Performance and Cost Trajectories of Clean Distributed Generation Technologies

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Disclaimer: This report forecasts the cost trajectories for DG and emission control technologies. The CARB DG emission certification regulations are used as the environmental performance targets for the technologies. The technology profiles developed over the course of this study represent a composite of previous Energy Nexus work, Energy Nexus staff DG project experience, other available reports, and input received from a number of DG stakeholders. The collection of input received by the stakeholders, with varying technical perspectives and many with competitive and regulatory agendas, resulted in a wide variation of inputs, many of which were not fully recognized in this study. Thus, the individual views of the aforementioned stakeholder participants are not necessarily reflected in this report.

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Introduction

Energy Nexus Group was engaged by The Energy Foundation to assess the cost trajectories and emission controls for distributed generation (DG) and combined heat and power (CHP) technologies. The purpose of the report is to understand the range of costs over time and the factors from economics of manufacture to technology breakthroughs that will drive clean DG technologies.

The Energy Foundation is a partnership of major foundations interested in sustainable energy. The Foundation, with support from the Pew Charitable Trusts, has launched the Clean DG Initiative, a national effort to ensure that new DG installations bring clean air benefits. Advocacy focuses on air emission policy and regulation to encourage clean distributed generation.

This study has been tasked to project cost and performance for representative DG/CHP technologies with appropriate emission control over a ten-year period. The emission benchmarks used to characterize these technologies are the CARB Emission Certifications Regulation for 2003 and 2007. Technologies covered include natural gas turbines, microturbines, reciprocating engines and fuel cells. The assessment projects a range of cost trajectories for various DG emissions control technologies and the factors (like manufacturing economies, technology breakthroughs, etc.) that might drive DG technologies toward one end of the range or another.

Historical DG activity in the U.S. has largely been in CHP applications, and DG market forecasts indicate that a large majority of future intermediate and baseload DG will be natural gas fueled CHP. For these factors, this report keyed in on the economics of CHP applications and not power-only DG.

The U.S. EPA and DOE are building upon the results of this study to examine additional DG product sizes, applications, and cycle configurations such as hybrid turbine fuel cells and recuperated turbines; and to assess market tradeoffs for alternative DG emission strategies.

CARB DG Emission Certification Regulation

The CARB Emission Certification Regulation evolved from California legislation (AB1298) directing CARB to develop transitional regulation for DG to achieve central station combined cycle emission levels on an output basis with appropriate credits being given for heat utilization and line loses. The CARB levels are summarized in Exhibit 1.

CARB provides two sets of emission levels for 2003. One set applies to DG without heat recovery and the other is for combined heat and power systems (CHP). For 2007, there is one set of numbers that include an allowance for heat utilization where the effective output is a sum of the electric output in MW-hr plus the thermal utilization in MW-hr. The CARB Regulation also indicates a 10% credit for the DG benefits associated with avoided line losses.

CARB	NOx	CO	VOC
	********** lb/MW-hr *************		
CC Central	0.07	0.10	0.02
DG 2003	0.5	6.0	1.0
DG 2003 w/CHP	0.7	6.0	1.0
DG 2007	0.07	0.10	0.02

Exhibit 1 – CARB DG Emission Certification Regulation

Current Technology Options

Technology options available today for DG include industrial and aero-derivative gas turbines, reciprocating engines, microturbines and fuel cells. The primary fuel option for these technologies is natural gas. Other fuel sources include landfill gas, digester gas, industrial waste fuel streams, propane, and diesel fuel. This study looked only at natural gas CHP applications.

Reciprocating engines and gas turbines have been used for decades in power generation and CHP applications. State-of-the-art technology evolved over decades of technology maturity and market experience. They have also benefited from the production base and technology investments for transportation, marine and aerospace applications.

Fuel cells and microturbines have just recently become commercially available for DG applications. Product sizes are currently limited as are the number of manufacturers. Today's prices are generally above the market-clearing price, and therefore, products are primarily used in niche applications or where significant government price support is available. With technology and market maturity, these technologies show potential for significant improvements in both cost and performance. These technologies each offer certain advantages, including low emissions.

Each of these technologies is briefly summarized below.

<u>Gas Turbines (500 kW to 30 MW)</u>

Industrial gas turbines are an established technology used for a variety of on-site generation and mechanical drive applications. Gas turbines produce high quality heat that can be used to generate steam for on-site use or for additional power generation (combined cycle). Gas turbines burn natural gas, a variety of petroleum fuels or can have a dual-fuel configuration. State of the art gas turbines control emissions to low levels using lean pre-mix combustion techniques. The combustors are often referred to as dry low emission (DLE) combustion. Lower emission levels, like those specified by CARB, typically require exhaust treatment such as selective catalytic reduction (SCR). Catalytic combustion, which has the capability to reach these lower emission levels without after-treatment, is now being introduced in selected turbine products. Low maintenance cost, high reliability and high quality exhaust heat make gas turbines an excellent choice for larger industrial and commercial CHP applications. Gas turbines are most competitive in sizes larger than 3 MW

Reciprocating Engines (30 kW to 5 MW)

Reciprocating internal combustion (IC) engines represent a well-known technology that is widely used for all types of power generation from small portable gen-sets to large industrial engines that power generators of several megawatts. Current generation IC engines offer low first cost, easy start-up, proven reliability when properly maintained, and good load-following characteristics. Drawbacks of IC engines include relatively higher emissions and the need for regular and extensive maintenance. Emissions of IC engines have been reduced significantly in the last several years by better design and control of the combustion process. Exhaust catalyst, including three-way catalyst, oxidation catalysts and SCR, can be used to achieve substantially reduced emissions signatures when required. IC engines are well suited for packaged CHP in commercial and light industrial applications less than 5 MW. Smaller IC engine systems produce hot water, while larger systems can be designed to produce low-pressure steam for use in either heating or cooling applications.

Spark ignition (SI) IC engines for power generation use natural gas as the preferred fuel, but can be set up to run on a variety of other fuels. There are two types of SI engines: rich-burn and lean-burn. Rich-burn engines generate relatively high levels of NOx but are readily treated with a passive 3-way catalyst similar to that used in automobiles. Lean-burn engines are inherently more efficient, less maintenance intensive, and produce considerably fewer pollutants than rich-burn engines. However, should additional cleanup be called for, a more expensive SCR system and oxidation catalyst would be required.

Diesel cycle, compression ignition IC engines operate on diesel fuel or heavy oil. Although very efficient and low cost, because of the high cost for diesel fuel, these engines are better suited for peaking than for continuous duty applications. The higher emission levels from these engines make them difficult to permit for stationary duties other than standby. After-treatment systems for diesels can be cost prohibitive. Compression ignition engines can be set up in a dual-fuel configuration that can burn primarily natural gas with a small amount of diesel pilot fuel. These engines have much lower emission characteristics.

Microturbines (30 kW to 350 kW)

Microturbine technology has evolved from the technology used in automotive and truck turbochargers and auxiliary power units for airplanes and tanks. Several companies have developed commercial microturbine products, ranging in size from 30 kW to 100 kW, and are in the early stages of market entry. In the typical configuration, the turbine shaft, spinning at up to 100,000 rpm, drives a high-speed generator. This high frequency output is converted to the 60 Hz power used in the U.S. by sophisticated power electronics. Microturbines are compact and lightweight with few moving parts. Many designs are air-cooled and some even use air bearings, thereby eliminating the cooling water and lube oil systems. Microturbines for CHP duty are typically designed to recover hot water. The simple design of microturbines holds the potential for cost effective manufacturing if adequate volumes can be achieved. It should be noted that many applications do require a fuel boost compressor, which adds to the cost, and detracts somewhat from performance.

Microturbines' potential for low emissions, reduced maintenance and simplicity could make on-site generation more palatable for many smaller commercial and industrial operations if plans for cost reduction are realized.

Fuel Cells (10 kW to 3 MW)

Fuel cell systems with applications in electric power generation, motor vehicles, portable electronic equipment and military/aerospace applications are largely in research, development, testing and other pre-commercialization stages. Fuel cells produce power electrochemically, more like a battery than like a conventional generating system. Unlike a storage battery, however, which produces power from stored chemicals, fuel cells produce power when hydrogen fuel is delivered to the anode of the cell and oxygen in air is delivered to the cathode. The resultant chemical reactions at each electrode create a stream of electrons (or direct current) that flows between the oppositely charged electrodes of the cell. The hydrogen fuel can come from a variety of sources, but the most economic is through reforming of natural gas, which is generally the only source for fuel cell emissions. There are several different liquid and solid media that can be used to create the fuel cell's electrochemical reactions – phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEM). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in early commercial market development with 200 kW units delivered to over 200 customers worldwide. The SOFC, MCFC, and PEM technologies are now in field test or pre-commercial demonstration. Fuel cells promise higher electric efficiencies than generation technologies based on prime movers such as recip engines or turbines. In addition fuel cells are inherently quiet and extremely clean running. Like microturbines, fuel cells require power electronics to convert direct current output to 60-Hz alternating current. Many fuel cell technologies are modular and capable of application in small commercial and even residential markets; other technologies utilize high temperatures in larger sized systems that would be well suited to industrial CHP applications. Fuel cell installations to-date have benefited by government support to counter current high costs. Otherwise, markets have been limited to niche markets such as very high electric rate areas requiring near zero emissions, and in some high power reliability applications. Substantial price reductions are necessary for meaningful market acceptance to occur.

CHP Market Overview

Almost all DG capacity in the U.S. today is CHP where the value of recovered heat tips the economics in favor of on-site generation. The inventory of CHP capacity in the U.S. is approximately 53 GW, with 90% in the industrial sector. Gas turbines and combined cycle units accounted for a majority of the capacity (64%), while reciprocating engines dominated the number of installations (48%).

The market for CHP is far from saturated with over 80 GW of untapped CHP potential remaining in the industrial sector and more than 75GW of new potential in the commercial and institutional markets. Making the most of this potential requires a broad DG product portfolio to address the varied size requirements as shown in Exhibit 2.

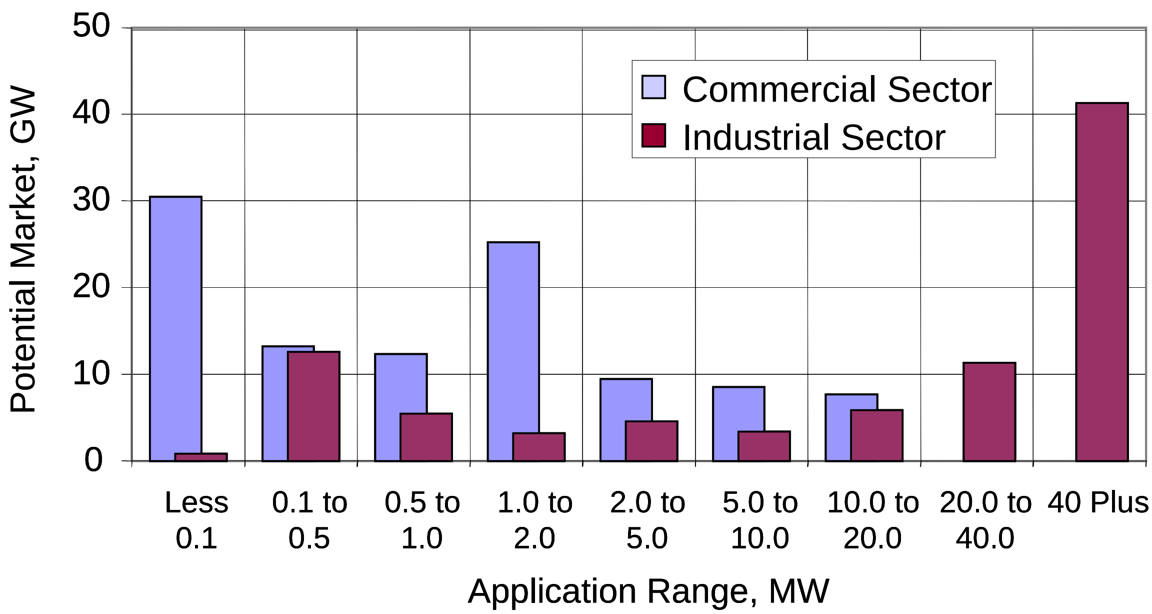

Exhibit 2 – US CHP Market Opportunities

The size span for the various DG technology classes is depicted in Exhibit 3. Also noted are the market dominant technologies by size.

