

# Chapter 5: Demand

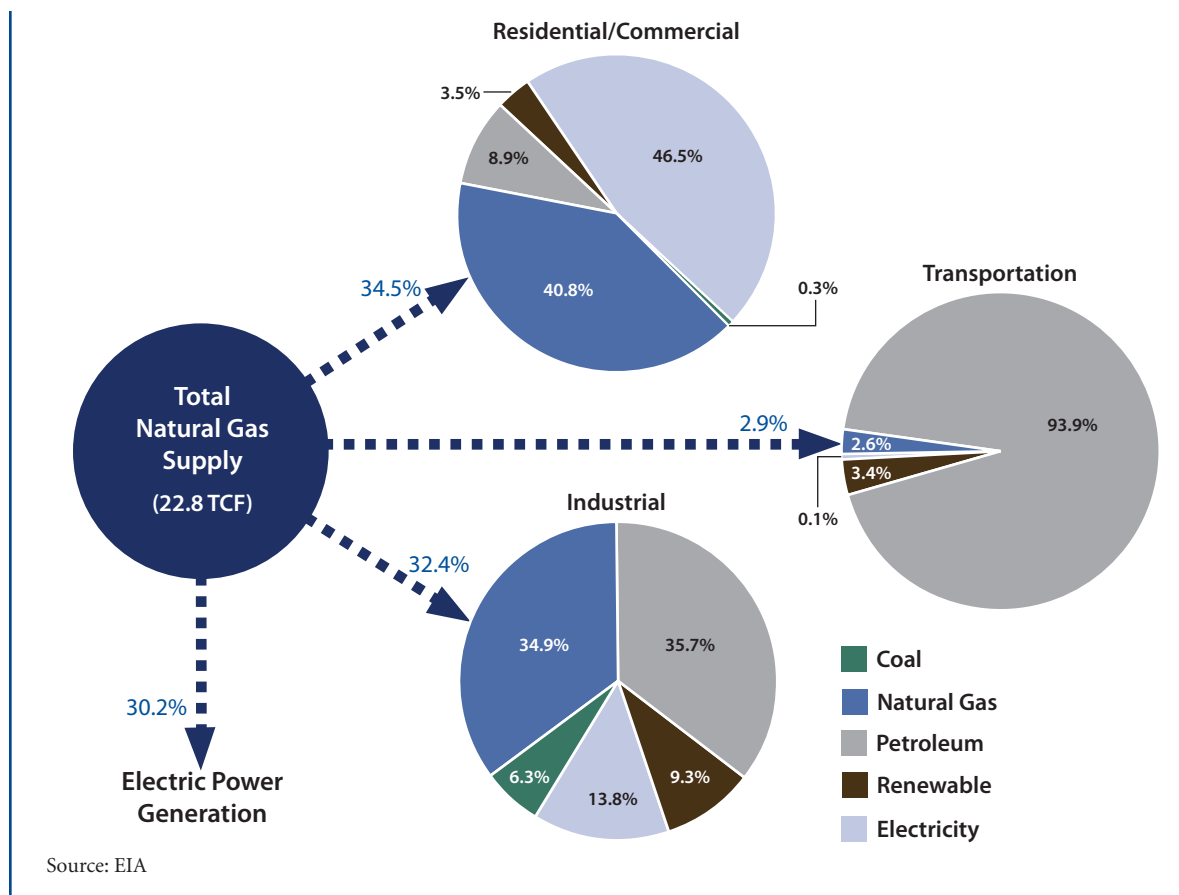
## INTRODUCTION

Natural gas is attractive for a variety of end-use applications because it is:

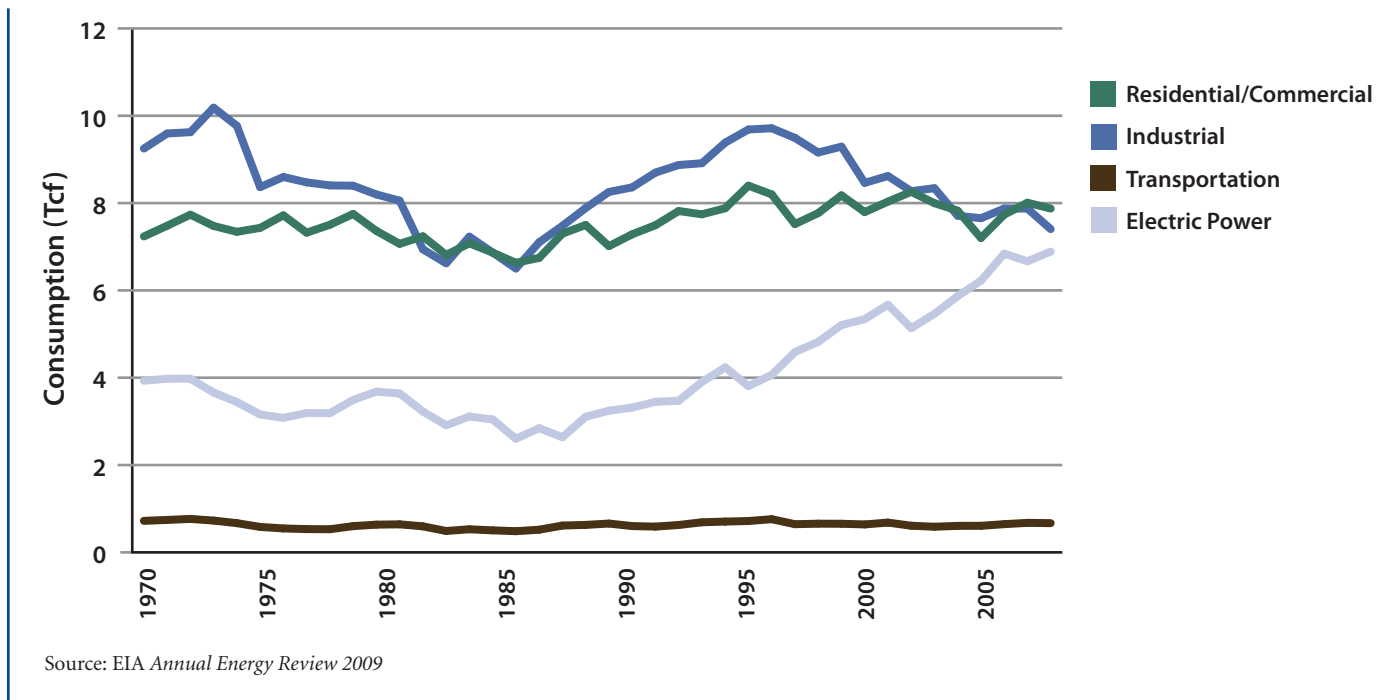
- clean burning;
- substantially less carbon intensive than coal and oil;
- efficient, with an average energy efficiency of 92% delivered to the burner tip;
- flexible, with use at small and large scales and responsive to demand changes; and
- versatile.

As shown in Figure 5.1, domestic natural gas supply is currently divided almost evenly among the residential/commercial, industrial and electric power generation markets and has a substantial market share in each. This pattern has changed over time principally because of the substantial increase in natural gas use for electricity generation over the last 20 years, as seen in Figure 5.2, a trend that is likely to continue. On the other hand, natural gas plays a minimal role in the U.S. vehicular transportation sector, comprising only around 0.15% of the energy use. Natural gas use for transportation is mainly to power gas transport in pipelines.

**Figure 5.1 Natural Gas End-Use Markets (2009)**



**Figure 5.2 Historical Trends in End-Use Consumption**



## CHAPTER OVERVIEW

We have analyzed a set of key issues in each of these sectors with a view toward possible significant increases or decreases in natural gas use, opportunities for emissions reductions and reduction of oil dependence in the transportation sector.

- In the industrial sector, over 60% of the total annual supply of 7.4 Trillion cubic feet (Tcf) of natural gas fires boilers and provides process heat, so we focus our analysis on efficiency in these uses and on the emissions reduction opportunities from coal displacement. Natural gas and Natural Gas Liquids (NGLs) also play an important role as chemical feedstock, an issue of importance to domestic retention of manufacturing activity.
- In the residential/commercial sector, electricity and natural gas compete as the two major sources of energy supply. In the U.S., about 70% of electricity (an energy carrier) and 35% of gas (a thermal energy source) is used in buildings. Efficiency in delivering energy services to buildings and institutions will be an important differentiator, and our analysis focuses on two issues: end-to-end efficiency of electricity and gas, and the opportunities for natural gas combined-heat-and-power delivery systems.
- For the transportation sector, our analysis focuses on the potential for natural gas to displace oil and reduce greenhouse gas (GHG) emissions both through direct use and indirectly through conversion to liquid fuels.

