MMBtu/year)	14,273	1,789	-	1,397	17,459

Town Hall - Tri-Generation
Basic Emmissions Data

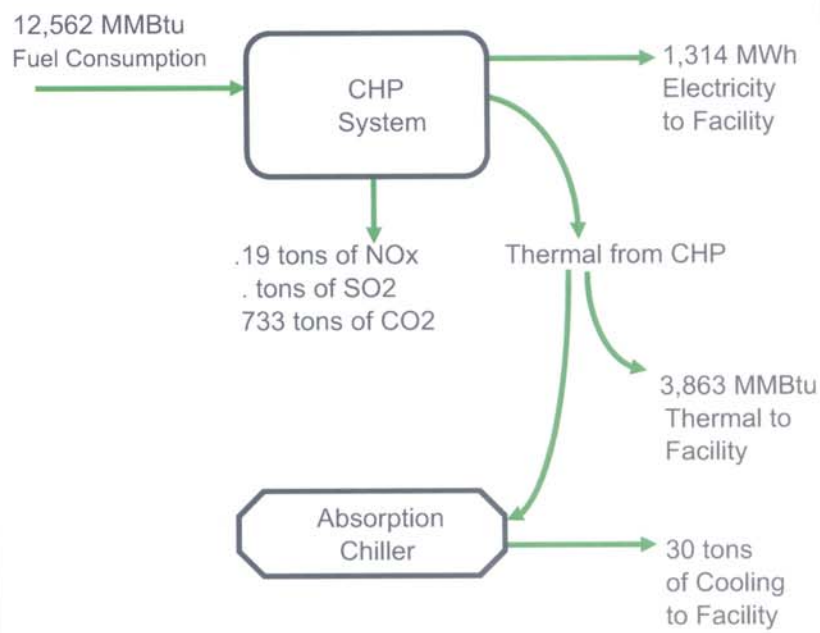
CHP Results

&EPA CHP COMBINED HEAT AND POWER PARTNERSHIP

Total Emissions for Conventional Production
.79 tons of NOx
1.08 tons of SO2
1,323 tons of CO2



Total Emissions for CHP System
.19 tons of NOx
. tons of SO2
733 tons of CO2



CHP Results

Emission Rates			
	CHP System including Duct Burners	Recip Engine - Rich Burn Alone	Displaced Electricity
NOx (lb/MWh)	0.30	0.30	0.69
SO2 (lb/MWh)	0.01	0.01	1.34
CO2 (lb/MWh)	1,116	1,116	1,295

Emission Rates	
	Displaced Thermal Production
NOx (lb/MMBtu)	0.10
SO2 (lb/MMBtu)	0.00059
CO2 (lb/MMBtu)	117

Energy Category	***Existing*** ***Energy*** ***"Debits"***	***Tri-Gen Energy*** ***"Debits"***	***Tri-gen*** ***Energy*** ***"Credits"***	
Existing Building Usage - Thermal 1:	-$24,957.00	-$122,289.71		
Excess Energy Required/Saved - Thermal 2:		$0.00	$0.00	*Excess Thermal 'sold'*
Chiller Electrical Savings - Thermal 3:			$30,120.65	*Electric Chiller Savings*
Town Hall Total - Electric:	**-$66,169.00**	$0.00	$116,496.35	*Excess Electricity Net Metered with Other Municipal Meters (10)*
Totals – 2006 - 2007:	**-$91,126.00**	**-$122,289.71**	**$146,617.00**	
		Maintenance Cost / Year plus Escrow:	-$10,442.29	
		Energy Difference Adjustment "+" or "-":	-$31,163.71	
		TOTAL SAVINGS PER YEAR:	**$105,011.00**	
		Estimated Project Cost - "1" - 150 kW Engine:	**$498,629.40**	
	4.75	**Year Payback**	***$49,863***	10% Grant
w/ 10% grant	**4.27**	**Year Payback**	***$448,766.46***	
w/ $200/kW credit	**4.62**	**Year Payback**	***$485,629.40***	

Large-Tri-Gen-NG Model
Emissions Metrics

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis

	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	52.33	16.25	22.45	(13.63)	-35%
SO2 (tons/year)	0.19	31.73	23.55	55.10	100%
CO2 (tons/year)	36,644	30,700	24,085	18,142	33%
Carbon (metric tons/year)	9,060	7,591	5,955	4,486	33%
Fuel Consumption (MMBtu/year)	627,996	514,877	299,382	186,264	23%
Acres of Forest Equivalent				3,738	
Number of Cars Removed				2,996	

This CHP project will reduce emissions of Carbon Dioxide (CO2) by 18,142 tons per year

This is equal to 4,486 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 3,738 acres of forest

OR

This reduction is equal to removing the carbon emissions of 2,996 cars

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

CHP Technology:	Combustion Turbine	
Fuel:	Natural Gas	
Unit Capacity:	4,600	kW
Number of Units:	1	
Total CHP Capacity:	4,600	kW
Operation:	8,760	hours per year
Heat Rate:	15,585	Btu/kWh HHV
CHP Fuel Consumption:	627,996	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**627,996**	**MMBtu/year**
Total CHP Generation:	**40,296**	**MWh/year**
Useful CHP Thermal Output:	224,537	MMBtu/year for thermal applications (non-cooling)
	45,051	MMBtu/year for electric applications (cooling and electric heating)
	269,588	**MMBtu/year Total**
Displaced On-Site Production for		Existing Distillate Oil Boiler
Thermal (non-cooling) Applications:	0.15	lb/MMBtu NOx
	0.15%	sulfur content
Displaced Electric Service (cooling and electric heating):	1,500	tons of cooling capacity from CHP system
CHP:	Single-Effect Absorption Chiller	
Replaces:	1.26 kW/ton (COP=2.8) Average new unit, rotary screw compressor, air-cooled, <150 tons capacity	
	2.79	COP
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	40,296	MWh/year CHP generation
	3,311	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	3,792	MWh/year Transmission Losses
	47,399	**MWh/year Total**

Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Annual Analysis for CHP	CHP System: Combustion Turbine			Total Emissions from CHP System
NOx (tons/year)	52.33	-		52.33
SO2 (tons/year)	0.19	-		0.19
CO2 (tons/year)	36,644	-		36,644
Carbon (metric tons/year)	9,060	-		9,060
Fuel Consumption (MMBtu/year)	627,996	-		627,996

Annual Analysis for Displaced Production for Thermal (non-cooling) Applications				Total Displaced Emissions from Thermal Production
NOx (tons/year)				22.45
SO2 (tons/year)				23.55
CO2 (tons/year)				24,085
Carbon (metric tons/year)				5,955
Fuel Consumption (MMBtu/year)				299,382

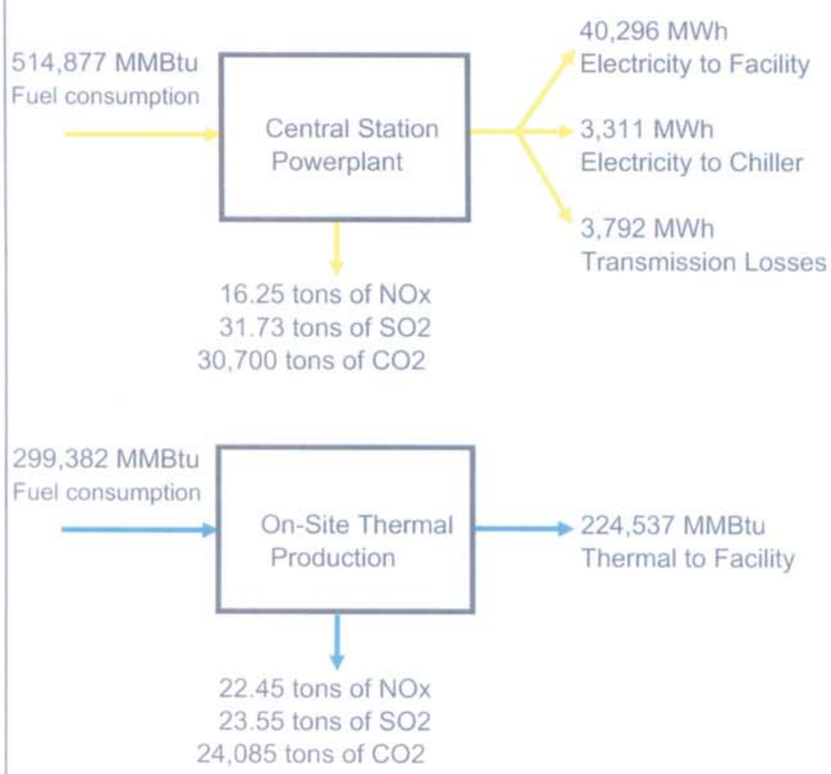
Annual Analysis for Displaced Electricity Production	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	13.82	1.14	-	1.30	16.25
SO2 (tons/year)	26.98	2.22	-	2.54	31.73
CO2 (tons/year)	26,099	2,144.67	-	2,455.99	30,700
Carbon (metric tons/year)	6,453	530	-	607	7,591
Fuel Consumption (MMBtu/year)	437,718	35,969	-	41,190	514,877