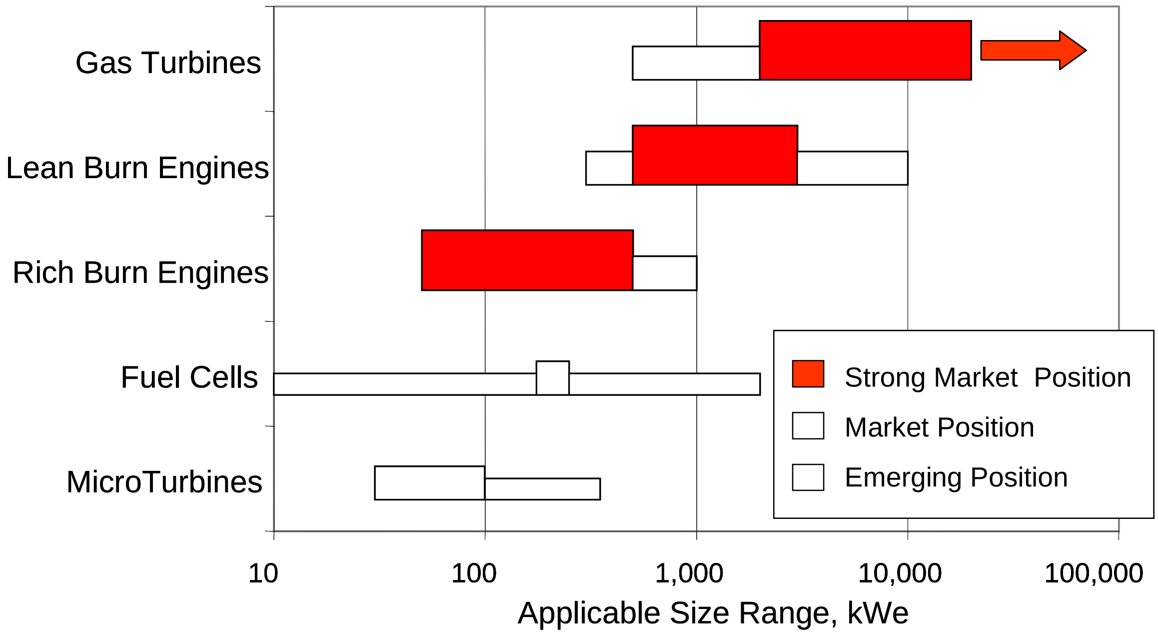

Exhibit 3 – Technology Size Coverage

Current Technology Performance and Cost Characteristics

<u>CHP Installed Costs</u>

A key economic indicator for CHP systems are the turnkey capital costs. Installed cost ranges for today's DG technologies without after-treatment are illustrated in Exhibit 4. As shown, installed costs are a function of technology type and size. Engine systems above 800 kW and turbine systems above 5 MW can often be installed at costs around $1,000/kW or below. The turbine equipment package, installation and transaction costs all contribute to the higher cost of smaller turbine systems. For smaller recip engines, the higher installation and transaction costs are the primary contributor. The high installed cost of microturbine and fuel cell systems is a combination of high costs for commercially infant products, and the high transaction and installation cost for the smaller sized systems.

<u>Electric Efficiency</u>

The electric efficiency of today's DG technologies is depicted in Exhibit 5. Note that efficiencies are presented in higher heating value (HHV). Engines have the highest electric efficiencies over a broad range of DG sizes. The one commercially available fuel cell product, at 200 kW, has a higher efficiency but has seen limited market acceptance because of high capital cost. Gas turbines show significant efficiency improvements in larger sizes and generally win out over their large engine counterparts when heat recovery (CHP), low emissions, and reliability are important determinants. Microturbines have been showing improved efficiency at the small end of the range and are beginning to approach levels achieved by today's small recip engines.

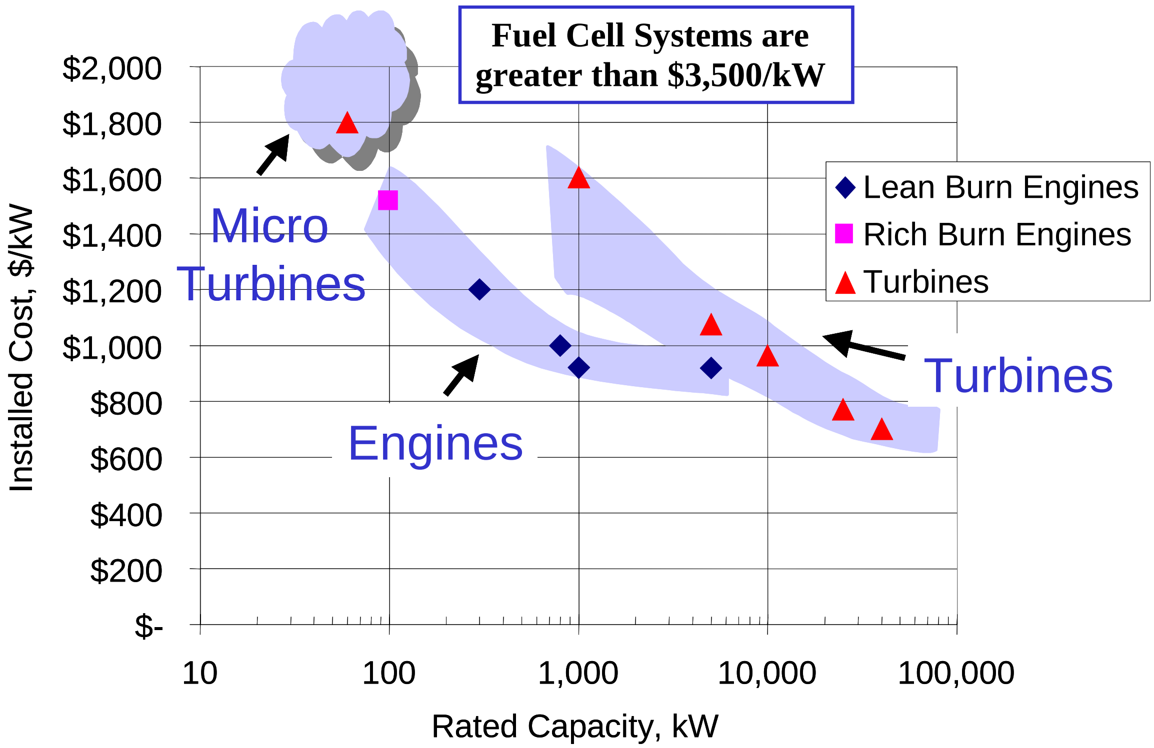

Exhibit 4 – Uncontrolled System Installed Costs

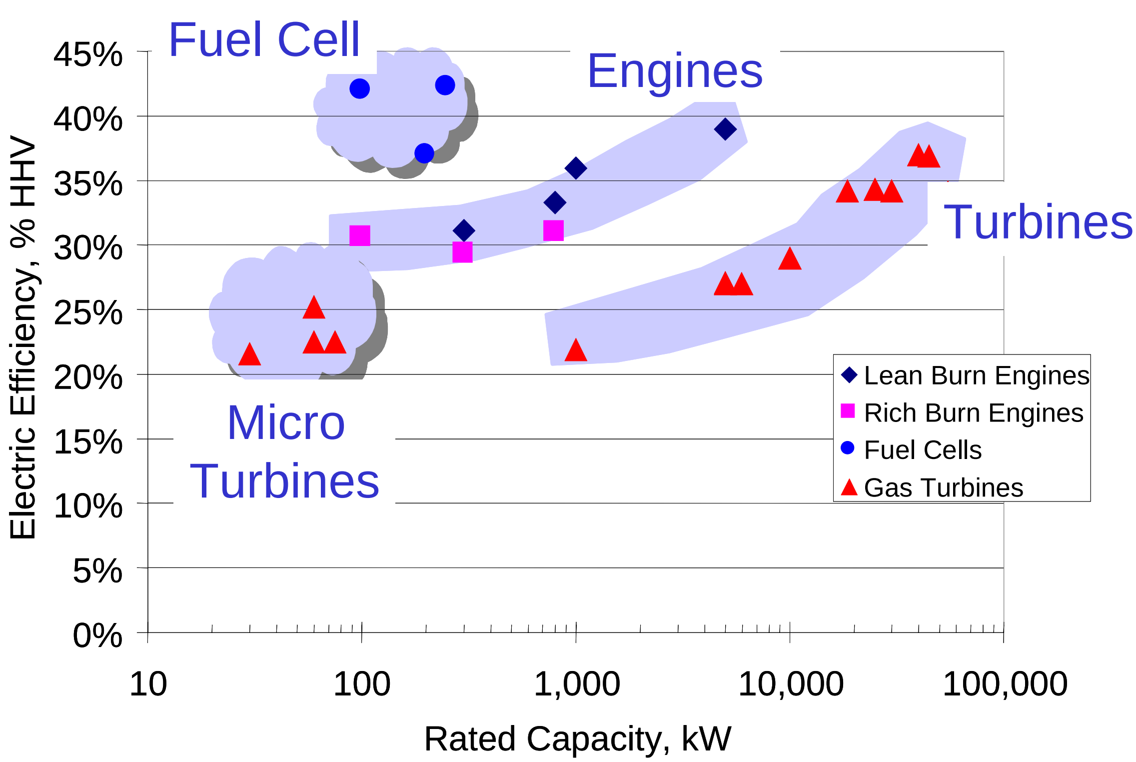

Exhibit 5 – Efficiency of Today's DG Technologies

Uncontrolled Emission Levels

The uncontrolled emission levels for current DG technologies without heat recovery credit are shown in Exhibit 6 for NO_x, Exhibit 7 for CO and Exhibit 8 for VOCs.