## NATURAL GAS IN THE INDUSTRIAL SECTOR

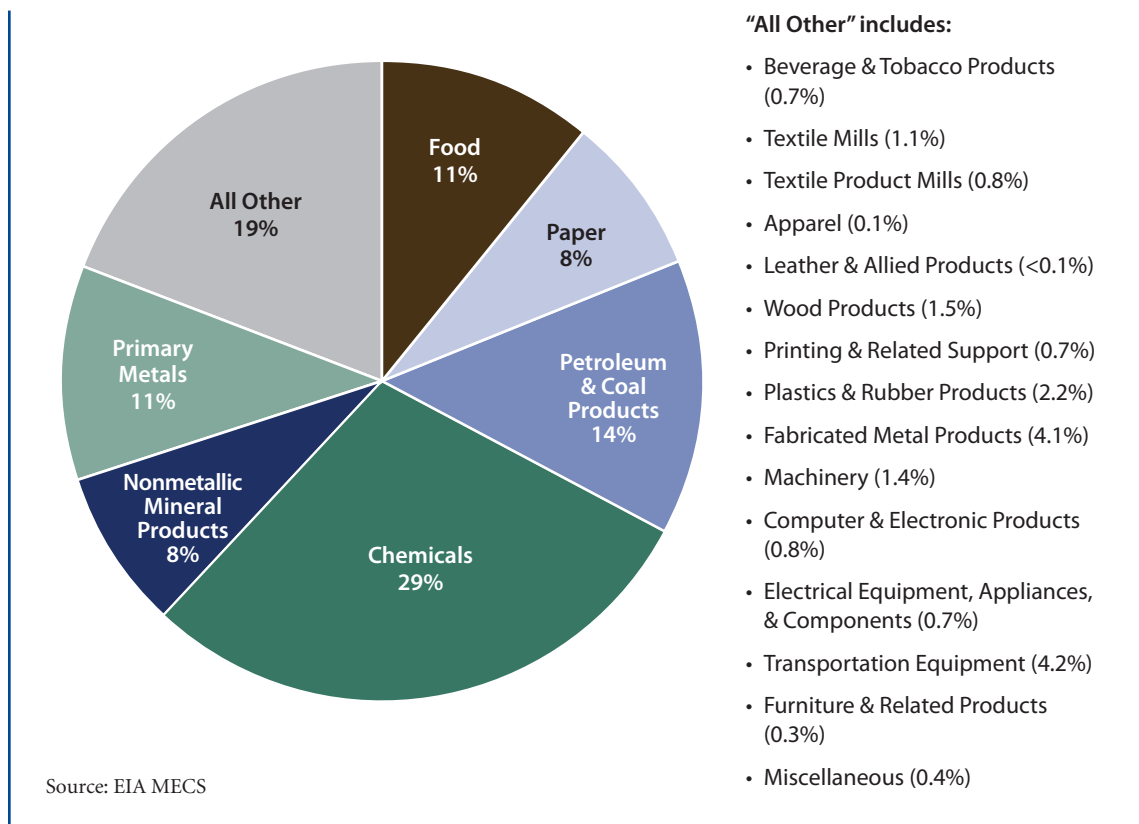
Industrial demand for natural gas was 7.4 Tcf in 2009, representing 32% of total U.S. natural gas use. Of this total, 1.3 Tcf was used in oil and gas field production and processing operations,<sup>1</sup> leaving a net total of 6.1 Tcf delivered to final customers for Industrial end-use applications. Natural gas accounts for 35% of total energy used in industry; petroleum products are the primary source of energy, and coal use is also significant.

Manufacturing comprises about 85% of total U.S. industrial natural gas use; the remaining 15% comprises non-manufacturing uses, such as

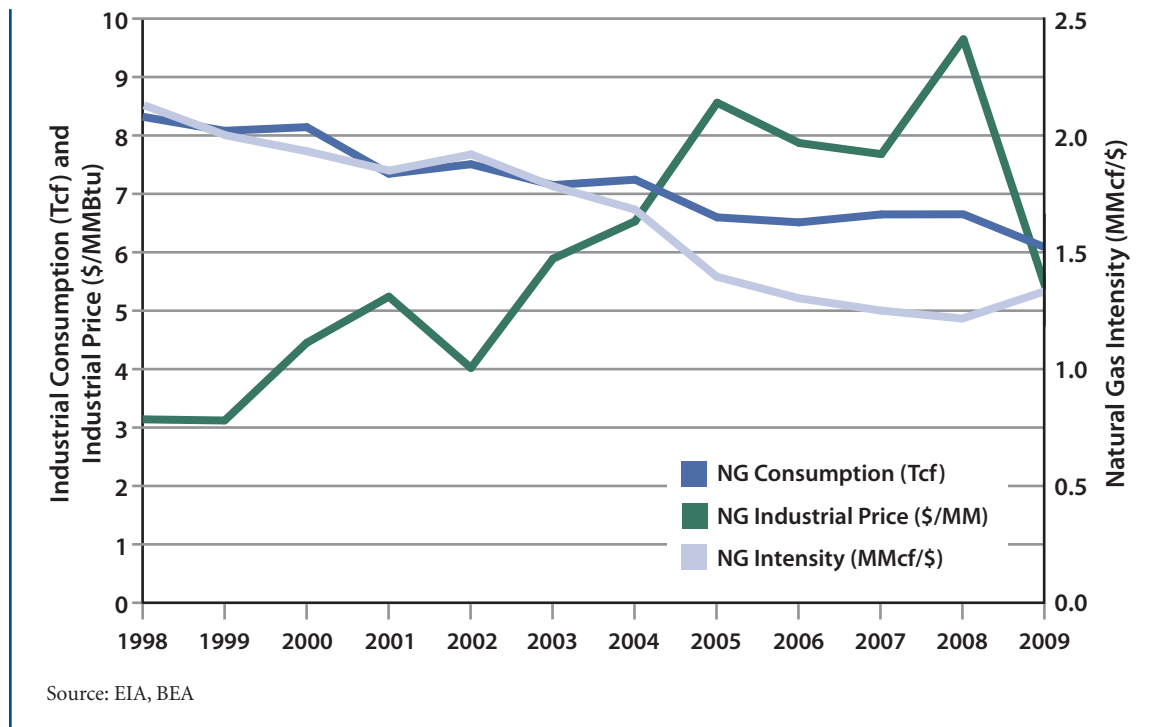
mining. Six industries account for 81% of total manufacturing demand, as shown in Figure 5.3.<sup>2</sup>

In this section, we first present an overview of trends in natural gas use and efficiency in manufacturing and projections of future demand, discussing the interaction among changes in output, changes in fuel mix and changes in end-use efficiency. We identify industrial boilers and process heating as the two principal uses of natural gas as a fuel, and discuss opportunities for changes in demand associated with improved efficiency as well as fuel switching. We also discuss potential for efficiency gains in process heating as well as research development and deployment (RD&D) opportunities.

**Figure 5.3 Natural Gas Use by U.S. Manufacturing Industry Sector**



**Figure 5.4 Trends in U.S. Industrial Natural Gas Consumption and Intensity**



### Natural Gas Consumption and Efficiency Trends

Since 1998, industrial natural gas use declined by 25%, or about 2.2 Tcf/year, the only end-use sector to do so.

Figure 5.4 shows that this decline has been steady, notwithstanding volatility in natural gas prices. The intensity of natural gas use (i.e., the quantity of natural gas used per dollar value of shipments) declined by more than total use, indicating that the reduction was due to a combination of increased efficiency of use and a shift to less energy-intensive activities. We estimate that natural gas consumption has declined at an average annual rate of 3%, while natural gas intensity has declined at an average annual rate of 5% over this period.

For energy-intensive industries, we estimate that the cost of natural gas as a percentage of value of shipments can range from 1% (for the

food products industry) to as much as 50% in the case of nitrogen-based fertilizers. In other industry sectors that are less energy intensive, we estimate the cost of natural gas in the range of only 0.2% to 0.6% of the value of shipments. Notwithstanding the low ratios of natural gas costs to value of shipments in many manufacturing industries, volatility in the price of natural gas could have a significant impact on the competitive position of those industries that operate in global markets.

Several factors contribute to the price elasticity of gas in this sector. Higher natural gas prices, particularly in relation to prices abroad, can lead to reduced manufacturing output. Also, rising prices provide incentives for increased energy efficiency measures and fuel switching. Falling prices have an opposite effect on industry output and fuel switching.