Large-Tri-Gen-NG Model
Emissions Metrics

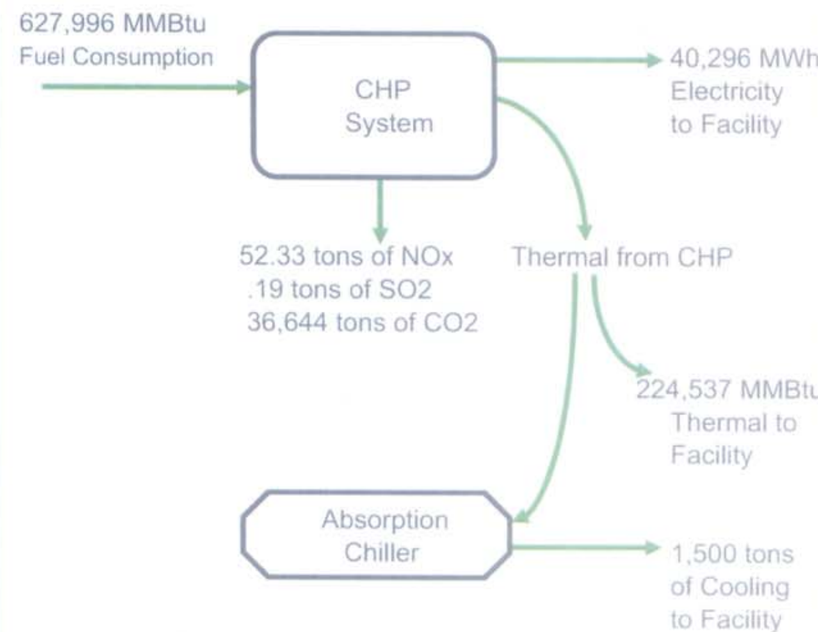
Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

Total Emissions for Conventional Production
38.71 tons of NOx
55.29 tons of SO2
54,785 tons of CO2



Total Emissions for CHP System
52.33 tons of NOx
.19 tons of SO2
36,644 tons of CO2



Combine Metrics with attached
Combined-Cycle S/T/G emissions data.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Emission Rates			
	CHP System including Duct Burners	Combustion Turbine Alone	Displaced Electricity
NOx (lb/MWh)	2.60	2.60	0.69
SO2 (lb/MWh)	0.01	0.01	1.34
CO2 (lb/MWh)	1,819	1,819	1,295

Emission Rates	
	Displaced Thermal Production
NOx (lb/MMBtu)	0.15
SO2 (lb/MMBtu)	0.15735
CO2 (lb/MMBtu)	161

Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

The results generated by the CHP Emissions Calculator are intended for eductional and outreach purposes only; it is not designed for use in developing emission inventories or preparing air permit applications.

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NOx (tons/year)	6.81	1.31	9.64	4.13	38%
SO2 (tons/year)	0.04	2.55	10.11	12.62	100%
CO2 (tons/year)	7,946	2,467	10,336	4,857	38%
Carbon (metric tons/year)	1,965	610	2,556	1,201	38%
Fuel Consumption (MMBtu/year)	136,181	41,372	128,480	33,671	20%
Acres of Forest Equivalent				1,001	
Number of Cars Removed				802	

This CHP project will reduce emissions of Carbon Dioxide (CO_2) by 4,857 tons per year

This is equal to 1,201 metric tons of carbon equivalent (MTCE) per year

This reduction is equal to removing the carbon that would be absorbed by 1,001 acres of forest

OR

This reduction is equal to removing the carbon emissions of 802 cars

Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP Technology:	Backpressure Steam Turbine	
Fuel:	Natural Gas	
Unit Capacity:	600	kW
Number of Units:	1	
Total CHP Capacity:	600	kW
Operation:	5,840	hours per year
Heat Rate:	38,864	Btu/kWh HHV
CHP Fuel Consumption:	136,181	MMBtu/year
Duct Burner Fuel Consumption:	-	MMBtu/year
Total Fuel Consumption:	**136,181**	**MMBtu/year**
Total CHP Generation:	**3,504**	**MWh/year**
Useful CHP Thermal Output:	96,360	MMBtu/year for thermal applications (non-cooling)
	-	MMBtu/year for electric applications (cooling and electric heating)
	96,360	**MMBtu/year Total**
Displaced On-Site Production for Thermal (non-cooling) Applications:		Existing Distillate Oil Boiler
	0.15	lb/MMBtu NOx
	0.15%	sulfur content
Displaced Electric Service (cooling and electric heating):		
	There is no displaced cooling service	
Displaced Electricity Profile:	eGRID Average Fossil 2005	
Egrid State:	ME	
Distribution Losses:	8%	
Displaced Electricity Production:	3,504	MWh/year CHP generation
	-	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	305	MWh/year Transmission Losses
	3,809	**MWh/year Total**

Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP

EPA COMBINED HEAT AND POWER PARTNERSHIP

Annual Analysis for CHP				
	CHP System: Backpressure Steam Turbine			Total Emissions from CHP System
NOx (tons/year)	6.81	-		6.81
SO2 (tons/year)	0.04	-		0.04
CO2 (tons/year)	7,946	-		7,946
Carbon (metric tons/year)	1,965	-		1,965
Fuel Consumption (MMBtu/year)	136,181	-		136,181

Annual Analysis for Displaced Production for Thermal (non-cooling) Applications				
				Total Displaced Emissions from Thermal Production
NOx (tons/year)				9.64
SO2 (tons/year)				10.11
CO2 (tons/year)				10,336
Carbon (metric tons/year)				2,556
Fuel Consumption (MMBtu/year)				128,480

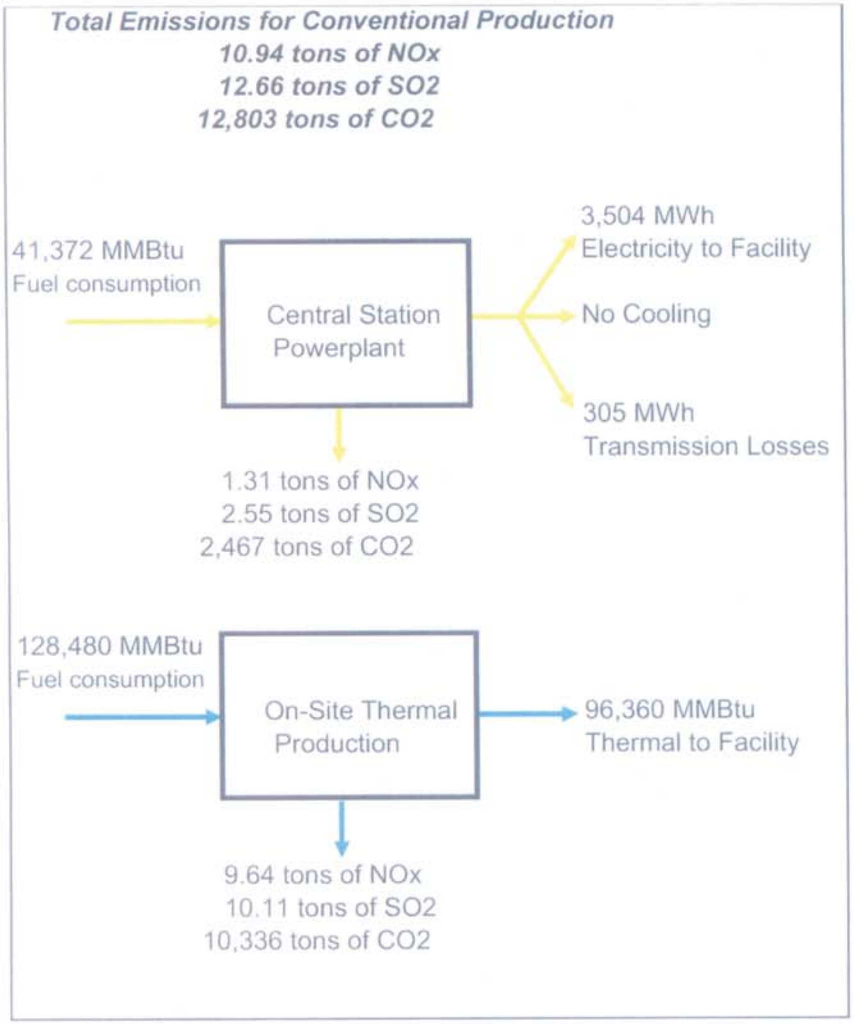
Annual Analysis for Displaced Electricity Production					
	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NOx (tons/year)	1.20	-	-	0.10	1.31
SO2 (tons/year)	2.35	-	-	0.20	2.55
CO2 (tons/year)	2,269	-	-	197.35	2,467
Carbon (metric tons/year)	561	-	-	49	610
Fuel Consumption (MMBtu/year)	38,062	-	-	3,310	41,372