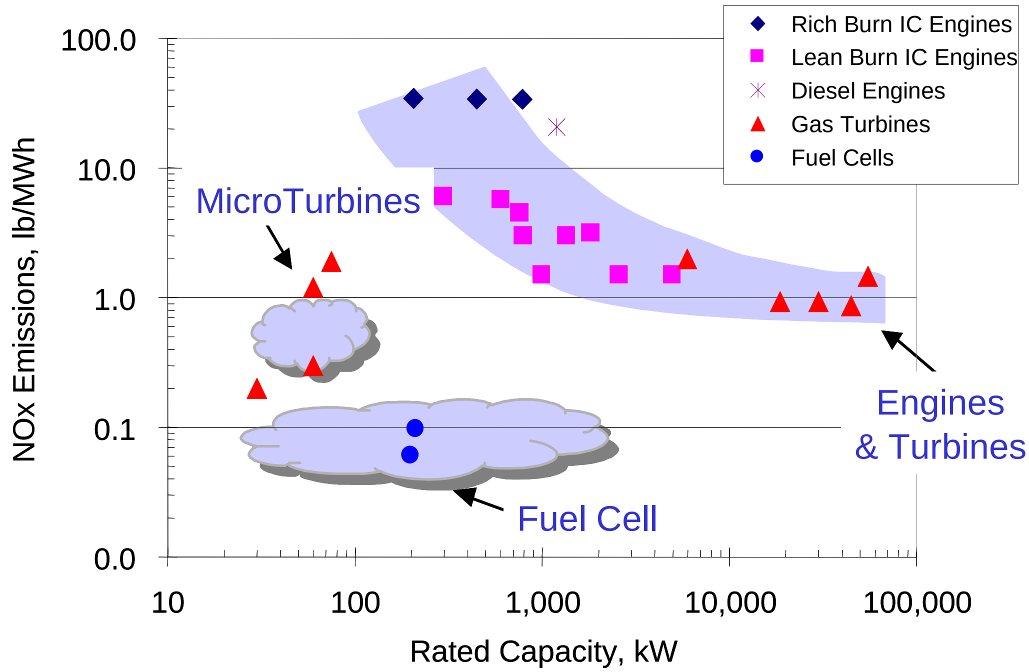

Exhibit 6 – Uncontrolled NOx Emissions

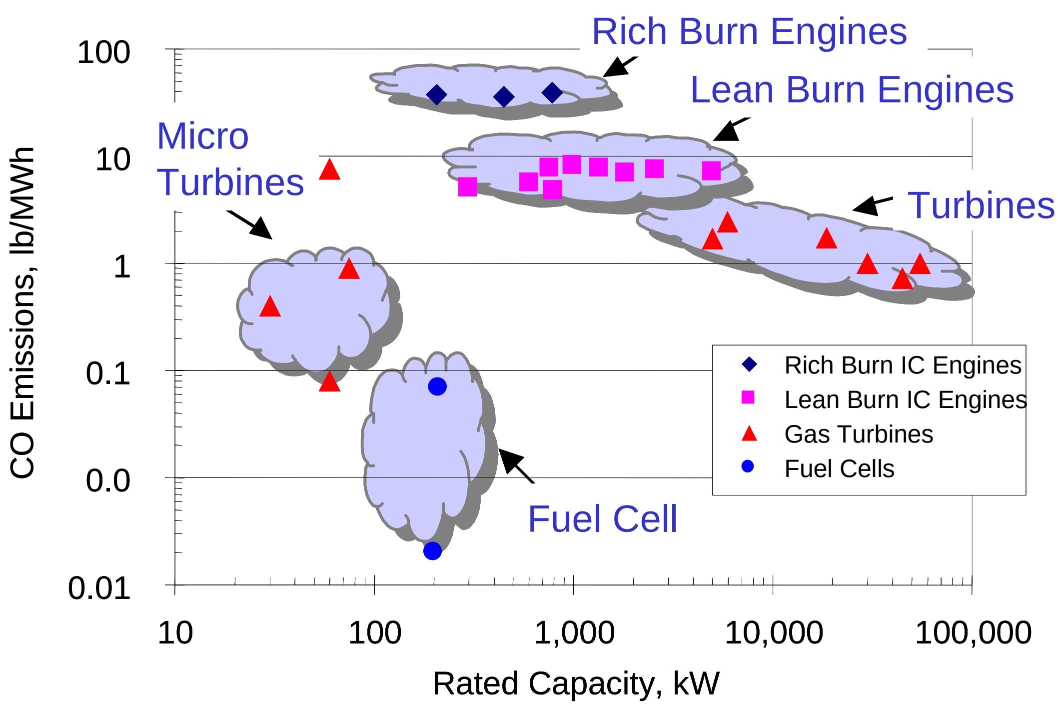

Exhibit 7 – Uncontrolled CO Emissions

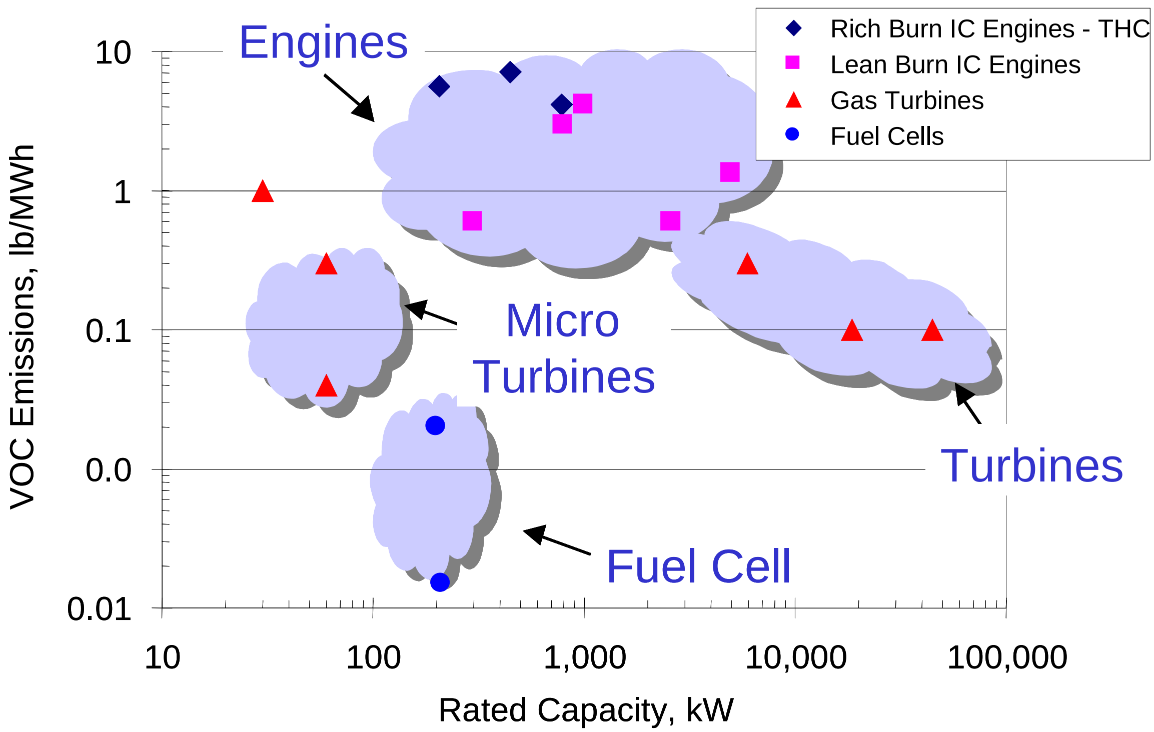

Exhibit 8 – Uncontrolled VOC Emissions

<u>After-treatment</u>

Selective Catalytic Reduction (SCR) consists of injecting ammonia upstream of a catalyst bed. NO_x combines with ammonia and is reduced to molecular nitrogen in the presence of the catalyst. It is currently the most cost-effective after-treatment method for significant NO_x reduction in an oxygen laden exhaust stream as is the case with gas turbines and lean-burn engines. A passive oxidation catalyst is often needed in addition to SCR to reduce CO and VOC emissions.

Another gas turbine and lean-burn recip NOx reduction option is EMx (formerly $SCONO_x$). EMx employs a precious metal catalyst and a NOx absorption/regeneration process to convert CO and NO_x to CO_2, H_2O and N_2. EMx does not utilize ammonia, which is a deterrent to SCR usage in some applications. However, except for those low-emission markets where ammonia is not allowed, EMx is cost prohibitive relative to SCR with oxidation catalysts.

Rich-burn recip engines that operate with precisely the exact amount of air to combust the fuel (stoichiometric) can utilize a 3-way catalyst similar to those employed in automobiles. These relatively inexpensive and passive non-selective catalytic reduction systems recombine NO_x, CO, and VOCs to CO_2, N_2 and H_2O. The premium catalyst systems that are in use today achieve the CARB 2003 levels.

Today's capital cost ranges for SCR, oxidation catalysts and 3-way catalysts are shown in Exhibit 9. Note that this exhibit does not communicate O&M costs attributable to the after-treatment options, including catalyst replacement. These costs were considered as part of the life cycle cost analysis covered in later sections of this report.

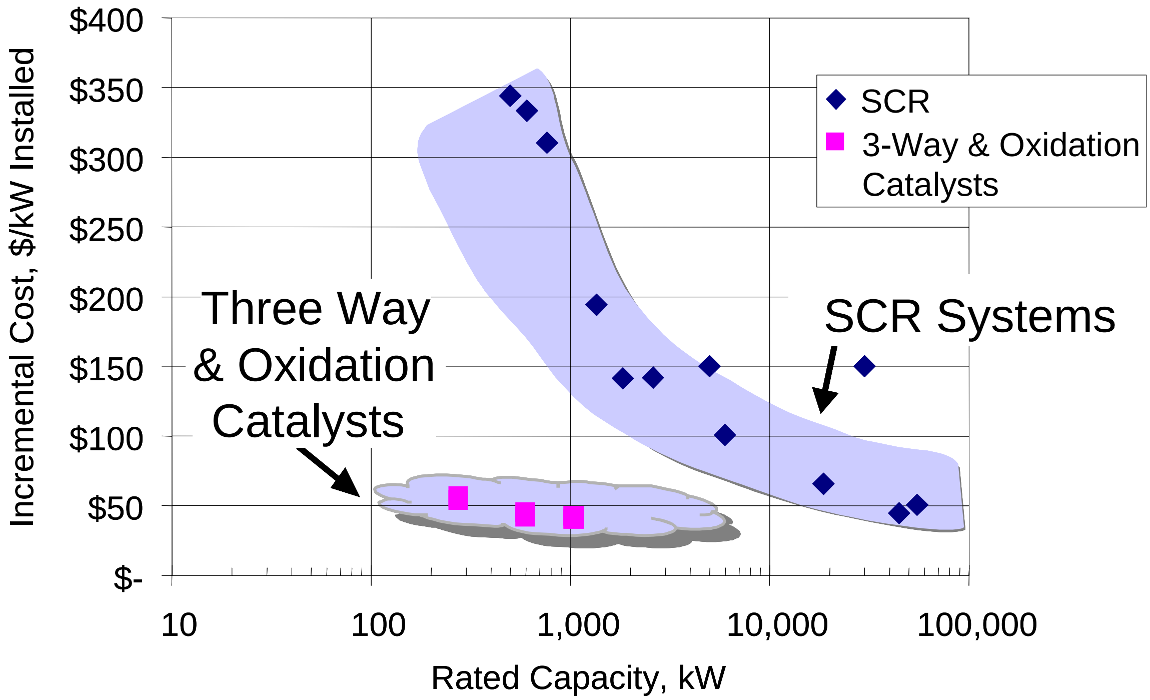

Exhibit 9 – Incremental Capital Cost Data of Emission Controls

Note that there is a rather limited experience with SCR in smaller turbine and engine applications to-date, due in part to the economic impact and general market reaction.

DG Performance and Cost Trajectories

Each of the four technology classes is on ever-changing performance and cost trajectories that are affected by a number of market, institutional and technical factors. These factors include:

- Level of DG market activity, trends and outlook.
    - Technology investments must meet business hurdle criteria
    - Competition for market share dependent on market size
    - Market volumes will impact cost for equipment and installation
- Policy and regulatory backdrop
    - Grid interconnect standards
    - Standby rates and other tariff features like non-by-passable fixed charges and exit fees
    - Payments or congestion rates to encourage DG solutions for grid and capacity support
    - Tax credits, accelerated depreciation or greenhouse gas trading programs to encourage private sector investment in CHP

- Technology forcing regulations
- Technology Initiatives
  - Evolutionary advancements driven more by resources than by risk
  - Innovations and technology breakthroughs with high risk profiles
  - Availability and commitment of private and public resources

Technology Profiling Process

Representative product sizes for each technology class were selected to project cost and performance characteristics. Again, the CARB Regulation was used as a benchmark for all considered technologies. Exhaust after-treatment is added as necessary and practical to meet or approach the regulation. DG technology profiling studies ongoing for DOE and EPA were used to start the data gathering process. Additional information was obtained from DG manufacturers, distributors, packagers, R&D organizations, and after-treatment suppliers on current and future technology solutions to achieve the aggressive CARB levels. The data profiles covered installed cost, O&M cost, efficiency, and emissions. For technologies with after-treatment, the incremental cost and emission improvement from exhaust cleanup were broken out separately.

CHP applications were the focus of this study as they historically have been and are projected to account for most DG systems primarily due to their inherent efficiency advantage over central station and grid alternatives. The technology and product sizes considered are summarized below:

- Natural Gas CHP Turbines
  - 3 MW and 10 MW with Catalytic Combustion
  - 3 MW and 10 MW with DLE combustor, SCR and oxidation catalyst as needed
- Natural Gas CHP Reciprocating Engines
  - 500 kW rich-burn with 3-way catalyst
  - 500 kW, 1 MW and 3 MW lean-burn with SCR and oxidation catalyst
- Natural Gas CHP Microturbines
  - < 100 kW
  - 200 kW
- Natural Gas CHP Fuel Cells
  - 200 kW PAFC
  - 200 kW PEM
  - 100 kW SOFC
  - 300 kW and 2 MW MCFC

Time and cost constraints for this study precluded a more comprehensive coverage of technologies, fuel sources, sizes, and applications. Furthermore, many of the stakeholders contacted were not able to fully respond to the above technology roster due to the time constraints on this project.

Scenario Development

For each of the three time periods analyzed: 2003/04, 2007 and 2012, a scenario analysis was conducted to better frame the future results. For 2003/04, three values for each parameter were tabulated to represent the natural variation in product performance and application, and installation complexity that is observed in the marketplace. For 2007 and 2012, three values were projected to represent a span of technology and market development scenarios: limited, base, and accelerated cases. In general, each of these cases is characterized by:

- Limited
  - Market and economic conditions for DG stagnate or erode. The market for DG in the U.S. remains below 500 MW/yr.
  - Restricted public and private funds for technology development
  - Minimal competition develops between technologies and among manufacturers
  - No monetary or regulatory recognition of DG benefits beyond displaced energy values
  - Minimal issues with capacity and T&D constraints
- Base
  - Continuation of current trends to gradually improve technology
  - Moderate recognition of DG market benefits by policy and regulatory communities
  - Reduction in barriers to DG, lessened utility resistance and some utility support
  - U.S. DG market activity is in excess of 1,000 MW/yr by 2007
  - Continuation of Government support for DG technology at current and projected levels
  - The demand momentum for lower emission products grows in the U.S. and internationally.
- Accelerated
  - Favorable policy and regulatory treatment of DG
  - Recognition and monetary quantification of DG benefits
  - Robust market activity and competition. By 2007, DG market activity exceeds 2,500 MW/yr in the U.S. and 5,000 MW/yr worldwide.
  - Robust investment in technology by the government and by private industry
  - Strong momentum world-wide for lower emissions DG
  - Capacity and T&D constraints become more acute

A detailed profile (data set) was developed for each of the fifteen technologies and each of the three scenarios. This data set consisted of cost, performance, and emissions of uncontrolled systems and similar data for the controlled systems with after treatment or advanced combustion technologies. This data set was then used with the same economic assumptions defined below to calculate CHP life cycle costs. The emissions data was compared to the CARB regulation to determine if the system would satisfy these requirements in both the electric-only and CHP applications. All costs are in current year (2002) dollars. An example data sheet is shown in Appendix A. Again, as noted in the Disclaimer, these data sheets represent a composite of input received and do not necessarily represent a consensus view nor individual perspectives of the stakeholders.

Life Cycle Cost Analysis for CHP

A life cycle cost analysis was performed for each of the technologies in the three timeframes and under each of the three scenarios. The following assumptions were applied to each of the cases:

- Overall efficiency – 70% HHV for all cases except 2007/2012 accelerated @ 75%
- Recovered Heat utilization – 75% of the available heat
- Capital Recovery – 10% interest over 10 years
- Current year (2002) dollars
- Displaced boiler efficiency – 80%
- Fuel price: \$5.50/mmbtu for natural gas DG $\leq$ 1 MW; \$4.00/mmbtu for natural gas DG > 1 MW

Overall efficiency, including recovered heat utilization is very application specific and can vary widely. To keep the results manageable, the same heat utilization assumptions were applied to all the technologies. CARB is revisiting the issue of efficiency thresholds and this analysis assumes no minimum requirement.

The CARB Regulation did not address measurement and verification requirements for emissions and for overall efficiency. The costs for compliance assurance could be very significant, particularly for smaller systems, and were not speculated for purposes of this study.

Base Case Scenario Results

The base cases for 2003/04, 2007 and 2012 are shown for the menu of CHP systems considered. Exhibits 10 & 11 show the cost buildup for the reciprocating engine, microturbine and fuel cell technologies at or below 1 MW. The cost buildup includes capital recovery, fuel net heat recovery credit, and O&M. The costs for after-treatment equipment, when applicable, are shown incrementally. Exhibit 12 depicts the economic performance of baseline CHP technologies above 1 MW, including engines, fuel cells and turbines. Although, not an after-treatment solution, the additional cost for catalytic combustors are shown incrementally on the 3 MW and 10 MW turbine cases.