Cost savings resulting from energy efficiency gains are increasingly viewed as a business opportunity, since the savings flow directly to the bottom line. New energy-efficient capital investments can offer attractive returns on investment, competing with other corporate capital investment opportunities. A recent study conducted for the Pew Center on Global Climate Change documented the nexus between business profitability, improved energy efficiency and CO<sub>2</sub> emissions reductions. It showed that companies do best in reducing energy use when they set aggressive energy reduction targets, closely monitor progress, have active top management involvement and take a comprehensive approach to analyzing energy efficiency opportunities from manufacturing to marketing.<sup>3</sup>

These general patterns are reflected in the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO 2011). The AEO 2011 projects natural gas demand in the Industrial sector to rebound to pre-2000 levels, in excess of 8 Tcf/year, by 2015.<sup>4</sup> The net increase is attributed to continued recovery from the recession, increased combined heat and power (CHP) and demand response to lower natural gas prices, partly offset by continued gains in energy efficiency. The AEO 2011 projects the average annual growth in natural gas demand in industry at 0.9% through 2035, about half of the projected growth rate of 1.9% in the value of industry shipments, reflecting a continuing decline in natural gas intensity.<sup>5</sup>

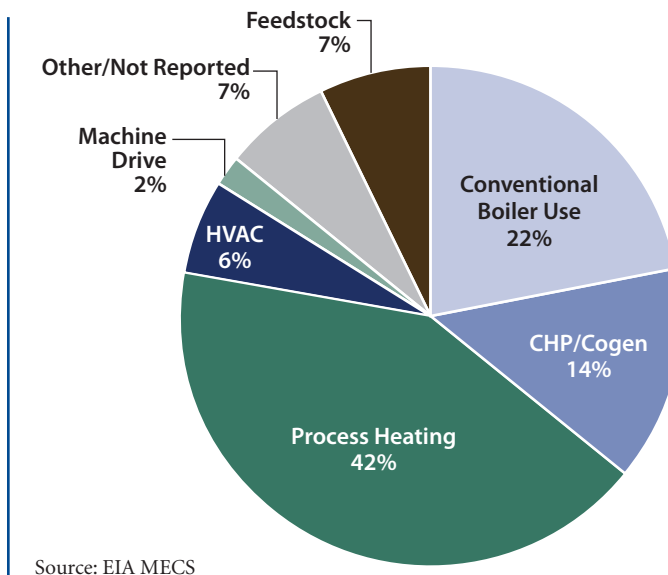
The economic modeling analysis that underlies the results presented in Chapter 3 shows a similar pattern of Industrial gas demand over coming decades. Under the assumption of no additional policy on GHGs, U.S. Industrial gas demand grows over the period to 2035 and beyond. On the other hand, under the price-based policy explored in Chapter 3, which reduces national GHG emissions to 50% of 2005 levels by 2050, total industry gas demand

declines over the next two decades as gas use shifts towards electric generation and away from other end uses. In the most energy-intensive U.S. manufacturing industries, gas use remains roughly constant at the 2005 level, substantially below the no-policy projection. However, because of modeled flexibility in this industry segment, the value of domestic output is only slightly below that in the no-policy case.<sup>6</sup>

### Principal Uses of Natural Gas as a Fuel and as a Chemical Feedstock

Natural gas is used in U.S. manufacturing both as a fuel and as a chemical feedstock. The two primary fuel uses are in boilers and process heating, and the two primary feedstock uses are in ammonia (NH<sub>3</sub>) manufacturing and hydrogen (H<sub>2</sub>) production. Figure 5.5 shows that process heating accounts for 42% of manufacturing natural gas consumption, with boilers (conventional and combined heat and power) accounting for an additional 36%. These two applications total 4.5 Tcf/year, or over three-fourths of total natural gas used in manufacturing (and over 60% of total industrial use), and thus provide the focus for our analysis.

**Figure 5.5 U.S. Manufacturing Natural Gas Use by End-Use Application**



## Natural Gas Use in Industrial Boilers

Industrial boilers, both conventional and CHP, consumed 2.1 Tcf of natural gas in 2006, accounting for 36% of total natural gas in manufacturing.<sup>7</sup> We examine two potential drivers affecting demand for natural gas in boilers: modernization of the current natural gas boiler fleet with more efficient units, and replacement of coal boilers with new natural gas boilers. Our analysis is summarized in the discussion that follows; a more detailed discussion is provided in Appendix 5A.

Industrial boilers are used to provide steam and hot water in all manufacturing industries, with the four largest applications in chemicals (39%); food processing (17%); paper (13%); and petroleum and coal products (13%). There is strong competition among boiler fuels in the energy intensive industries that employ larger boilers and have ready access to alternative fuel supplies. Natural gas is the predominant boiler fuel in other manufacturing industries, which typically employ smaller boilers and do not have the same opportunities for use of by-products and waste fuels.

Our analysis is based on a 100 Million British thermal units (MMBtu)/hour boiler<sup>8</sup>, which is relatively large for natural gas boilers but comparable to many coal boilers. As a sensitivity analysis, we also analyzed a smaller size boiler (50 MMBtu/hour.)

### *Modernization of the Natural Gas Industrial Boiler Fleet*

Most existing natural gas boilers have been in service for decades and experience low turnover rates. On average, the existing fleet of pre-1985 boilers has an average energy efficiency in the range of 65% to 70%.<sup>9</sup> These boilers reject waste heat in the exhaust gases; this heat is comprised of the latent heat that can be recovered from condensing the water vapor into

a liquid, as well as the sensible heat contained in the exhaust.

In 2004, the Department of Energy (DOE) set minimum energy efficiency standards for new natural gas boilers in the range of 77% to 82%, depending upon boiler size and boiler technology.<sup>10</sup> New boilers meet this standard through the use of additional heat recovery systems (i.e., condensing technology) to capture the latent heat and a portion of the sensible heat in the exhaust gases. In addition, use of economizers allows for waste heat to be recovered by pre-heating the boiler feed water. These improvements can boost overall energy efficiency to the 80% to 85% level. Further technology advances entering the marketplace include multi-stage combustion systems — which also reduce NOx (a mixture of nitric oxide and nitrogen dioxide emissions) — and advanced condensers and air pre-heating systems. These “super” efficient boilers can achieve efficiencies in the range of 94% to 95%.

We compared the net present value (NPV) of the pre-tax cost of replacing an existing 100 MMBtu/hour natural gas boiler with either a high-efficiency or super-high-efficiency unit. We estimate that replacement of current natural gas boilers with high-efficiency models would, at a 15% discount rate, yield a reduction of 8% in annualized costs on a pre-tax basis. Replacement with super-high-efficiency boilers would yield annualized savings of 20%. A sensitivity analysis on smaller size natural gas boilers (i.e., 50 MMBtu/hour) yields similar results.

The payback periods for these boiler replacements range from 1.8 to 3.6 years, based on 2010 actual industrial natural gas prices, and assuming no increase in natural gas prices over this period. Higher natural gas prices would improve the results; lower natural gas prices would reduce the projected annualized savings and extend the payback period.

The cost estimates are for equipment only; installation costs will reduce these returns somewhat. Also, in particular instances, the attractiveness of boiler modernization will depend on other factors such as: the remaining book value of existing boilers that a firm might write off; the availability of investment capital; the return on investment in boiler modernization relative to other opportunities; and the availability of tax incentives, such as accelerated depreciation or investment tax credits. Considering all these factors, however, it appears that replacement will be cost effective in many installations.

Two scenarios can provide an indication of the impact on natural gas consumption: (1) a replacement of 50% of current natural gas industrial boiler capacity with high-efficiency natural gas boilers would reduce demand for natural gas by 129 Billion cubic feet (Bcf) annually, while (2) a replacement of 50% of current natural gas boiler capacity with super-high-efficiency natural gas boilers would reduce demand by 263 Bcf annually. The reduction in carbon dioxide (CO<sub>2</sub>) emissions ranges from about 4,500 to over 9,000 tons per year per boiler.

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#### **FINDING**

**Replacement of existing industrial natural gas boilers with higher efficiency models could cost-effectively reduce natural gas demand and reduce GHG emissions.**

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#### **RECOMMENDATION**

**The DOE should review the current energy efficiency standards for commercial and industrial natural gas boilers and assess the feasibility of setting a more stringent standard.**

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#### *Replacement of Existing Coal Industrial Boilers with Efficient Natural Gas Boilers*

A CO<sub>2</sub> emissions reduction requirement could lead to a significant level of replacement of existing coal boilers by natural gas. Absent a carbon constraint, a potential driver for fuel switching of coal boilers to natural gas is the establishment of National Emissions Standards for Hazardous Air Pollutants (NESHAPS) based on the application of maximum achievable control technology (MACT).

Our analysis is based on the February 23, 2011, EPA MACT emissions standards for mercury (Hg), metals, dioxin, acid gases and other hazardous air pollutants emitted from industrial boilers and process heaters. On May 16, 2011, EPA administrator Jackson issued a stay of the new standards to allow for additional review and comment.

Natural gas boilers, because of the clean-burning nature of the fuel, are not subject to new emissions reduction requirements. On the other hand, three subcategories of coal boilers utilizing different technologies — stoker, fluidized bed and pulverized coal combustion — are subject to new standards for the control of particulate matter, acid gases, toxic chemicals and Hg. Achieving these emission standards will require the installation of wet scrubbers and fabric filters. Installation of activated carbon injection for control of Hg emissions also may be required in some instances.

The EPA economic analysis supporting the new MACT standards assumed that existing coal boilers would retrofit post-combustion controls. The EPA considered and rejected fuel switching as a control option, primarily because of assumed high natural gas prices (\$9.58 per MMBtu for industrial delivery in 2008) and assumed 5% loss of efficiency from replacement of burners in existing boilers.

We performed an analysis, using current natural gas price assumptions, comparing four possible compliance options for coal boilers: (1) retrofit of post-combustion controls (using EPA cost assumptions); (2) retrofit of natural gas burners within the existing coal boiler (with EPA efficiency assumptions); (3) replacement of the existing coal-fired boiler with a high-efficiency natural gas boiler; and (4) replacement of the existing coal boiler with one of the new super-high-efficiency natural gas boiler technologies.

Our analysis indicates that replacement of coal boilers with efficient or super-efficient natural gas boilers is cost competitive with retrofitting post-combustion controls. The NPV cost, at a 15% discount rate, of high-efficiency natural gas boilers is slightly higher than the NPV cost of post-combustion controls, while the NPV of super-efficient boilers is slightly lower than the cost of retrofitting. The higher energy efficiency performance levels of new natural gas boilers, at current gas prices, make boiler replacement an attractive option. Neither factor was considered in the EPA analysis.