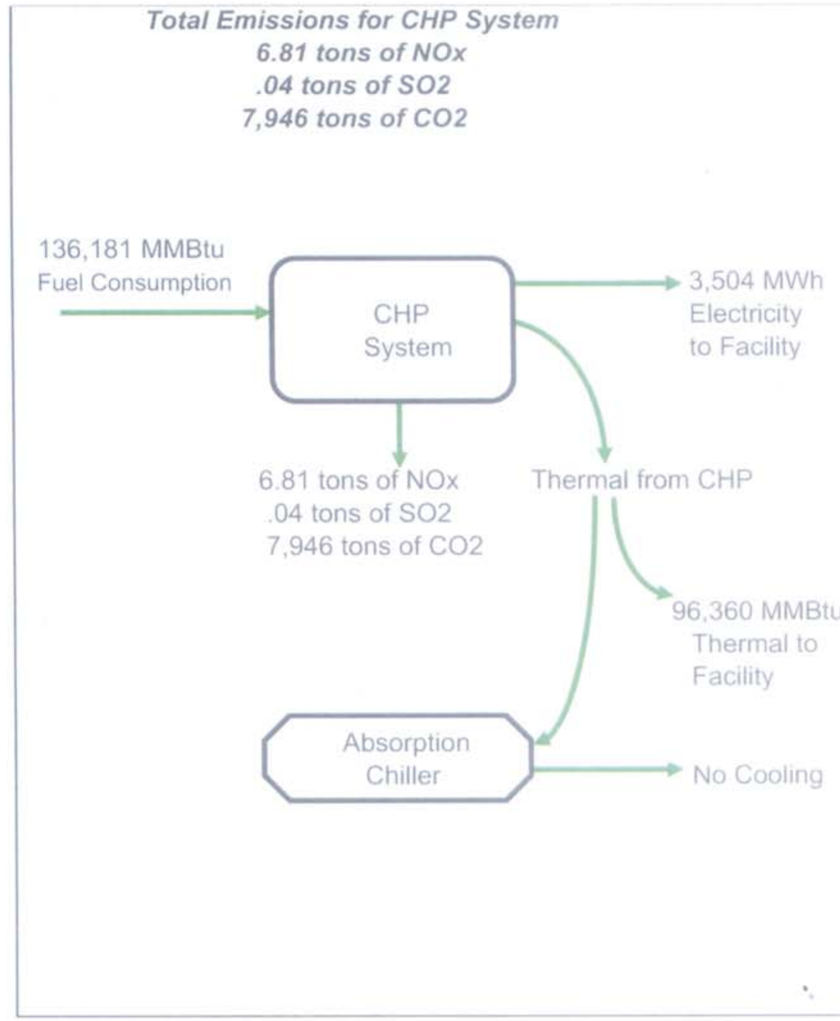
Large Tri-Gen - 600 kW Back-Pressure Steam-Turbine-Generator

Combined Cycle Model

Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results





Note: Energy Source is excess waste steam for combined-cycle model, not NG.

CHP Results

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

Emission Rates			
	CHP System including Duct Burners	Backpressure Steam Turbine Alone	Displaced Electricity
NOx (lb/MWh)	3.89	3.89	0.69
SO2 (lb/MWh)	0.02	0.02	1.34
CO2 (lb/MWh)	4,535	4,535	1,295

Emission Rates	
	Displaced Thermal Production
NOx (lb/MMBtu)	0.15
SO2 (lb/MMBtu)	0.15735
CO2 (lb/MMBtu)	161

PRIVILEGED AND CONFIDENTIAL INFORMATION OF SELF-GEN, INC.

Self-Gen
integrated energy solutions & services
www.self-gen.com

ABC MEDICAL CENTER - TRI-GENERATION ENERGY MODEL

PRIVILEGED AND CONFIDENTIAL INFORMATION OF SELF-GEN, INC.

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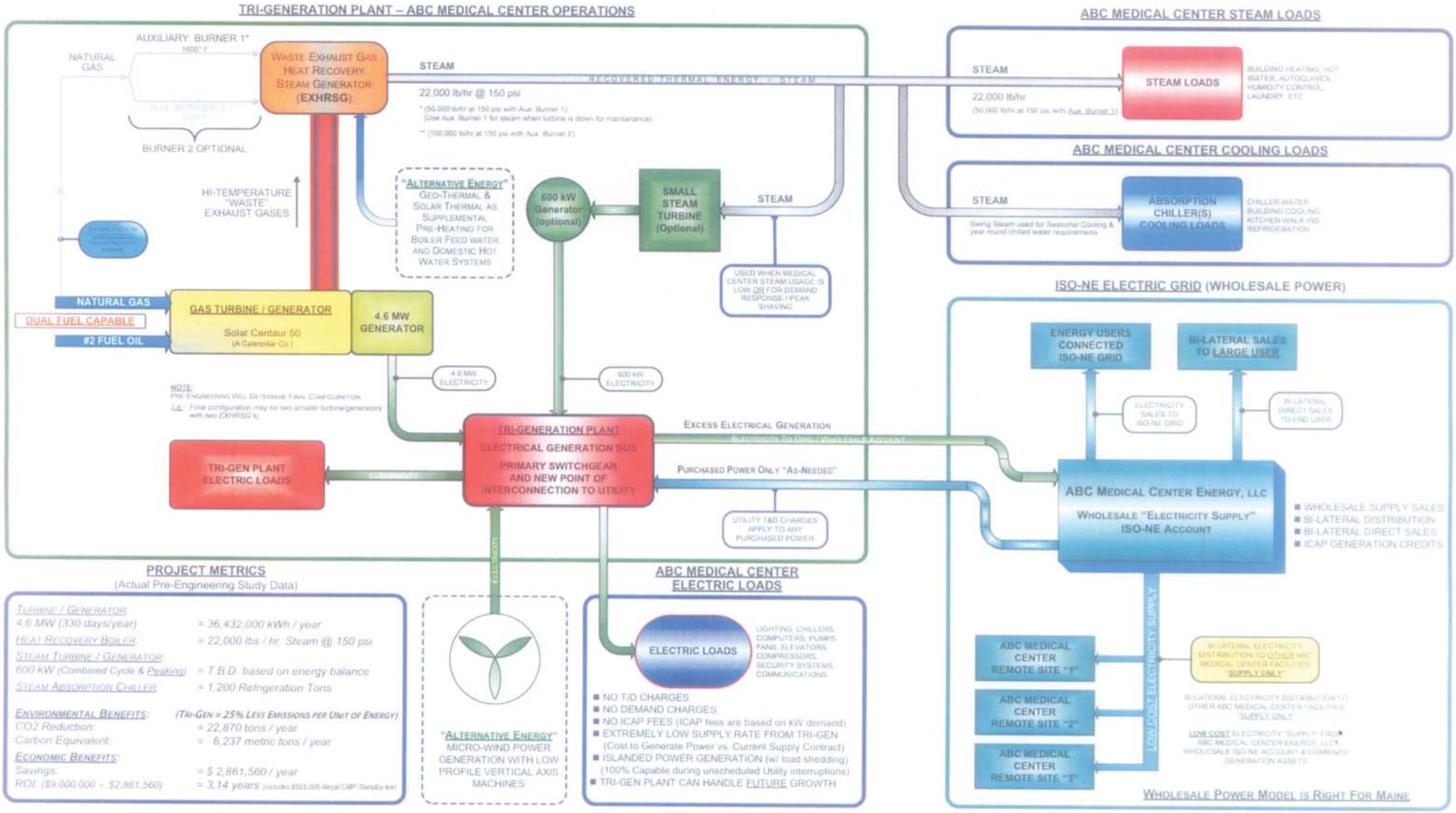
integrated energy solutions & services
www.self-gen.com