The fuel cell projections (except PAFC) are keyed to their respective market entry (ME) dates, which were assumed to be 2003. Should the ME dates be different, the 2007 and 2012 projections slip accordingly. The price reductions for these systems are primarily dependent on manufacturing learning and continued technology advancements, which will occur with successful product introductions. If limited market acceptance occurs during the brief 10-year perspective of this study, projected cost reductions will likely not be achieved.

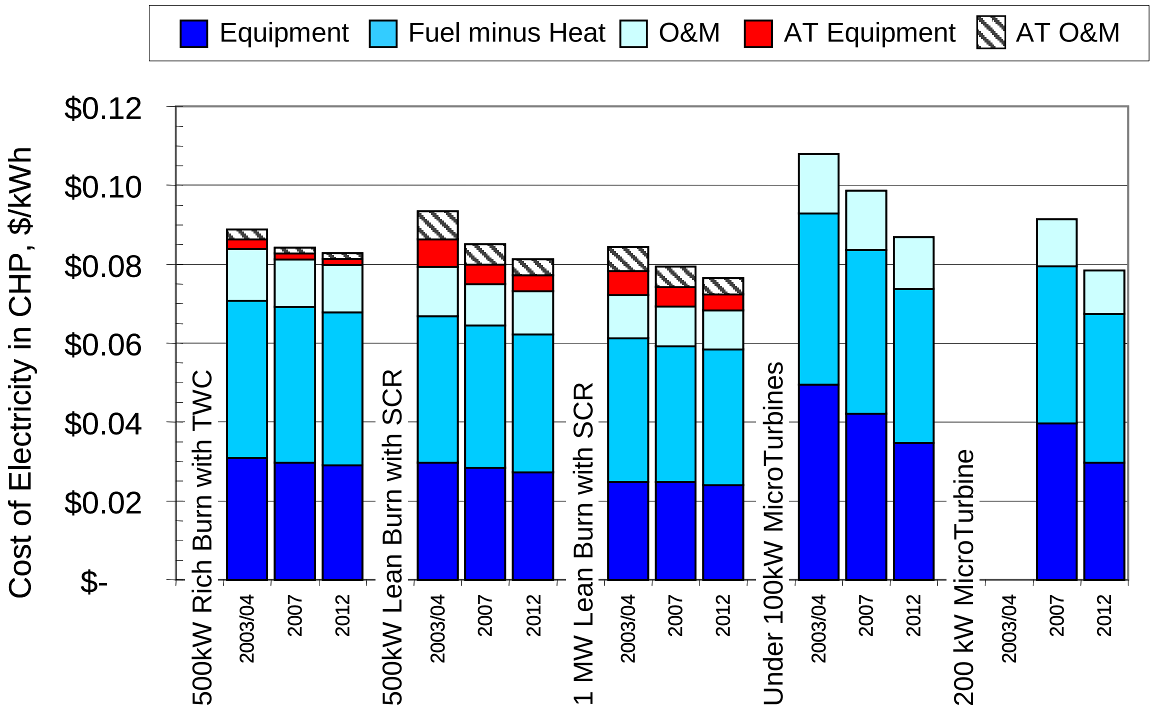

Exhibit 10 – COE for 1MW and Smaller CHP Systems (Base Case)

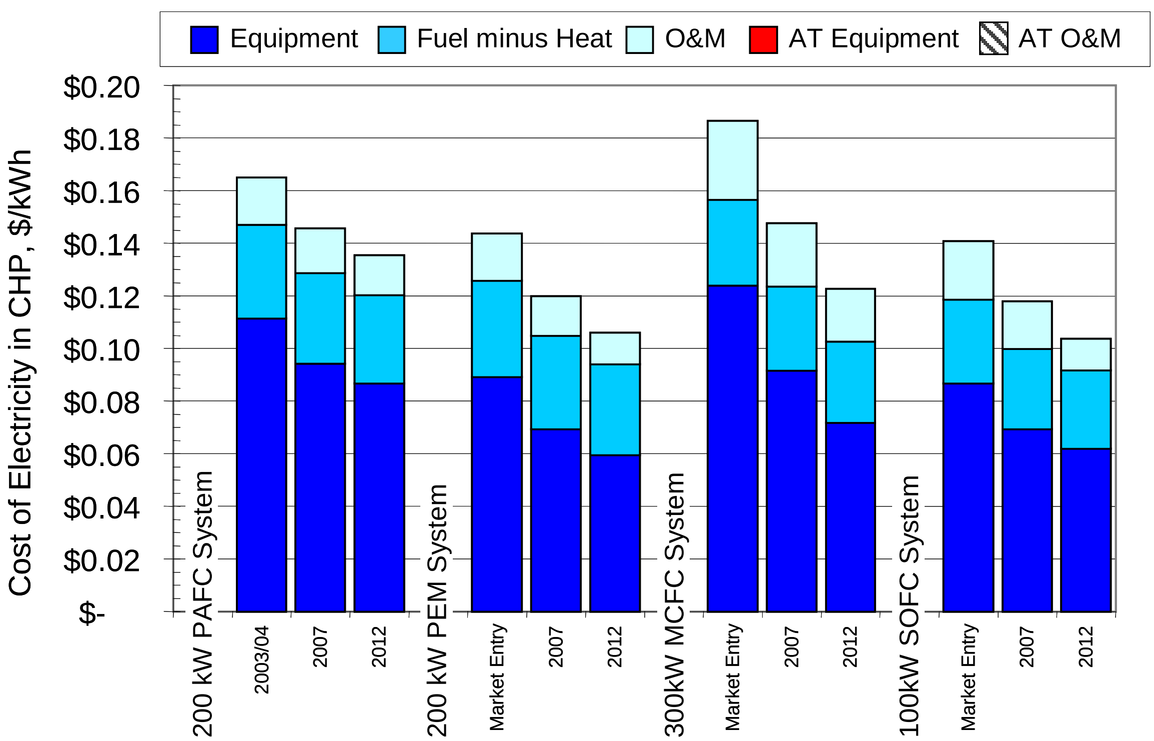

Exhibit 11 – COE for <1MW Fuel Cell CHP Systems (Base Case)

For the baseline cases, the 500kW and 1 MW gas engines show better economics than the 100 kW to 300 kW fuel cell and microturbine cases. In 2012, with successful technology development, commercial introduction, and sufficient sales volumes, solid oxide fuel cells show potential to narrow the cost gap with smaller recip engines.

In the 500 kW size range the rich-burn engine system shows slightly lower costs than the lean-burn engine counterpart. Although the lean-burn engine has an electric efficiency and operating cost advantage over rich-burn, the cost burden of SCR is much greater than that of a much simpler 3-way catalytic converter. It should be noted that very few lean-burn recip engines in this small size range have been commercially installed to-date with SCR due to the economic premium (~$.01/kWh) and other siting and operational issues.

All commercial technologies (some equipped with after treatment) meet the CARB 2003 levels in both the power only and CHP modes. Today's fuel cells meet the 2007 CARB levels in the base case for power-only and for CHP. In 2007, Microturbines meet 2007 CARB for CHP but not for power-only. By 2012, technology improvements allow Microturbines to meet 2007 CARB for power-only as well as CHP. For the base case, none of the engine cases considered meet 2nd tier CARB by 2012.

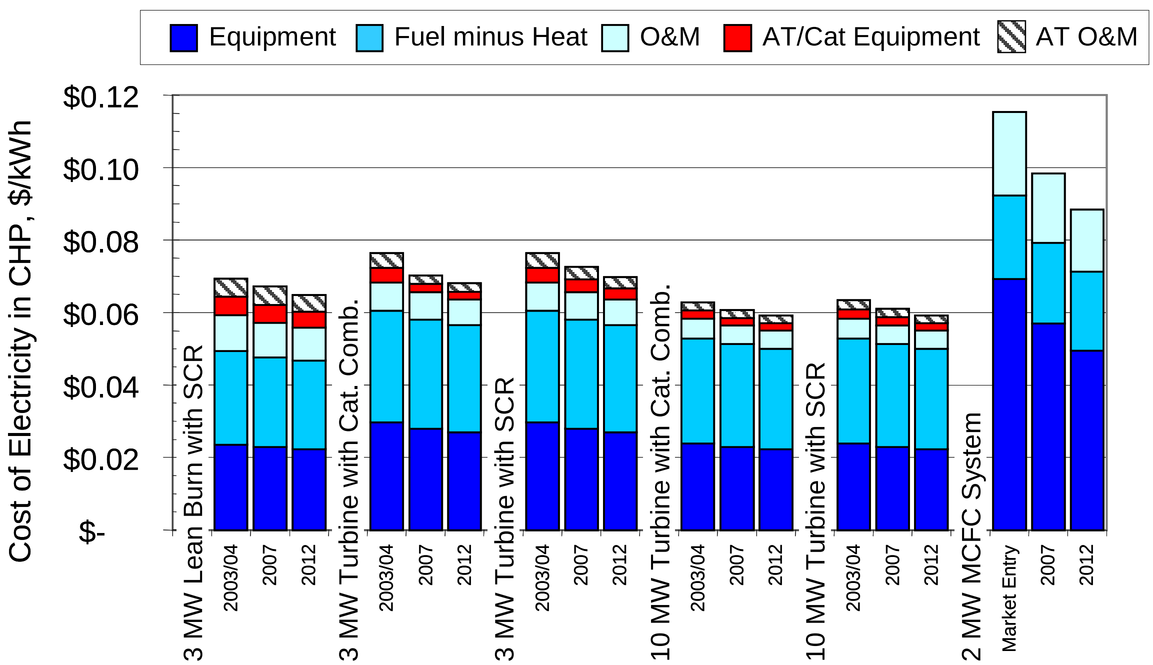

Exhibit 12 – COE for >2MW CHP Systems (Base Case)

For the larger suite of technologies, engines are cost effective in the 3 MW class against turbines today when lower grade heat from the recip is useful. Turbines more often win in the market today in sizes greater than 5 MW particularly when high quality heat and baseload operation are called for.

Turbines equipped with catalytic combustors have the economic edge over SCR and avoid the permitting and operating hassle of ammonia. Larger molten carbonate fuel cells show potential to achieve very high electric efficiencies and lower emission levels but their economics do not stack up against turbines operating in CHP applications because of the high initial capital cost. MCFCs, with a successful market launch, will fare better in base-load applications with low thermal requirements.

The base case fuel cell system and turbines equipped with SCR and oxidation catalysts meet CARB in all timeframes for power-only and CHP. Turbines with catalytic combustors, meet CARB for power-only and CHP in 2003/04 and 2012 but need an oxidation catalyst in 2007 for power only applications due to CO and VOC emissions.

The base case 3 MW lean burn engine outfitted with SCR and oxidation catalyst, meets CARB in 2003 but not in 2007 nor in 2012. Although not as expensive as for the smaller engines, SCR still adds an appreciable premium to larger recips and smaller turbines. This premium has limited their commercial use, and therefore, the amount of CHP implementation in environmentally stringent regions.

Scenario Analysis

As mentioned previously, a scenario analysis was conducted for each of the three time periods analyzed: 2003/04, 2007 and 2012. For 2003/04, three values for each parameter were tabulated to represent the natural variation in product performance and application, and installation complexity that is observed in the marketplace. For 2007 and 2012, three product value sets were projected to represent a span of technology and market development scenarios: limited, base, and accelerated cases.

A detailed data set was developed for each of the fifteen technologies and each of the three scenarios and timeframes. This data set consisted of cost, performance, and emissions of uncontrolled systems and similar data for the controlled systems with after treatment or advanced combustors. This data set was then used with the same economic assumptions defined above to calculate CHP life cycle costs. The emissions data was compared to the CARB regulation to determine if the system would satisfy these requirements in both the electric-only and CHP applications. Exhibit 13 summarizes the trajectories for NOx emissions. Systems that meet the CARB levels are shown with a check mark. The projected emission levels are shown for those that do not meet CARB.

Each of the four technology groupings are reviewed and technical opportunities to achieve improvements in performance, cost and emissions are discussed.