The results of this analysis are sensitive to two assumptions: (1) the estimates of capital equipment cost for retrofitting post-combustion controls for coal; and (2) the relative prices of coal and natural gas. Our analysis uses the EPA capital cost assumptions for installation of post-combustion controls (i.e., wet scrubbers and fabric filters at existing coal boilers). For coal boilers that may require additional controls to achieve MACT limits for Hg emissions, costs would increase substantially, making the options for replacement with natural gas boilers much more cost effective. The comparative results also are sensitive to the price differential between natural gas and coal. Based on actual average delivered prices in 2010, the price of natural gas was on average higher than coal

by \$2.31/MMBtu. A lower price differential (i.e., a smaller price spread between natural gas and coal) would make conversion to natural gas more attractive; a larger price differential would make continued use of coal more attractive.

The potential impact of replacing industrial coal boilers with new high-efficiency natural gas boilers is significant. The EIA Manufacturing Energy Consumption Survey (MECS) data show that industrial coal boilers and process heaters currently use 892 trillion Btu of coal each year. Conversion of this capacity to natural gas would increase demand for natural gas by 0.87 Tcf/year. The actual rate of market penetration would depend upon individual facility analyses.

Replacement of existing coal boilers with new efficient natural gas boilers in order to meet MACT requirements could reduce annual CO<sub>2</sub> emissions by 52,000 to 57,000 tons per year per boiler. We estimate that, even if the NPV cost of boiler replacement with natural gas is slightly more expensive than retrofitting post-combustion controls, assigning this incremental cost to the CO<sub>2</sub> reductions would yield an incremental cost for CO<sub>2</sub> reduction of about \$5/ton.

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## FINDING

**Replacement of existing industrial coal boilers and process heaters with new, efficient natural gas boilers could be a cost-effective alternative for compliance with the EPA MACT Standards. Fuel switching has the potential to increase demand for natural gas while achieving substantial CO<sub>2</sub> emissions reductions at a modest incremental cost.**

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## Natural Gas Use in Manufacturing Process Heating

The use of some form of process heating is ubiquitous across virtually all manufacturing sectors, accounting for 2.4 Tcf of natural gas consumption in 2006, or 42% of all manufacturing gas use (and nearly one-third of total industrial use). Three manufacturing industries — coal products (20%), primary metals (19%) and chemicals (16%) — comprise over half of process heating demand for natural gas.

Process heating involves the transfer of heat energy to materials in a manufacturing process through conduction, convection or radiation, involving direct or indirect contact with steam or another hot fluid. Process heating is an integral step in the manufacturing of a variety of products including metals, rubber, plastic, concrete, glass and ceramics. Process heating conditions can vary widely by temperature (e.g., several hundred to several thousand degrees Fahrenheit), by throughput rates (e.g., short or long contact periods) and by type of process (e.g., batch or continuous). Natural gas and electricity are the two primary sources of energy for process heat.

The DOE-sponsored collaborations involving National Laboratories and industry have identified four best management approaches to improving energy efficiency in process heating: (1) improve the efficiency of the combustion process; (2) reduce heat losses in the process of transporting and transferring process heat; (3) improve the overall rate of heat transfer from the process heat medium to the product; and (4) recover a portion of the residual waste heat.<sup>11</sup> The DOE reports that application of many of the identified best management practices can improve efficiency of process heating typically in a range of up to 10%, with some measures, such as preheating combustion air, increasing efficiency by 20% or more. These measures typically result in paybacks within a 24-month period.

Implementation of process heating efficiency improvements have to be carefully integrated with process operating parameters so as not to impair performance; for example, heat recovery and integration can make process control more difficult. Well-designed process heating improvements can actually enhance process performance and reduce environmental emissions. The Pew Center report<sup>12</sup> on industry case studies highlighted several such examples: (1) installation of oven draft controls at Frito-Lay tortilla chip operations not only saved natural gas, but also improved the quality of the chips; (2) waste heat recovery from the incineration of exhaust gases from painting operations at a Toyota manufacturing facility also enabled the plant to replace centralized steam generation with a distributed hot water supply system; and (3) replacement of existing ethylene furnaces at the Dow Chemical Freeport, TX, facility for compliance with NO<sub>x</sub> emissions requirements also improved process heating efficiency by 10%, and reduced CO<sub>2</sub> emissions by 105,000 tons/year.<sup>13</sup>

Significant reductions in demand for process heating may require changes in the underlying manufacturing processes themselves. These could include the substitution of membrane separation for temperature-based separations, more selective catalysts that reduce reaction temperatures and greater process integration.<sup>14</sup> The steel industry achieved significant reductions in process heating requirements as a result of deployment of continuous casting machines and advances in near-net-shape casting that minimize the need for follow-up forming operations. In the chemicals industry, Dow and BASF deployed the world's first commercial-scale plant to convert hydrogen peroxide to propylene oxide, reducing energy use by 35% and wastewater production by 80%.<sup>15</sup> Research is underway to develop new catalysts that would achieve the oxidative coupling of methane to convert methane to ethylene, replacing the energy intensive cracking process.<sup>16</sup> Other possible new approaches in the chemicals

industry involve the utilization of biomass feedstock materials to replace conventional hydrocarbon feedstock, bio-processing technologies that may require less process heating or both.

Finally, product substitution offers opportunities for reductions in demand for natural gas. Such examples include new cements, nano-materials and biomimetic materials that require less energy to produce than current materials.

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## FINDING

**The potential for significant reductions in the use of natural gas for process heating lies in a shift to new manufacturing process technologies that use less energy-intensive processes and materials.**

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### RD&D Opportunities in Energy-Efficient Technologies

Additional opportunities for advances in industrial technologies lie in the nexus of energy efficiency, environmental quality and economic competitiveness. Advances in energy-efficient process technologies are well incentivized by normal industry economics due to the potential to also improve profitability through either product improvements or cost reduction. Because these advances also provide important contributions to U.S. energy security and environmental policy goals, the DOE has historically played an important role. Under the former Industries of the Future Program, the DOE served as the convener of industry working groups that developed technology roadmaps. The DOE then funded selected RD&D projects consistent with the roadmaps. For example, the development of the “Super Boiler” described earlier in this chapter was the result of an Industrial Combustion Technology Roadmap prepared by a DOE-formed industry working group in 1999.

The DOE subsequently cost shared an R&D effort with the Gas Technology Institute (GTI), a not-for-profit R&D organization. The partnership was subsequently expanded to include other sponsoring and performing entities, including Cleaver-Brooks, Inc., which served as the commercialization partner.<sup>17</sup>

A 2001 evaluation of the DOE Office of Industrial Technologies (OIT) R&D program by the National Academy of Sciences concluded that “...the OIT industrial programs are cost-effective and have produced significant energy, environmental and productivity benefits for both the industrial sector and the country.”<sup>18</sup> The Academy report identified four lessons from the OIT experience: (1) the value of OIT as a catalyst for convening industry; (2) the advantages of early agreement on goals and metrics for success; (3) the importance of non-energy benefits to industry as a driver for the adoption of technology; and (4) the significance of demonstration as a means of promoting technology adoption. The CO<sub>2</sub> emission reduction benefits of DOE OIT supported technologies and activities undertaken since 1977 have been estimated at 187 million metric tons of carbon equivalent (MMTCe).<sup>19</sup>

Early in the last decade, termination of the Industries of the Future Program was proposed, on the assumption that market forces should drive the size and pace of future energy efficiency improvements in industry. The President’s fiscal 2012 budget proposes to replace the Industries of the Future Program with a suite of new manufacturing R&D initiatives and a new critical materials innovation hub, focusing more on pre-competitive R&D targeted to transformational changes in manufacturing technologies.

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## FINDING

**Industrial energy efficiency RD&D programs supported by the DOE have historically led to significant improvements in energy-efficient technologies: technologies that also achieved significant reductions in CO<sub>2</sub> emissions while improving the economic competitiveness of manufacturing.**

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## RECOMMENDATION

**The DOE should continue to play a role in accelerating the development of new technologies that can improve energy efficiency. The DOE should again serve as a convener of industry technology working groups to develop roadmaps for future energy-efficiency technology improvements. Based on these roadmaps, the DOE should develop a federally funded RD&D portfolio consisting of applied pre-competitive R&D as well as transformational approaches. The DOE RD&D portfolio should encompass both industry-specific technologies in energy-intensive industries and crosscutting technologies applicable across a broad spectrum of manufacturing industries.**

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### CHP Systems for Industrial Applications

In most cases, industrial boiler and process heating installations typically support a single application. The modification of current process heating and industrial boilers to enable CHP applications could have a significant impact on natural gas demand.

Installation of CHP systems does not necessarily increase the efficiency of the process heat or steam system, nor does it generate electricity

more efficiently than a large-scale central station power plant. The attractiveness of CHP stems from the increase in overall system efficiency that can be achieved by obtaining both electric power generation and steam generation from a single on-site system. CHP results in increased demand for natural gas at the industrial point of use site, with some offsetting reduction in demand for fuels at central station power generation facilities. From an energy systems standpoint, the improvement in overall energy efficiency has to take into account the reduction in purchased electricity, which reduces demand for electricity from the grid.