25% Less Harmful Emissions With the Tri-Generation Energy Model



ENERGY BALANCE TABLE

Without Tri-gen (SHP)

ELECTRICITY – "WITHOUT" TRI-GEN

DEBITS

Existing Usage:
30,000,000 kWh / year x $ 0.14/kWh = **$ 4,200,000 / yr**

New Expansion:
4,257,360 kWh / year x $ 0.14/kWh = $ **596,030 / yr**
Assumes:
(4.5 Watts / sq. ft; 180,000 sq. ft.; 60% / Duty cycle)
(plug power, lighting, Fans, Pumps)
4.5 watts / sq. ft. x 180,000 sq. ft. = 810,000 watts
810,000 watts x 0.60 Duty Cycle = 486,000 watts
486,000 watts x 24 hrs/day x 365 days/yr = 4,257,360,000 Whr/yr
4,257,360,000 watt/hrs ÷ 1,000 watts / kW = 4,257,360 kWh / yr.

New Chillers (74% Increase):
3,023,076 kWh / yr x $ 0.14/kWh = $ **423,230 / yr**
3990 Tons New – 2290 Tons Existing = 1700 Tons **New Load**
1700 Added Tons x 0.58 kWe / Ton = 986 kWe
986 kWe x 24 hr / day x 70% Run Time = 16,564.8 kWh / day
16,564.8 kWh / day x 182.5 days/yr = 3,023,076 kWh / yr
*Erring on the side of Non-Tri-gen assume **50% or 182.5** days/year*
(Duty Cycle Data for Chiller Loads is not available)

Utility (T&D Standby Fee – illegal per deregulation):
T&D charges are already included in the $ 0.14 / kWh cost for the all kWh consumed and kW demand charges. There is no Standby Fee for the CUP. We assume the MC T&D charge per kWh is a negotiated rate of $ 0.015, which is typical for large users, but no data supporting this has been provided to us.

CREDITS

CREDITS FOR

SEPARATE HEAT & POWER (SHP) ENERGY MODEL (Non-Tri-gen)

N O N E

(37,280,436 kWh / year estimated)

TOTAL PROJECTED ELECTRICITY COSTS FOR - NON-TRI-GEN

$ 5,219,260 - Debit (Non-Tri-gen - Annual Cost)

Electricity Cost **Savings** with **Tri-generation**: **$ 2,361,068**

Comprehensive Pre-Engineering will refine these values

With Tri-gen (CCHP)

ELECTRICITY – "WITH" TRI-GEN (CCHP)

DEBITS

Existing Usage:
30,000,000 kWh / year x $ 0.14/kWh = $ 4,200,000 / yr

New Expansion:
4,257,360 kWh / year x $ 0.14/kWh = $ 596,030 / yr
Assumes:
(4.5 Watts / sq. ft; 180,000 sq. ft.; 60% / Duty cycle)
(plug power, lighting, Fans, Pumps)
4.5 watts / sq. ft. x 180,000 sq. ft. = 810,000 watts
810,000 watts x 0.60 Duty Cycle = 486,000 watts
486,000 watts x 24 hrs/day x 365 days/yr = 4,257,360,000 Whr/yr
4,257,360,000 watt/hrs ÷ 1,000 watts / kW = 4,257,360 kWh / yr.

New Chillers (74% Increase):
3,023,076 kWh / yr x $ 0.14/kWh = $ **423,230 / yr**
3990 Tons New – 2290 Tons Existing = 1700 Tons **New Load**
1700 Added Tons x 0.58 kWe / Ton = 986 kWe
986 kWe x 24 hr / day x 70% Run Time = 16,564.8 kWh / day
16,564.8 kWh / day x 182.5 days/yr = 3,023,076 kWh / yr
*Erring on the side of Non-Tri-gen assume **50% or 182.5** days/year*
(Duty Cycle Data for Chiller Loads is not available)

Utility (T&D Standby Fee – questionable per deregulation):
35,000,000 kWh / yr x $ 0.015 / kWh = $ **525,000 / yr**
Assume: *(Bangor EMMC budgeted $ 300,000 for their Tri-gen)*
A standby fee equal to T&D charges for **ALL** kWh consumed for 2006 will be used however, this is a very inflated number based on rulings with the Maine PUC, however we don't want it to be a point for "misleading" MC leadership (fee is questionable).

CREDITS

New Tri-generation 4.6 MW of Generation:
37,280,436 kWh/yr x $ **0.062** / kWh = **$ 2,311,387 / yr**
($ 0.078 / kWh – Electric Gen. Costs; $ 0.042 / kWh Thermal Cost)
*($ 0.14 / kWh – $ 0.076 / kWh = $ 0.062 / kWh - **Savings**)*
2,463,564 kWh/yr x $ 0.06/kWh (Wholesale Bank) = $ **147,814 / yr**
(ABC Energy, LLC sells power to ABC facilities at $ 0.08 / kWh, saving the current ABC facility $ 0.06 / kWh from current Electricity prices)
4.6 MW x 24 hrs/day x 360 days/yr = 39,744,000 kWh/yr
(39,744,000 – 37,280,436 = 2,463,564 kWh) *(Total Generation)*

New Chillers (Steam Absorption Chiller Offset):
$ 2,339 / day x 182.5 days = $ **426,867 / yr**
50 % of 365 days / year *(cooling per utility kW)* = 182.5 days / year
(The seasonal increase time frame is taken Directly from utility Electric kW Profile and the MC Steam Measure Steam flow Data Profiles)
5.5 MW (cooling season) – 3.2 MW (heating season) = 2.3 MW or 2300 kW
Assumes "All" of the 2300 kW increase is for Chillers
2300 kW (cooling season) ÷ 0.58 kW/Ton = **3,965 Tons Cooling**
1200 Ton Steam Chiller x 0.58 kWe / Ton = 696 kWe
696 kWe x 24 hr / day = 16,704 kWh / day
(Assume 100 % Run Time to Base Load 3,965 Tons Required)
16,704 kWh / day x $ 0.14 / kWh = $ **2,339 / day**

Back-Pressure Turbine / Generators "Before" Chillers:
During the pre-engineering phase we will look at utilizing back pressure turbine/generators for prior to each steam chiller as a "PRV" station.

TOTAL PROJECTED ELECTRICITY COSTS "TRI-GEN"

$ 5,744,260 - Debit
$ 2,886,068 - Less Credits
$ 2,858,192 - Debit (Tri-gen Annual Costs)

Comprehensive Pre-Engineering will refine these values

ENERGY BALANCE TABLE

Without Tri-gen (SHP) | **With Tri-gen (CCHP)**

THERMAL (HEATING) – "WITHOUT" TRI-GEN

DEBITS

Existing Natural Usage (Year Round & Heating):
1,300,000 therms/year x $ 1.20/therm = **$ 1,560,000 / yr**
2005 - Actual Usage:
1,276,944 ccf /yr x 100 (c) = 127,694,400 cf /yr
127,694,400 cf/yr x 1000 btu/cf (nat. gas) = 127,694,400,000 btu/yr
127,694,400,000 btu/yr ÷ 100,000 btu/therm = 1,276,944 therm/yr
Assume a slight increase per historical data: = 1,300,000 therm/yr

(NYMEX gas prices today are at $ 0.71/therm, plus add-ins, No volume discount, but discount from Current $ 1.45 therm rate)

New Building Natural Gas Usage (Heating Months):
175,200 therms/year x $ 1.20/therm = **$ 210,240 / yr**
Assumes:
180,000 sq. ft. bldg, 4 floors, Rule-of-Thumb = 4,000,000 btu/hr
4,000,000 btu / hr. x 24 hrs/day = 96,000,000 btu/day
96,000,000 btu/day x 182.5 days / year = 17,520,000,000 btu/yr
17,520,000,000 btu/yr ÷ 100,000 btu/therm = 175,200 therms/yr