Summary System NOx Emissions

	2003/2004 Application Range			2007 Period			2012 Period		
	Standard	Improved	Best	Limited	Base	Accelerated	Limited	Base	Accelerated
CARB Standard Electric Only, lb NOx/MWh	0.50	0.50	0.50	0.07	0.07	0.07	0.07	0.07	0.07
CARB Standard CHP, lb NOx/MWh	0.70	0.70	0.70	0.07	0.07	0.07	0.07	0.07	0.07
Systems Less than 2 MW Capacity									
500kW Rich Burn with TWC	✓	✓	✓	0.31	0.25	0.15	0.31	0.24	0.13
500kW Rich Burn with TWC in CHP	✓	✓	✓	0.15	0.12	✓	0.15	0.12	✓
500kW Lean Burn with SCR	✓	✓	✓	0.47	0.31	0.19	0.37	0.22	0.16
500kW Lean Burn with SCR in CHP	✓	✓	✓	0.25	0.18	0.11	0.21	0.13	0.09
1 MW Lean Burn with SCR	✓	✓	✓	0.28	0.22	0.13	0.26	0.16	✓
1 MW Lean Burn with SCR in CHP	✓	✓	✓	0.16	0.13	0.08	0.16	0.10	✓
Under 100kW MicroTurbines	0.83	✓	✓	0.44	0.16	✓	0.23	✓	✓
Under 100kW MicroTurbines in CHP	0.83	✓	✓	0.19	✓	✓	0.11	✓	✓
200 kW MicroTurbine	✓	✓	✓	0.44	0.15	✓	0.21	✓	✓
200 kW MicroTurbine in CHP	✓	✓	✓	0.19	✓	✓	0.11	✓	✓
200 kW PAFC System	✓	✓	✓	✓	✓	✓	✓	✓	✓
200 kW PAFC System in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
Systems Greater Than 2 MW Capacity									
3 MW Lean Burn with SCR	✓	✓	✓	0.22	0.19	0.11	0.20	0.16	✓
3 MW Lean Burn with SCR in CHP	✓	✓	✓	0.13	0.12	✓	0.13	0.10	✓
3 MW Turbine with Cat Combustion	✓	✓	✓	✓	✓	✓	✓	✓	✓
3 MW Turbine with Cat Comb. in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
3 MW Turbine with SCR	✓	✓	✓	0.12	✓	✓	0.12	✓	✓
3 MW Turbine with SCR in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
10 MW Turbine with Cat Combustion	✓	✓	✓	✓	✓	✓	✓	✓	✓
10 MW Turbine with Cat Comb. in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
10 MW Turbine with SCR	✓	✓	✓	✓	✓	✓	✓	✓	✓
10 MW Turbine with SCR in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
Developmental Fuel Cell Systems									
200 kW PEM FC System	✓	✓	✓	✓	✓	✓	✓	✓	✓
200 kW PEM FC System in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
300kW MCFC System	✓	✓	✓	✓	✓	✓	✓	✓	✓
300kW MCFC System in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
100kW SOFC System	✓	✓	✓	✓	✓	✓	✓	✓	✓
100kW SOFC System in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓
2 MW MCFC System	✓	✓	✓	✓	✓	✓	✓	✓	✓
2 MW MCFC System in CHP	✓	✓	✓	✓	✓	✓	✓	✓	✓

Note : Systems that meet the CARB emissions levels are shown with a check mark.
The projected emission in lb/MWh are shown for those that do not meet the CARB levels.

Exhibit 13 - System NO_x Emissions Summary

Reciprocating Engines (500kW to 3MW) in CHP Applications

Reciprocating engine technology has improved dramatically over the past decade, and the steady pace of evolutionary improvements is expected to result in gradually declining capital and maintenance costs. Emissions are the biggest challenge confronting reciprocating engines in environmentally sensitive markets. CARB 2007 levels are a stretch for lean-burn engine technology, beyond the reach of evolutionary technology advancements. Rich-burn engines with 3-way catalysts show potential for reaching these levels over time by extending the limits of the existing technical approach, but catalyst, controls and sensor technology need to be pushed to very high levels of performance and durability.

In the **limited case**, lackluster policy and R&D funding support result in an anemic market outlook. The demand for "CARB" emissions does not expand beyond a few regions of the U.S. Engine manufacturers and packagers have limited resources for product advancements. Project developers lack sales volume to streamline transaction, design and installation expenses. Utility grid interconnection continues to be a lengthy and costly process for the smaller systems. The result is marginal improvements in cost, performance and emissions. Engines with practical levels of exhaust after-treatment are able to meet 2003 CARB but do not meet the 2nd tier requirements over the timeframe of this analysis.

In the **base case**, the demand for smaller DG is appreciable with successful policy and regulatory initiatives to minimize the historical institutional and utility barriers. The Advanced Reciprocating Engine System (ARES) Program, a public/private R&D partnership between DOE and the engine community continues at a modest level over the next ten-year period at an investment level approaching $200 million. The demand for Clean DG systems in the 500 kW to 3 MW size range, even though short of the CARB levels, approaches 200 units/yr in 2007, about a third of the total market in this size range. By 2007, clean engine technology has progressed substantially, but still does not reach the CARB levels. Technology advancements likely to be in commercial use for **lean-burn engines** by 2007 include:

- Variable valve timing (Miller cycle) features along with reduced internal friction for improved cycle efficiency
- Combustion and controls precision and higher energy ignition to push out lean limits, coupled with exhaust gas re-circulation (EGR) for reduced emission formation and more thorough combustion
- Higher efficiency turbochargers and air systems
- SCR and oxidation catalyst formulation enhancements, package integration and shared controls for improved performance, reliability and cost
- Increased market activity and reduced barriers will yield additional cost improvements through a more streamlined sales and support infrastructure.

By 2012, additional improvements move costs and emissions lower but still do not reach the CARB requirements.

At the **accelerated pace**, recognition of DG grid benefits provides monetary support for DG in addition to the removal of barriers. Market activity for Clean DG recip engines exceeds 500 units/yr by 2007 to spur robust competition and market delivery streamlining. The 10-year public/private sector R&D initiative is funded in the vicinity of $400 million.

By 2012, "technology tipping" combustion cycle and control concepts can be expected. These advancements in the 1 MW and 3 MW engines with SCR allow CARB 2nd tier targets to be achieved for both CHP and power-only duty. The 3MW engine meets CARB for CHP in the 2007 accelerated case. The "sweet spot" for lean-burn engine technology and market activity is in the 1 MW to 3 MW range. Smaller engine sizes (500kW), facing greater technical challenges and less market demand, are not likely to receive the same degree of product support or progress and do not keep pace with CARB. In addition, further market maturity, competition, and technology progress are expected to produce incremental improvements to efficiency and cost. Technology concepts likely to lead to the accelerated case product characteristics by 2012 include:

- Advanced combustion concepts such as micro-pilot ignition, hydrogen augmentation, and homogeneous charged compression ignition (HCCI).
- Electronic turbo-compounding and refinements to variable valve timing

Exhibits 14, 15 and 16 illustrate the economic outcome for the 500 kW, 1 MW and 3 MW lean burn cases respectively. Shown are the cost of electricity ranges associated with the limited, base and accelerated CHP cases for 2007 and 2012. Also shown is the price range for CHP to be found in the market in 2003/04. The exhibit indicates which scenarios meet the appropriate CARB levels (note solid dark bar on right) for each time period as well as the incremental cost for after-treatment in each of the time periods.

The CARB 2nd tier targets for lean-burn reciprocating engines require "breakthrough" combustion solutions to be researched, developed, applied to specific engine products, engineered for reliability and production, manufactured and introduced to market with acceptable business risk. It should be noted that engine manufacturers were divided on the commercial timing and feasibility of achieving 2nd tier CARB by 2012 even in the accelerated case.