The feasibility of CHP applications in manufacturing applications depends upon the ability to match the quantity and quality of the steam or hot water produced from the CHP system with the industrial end-use requirements for heat and power. For industrial applications, CHP systems are designed to meet heat loads, because it is easier to balance electricity generation and load with the electrical grid. If the level of electricity generation is less than the manufacturing load the facility purchases the remainder from the grid; if CHP electricity generation exceeds electrical load, the excess is sold back into the grid. Matching CHP systems to heat and power loads at smaller scale, such as institutional, commercial and residential applications, is more challenging, as discussed later in this chapter.

The EIA reported<sup>1</sup> that 964 Bcf of natural gas was used for industrial CHP in 2009, representing 13% of total industrial natural gas use. The EIA AEO 2011 projects an increase of 181% in electricity generated from end-user CHP systems by 2035.<sup>20</sup> While this would imply an increase in natural gas use of about 1.7 Tcf per year by 2035, this increase is essentially offset by other energy-efficiency gains in the Industrial sector, so that the EIA projection shows relatively flat demand for natural gas in the industry sector from the period 2015 to 2035. In

addition, increased demand in the Industrial sector for CHP also would mitigate increases in demand for grid-supplied electricity.

### Natural Gas Use as a Chemical Feedstock

About 7%, or 0.36 Tcf, of natural gas demand in manufacturing is for use as a feedstock for the production of hydrogen and ammonia. Hydrogen is used extensively in the petroleum-refining industry to upgrade petroleum products, and ammonia is primarily used in the manufacture of fertilizer products. In addition, Natural Gas Liquids (NGLs), which consist primarily of ethane and propane, are key feedstock materials for manufacturing of a variety of chemical products.

Our detailed analysis of chemical feedstock issues is presented in Appendix 5B. The analysis indicates that lower natural gas prices make the operation of current domestic ammonia manufacturing capacity more competitive in the global market. Ammonia is the key intermediate step in the manufacturing of a variety of nitrogenous fertilizer products. We also estimate that, due to current petroleum/natural gas price spreads, NGLs will have significant cost advantage relative to naphtha in the domestic manufacturing of ethylene. Ethylene is an intermediate product in the manufacturing of polyethylene, polyvinyl chloride and other plastics. We have not estimated changes in U.S. natural gas demand associated with potential changes in global market competitiveness of these commodities; this is dependent upon other factors, such as global demand projections and capital investment plans, which are outside the scope of our analysis.

The demand for NGLs for domestic ethylene production will incentivize increased production of NGLs from domestic natural gas resources that are relatively “wet” (i.e., higher NGL content). The implications for NGL processing and infrastructure are discussed further in Chapter 6 on Infrastructure and in Appendix 5B.

## COMMERCIAL AND RESIDENTIAL APPLICATIONS OF CHP SYSTEMS

Smaller-scale CHP systems are available for applications in Residential and Commercial settings. There is a wide variety of technology options for smaller-scale CHP systems, including fuel cells, gas turbines, micro-turbines and reciprocating engines (such as the Stirling engine). Except for fuel cells, these technologies rely on the combustion of fossil fuel to produce heat, later converted into mechanical energy to drive the generator that produces electricity. Fuel cells are based on electrochemical conversion of the chemical energy stored in hydrocarbon fuels into water and electric energy.

The choice of CHP technology for a particular application will depend on the different characteristics of the technology and how they match end-use requirements:<sup>21</sup>

- Natural gas micro-turbines have relatively high capital costs, but have lower maintenance costs than other technologies. Micro-turbines have a high-quality exhaust that can be used to increase the production of high-pressure steam for other high-temperature applications. However, turbines are sensitive to changes in ambient air conditions, and have a poor efficiency at part-load conditions;
- Reciprocating engines have low investment costs, good part-load performance and quick start-ups. Their principal disadvantages include high maintenance costs, high noise levels and high air emissions; and
- Fuel cells have high initial capital costs, but are virtually emissions free at the point of end use, quiet and efficient over a range of loads.

Additional details on performance characteristics and cost data of CHP technologies are provided in Appendix 5C.

A critical parameter in assessing the feasibility of a CHP system is the ability to match the heat-to-power ratio (HPR) of the CHP system with the power and heating loads. As the size of the application becomes smaller, matching the HPR characteristics of the CHP system to load becomes a greater challenge, since it will depend on the CHP system's technical characteristics and its suitability to meet the variation in the customer's heat and power-load requirements. In Residential applications, micro-CHPs have very small electrical capacities (less than 5-kilowatt electric (kW-e)), with different efficiency and HPR values depending on the conversion technology. Fuel cells offer the highest electrical efficiency, followed by reciprocating engines and Stirling engines. By comparison, Stirling engines have a relatively high heat output per unit of electrical generation (i.e., high HPR), followed by reciprocating engines, and with a relatively low HPR for fuel cell technologies.<sup>22</sup>

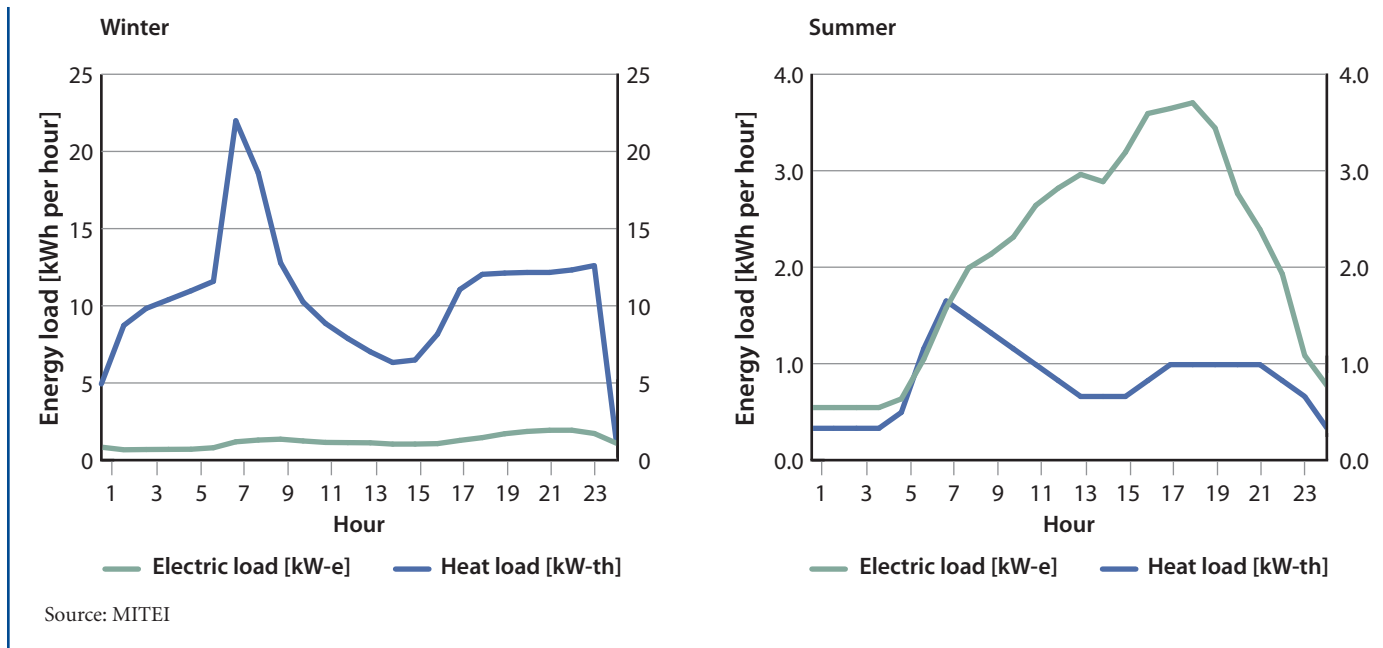
To gain further insight on these trade-offs, we performed an analysis of several scenarios for application of CHP systems in smaller-scale Institutional and Residential applications. We chose the MIT campus as a case study for CHP application in an Institutional market. The MIT CHP system consists of a 21 megawatt electric (MWe) gas turbine combined with a Heat Recovery Steam Generator (HRSG) to generate steam from the turbine exhaust gas. The MIT CHP system provides about 75% to 80% of the campus electrical load and the majority of the campus steam requirements. The gas turbine has been used mostly as baseload power, with the remainder of electricity purchased from the grid. The remaining steam load not served by the CHP system is met with conventional boilers. We analyzed the costs of the MIT CHP system relative to a no-CHP option, i.e., purchasing all electricity from the grid and generating all campus steam requirements from boilers. Our analysis showed that installation of a CHP system provided a present value cost savings of about 20%, at a discount rate of 7.1%,

with a corresponding reduction of about 17% in CO<sub>2</sub> emissions.<sup>23</sup> Our findings are described in more detail in Appendix 5C.