Fuel Oil – Existing Usage:
310,000 / gals. / year x $ 1.97 / therm = $ 610,700
(assumes 2006 fuel oil rate of $ 1.97 / gal)

TOTAL PROJECTED "THERMAL" (HEATING) COSTS for "NON-TRI-GEN" (SHP)

$ 2,380,940 – (Annual Cost w/out Cogen)

SAVINGS PER YEAR IN "THERMAL" (HEATING)

$ 2,380,940 – Without Tri-gen Model
$ 1,880,448 – With Tri-gen (CCHP) Model
$ 500,492 – Thermal Savings/Year With Tri-gen

Comprehensive Pre-Engineering will refine these values

THERMAL (HEATING) – "WITH" TRI-GEN (CCHP)

DEBITS

Tri-gen Natural Usage (Year Round – Electricity, Heating, & Cooling):
39,744,000 kWh/yr x $ **0.042** / kWh = **$ 1,669,248 / yr**
Assumes:
*($ 0.078 / kWh – Electric Gen. Costs; **$ 0.042 / kWh Thermal Cost**)*

(NYMEX (www.nymex.com) gas prices today are at $ 0.71/therm, plus add-ins and "Volume Discounting" on Supply and T&D rates)

New Building Natural Gas Usage (Heating Months):
175,200 therms/year x $ **1.00**/therm = **$ 175,200 / yr**
Assumes:
180,000 sq. ft. bldg, 4 floors, Rule-of-Thumb = 4,000,000 btu/hr
4,000,000 btu / hr. x 24 hrs/day = 96,000,000 btu/day
96,000,000 btu/day x 182.5 days / year = 17,520,000,000 btu/yr
17,520,000,000 btu/yr ÷ 100,000 btu/therm = 175,200 therms/yr

Aux. Burner 1 Rated for Max. output of 26.13 MMBtu for a HRSG total steam output of 50,000 PPH steam output used for "Peak Steam Loading" and "New Expansion" steam loads as needed.

"Avg. Peak" Steam Loads – Using HRSG Aux. Burner (Heating Months):
36,000 therms/year x $ 1.00/therm = **$ 36,000 / yr**
Assumes:
4,000,000 btu / hr. x 10 hrs/day (peaking profile) = 40,000,000 btu/day
40,000,000 btu/day x 90 days / year = 3,600,000,000 btu/yr
3,600,000,000 btu/yr ÷ 100,000 btu/therm = 36,000 therms/yr

Per Steam Usage flow Measurements; Jan, Feb., & March require more than 22,000 PPH Steam flow, the Cogen. HRSG will have an Aux. Burner 1 to make-up the difference during these 3 months. Aux. Burner 1 is rated at 26.13 MMBtu/hr for a max of 50,000 PPH Steam as needed for "peaking" and "the Expansion" loads.

TOTAL PROJECTED "THERMAL" (HEATING) COSTS for TRI-GEN (CCHP)

$ 1,880,448 – (Annual Cost With Tri-gen)

Comprehensive Pre-Engineering will refine these value

CORE TRI-GENERATION - ENERGY BALANCE – SPRING 2006 FOUNDATIONAL CALCULATIONS

Turbine / Generator "Fuel" Requirement:
50 MMBtu/hr or 500 Therms / hr per manufacturer @ 100% output

Turbine / Generator "Running" Costs:
(500 therms / hr ÷ 4600 kW) x $1.00 / therm = $ 0.1090 / kWh *(Quoted Gas Pricing, also NYMEX is a $ 0.71 / therm)*
Maintenance Costs per kWh Generated: = $ 0.0040 / kWh
Misc. Operating Costs: *($ 278,000 / yr. misc.)* = $ 0.0070 / kWh *(**added** to 0.113 / kWh to round-up to 0.12 / kWh)*
Total Turbine / Generator "Running" Costs: = $ 0.1200 / kWh

Total Turbine / Generator "Running" Costs @ 100%:
$ 0.120 / kWh x 4,600 kW = **$ 552 / hr**

MC's "THERMAL" Costs for 2005 (Heating): *(This value can vary based on Energy profiles and can be Optimized)*
From MC Energy Usage, 2005 Thermal Usage = 170,374.0 MMBtu/yr **or** (19.4 MMBtu / hr)
From MC Energy Usage, 2005 Thermal Costs: = $ 9.83 / MMBtu
19.4 MMBtu/hr x $ 9.83 / MMBtu = **$ 190.0 / hr** (Total Heating Thermal Energy Costs for 2005)

Turbine/Generator "Electrical Energy" Costs per kWh Generated:
$ 552 /hr (Total Oper. Cost) - $ 190 / hr (Thermal Costs) = $ 362 / hr
$ 362 / hr ÷ 4,600 kW = **$ 0.078 / kWh** (**Electricity** Generation Cost for Tri-gen Model)

Turbine/Generator "Thermal Energy" Costs per kWh Generated:
$ 0.12 kWh (Total Cost) - $ 0.078 kWh (Electric Gen. Cost) = **$ 0.042 / kWh** (**Thermal** Generation Cost for Tri-gen Model)

SIMPLE PAYBACK SUMMARY FOR TRI-GENERATION (CCHP):
$ 2,361,068 – Electricity Savings with Tri-gen (CCHP)
$ 500,492 – Thermal Savings with Tri-gen (CCHP)
$ 2,861,560 $ 9,000,000 ÷ $ 2,861,560 = **3.14 Year Simple Payback** (including Utility Standby Fee of $ 525,000)

APPENDIX E: CHP FACILITIES IN MAINE

Combined Heat and Power Units located in Maine

(Source: http://www.eea-inc.com/chpdata/States/ME.html)

State	City	Organization Name	Facility Name	Application	SIC4	NAICS	Op Year	Prime Mover	Capacity (kw)	Fuel Type
ME	Auburn	Mid-Maine Waste Action Corp	Mmwac Resource Recovery Facility	Solid Waste Facilities	4953	562212	1992	B/ST	5,000	WAST
ME	Bangor	Eastern Maine Medical Center	Eastern Maine Medical Center	Hospitals/Healthcare	8062	62211	2005	CT	4,400	NG
ME	Bangor	Auto Dealership	Auto Dealership	Automotive Services	5511	44111	2004	MT	60	NG
ME	Bethel	P. H. Chadbourne & Co.	P. H. Chadbourne & Co.	Wood Products	2411	11331	1987	B/ST	1,814	WOOD
ME	Bucksport	Bucksport Energy LLC	International Paper/ Champion Clean Energy	Pulp and Paper	2600	322	1988	B/ST	251,000	NG
ME	Hinckley/Skowhegan	Sappi / S.D. Warren/Scott Paper Company	S.D. Warren Somerset Mill	Pulp and Paper	2621	322121	1976	B/ST	113,000	WAST
ME	Jay	International Paper Company	Androscoggin Mill	Pulp and Paper	2621	322121	1965	B/ST	80,000	WAST
ME	Jay	Wassau-Moisinee	Wassau-Moisinee	Pulp and Paper	2621	322121	2001	B/ST	2,821	OIL
ME	Jay	Calpine - Androscoggin Energy LLC	Androscoggin Energy Center	Pulp and Paper	2621	322121	1999	CT	163,500	NG
ME	Kittery	U.S. Navy	Portsmouth Naval Ship Yard (ESPC #1)	Military/National Security	9711	92811	2000	CT	10,500	NG
ME	Kittery Point	Residential Project	Residential Cogeneration System	Private Households	8811	81411	1992	ERENG	5	OIL
ME	Lewiston	Corporate Energy Management ,Nc	Bates Energy Associates	Colleges/Univ.	8221	61131	1986	B/ST	1,125	WOOD
ME	Lincoln	Lincoln Pulp And Paper Company	Lincoln Sawmill	Wood Products	2421	321113	1991	B/ST	2,940	WAST
ME	Madawaska	Fraser Paper, Ltd.	Fraser Paper, Ltd.	Pulp and Paper	2621	322121	1989	B/ST	20,000	OTR
ME	Madison	Madison Paper Industries Inc	Anson Abenaki Hydros	Pulp and Paper	2621	322121	1994	B/ST	3,000	OIL
ME	Mattawamkeag	Aroostook & Bangor Reload Co	Aroostook Bangor Reload Co Perma Treat Plant	Wood Products	2421	321113	1992	B/ST	1,000	WOOD
ME	Old Town	Old Town Fuel and Fiber (Former James River Paper Company)	Old Town Fuel and Fiber (Former James River Corporation)	Pulp and Paper	2621	322121	1946	B/ST	19,300	NG
ME	Penobscot	Great Northern Paper/Inexcon Maine	Millinocket Thermal Facilities	Pulp and Paper	2621	322121	1957	B/ST	95,100	OIL
ME	Penobscot	Great Northern Paper Inc	East Millinocket	Pulp and Paper	2621	322121	1954	B/ST	61,400	WOOD
ME	Rumford	Boise Cascade Corporation	Boise Cascade Corporation	Pulp and Paper	2621	322121	1955	B/ST	10,000	NG
ME	Rumford	Rumford Cogen Company	Mead Paper Company	Pulp and Paper	2621	322121	1990	B/ST	85,000	COAL
ME	Sanford	Lavalley Lumber LLC	Lavalley Lumber LLC	Wood Products	2421	321113	1989	B/ST	1,500	WOOD
ME	Searsmont	Robbins Lumber Inc	Robbins Lumber Inc	Wood Products	2421	321113	1981	B/ST	1,250	WOOD
ME	Sherman Station	Wheelabrator Sherman Energy/Duke Solutions	Sherman Lumber Company/Stacyville	Wood Products	2421	321113	1986	B/ST	21,000	WOOD
ME	Strong	Forster Manufacturing Co Inc/Diamond Brands	Forster Manufacturing Co Inc.	Wood Products	2400	321	1979	B/ST	1,300	WOOD
ME	Waterville	Colby College	Colby College	Colleges/Univ.	8221	61131	1999	B/ST	600	OIL
ME	Westbrook	Sappi / S.D. Warren/Scott Paper Company	S.D. Warren Division / Westbrook	Pulp and Paper	2621	322121	1965	B/ST	62,500	WOOD
ME	Woodland	Georgia-Pacific Corporation	Georgia-Pacific Corporation	Pulp and Paper	2621	322121	1966	B/ST	44,500	WAST
ME	Woodland	Georgia-Pacific Corporation	Woodland OSB Plant	Pulp and Paper	2631	32213	1977	B/ST	67,200	WOOD