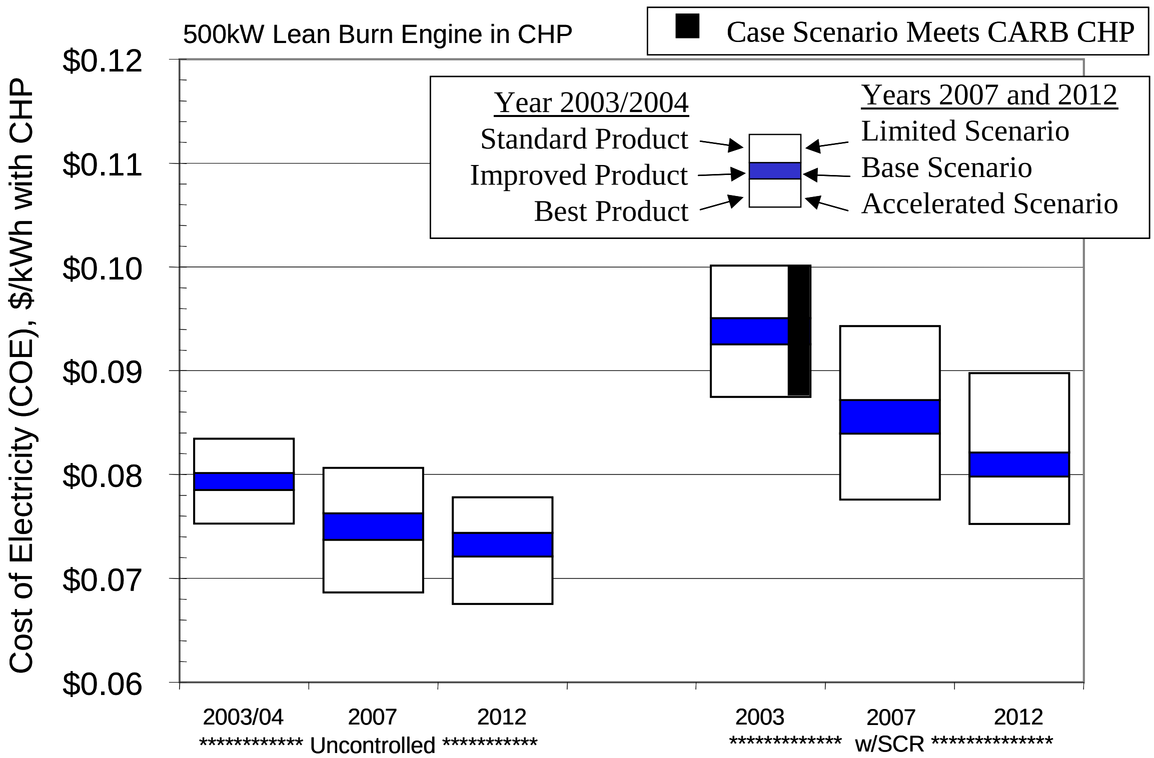

Exhibit 14 – 500 kW Lean Burn Engine in CHP

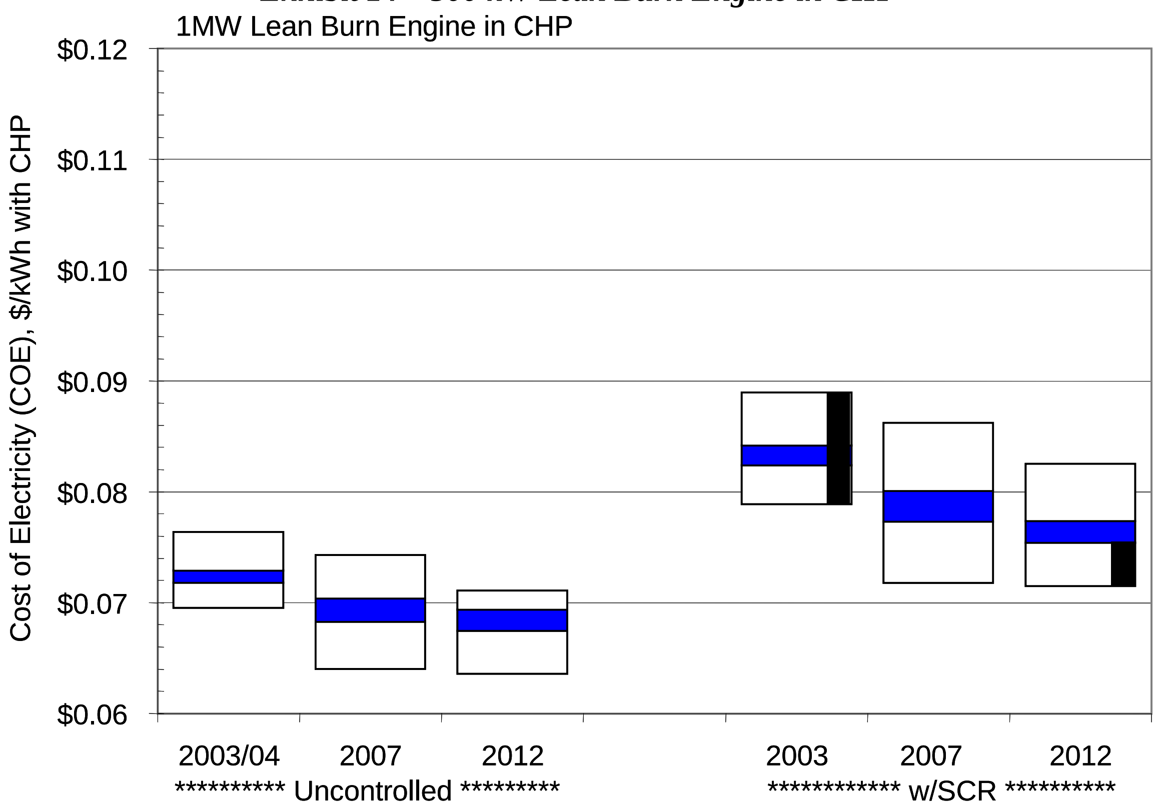

Exhibit 15 – 1MW Lean Burn Engine in CHP

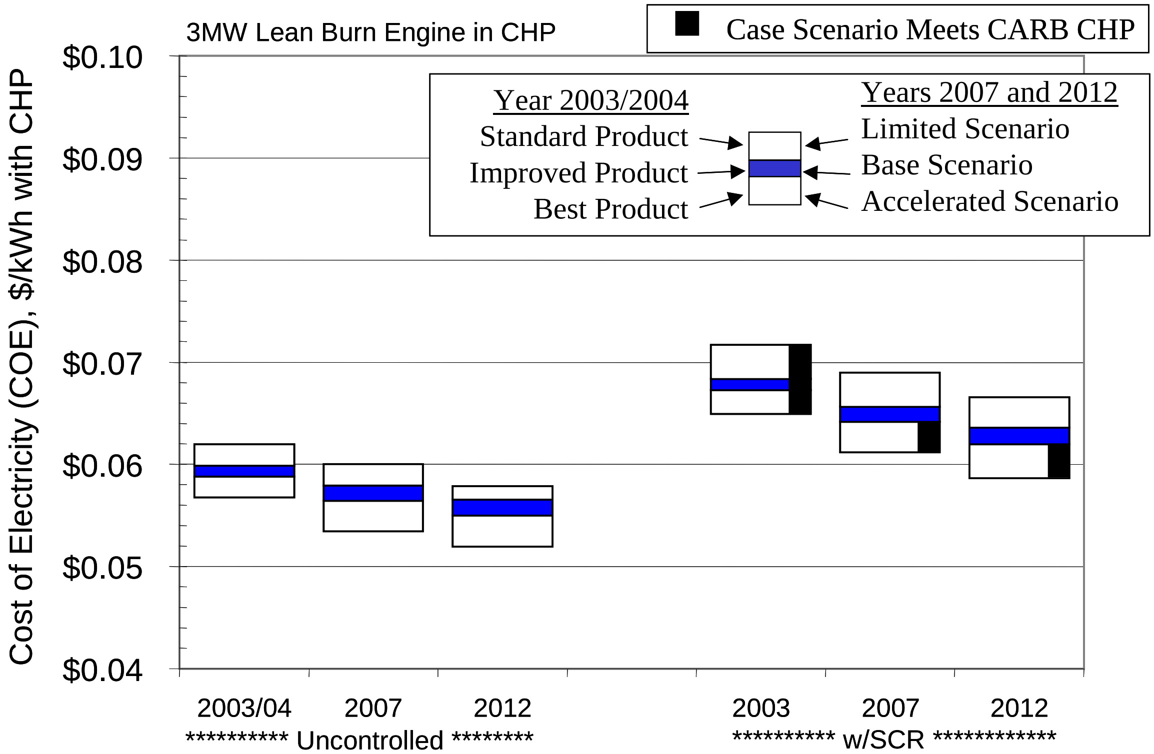

Exhibit 16 – 3MW Lean Burn Engine in CHP

For **rich-burn engines**, the engine manufacturers and the government are not planning significant resources in the limited nor base case. Most development is supported by a handful of micro-gen packagers and catalyst manufacturers. So, there is not significant progress in either the limited or base case to reach 2nd tier CARB by 2007. With public R&D support in the accelerated case, there is a reasonable chance that these levels can be achieved by 2007 for CHP. The technology enhancements to reach 2nd tier CARB include refined catalyst formulation, durability, and ultra-precision O_2 sensors and fuel/air ratio controls. As for electric efficiency, there is not as much room for improvement with rich-burn as there is for lean-burn engines. The efficiency improvements will come primarily from combustion refinements and friction reduction. Rich-burn engines will also benefit from market maturity, competition, infrastructure streamlining and barrier reductions described for lean-burn engines. The scenario analysis for the 500 kW rich-burn engines CHP system is shown in Exhibit 17.

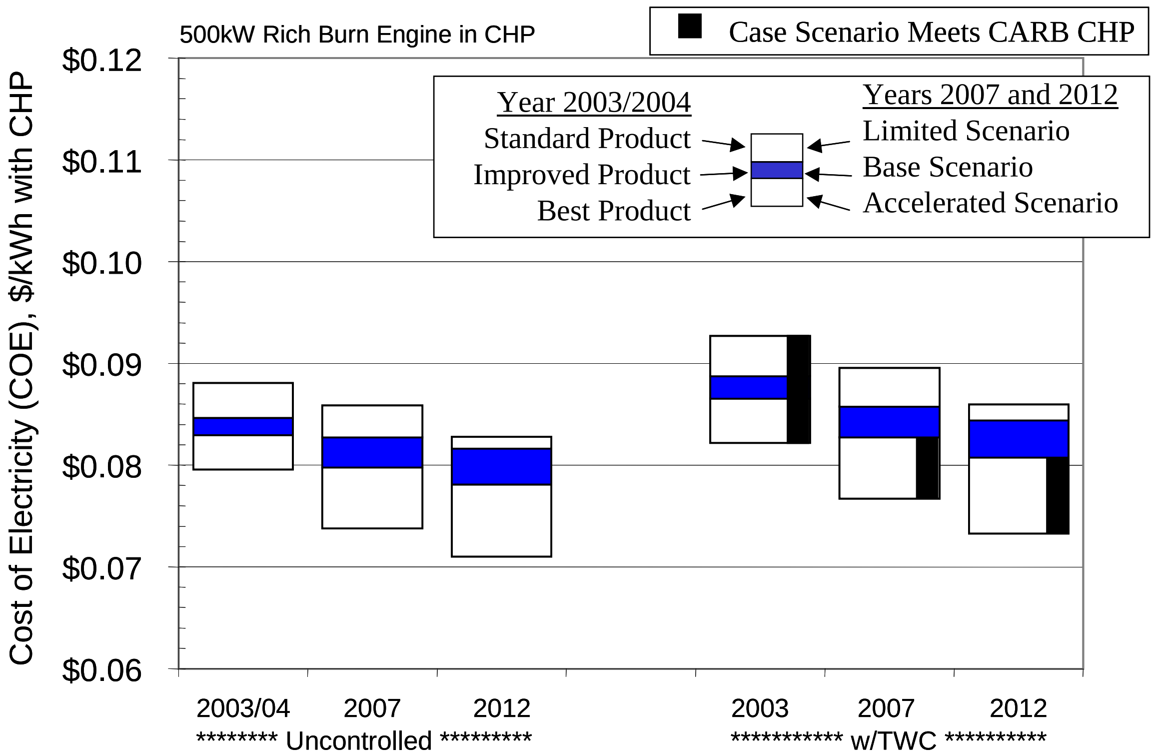

Exhibit 17 – 500kW Rich Burn Engine in CHP

<u>Microturbines (30 kW to 350 kW) in CHP Applications</u>

The primary challenges confronting microturbines are to reduce equipment, transaction, and installation costs associated with small CHP in general and microturbines in particular. Other inter-related development priorities include higher electric efficiencies and larger product sizes. Although emission technology challenges remain, they appear surmountable with refinements to conventional DLE techniques such as lean-pre-mix and rich-quench-lean approaches in the near-term. For 2nd tier CARB, catalytic combustion systems should be available by 2007 at a modest cost premium if meaningful sales volumes can be achieved.

Technology advancement efforts include more precise manufacturing tolerances, higher firing temperatures and tolerant hot section parts, higher effectiveness recuperator, and lower cost manufacturing techniques. Many of these performance goals create additional difficulties on achieving emissions and equipment cost targets. Substantial resources and a departure from simple microturbine fundamentals will likely be required to take microturbines to the mass-market level.

In the **limited case,** market and policy conditions for small CHP do not improve, government technology support is limited, and sales volumes stay below 1,000 units/yr. The result will likely be a continuation of high installed microturbine prices and operating costs. Microturbines will not likely meet 2nd tier CARB levels in the limited case.

In the **base case**, sales volumes in 2007 approach 3,000 units/yr in the U.S. and 5,000 units worldwide. The ten-year public/private investment track for microturbine technology is on the order of $300 million. Fast track standardized interconnection requirements and even-handed utility tariff structures are adopted on a widespread basis. CARB 2nd tier standards are met for CHP in 2007 and for power-only in 2012. Technology and market advancements likely to contribute to the base case economics for microturbines by 2007 include:

- Catalytic pilot with DLE combustion
- Selected higher temperature metallic components
- Higher effectiveness recuperators
- More efficient compressors and turbine sections and optimized cycle
- Streamlined product sales and support infrastructure
- Larger (200 – 300 kW) product sizes

By 2012, the following features will be added in the base case:

- Catalytic combustion
- Selected ceramic components in the 200 kW class machines

In the **accelerated case**, Government or utility incentives exist to recognize Clean DG benefits to the grid and environment. Delivery infrastructure approaches plug-n-play targets with low transaction and installation costs. The private/public investment from 2003 through 2012 exceeds $400 million. The pace of technology advancements quickens. 2007 sales volumes top 5,000 units/yr in the U.S. and 10,000 units/yr worldwide. CARB Standards for power-only are met in 2007.

The economic scenarios for a 200 kW product and a sub-100 kW product are illustrated in Exhibit 18.

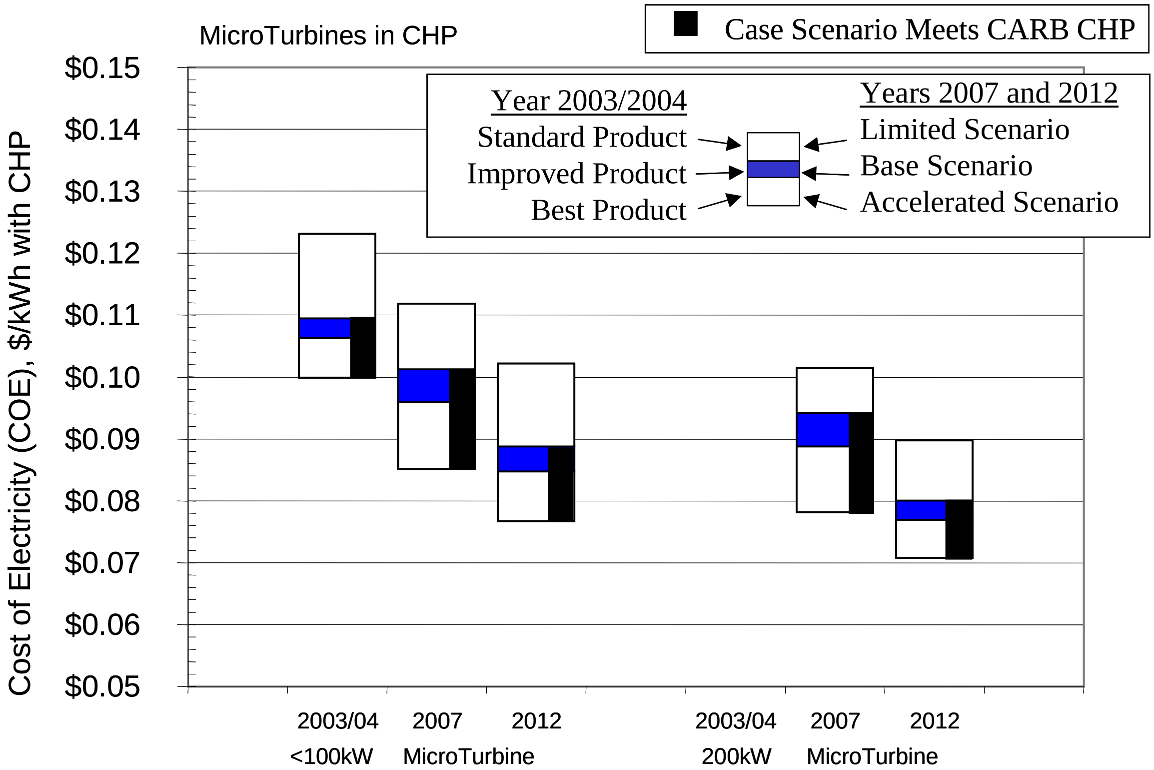

Exhibit 18 – Microturbines in CHP

Gas Turbines (1MW to 20MW) in CHP Applications

Advanced technology efforts focused on internal blade cooling and ceramic materials are expected to result in continuing improvements in efficiency (beginning with the largest sizes) along with gradual declines in capital and maintenance costs. Gas turbine emissions are among the lowest of commercially available DG technologies and will continue to decline as combustion technologies advance and are adapted to specific hardware configurations.

In the **limited case**, the soft market for Clean DG and weak government support for larger DG technology restricts advancements and product integration by turbine manufacturers and packagers. Catalytic combustors, for example, even if technically developed will be more slowly integrated into turbine packages. And there will be less motivation to integrate and cost reduce SCR systems in turbine packages.

In the **base case**, the market for Clean CHP turbines will see modest growth from the industrial, institutional and large commercial markets both in the U.S. and internationally. There will be lessened resistance from utilities and a stabilization of utility regulations. By 2007, the market will be in the range of 600 MW/yr U.S. and 1500 MW worldwide. About half of the market will be emissions sensitive, a portion of which will demand CARB levels. Stationary products will continue to depend on military and aero technology advances for application to the power turbine. The manufacturers will internally fund the application of aero technology and most stationary specific product technology and cycle developments. Modest government support will continue mostly for low-emission combustion. The 10-year level of government/private support for advanced combustors is around $100 million. Product advances by 2007 would likely include:

- Further increases in turbine inlet temperature and pressure ratio. In parallel, more advanced blade cooling techniques and DLE combustor modifications would be required.
- More precise manufacturing tolerances.
- Lean-pre-mix DLE combustors reach single digit NOx (<10 ppm) levels in selected products
- Low-NOx pilots enable DLE combustors to approach 5 ppm for selected products
- Catalytic combustors applied to several gas turbine products
- Other advanced combustion concepts such as surface combustion become ready for commercial application
- Evolutionary cost refinements to SCR systems
- Low emission combustors for HRSG duct burners
- Improvements to high electric efficiency cycles such as recuperation and steam turbine bottoming (combined cycle) in the smaller sizes. Note that depending on the application, these cycles often increase electric efficiency at the expense of overall CHP efficiency.