Another potential application for CHP is in district heating/cooling systems. District heating/cooling is a system for distributing heat (in the form of steam or hot water) or chilled water generated in a centralized location for residential or commercial space heating/cooling and hot water applications. District heating is used extensively in a number of European countries for industrial, commercial and residential applications. For example, over six in ten homes in Denmark are served by district heating; market penetration is 50% or more in Poland, Sweden and Estonia; and geothermal-based district heating serves 95% of Iceland's residences. U.S. experience is much more limited and focused on institutional users. While the U.S. currently has over 500 district heating/cooling systems,<sup>24</sup> about 85% serve hospitals and university campuses (such as the MIT campus used as a case study in our analysis). The U.S. also has 85 urban utility district heating systems, serving about 1.9 billion square feet of commercial space.<sup>25</sup> Most U.S. district heating systems are single-purpose systems, but there is growing interest in CHP systems for this purpose. To stimulate this market, the DOE cost-shared several new CHP district heating projects using funds from the American Recovery and Reinvestment Act (ARRA). As the MIT case study illustrates, the market opportunities for expanded CHP district heating systems are promising.

We also examined the feasibility of CHP systems for residential applications in New England. As illustrated in Figure 5.6, there is a considerable mismatch between electricity and heating requirements. During winter, the heat load is significantly higher than the power load, while during summer, the power load is significantly higher due to demand for air-conditioning.

**Figure 5.6 Hourly Energy Load Profile for One Type of Residential Customer in New England – Sample for one day during Winter and Summer**



Our analysis shows that the energy, environmental and economic benefits of a CHP residential application varied greatly depending upon the customer energy management strategy. Designing and operating a Residential CHP system to follow heat loads was economically competitive, with the greatest benefit during the winter season. Operating the CHP system to follow electricity requirements was not economically attractive, because the CHP system would produce large quantities of excess heat during summer months, significantly reducing overall performance of the system.

Finally, for the residential applications, a technology such as fuel cells, with a relatively low HPR, was more attractive than an alternative engine-based technology with higher HPR. The relative high electric efficiency of fuel cells makes this technology competitive for meeting electrical loads.<sup>26</sup> The detailed results of the MIT and New England Residential case studies are described in greater detail in Appendix 5C.

#### FINDING

**Matching heat and power loads for residential and other small-scale applications poses a significant challenge to the feasibility of small-scale CHP systems based on current technologies.**

#### NATURAL GAS DEMAND IN BUILDINGS

The residential/commercial sectors account for over 40% of total energy consumption in the U.S., almost exclusively in buildings. While these two sectors represent over two-fifths of overall energy demand, they account for more than 55% of the nation's natural gas demand when the natural gas used to generate electricity for buildings is added to the direct use of natural gas in homes and businesses.<sup>27</sup>

Within the residential/commercial sectors, the direct use of fuels such as natural gas, fuel oil and liquid petroleum gas (LPG) are concentrated in thermal end uses, especially space heating and

hot water. Figure 5.7 shows the breakdown of energy consumption for major end uses in the residential/commercial sectors. Of particular note are the differences between electricity and direct fuel consumption across different end uses, and how this influences not only the sales of electricity, natural gas and other fuels, but overall energy consumption once electricity conversion losses are included. As can be seen, electricity and fuel sales — often called “site energy” — masks overall energy consumption since only about a third of energy consumed in power generation becomes electricity sold to the consumer.

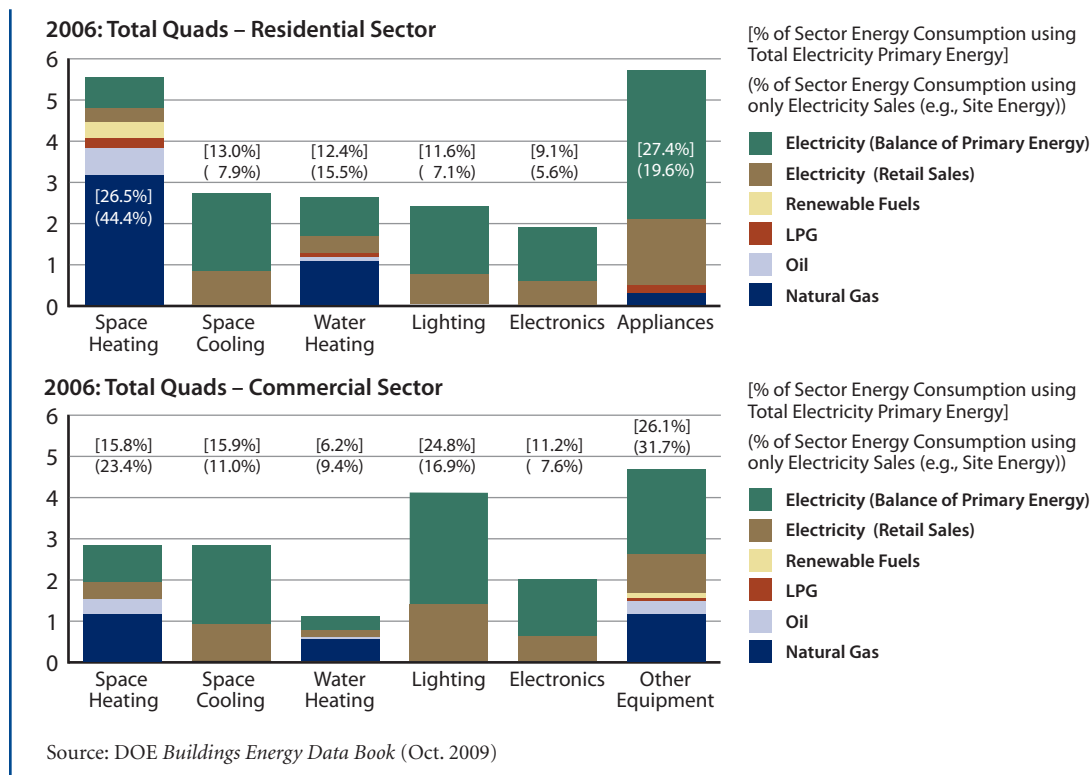
### Comparing the Efficiency of Space Conditioning and Hot Water Technologies

When considering policies to cost-effectively reduce energy consumption and CO<sub>2</sub> emissions in buildings, it is important to consider both the end use and the energy carrier. This is especially true when looking at appliances and building energy systems than can be run on either

electricity or fuels such as natural gas. Until recently, buildings commonly had separate systems for heating and cooling. Boilers or furnaces for heating can run on natural gas, oil, and LPG. As shown in Figure 5.7, space cooling which usually includes humidity control (e.g., air-conditioning (AC)) is almost exclusively electricity based, although large Commercial AC systems are available that run on natural gas, and in the past gas-fired AC systems for the residential sector have been commercially available.

In the last several decades, heat pump systems have become much more common. A heat pump is essentially an air conditioner that can run backwards, delivering either hot or cold air to a building’s interior. Most heat pump systems are air-source heat pumps, using external air as the temperature reservoir from which to provide heating or cooling. This is sufficient for regions that experience mild winters, but not where temperatures get very low for very long.<sup>28</sup>

**Figure 5.7 2006 Breakdown of Building Energy Consumption in the Residential and Commercial Sectors**



Ground source (or geothermal) heat pumps, which use the temperature of the earth instead of the air to provide heating and cooling overcome this cold winter problem. However, this comes at a significant increase in installed costs since an external heat exchange loop needs to be installed in the ground outside the building. The cost of this heat exchanger can vary significantly depending on the type of ground source heat pump, soil type and temperature.

Hot water systems are more straightforward since the seasonality of use is less of a factor. Common systems use the heat from fuel combustion or electric resistance heating to keep a tank of water at the desired temperature. Recently, heat pump hot water systems have entered the market, as have instantaneous (or tankless) water heaters.

For all of these systems, whether furnaces, central AC, heat pumps or hot water heaters, the differential equipment and life-cycle costs of systems are important factors to builders, homeowners and policy makers, as builders seek to minimize installed costs, consumers seek to minimize operating costs and policy makers seek to minimize social costs including effects on the environment. Balancing all these factors is challenging especially when comparing systems that use different energy carriers, in particular electricity versus natural gas and other “direct” use fuels.

As described in more detail in Appendix 5D, there is a broad range of efficiency metrics for furnaces, air conditioners, heat pumps and hot water heaters that offer little guidance to consumers when trying to compare technologies across fuel types. Even heat pumps, which provide both space heating and AC, have different efficiency metrics depending on whether they are in heating or cooling mode, or use outside air versus the temperature of the earth as a heat source/sink. For furnaces, air conditioners and

air source heat pumps, these efficiency metrics are also “averaged” across reference heating or cooling seasons, and so do not inform individual consumers about how they might perform locally. Even this rough seasonal adjustment is not possible for ground-source heat pumps, since baseline ground temperature information is not available. And so, ground source heat pump manufacturers report an optimal, and substantially higher coefficient of performance than reported for air-source heat pumps.

To allow comparison, we normalize these diverse efficiency metrics for select Residential appliances and space conditioning systems in Table 5.1.<sup>29</sup> This table focuses on the Residential sector, since it is larger in both overall size and the number of systems in the field, and also because it is an area where policies including appliance efficiency and building standards may overcome market inertia, especially as it pertains to equipment versus life-cycle cost calculations for smaller, less experienced consumers.