Prime Mover Code	Description		Fuel Code	Description
B/ST	Boiler/Steam Turbine		BIOMASS	Biomass, LFG, Digester Gas, Bagasse
CC	Combined Cycle		COAL	Coal
CT	Combustion Turbine		NG	Natural Gas, Propane
FCEL	Fuel Cell		OIL	Oil, Distillate Fuel Oil, Jet Fuel, Kerosene, RFO
MT	Microturbine		WAST	Waste, MSW, Black Liquor, Blast Furnace Gas, Petroleum Coke, Process Gas
ERENG	Reciprocating Engine		WOOD	Wood, Wood Waste
OTR	Other		OTR	Other

State Summary for Maine

Prime Mover Code	Sites	Capacity (kW)
Total	29	1,130,815
B/ST	24	952,350
CC	0	0
CT	3	178,400
FCEL	0	0
MT	1	60
OTR	0	0
ERENG	1	5

Additional CHP Facility: Old Town/Orono YMCA - 65 kW Capstone Micro-Turbine CHP system (Source: Bill Lovejoy - Project Manager/Board Member)

APPENDIX F: CHP INCENTIVES

Appendix F
Incentives and Funding Programs

Name	Type	Description	Expiration Date
CHP Investment Tax Credit (ITC)	Tax	The Emergency Economic Stabilization Act 0f 2008, enacted on October 3, 2008, created a new investment tax credit (ITC) for CHP and waste energy recovery systems. The CHP ITC extends from the date of enactment through December 31, 2016. The American Recovery and Reinvestment Act of 2009 (ARRA), enacted February 2009, allows taxpayer eligibility for the CHP ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC from new installations. For eligible CHP projects, Treasury will make payments to qualified applicants in an amount equal to 10% of the system cost. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document (PDF), terms and conditions (PDF), and a sample application (PDF), please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site. EIEA created a 10% investment tax credit (ITC) for the costs of the first 15 MW of CHP property. To qualify for the tax credit, the CHP system must: • Produce at least 20% of its useful energy as electricity and 20% as thermal energy; • Be smaller than 50 MW; • Be constructed by the taxpayer or have the original use of the equipment begin with the taxpayer; • Be placed in service after October 3, 2008 and before January 1, 2017; and • Be 60% efficient on a lower heating value basis. The 60% efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source. The ITC may be used to offset the alternative minimum tax and the CHP system must be operational in the year in which the credit is first taken. The CHP ITC is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).	01/01/2017
Investment Tax Credits for Micro-Turbines and Fuel Cells	Tax	The EIEA extended the ITC to micro-turbines and fuel cells. For micro-turbines, the credit is equal to 10% of expenditures, with no maximum limit stated (explicitly), but it is capped at $200 per kW of capacity. Eligible property includes micro-turbines up to two MW that have an electricity-only generation efficiency of 26% or higher. For fuel cells, the credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kW of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher. (The credit for property placed in service before October 4, 2008, is capped at $500 per 0.5 kW.) The ITC for both micro-turbines and fuel cells is available for eligible systems placed in service on or before December 31, 2016. As with the CHP ITC, facility owners can choose to receive a one-time grant equal to 30% of the construction and installation costs for the facility, as long as the facility is depreciable or amortizable. To be eligible, the facility must be placed in service in 2009 or 2010, or construction must begin in either of	None

Appendix F
Incentives and Funding Programs

Name	Type	Description	Expiration Date
		those years and be completed prior to the end of 2013. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site. To apply for a grant in lieu of the tax credit, please visit the application web site. The ITC for micro-turbines and fuel cells is claimed through IRS Form 3468, available on the IRS's Web site. Facility owners who claim the ITC can not claim the production tax credit (PTC).	
Renewable Electricity Production Tax Credit	Tax	The EIEA extended the PTC for biomass, geothermal, hydropower, landfill gas, waste-to-energy, and marine facilities and other forms of renewable energy through 2010, and the ARRA further extended the tax credit through 2013. The renewable electricity PTC is a per kWh federal tax credit included under Section 45 of the U.S. tax code for electricity generated by qualified energy resources. The PTC provides a corporate tax credit of 1.0 cents/kWh for landfill gas, open-loop biomass, municipal solid waste resources, qualified hydropower, and marine and hydrokinetic (150 kW or larger). Electricity from wind, closed-loop biomass, and geothermal resources receive 2.1 cents/kWh. Projects that receive other government grants or subsidies receive a discounted tax credit. The ARRA allows taxpayers eligible for the federal PTC to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The Treasury Department is now accepting applications for the grant program. For more information including the guidance document, terms and conditions and a sample application, please visit the U.S. Department of Treasury's Web site. The Renewable Energy PTC is claimed through IRS Form 8835 and IRS Form 3800.	2013
Bonus Depreciation	Tax	Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. The ARRA extended the five-year bonus depreciation schedule through 2010 and includes CHP, thereby allowing 50% of the depreciation value to be taken in the first year and the remainder over the following four years. To qualify for bonus depreciation, a project must satisfy these criteria: • The property must have a recovery period of 20 years or less under normal federal tax depreciation rules; • The original use of the property must commence with the taxpayer claiming the deduction; • The property generally must have been acquired during 2009 or 2010; and • The property must have been placed in service during 2009 or 2010. The bonus depreciation rules do not override the depreciation limit	2010