By 2012:

- Further increases in turbine inlet temperature and pressure, in part, through the gradual introduction of ceramics
- Durability improvements to catalytic combustors and other advanced combustors to reduce O&M costs.
- Small incremental cost refinements to SCR
- Application of advanced (catalytic and surface) combustors to a broad array of turbine products

In the **accelerated case**, the customer momentum grows and regulatory actions encourage utility support grid support incentives. Sales volumes double from the base case levels. Government RD&D support is doubled to speed up emission, efficiency and cycle improvements; and to encourage new (non-traditional) applications of gas turbines. Competition gets intense by 2007. The primary effects are an acceleration of the pace of product advancements and an increased probability that the accelerated case will be realized. Additional technology advances possible by 2012 include:

- More aggressive inclusion of ceramic parts
- Dual-fuel solution for catalytic combustion

The scenario analysis for gas turbines is shown in Exhibits 19 and 20.

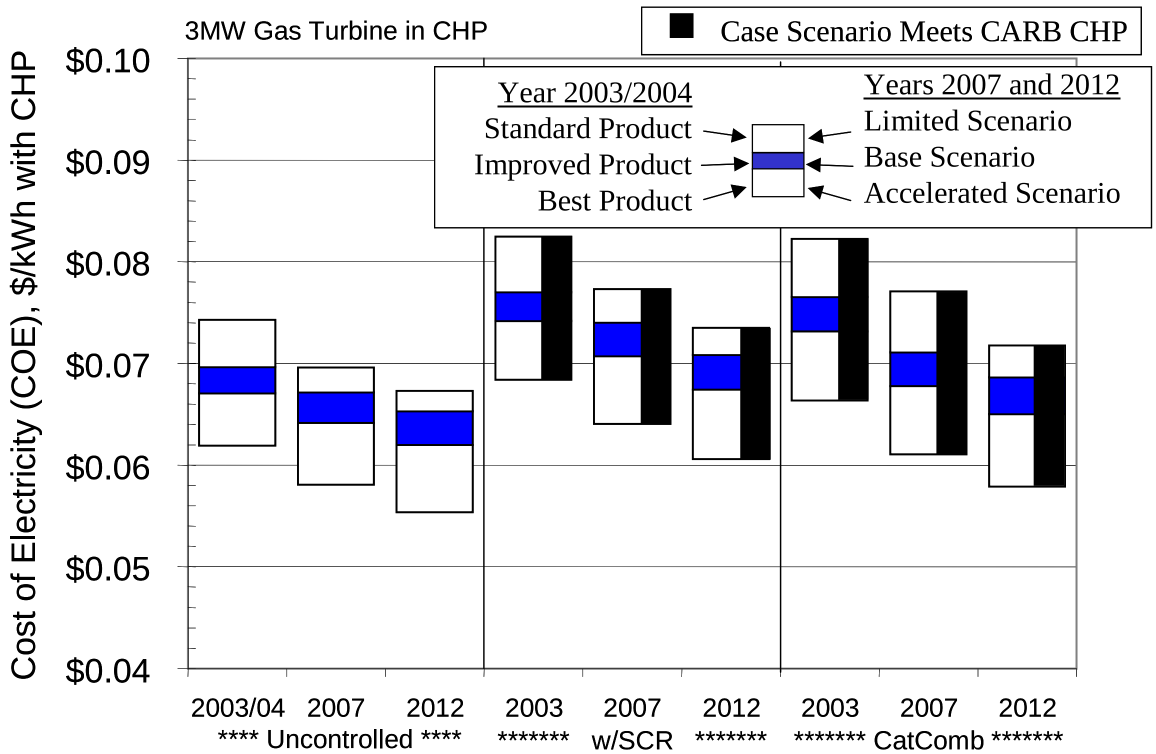

Exhibit 19 – 3MW Gas Turbines in CHP

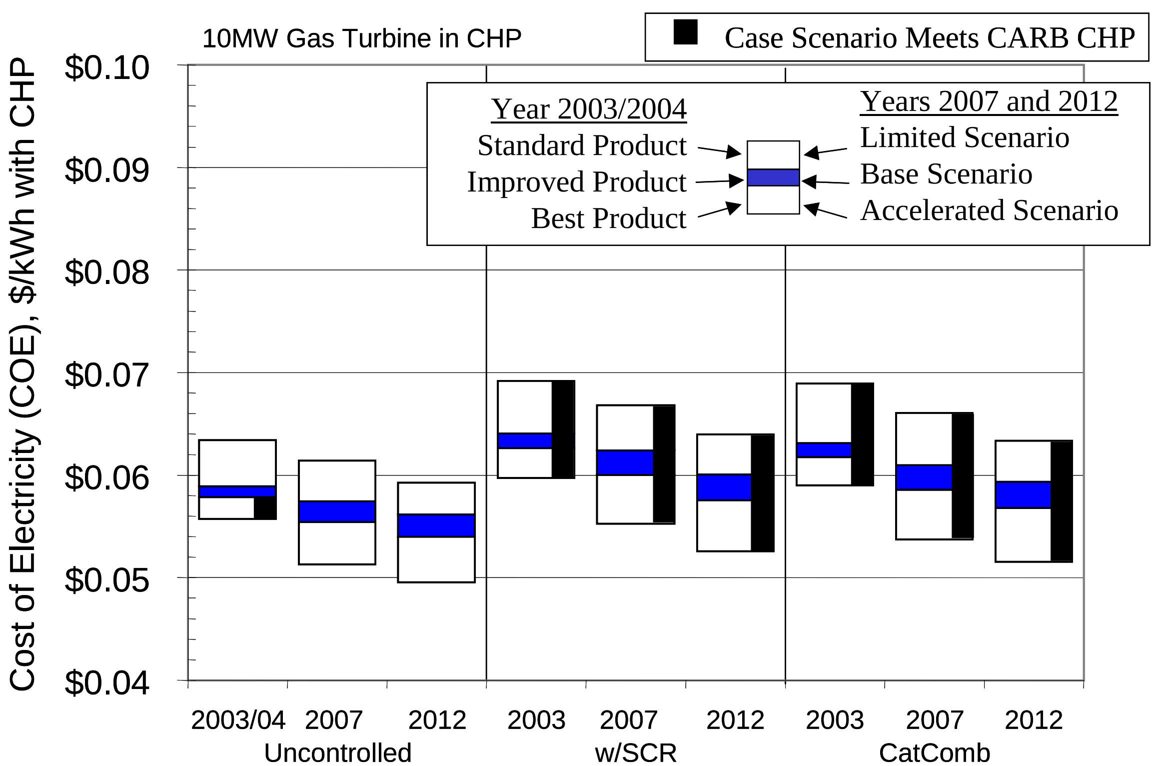

Exhibit 20 – 10 MW Gas Turbines in CHP

Fuel Cells (100kW to 2MW) in CHP Applications

The major areas with potential for cost reduction and advancement is the establishment and use of manufacturing facilities and engineering simplifications of market entry products. Except for PAFCs the other fuel cell technologies are in various pre-market entry stages. We linked market entry to the sales and delivery of products with firm prices, delivery schedules and product warranties. We were unable to verify planned market entry timing from the various fuel cell developers and assumed it would occur in 2003. The projections for 2007 and 2012 are keyed to the market entry date so a later market entry date would mean corresponding slippage in the progress illustrated for the 2007 and 2012 dates.

The three scenarios for 2007 and 2012 for all the fuel cell systems show much more progress directed toward cost reductions than performance improvements. The major reductions in cost will occur with the natural maturing of manufacturing facilities and products as market acceptance occurs. Other cost reductions occur with the commoditization of components within the system, such as the membrane electrode assembly (MEA) in PEM fuel cells, power conditioning and controllers, heat transfer and condensing units, and the fuel processing or reformer. Other cost improvements will be the result of overall system simplification, which eliminates parts and components. Techniques will be developed that allow the use of lower grade raw materials to be used for component fabrications. Fuel cell developers expect to achieve learning curve cost reductions of about 80% during the introductory years of commercialization. As markets mature beyond the 2012 time period these learning curves will increase toward the 85 to 90% expected for mature products. Exhibit 21 illustrates the improvements and the steady project cost reductions.

In the **limited case**, stalled policy and mediocre R&D funding support results in a continued inability of these infant technologies to achieve any significant market share. Production facilities never expand beyond the current prototype plants developed to meet markets of only a few 10s of MW per year. Cost reductions are achieved but never sufficient to stimulate meaningful market activity. Component supplier base does not respond with new integrated products geared toward simplification of the balance of plant subsystems. Catalyst suppliers do not develop advanced catalyst systems to improve either stack or reformer performance. Research funding from the private sector dwindles and the government backtracks into supporting only high-risk research with no product development and demonstrations.

In the **base case,** the market begins to materialize and some manufacturer consolidation occurs to expand dedicated production. Sufficient alternatives in both technology and manufacturers remain to stimulate competitive pressures toward price reductions. Component suppliers begin to offer non-customer built heat exchange, membrane electrode assemblies, fuel processing components, and power conditioning subsystems to drive prices down and begin the commoditization process. Catalyst vendors competitively develop alternatives that allow performance and life targets to be met.

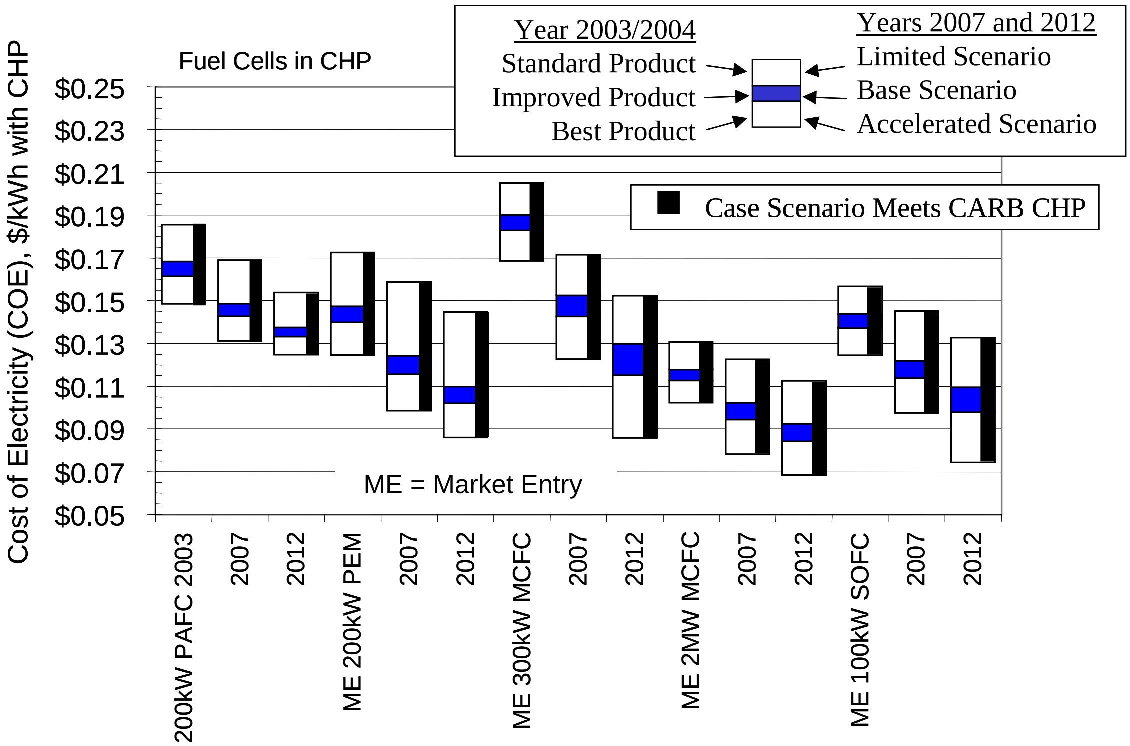

Exhibit 21 – Fuel Cell Systems in CHP

Alternate products, such as automotive PEM systems, establish a production foundation to help learning curve cost reduction materialize. Total government support for both automotive and stationary products continue at pace of about $100 to $200M per year through 2007, stimulating private sector matching funds in facility investments and market entry products. These private sector investments continue through 2012 directed at reduced product costs and improved manufacturing technologies. Experimental activities continue to frame the benefits of advanced concepts such as hydrogen systems for peak-shaving and integrated SOFC-gas turbine products. Some of the technology and policy "tipping points" that could stimulate achieving market targets by 2012 include:

- Automotive base PEM manufacturing for prototype products continue to stimulate second tier suppliers for membrane electrode assemblies to invest in production capacity and technologies.
- Technical limitations of conductive plastic, injection-molded interconnect plates for PEM stacks are overcome or low-cost, metal fine film technologies mature decreasing production costs.
- High temperature PEM systems are developed that increase stack tolerance to carbon monoxide concentrations from 10ppm to 10,000ppm, and allowing fuel processing subsystem simplifications and cost reductions.
- Materials properties for MCFC stack components are achieved eliminating risk of short stack life cycles.

- Integrated high-temperature fuel cell and gas turbine systems validate process models and achieve enhanced electrical efficiency capabilities. Systems are designed and developed, efficiency capabilities are translated into cost reductions initially stimulating market acceptance and later used for efficiency gains in the post 2012 timeframe.