Table 5.1 shows the “Seasonal Co-efficient of Performance” (SCOP) for a range of Residential heating, cooling and hot water systems, across a range of commercially available systems, including “low” energy efficiency systems, higher efficiency “Energy Star” systems (minimum efficiency to qualify as an Energy Star system) and a best-available energy efficiency system. The SCOP is simply the ratio of the amount of useful energy provided divided by the amount of retail energy (fuel or electricity) consumed. For direct thermal systems, such as furnaces, the efficiency or SCOP will be less than one. However, for AC and heat pump systems, where the electricity moves heat between the inside and outside, instead of consuming the electricity as heat, the amount of useful energy can be substantially greater than the “thermal value” of electricity, resulting in SCOPs in the range of two and a half to seven.

**Table 5.1 Site vs. Source Energy Efficiency of Residential Heating, Cooling and Hot Water Systems**

|                                       | Site Energy Efficiency (SCOP*) |             |      | Source-to-Site Efficiency | Full-Fuel-Cycle Efficiency (FFC) |             |      |
|---------------------------------------|--------------------------------|-------------|------|---------------------------|----------------------------------|-------------|------|
|                                       | Low                            | Energy Star | Best |                           | Low                              | Energy Star | Best |
| <b>Heating System Type</b>            |                                |             |      |                           |                                  |             |      |
| Electric Furnaces                     | 0.95                           | —           | 0.99 | 0.32                      | 0.31                             | —           | 0.32 |
| Oil-Fired Furnaces                    | 0.78                           | 0.83        | 0.95 | 0.88                      | 0.69                             | 0.73        | 0.84 |
| Gas-Fired Furnaces                    | 0.78                           | 0.90        | 0.98 | 0.92                      | 0.72                             | 0.83        | 0.90 |
| Air Source Heat Pumps <sup>†</sup>    | 2.30                           | 2.40        | 5.20 | 0.32                      | 0.74                             | 0.77        | 1.67 |
| Ground Source Heat Pumps <sup>‡</sup> | 2.50                           | 3.30        | 4.80 | 0.32                      | 0.80                             | 1.06        | 1.54 |
| <b>Cooling System Type</b>            |                                |             |      |                           |                                  |             |      |
| Central AC <sup>†</sup>               | 3.81                           | 4.25        | 6.74 | 0.32                      | 1.22                             | 1.37        | 2.17 |
| Air Source Heat Pumps <sup>†</sup>    | 3.81                           | 4.25        | 4.98 | 0.32                      | 1.22                             | 1.37        | 1.60 |
| Ground Source Heat Pumps <sup>‡</sup> | 2.55                           | 4.13        | 6.57 | 0.32                      | 0.82                             | 1.33        | 2.11 |
| <b>Hot Water System Type</b>          |                                |             |      |                           |                                  |             |      |
| Electric Storage Tank                 | 0.92                           | —           | 0.95 | 0.32                      | 0.30                             | —           | 0.31 |
| Oil-Fired Storage Tank                | 0.51                           | —           | 0.68 | 0.88                      | 0.45                             | —           | 0.60 |
| Gas-Fired Storage Tank                | 0.59                           | 0.62        | 0.70 | 0.92                      | 0.54                             | 0.57        | 0.64 |
| Electric Heat Pump Tank               | 0.92                           | 2.00        | 2.35 | 0.32                      | 0.30                             | 0.64        | 0.76 |
| Electric Instantaneous                | 0.93                           | —           | 0.99 | 0.32                      | 0.30                             | —           | 0.32 |
| Gas-Fired Instantaneous               | 0.54                           | 0.82        | 0.94 | 0.92                      | 0.50                             | 0.75        | 0.87 |

Source: MITEL

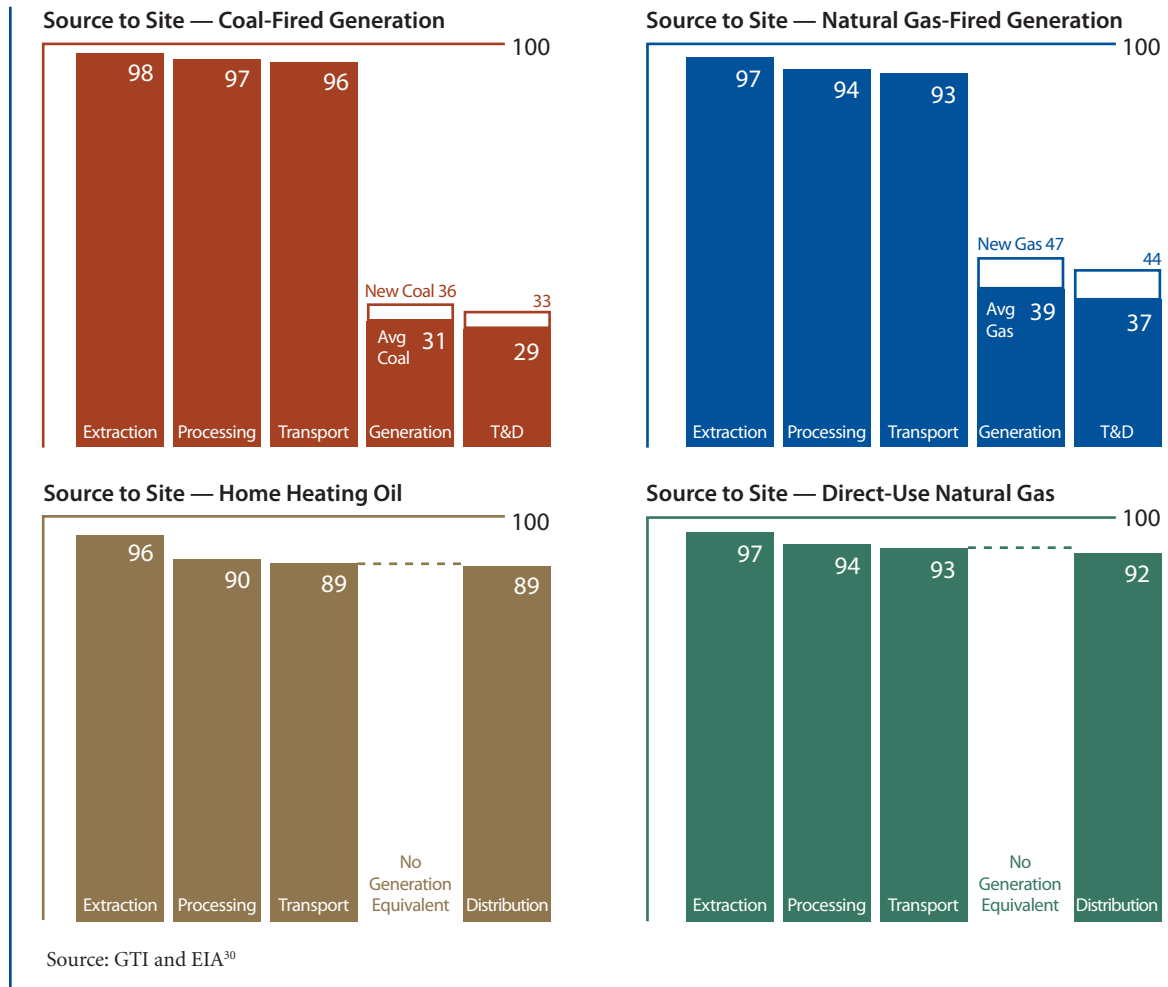
\*COP for Ground Source Heat Pump Systems, <sup>†</sup>Split Systems, <sup>‡</sup>Closed Loop Systems

More importantly, Table 5.1 shows the difference between “site” (SCOP) and “source” (Full-Fuel-Cycle (FFC)) energy efficiencies. FFC efficiencies account for all the energy used to extract, refine, convert and transport the fuel to the end user, as well as the efficiency of the end-use equipment. Almost all building energy equipment is sold on the basis of end use or “site” energy efficiency. However, looking at site or end-use efficiency alone masks large energy conversion losses particularly those from generating electricity. FFC efficiency combines these source-to-site losses with end-use energy consumption.

Figure 5.8 shows the “Source to Site” energy losses of bringing energy to the consumer. All fuels, whether coal or natural gas for power

generation, or oil and natural gas for household use, consume some energy in the extraction, processing and bulk transportation of fuel. There is also additional energy use or losses in the delivery of electricity and fuels to the retail customer, such as the transmission and distribution (T&D) of electricity, distribution systems for natural gas or truck delivery of home heating oil. The biggest difference comes in the conversion losses associated with electricity production. When these are all added together, source to site losses for electricity are 68%, compared to 8% for natural gas and 12% for home heating oil.<sup>30</sup> These “source to site” losses are then combined with end-use energy efficiencies to calculate the FFC efficiencies as shown in Table 5.1.