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		applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies. For more information on the federal MACRS, see IRS Publication 946, IRS Form 4562: Depreciation and Amortization, and Instructions for Form 4562.	
Advanced Energy Manufacturing Tax Credit	Tax	ARRA established the advanced energy manufacturing tax credit to encourage the development of a U.S.-based renewable energy manufacturing sector. ARRA authorizes the Department of the Treasury to issue $2.3 billion of credits under the program. In any taxable year, the investment tax credit is equal to 30% of the qualified investment required for an advanced energy project that establishes, re-equips, or expands a manufacturing facility that produces any of the following: • Equipment and/or technologies used to produce energy from solar, wind, geothermal, or other renewable resources; • Fuel cells, micro-turbines, or energy-storage systems for use with electric or hybrid-electric motor vehicles; • Equipment used to refine or blend renewable fuels; or • Equipment and/or technologies to produce energy-conservation technologies (including energy-conserving lighting technologies and smart grid technologies). Qualified investments generally include personal tangible property that is depreciable and required for the production process. Other tangible property may be considered a qualified investment only if it is an essential part of the facility, excluding buildings and structural components. To be eligible for the tax credit, a project must be certified by the Department of the Treasury. In determining which projects to certify, ARRA directs the Department of the Treasury to consider those projects that most likely will: • Be commercially viable; • Provide the greatest domestic job creation; • Provide the greatest net reduction of air pollution and/or greenhouse gases; • Have the greatest potential for technological innovation and commercial deployment; • Have the lowest levelized cost of generated (or stored) energy or the lowest levelized cost of reduction in energy consumption or greenhouse gas emissions; and • Have the shortest project time from certification to completion. After certification is granted, the taxpayer has up to one year to provide additional evidence that the requirements of the certification have been met and three years to put the project in service. On August 13, 2009, the Department of the Treasury announced the availability of funds under the program and preliminary applications were due to DOE September 16, 2009, followed by final applications being due to DOE and IRS on October 16, 2009. By January 15, 2010, the IRS certified or rejected applications, and notified the certified projects with the approved amount of their tax credit. Awardees received acceptance agreements from the IRS by April 16, 2010. Credits will be allocated until the program funding	01/01/2017

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		is exhausted. Subsequent allocation periods will depend on remaining funds.	
Clean Renewable Energy Bonds	Tax	The 2005 Energy Policy Act created Clean Renewable Energy Bonds (CREBs) within Section 54 of the U.S. tax code. Unlike traditional bonds that pay interest, tax credit bonds pay the bondholders by providing a credit against their federal income tax. In effect, CREBs provide interest-free financing for clean energy projects. In 2008, EIEA provided authority for the issuance of an additional $800 million in "new" CREBs, and in 2009, ARRA allocated an additional $1.6 billion for CREBs. The 2008 legislation also extended the deadline by which bonds must be issued for previous allocations to December 31, 2009. The types of projects for which bonds can be issued include renewable energy projects utilizing landfill gas, wind, biomass, geothermal, solar, municipal solid waste, small hydroelectric, marine, and hydrokinetic. The IRS has determined that facilities "functionally related and subordinate" to the generation facility itself are also eligible for CREB financing. Examples of these auxiliary components include transmission lines and interconnection upgrades. The EIEA directs the IRS to allocate the bonding authority equally among electric cooperatives, government entities, and public power producers. Other changes for "new" CREBs are as follows: • The federal tax credit is reduced to 70% of the interest payment; • The bond holder can transfer the tax credit to another party; • Taxpayers can carry forward unused credits into future years; and • Bond proceeds must be used within three years or a request for an extension must be made.	
Qualified Energy Conservation Bonds	Tax	The EIEA created a new funding mechanism called Qualified Energy Conservation Bonds (QECBs), similar to the CREB model in which a bondholder receives tax credits in lieu of interest. The act authorizes state, local, and tribal governments to issue energy conservation bonds to finance qualified projects. The 2008 legislation allows the IRS to distribute up to $800 million in bond authorizations. In 2009, ARRA provided an additional $2.4 billion in bonding authority. The bond proceeds can be used to finance capital expenditures that achieve one of the following goals: • Reduction of energy consumption by at least 20%; • Implementation of a green community program; or • Electricity generation from renewable resources in rural areas. An IRS notice contains more details about the bond program, including an outline for the bond cap for each state. The IRS is expected to issue further guidance on how the program will work soon.	None
Deployment of CHP Systems, District Energy Systems, Waste Energy Recovery Systems, and Efficient Industrial Equipment	Grant	On June 1, 2009 the DOE announced plans to provide $156 million from ARRA to support projects that deploy efficient technologies in the following four areas of interest: • CHP; • District energy systems; • Industrial waste energy recovery; and • Efficient industrial equipment. Applications were due by July 15, 2009. On November 3, 2009, the DOE announced its award of more than $155	

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		million to 41 industrial energy efficiency projects across the country. The nine largest projects, totaling $150 million and leveraged with $634 million in private industry support, will promote the use of CHP, district energy systems, waste energy recovery systems, and energy efficiency initiatives at hospitals, utilities, and industrial sites. A full list of recipients is available on the DOE's Industrial Technology Program Web site.	
Combined Heat and Power Systems Technology Development Demonstration	Grant	The Combined Heat and Power Systems Technology Development Demonstration aims to accelerate the development and deployment of CHP technologies and systems to work towards a goal of increasing U.S. electricity generation capacity from CHP. Applications for CHP technology development and demonstration will be considered for three areas of interest. The areas of interest are based on the output range of the CHP system and are as follows: • Large CHP systems (less than or equal to 20 MW); • Medium CHP systems (less than or equal to 1 MW to greater than 20 MW); and • Small CHP systems (less than or equal to 5 kW to greater than 1 MW). All three areas sought applicants that can perform research, development, and demonstration of technologies that increase the efficiency and reduce the cost of CHP systems. Applications were due by August 4, 2009. The large CHP systems have an estimated total budget of $30 million – $15 million from the DOE. The medium systems have an estimated budget of $30 million – $15 million from the DOE. Small CHP systems have an estimated budget of $20 million – $10 from the DOE. Funded demonstration projects are aimed at accelerating the project development process through collaborative partnerships with key industry partners. Key technologies are those capable of sizable energy savings and corresponding greenhouse gas emissions reductions while providing a least cost approach to compliance with relevant emissions regulations. All technologies have a defined pathway to commercialization.	
Waste Energy Recovery Registry and Grant Program	Grant	Title IV of the Energy Independence and Security Act of 2007 contains extensive new provisions designed to save energy in buildings and industries. Subtitle D of the Act focuses on industrial energy efficiency and contains new provisions designed to improve energy efficiency by promoting CHP, waste energy recovery, and district energy systems. EPA is required under EIEA Subtitle D, Part E to establish a recoverable waste energy inventory program. Subject to appropriations, the EIEA also directs the DOE to develop a waste energy recovery incentive grant program to provide incentive grants to: • Owners and operators of projects that successfully produce electricity or incremental useful thermal energy from waste energy recovery; • Utilities purchasing or distributing the electricity; and • States that have achieved 80% or more of recoverable waste heat recovery opportunities. US EPA's obligation under EISA is to develop an ongoing survey of major	

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		domestic industrial and large commercial sources, as well as the sites at which the sources are located, and to conduct a review of each source for the quantity and quality of potential waste energy produced. This survey is a necessary first step to gather the data needed to establish the Registry of Recoverable Waste Energy Sources (Registry). The purposes of the survey and Registry are to: • Provide a list of the economically feasible existing waste energy recovery opportunities in the US, based on a survey of major industrial and large commercial sources. • Provide state and national totals of the existing waste energy recovery opportunities, as well as the potential criteria pollutant and greenhouse gas emissions reductions that could be achieved with the capture and use of the waste energy recovery opportunities listed in the Registry. • Serve as the basis for potential waste energy recovery projects to qualify for financial and regulatory incentives as described in Energy Policy and Conservation Act (EPCA) Sections 373 "Waste Energy Recovery Incentive Grant Program" and 374 "Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy," as added by EISA. On July 16, 2009, the US EPA Administrator signed a draft rule which proposes to establish the criteria for including sources or sites in the Registry, as required by EISA. The draft rule also proposes the survey processes by which US EPA will collect data and populate the Registry. The proposed rule would apply to major industrial and large commercial sources as defined by US EPA in the rulemaking. The proposed rule would not require the installation of new monitoring equipment, rather it would require only that sources above certain threshold levels that wish to be included in the Registry enter specific already-monitored data points into the survey. The survey is a software tool that will calculate the quantity and quality of potentially recoverable waste energy. The proposed rule and relevant background information can be accessed on the Waste Energy Recovery Registry Web site. Public comments were accepted through September 21, 2009. For general questions about the proposed rule, contact Katrina Pielli.	
EPA Clean Water and Drinking Water State Revolving Funds	Grant	ARRA provides funding for states to finance high-priority infrastructure projects needed to ensure clean water and safe drinking water. It provided $4 billion for the Clean Water State Revolving Fund (CWSRF) program, in place since 1987, including funds for Water Quality Management Planning Grants. ARRA also provided $2 billion for the Drinking Water State Revolving Fund (DWSRF) program, in place since 1997. States must provide at least 20% of their grants for green projects, including green infrastructure, energy or water efficiency, and environmentally innovative activities. CHP projects at wastewater treatment facilities qualify for grants under the 20% set-aside. The CWSRF program is available to fund a wide variety of water quality projects, including all types of nonpoint source, watershed protection or restoration, and estuary management projects, as well as more traditional municipal wastewater treatment projects. Through the CWSRF program, each state and Puerto Rico maintain revolving loan funds to provide independent and permanent sources of low-cost financing for a wide range	