In the **accelerated case** the recognition of DG grid benefits and the aggressive capture of DG opportunities by engine and turbine systems continue to stimulate fuel cell developments and advancements. Automotive products expand beyond prototype validation programs and begin to achieve recognizable market capture. Hydrogen storage technologies expand and mature, introducing the capability for low-cost, energy storage capacity for load-leveling and peaking functions. The customer base begins to recognize and seeks out products that provide a foundation for a sustainable energy system. The framework for the hydrogen economy begins to be defined and implemented. Research and infrastructure investments increase to levels greater than $300M per year through 2007 and then expand as alternative manufacturing, refueling, and hydrogen infrastructure networks begin to be implemented on a commercial basis through 2012.

The ability of the systems to meet the CARB regulation appears not to be an issue. The only source of emissions in a fuel cell system is combustion of the low energy content fuel stream exiting the anode after 80 to 85% of the hydrogen has been consumed. This is normally done in a pre-mixed, very lean combustion that minimizes flame temperatures. The combustion unit is also often a surface combustion or catalytic combustion unit that minimizes emissions. The flame temperatures are typically low enough to prevent NOx formation and high enough to ensure CO and VOC reactions.

Another potential advanced system configuration is hybrid turbine-fuel cell power systems. Such systems combine the advantages of both technologies to offer high efficiencies and clean power. These advanced systems would be included in an accelerated program but were excluded from the scope of this study.

Other Considerations

Alternative Heat Recovery Credit Methods

One of the important aspects of this effort was to assess the ability of DG technologies to met the equivalent emissions levels achieved by today's clean, central station combined cycle power plants. CARB recognizes the benefits of heat recovery in CHP applications and proposes an accounting of the thermal energy as equivalent to the electric energy of the unit on lb/MWh basis. The NRDC has proposed that the thermal energy credit should be equivalent to the prevailing boiler emission regulations. To assess this impact the NRDC proposed to examine one unit using a 0.15lb NOx/MWh thermal regulations and a 0.07lb NOx/MWh electric regulation. This thermal regulation value was derived from a boiler regulation of 0.035lb NOx/MMBtu fuel input requirement. The requirement was converted using 80% baseline boiler efficiency and 3412 Btu/kWh. The emissions from the CHP unit was calculated by adjusting the thermal energy load by the ratio of the

Boiler Regulation and the Electric Regulation (0.15lb/MWh th)/(0.07lb/MWh elec), which gives a 2.14 value. This technique allows comparison of the CHP emissions to the electric only regulation, but fairly allocates emission to be equivalent to a parallel system consisting of a separate boiler and electric generator. The calculation was as follows:

$$\text{CHP Emissions} = \frac{\text{lb NOx Emitted}}{(\text{MWh of elec generated} + 2.14^*(\text{MWh of heat recovered})}$$

This analysis was completed for the 1 MW lean burn engine in 2007, because it could not meet the requirements under the CHP calculation proposed by CARB. According to the electric only regulations, the 1MW unit would be allocated 0.07 lb NOx per MWh of electricity and 0.15lb NOx per MWh of heat used in the application. Since the overall CHP efficiency of the unit is 70% HHV and the electric efficiency is 38% for the 2007 Base Case Scenario, the 1MW engine has a power to heat ratio of 1.19 and generates 0.84 MWh of thermal energy. With the 75% heat utilization factor the application the effective power to heat ratio is 1.58 because the average annual heat used is 0.63 MWh of heat. This used heat would be given an emission allowance of 0.095lb NOx for a total allowance of 0.165 lb NOx. According to the formula the 1MW unit generates 2.35 MWh of used energy (1MWh electric + 2.14*0.63MWh heat). Inserting this allowance of 0.165 as the lb NOx Emitted and dividing by 2.35 MWh equivalent energy, the CHP Emissions are calculated at 0.070lb/MWh energy. This indicates that the unit just meets the CARB Regulation.

Exhibit 22 illustrates the results when the actual NOx emissions from the three scenarios for the year 2007 are applied. As can be seen the 1MW lean burn unit does not meet the CARB CHP method targets under any scenario, but using the NRDC approach the unit actually achieves the target in the Accelerated scenario. As indicated above, achieving the 0.07lb/MWh equivalent energy level implies that the unit achieves the regulations when benchmarked against a stand-alone boiler and generator.

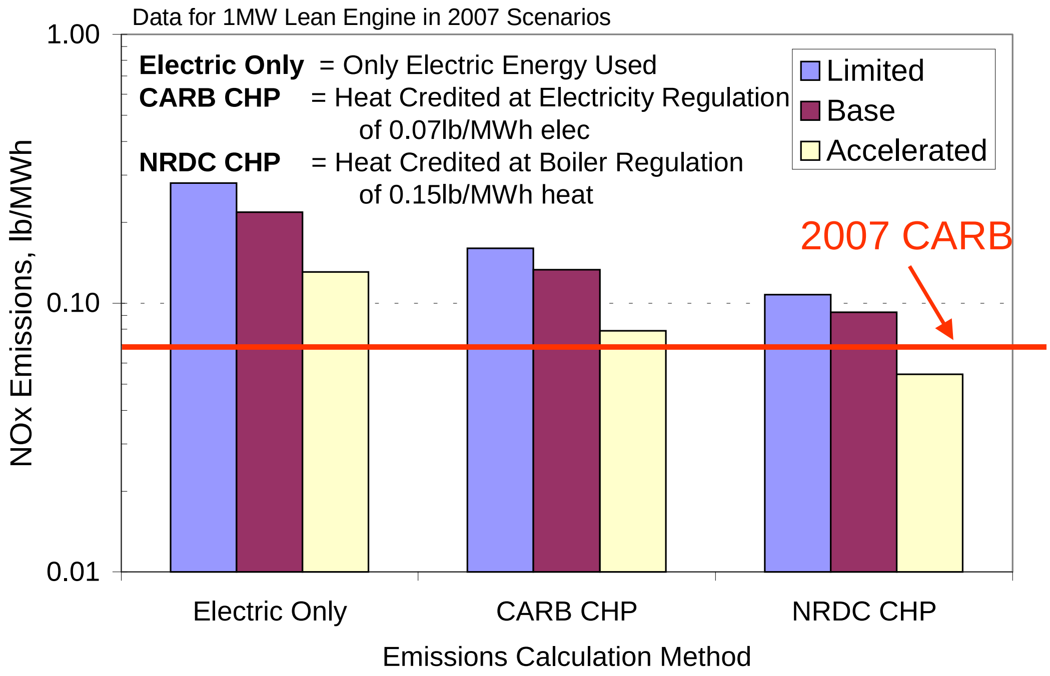

Exhibit 22 – Comparison of Alternate CHP Emission Calculations - 1MW Lean Burn Engine

<u>Measurement and Verification</u>

As mentioned previously, no costs were included for measurement and verification of emission levels and efficiency. Depending of the protocols required, this could be an onerous and expensive proposition that would hurt smaller systems the hardest.

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Appendix A

Sample Data Sheet

Equipment Class **10 MW Class Gas Turbine with CHP**

		Time Period																	
		2003/2004 Application Range						2007						2012					
Baseline Definition w/o Aftertreatment		Standard	Note #	Improved	Note #	Best	Note #	Limited	Note #	Base	Note #	Accelerated	Note #	Limited	Note #	Base	Note #	Accelerated	Note #
• Rate Capacity Continuous	kWe	10,000		10,000		10,000		10,000		10,000		10,000		10,000		10,000		10,000	
• Electrical Efficiency	% LHV	30.0%		32.2%		33.3%		32.2%		33.6%		35.6%		33.3%		35.0%		36.7%	
• Electrical Efficiency	% HHV	27.0%		29.0%		30.0%		29.0%		30.2%		32.0%		30.0%		31.5%		33.0%	
• Overall CHP Efficiency	% HHV	70%		70%		70%		70%		70%		75%		70%		70%		75%	
• Installed Capital Cost (1)	$/kWe	$ 1,100		$ 965		$ 900		$ 1,075		$ 925		$ 850		$ 1,025		$ 900		$ 800	
• O&M Costs (2)	$/kWh	$ 0.0060		$ 0.0055		$ 0.0050		$ 0.0058		$ 0.0052		$ 0.0048		$ 0.0054		$ 0.0051		$ 0.0047	
• NOX Controlled (3)	lb/MW-hr	1.18		1.10		0.64		0.660		0.380		0.199		0.383		0.203		0.193	
	lb/MWh chp	1.18		1.10		0.64		0.320		0.191		0.099		0.191		0.106		0.099	
	ppm @ 15%	25.0		25.0		15.0		15.0		9.0		5.0		9.0		5.0		5.0	
	gm/bhp-hr	0.4		0.4		0.2		0.2		0.1		0.1		0.1		0.1		0.1	
• CO Controlled (3)	lb/MW-hr	0.81		0.76		0.73		0.45		0.44		0.41		0.26		0.25		0.19	
	lb/MWh chp	0.81		0.76		0.73		0.221		0.22		0.21		0.132		0.13		0.10	
	ppm @ 15%	25.0		25.0		25.0		15.0		15.0		15.0		9.0		9.0		7.0	
	gm/bhp-hr	0.3		0.2		0.2		0.1		0.1		0.1		0.1		0.1		0.1	
• VOC Controlled (3)	lb/MW-hr	0.05		0.05		0.04		0.03		0.03		0.03		0.02		0.02		0.02	
	lb/MWh chp	0.05		0.05		0.04		0.013		0.013		0.012		0.009		0.009		0.008	
	ppm @ 15%	2.5		2.5		2.5		1.5		1.5		1.5		1.0		1.0		1.0	
	gm/bhp-hr	0.0		0.0		0.0		0.0		0.0		0.0		0.0		0.0		0.0	
Emissions Control		SCR						SCR and Oxidation Catalyst						SCR and Oxidation Catalyst					
• Incremental Capital Cost (1)	$/kWe	$ 110		$ 100		$ 80		$ 110		$ 100		$ 80		$ 90		$ 70		$ 60	
• O&M Costs (2)	$/kWh	$ 0.0030		$ 0.0025		$ 0.0020		$ 0.0027		$ 0.0023		$ 0.0020		$ 0.0025		$ 0.0020		$ 0.0015	
• NOX Conversion	%	60%		56%		27%		89%		82%		65%		82%		65%		65%	
• NOX Controlled (3)	lb/MW-hr	0.47		0.48		0.47		0.073		0.068		0.070		0.069		0.071		0.068	
	lb/MWh chp	0.47		0.48		0.47		0.035		0.034		0.035		0.034		0.037		0.035	
	ppm @ 15%	10.0		11.0		11.0		1.7		1.6		1.8		1.6		1.8		1.8	
	gm/bhp-hr	0.2		0.2		0.2		0.0		0.0		0.0		0.0		0.0		0.0	
• CO Controlled (3)	lb/MW-hr	0.81		0.76		0.73		0.10		0.10		0.09		0.10		0.09		0.09	
	lb/MWh chp	0.81		0.76		0.73		0.049		0.05		0.05		0.048		0.05		0.04	
	ppm @ 15%	25.0		25.0		25.0		3.3		3.3		3.3		3.3		3.3		3.3	
	gm/bhp-hr	0.3		0.2		0.2		0.0		0.0		0.0		0.0		0.0		0.0	
• VOC Controlled (3)	lb/MW-hr	0.05		0.05		0.04		0.02		0.02		0.02		0.02		0.02		0.02	
	lb/MWh chp	0.05		0.05		0.04		0.009		0.009		0.008		0.009		0.009		0.008	
	ppm @ 15%	2.5		2.5		2.5		1.0		1.0		1.0		1.0		1.0		1.0	
	gm/bhp-hr	0.0		0.0		0.0		0.0		0.0		0.0		0.0		0.0		0.0	
• Capacity Derating	% of Baseline	0%		0%		0%		0%		0%		0%		0%		0%		0%	
• Efficiency Derating	% of Baseline	0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%	

Conversions	NOX	CO	VOC	HU Factor
gm/mole	40.7	28.0	17.0	75%
(%CHPeff,LHV)*(lb/MW-hr) per 1 ppm @15%O2	0.01418	0.00977	0.00593	
(%eff,LHV)*(lb/MW-hr) per (lb/MMBtu input HHV)	3.791	3.791	3.791	Gen Eff
(lb/MW-hr) per (gm/bhp-hr)	3.112	3.112	3.112	95.0%

1) Capital Cost w/o emission controls (EC) is for equipment in CHP application.

2) O&M Costs include sinking fund for overhauls and catalyst replacements.

3) All emissions are in lb/Mwe-hr in 2003/2004 and in both lb/MWe-hr & lb/MW-hr with CHP credit in 2007 and 2012.

4) All costs are current dollars

Limited Column

Limited market and technology development
Very Limited market competition
Limited funding for technology development and support of breakthrough technologies
Market and economic conditions do not improve for DG

Base Column

Best estimate based on current market and technology trends

Accelerated Column

Accelerated market and technology development
Robust market activity and aggressive competition
Ample R&D funding to support advancements
Monetary recognition for DG grid benefits

Revisions Sheet

The following modifications were made to the May 6, 2002 original release of the report:

- Exhibit 1
- Page 19, Paragraph 3
- Exhibit 13
- Exhibit 20
- Appendix A