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		of water quality infrastructure projects. Funds to establish or capitalize the CWSRF programs are provided through federal government grants and state matching funds (equal to 20% of federal government grants). The DWSRF program provides public water systems with affordable financing for infrastructure improvements which enable them to comply with national primary drinking water standards and protect public health. States use federal capitalization grant money awarded to them under this program to set up an infrastructure funding account from which assistance is made available to public water systems. Loans made under the program can have interest rates between 0% and market rate and repayment terms of up to 20 years. Loan repayments to the state provide a continuing source of infrastructure financing. More information and program guidance, including grant allocations to each of the states is available through the Clean Water and Drinking Water State Revolving Funds Web site.	
Renewable Energy Production Incentive	Rebate	The Renewable Energy Production Incentive (REPI) Program was created by the Energy Policy Act of 1992 and reauthorized by the Energy Policy Act of 2005 to extend through 2026. REPI provides financial incentives for renewable energy electricity produced and sold by qualified renewable energy generation facilities, which include not-for-profit electrical cooperatives, public utilities, state governments, U.S. territories, the District of Columbia, and Indian tribal governments. The facilities are eligible for annual incentive payments of approximately 2 cents/kWh for: • Landfill Gas • Solar • Wind • Geothermal • Biomass • Livestock Methane • Ocean • Fuel cells using hydrogen derived from eligible biomass facilities To be eligible, qualified renewable energy facilities must be operational before October 1, 2016. Funding is subject to annual appropriation, and the program has historically been under-funded. During years in which there is a funding shortfall, legislation requires DOE to allocate 60% of REPI funds to solar, wind, ocean, geothermal, or closed-loop biomass technologies and the remainder to landfill gas, livestock methane, and open-loop biomass projects. If funds are not sufficient to make full payments to all qualifying facilities, payments are made to those facilities on a pro rata basis. To assist DOE in its budget planning, DOE requests that the owner or operator of a qualified renewable energy facility provide notification at least six months in advance of electricity generation. To receive payment, qualified facility owners and operators submit information, such as monthly electricity generation, to DOE during the first quarter (i.e., October 1 through December 31) of the next fiscal year. More information and details about the application procedures are provided on the REPI Web site and in the Partnership's funding database.	12/31/2026
Energy Efficiency and Conservation	Grant	The Energy Efficiency and Conservation Block Grant (EECBG) Program provides grants to local governments, tribal governments, states, and U.S.	

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Block Grant Program		territories to reduce energy use and fossil fuel emissions, and to implement energy efficiency improvements. Through formula and competitive grants, the Program empowers local communities to make strategic investments to meet the nation's long-term goals for energy independence and leadership on climate change. The EECBG Program is intended to help U.S. cities, counties, states, territories, and Indian tribes to develop, promote, implement, and manage energy efficiency and conservation projects and programs designed to: • Reduce fossil fuel emissions; • Reduce the total energy use of the eligible entities; • Improve energy efficiency in the transportation, building, and other appropriate sectors; and • Create and retain jobs. Funding for the EECBG Program under ARRA totals $3.2 billion. Of this amount, approximately $2.7 billion will be awarded through formula grants. In addition, approximately $454 million will be allocated through competitive grants. All states are eligible to apply for direct formula grants and competitive grants from DOE. Depending on population, cities and counties are eligible for EECBG Program funds either directly from DOE or from the state in which they are located. To date, DOE has awarded more than 1,200 EECBGs, totaling over $1.4 billion. The first EECBG formula grant awards were made on July 24, 2009, and continue to be made each week. On October 19, 2009, DOE issued its competitive EECBG funding opportunity announcement. The announcement seeks innovative state and local government and Indian tribe programs, and will use up to $454 million in ARRA EECBG funds for these competitive grants awarded in the two topic areas described below. Applications were due to DOE by December 14, 2009, and the voluntary letters of intent were due by November 19, 2009. • **Topic 1: Retrofit Ramp-Up, $390 million.** The first topic area will award funds for innovative programs that are structured to provide whole-neighborhood building energy retrofits. These will be projects that demonstrate a sustainable business model for providing cost-effective energy upgrades for a large percentage of the residential, commercial, and public buildings in a specific community. DOE expects to make 8 to 20 awards under this topic area, with award size ranging from $5-75 million. Eligible entities include states, formula-eligible local and tribal governments, entities eligible under Topic 2, and nonprofit organizations authorized by the preceding entities. • **Topic 2: General Innovation Fund, $64 million.** The second topic area will award up to $64 million to help expand local energy efficiency efforts and reduce energy use in the commercial, residential, transportation, manufacturing, or industrial sectors. DOE expects to make 15 to 60 awards, with award size ranging from $1-5 million. Eligible entities include local and tribal governments that were not eligible to receive population-based formula grant allocations from DOE under the EECBG program; a governmental, quasi-	

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		governmental, or non-governmental, nonprofit organization authorized by and on behalf of a unit of local government (or Indian tribe) that was not an eligible entity; or a consortia of units of local governments (or tribes) that were not eligible entities. For complete details on the availability of funds please visit the EECBG Web site, or the Partnership's funding database.	
State Energy Program	Grant	The State Energy Program (SEP) provides grants to states to address their energy priorities in the areas of energy efficiency and development of renewable energy technologies. The ARRA appropriated $3.1 billion for the program for fiscal year 2009. In order for a state to be eligible for these funds, it must commit to all three of the following: • Instituting policies at state-regulated utilities that support energy efficiency; • Adopting energy efficient building codes; and • Prioritizing grants toward funding energy efficiency and renewable energy programs. States will have discretion over how the money is distributed. Local governments and others interested in developing CHP projects should contact their State Energy Office to learn more about their state's process for distributing grants. DOE has posted the list of State Energy Offices. In Maine, SEP funds are directed to Efficiency Maine and starting July 1, 2010 will be directed to the Efficiency Maine Trust. The Weatherization and Intergovernmental Program in the DOE Office of Energy Efficiency and Renewable Energy manages SEP. More information about SEP can be viewed on the SEP Web site.	
Innovative Energy Efficiency, Renewable Energy, and Advanced Transmission and Distribution Loan Guarantees	Loan	The Energy Policy Act of 2005 authorized the U.S. Department of Energy to issue loan guarantees to eligible projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The projects need to employ new or significantly improved technologies when compared to technologies in service in the United States at the time the guarantee is issued. Under the solicitation that closed in February 2009, the minimum application fee was $75,000, which indicates that the program has historically been designed to support larger scale renewable energy and bio-fuel projects. DOE periodically publishes requests for applications for loan guarantees, which can target specific technologies or be general. ARRA expanded the loan guarantee program with $6 billion for renewable energy systems, bio-fuel, and electric power transmission projects. "Renewable energy systems" include those that generate electricity or thermal energy (or manufacture component parts of such systems). Bio-fuel projects are limited to those that are likely to become commercial technologies and will produce transportation fuels that substantially reduce life-cycle greenhouse gas emissions compared to other transportation fuels. The 2009 funds are limited to projects that commence construction by September 30, 2011. More information about DOE's loan guarantee program, including solicitation announcements, is available on the program's Web site.	
Community Based Renewable	Loan	In response to legislative direction, the MPUC established a community-based renewable energy pilot program to encourage the sustainable development of community-based renewable energy in the State. The	

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Energy Pilot Program		program is not to exceed 50 megawatts (MW) in capacity and eligible projects must include qualifying owners, community support, grid-connection, and capacity not to exceed 10 MW. One of two incentives can be applied to projects, either long-term contracts or a set renewable energy credit multiplier set at 150% of the amount of the electricity. The State may give purchasing preference to electricity generated by community-based renewable projects, the MPUC can incorporate into the supply of the standard-offer service and shall arrange for a green power offer composed of green power supply and will incorporate green power supply from community-based renewable energy projects to the maximum extent possible.	