**Figure 5.8 Combined Source to Site Energy Efficiencies for Delivering Coal and Natural Gas-Fired Generation Versus Oil and Natural Gas to End-Use Customers**



**FINDING**

**Source-to-site energy losses should be considered when choosing among energy options, especially ones that use different energy carriers.**

In 2009, a National Research Council report recommended that the DOE move to the FFC approach in setting energy efficiency and appliance standards, especially when there are multiple fuel choices. In 2010, the DOE initiated a rulemaking process to move toward the FFC approach in the design of efficiency standards for appliances and space conditioning and hot water systems.<sup>31</sup>

The main comparison to draw from Table 5.1 is that although heat pump systems, as well as central air conditioners, have significantly higher site energy efficiencies, when roughly two-thirds losses in electricity generation and transmission are included, these gains effectively disappear except for the most efficient systems. Thus, improved efficiency information is needed to allow consumers to accurately compare the overall energy efficiency and cost effectiveness of direct fuel and electricity end uses. This is especially true for space conditioning and hot water systems.

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**RECOMMENDATION**

**Improved energy efficiency metrics that provide an FFC comparison of energy efficiency should be incorporated into national standard setting activities. The improved metrics should include both FFC efficiency and cost-to-consumer factors.**

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**Looking Beyond Equipment Efficiency Standards**

FFC and end-use efficiencies alone are not enough to determine which building energy systems will have the lowest cost to the consumer. The cost effectiveness of space conditioning and other technologies is a mix of equipment efficiency and fuel costs, equipment costs (including operation and maintenance costs), as well as the duty-cycle of the system. For example, a less efficient electric furnace may be more cost effective, on a total cost-to-consumer basis, in regions where it gets cold only occasionally, electricity prices are low or the housing unit is not occupied year-round.

The depth and duration of a region's heating and cooling seasons have a dramatic impact on the applicability and overall cost effectiveness of different energy technologies. Heating and cooling degree days are a rough estimate of a region's annual heating and cooling needs, and compare the daily average temperature to a reference temperature (usually 65°F in the U.S.). For example, New York City and St. Louis have 40% fewer heating degree days than Minneapolis-St. Paul. However, St. Louis is considerably warmer than New York City, with almost half again as many cooling degree days.

Different regions of the U.S., and even different locations within states, have very different heating and cooling requirements, and so generic appliance efficiency standards may not provide enough information to make the best choice. As such, no city is “typical,” and, therefore, tailored information is needed in order for consumers, architects, builders and others to make better choices. Add to this information about regional building stock age and efficiency, and demographic factors, and the need for a more nuanced approach to designing cost-effective, low-carbon building energy policies becomes more pronounced.

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**FINDING**

**Energy efficiency metrics alone are not sufficient to inform consumers about the most energy efficient and cost-effective options for meeting household energy needs in different regions.**

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Although “Energy Guide” labels for appliances such as hot water heaters, air conditioners and heat pumps are commonplace in retail establishments, comparative energy and life-cycle cost information is far from prominent in stores and on major retailers' websites, even when performing head-to-head comparisons of similar products.

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**RECOMMENDATION**

**In addition to improved efficiency metrics for comparing appliances and building energy technologies, there is a need to inform consumers and developers as well as state and local regulators about the cost-effectiveness and suitability of various technologies, relative to local conditions.**

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## FFC Efficiency and CO<sub>2</sub> Emissions

When considering climate policy, the situation becomes even more complex. While the carbon content of retail fuels is reasonably consistent across the U.S., this is not so for electricity, where regional differences in the mix of generation can substantially impact the CO<sub>2</sub> emissions associated with electricity use. Table 5.2 shows how source-to-site efficiency factors and CO<sub>2</sub> emissions rates change across the continental U.S. Efficiency and emissions factors are also shown by North American Electric Reliability Corporation (NERC) region.

In all cases, source-to-site CO<sub>2</sub> emissions from direct combustion of fuels are substantially

lower than from the use of electricity. Regions with greater concentrations of coal-fired generation commonly have *both* higher source-to-site losses, as well as higher carbon content fuels. Also included in Table 5.2 are the pre-combustion CO<sub>2</sub> emissions from the extraction, processing and transportation of bulk fuels. The source-to-site efficiency factors for electricity in Table 5.2 vary by -11% to +18% around the national average of 32%. Most of this is due to the fuel mix, especially the mix of coal versus natural gas, nuclear and hydropower in each NERC region. These differences become magnified in a measure of CO<sub>2</sub> emissions per unit of generation, where (in 2005) the CO<sub>2</sub> content of electricity varied by +36% to -30% around the national average of 1,470 lb. CO<sub>2</sub> per MWh.

**Table 5.2 Retail Electricity and Fuel — Source-to-Site Efficiencies and CO<sub>2</sub> Emissions**

| Regional Site-to-Source and CO <sub>2</sub> Emissions Factors by NERC Region (2005) |      | Source-to-Site Efficiency | CO <sub>2</sub> Emissions (lb CO <sub>2</sub> /MWh) |              |            |              | Δ% from US Avg. |
|---|------|---------------------------|---|--------------|------------|--------------|-----------------|
|   |      |                           | Precomb.  | Generation   | T&D        | Combined     |                 |
| <b>United States Average</b>  |      | <b>0.32</b>               | <b>54</b>   | <b>1,329</b> | <b>86</b>  | <b>1,469</b> | <b>-</b>        |
| Midwest Reliability Organization  | MRO  | 0.28                      | 55  | 1,824        | 120        | 1,999        | 36.1            |
| Southwest Power Pool  | SPP  | 0.30                      | 63  | 1,751        | 114        | 1,929        | 31.3            |
| Reliability First Corporation   | RFC  | 0.31                      | 38  | 1,427        | 94         | 1,559        | 6.1             |
| Florida Reliability Coordinating Council  | FRCC | 0.33                      | 99  | 1,319        | 91         | 1,508        | 2.6             |
| SERC Reliability Corporation  | SERC | 0.31                      | 45  | 1,369        | 90         | 1,504        | 2.4             |
| Texas Regional Entity   | TRE  | 0.32                      | 74  | 1,324        | 87         | 1,485        | 1.1             |
| Western Electricity Coordinating Council  | WECC | 0.38                      | 51  | 1,033        | 57         | 1,142        | -22.3           |
| Northeast Power Coordinating Council  | NPCC | 0.33                      | 85  | 876          | 61         | 1,022        | -30.4           |
| <b>Primary Residential Fuels</b>  |      |                           | Precomb.  | Distribution | Combustion | Combined     |                 |
| Distillate Oil  | US   | 0.89                      | 107   | 4            | 550        | 661          | -55.0           |
| Liquid Petroleum Gas  | US   | 0.89                      | 74  | 4            | 476        | 553          | -62.3           |
| Natural Gas   | US   | 0.92                      | 36  | 5            | 404        | 444          | -69.8           |

Source: Energy and Emissions Factors for Building Energy Consumption, Gas Technology Institute, 2009.

**Table 5.3 Combined Energy and Emissions Impacts of Using FFC Efficiency for Select NERC Regions for Energy Star Appliances**

|                                       | Energy Consumption (MWh) |       |       | Full Fuel Cycle CO <sub>2</sub> Emissions (Ton CO <sub>2</sub> ) |     |      |     |     |
|---------------------------------------|--------------------------|-------|-------|--|-----|------|-----|-----|
|                                       | Useful                   | Site  | FFC   | National   | MRO | NPCC | SPP | TRE |
| <b>Heating System Type</b>            |                          |       |       |  |     |      |     |     |
| Electric Furnaces                     | 100                      | 101.0 | 314.2 | 74   | 114 | 49   | 104 | 75  |
| Oil-Fired Furnaces                    | 100                      | 120.5 | 136.7 | 45   |     |      |     |     |
| Gas-Fired Furnaces                    | 100                      | 111.1 | 120.7 | 27   |     |      |     |     |
| Air Source Heat Pumps <sup>†</sup>    | 100                      | 41.7  | 129.6 | 31   | 47  | 20   | 43  | 31  |
| Ground Source Heat Pumps <sup>‡</sup> | 100                      | 30.3  | 94.3  | 22   | 34  | 15   | 31  | 23  |
| <b>Cooling System Type</b>            |                          |       |       |  |     |      |     |     |
| Central AC <sup>†</sup>               | 100                      | 23.5  | 73.2  | 17   | 27  | 11   | 24  | 17  |
| Air Source Heat Pumps <sup>†</sup>    | 100                      | 23.5  | 73.2  | 17   | 27  | 11   | 24  | 17  |
| Ground Source Heat Pumps <sup>‡</sup> | 100                      | 24.2  | 75.3  | 18   | 27  | 12   | 25  | 18  |
| <b>Hot Water System Type</b>          |                          |       |       |  |     |      |     |     |
| Electric Storage Tank                 | 100                      | 105.3 | 327.4 | 77   | 119 | 51   | 109 | 78  |
| Oil-Fired Storage Tank                | 100                      | 147.1 | 166.9 | 55   |     |      |     |     |
| Gas-Fired Storage Tank                | 100                      | 161.3 | 175.2 | 39   |     |      |     |     |
| Electric Heat Pump Tank               | 100                      | 50.0  | 155.5 | 37   | 56  | 24   | 52  | 37  |
| Electric Instantaneous                | 100                      | 101.0 | 314.2 | 74   | 114 | 49   | 104 | 75  |
| Gas-Fired Instantaneous               | 100                      | 122.0 | 132.5 | 29   |     |      |     |     |

\*COP for Ground Source Heat Pump Systems, <sup>†</sup>Split Systems, <sup>‡</sup>Closed Loop Systems  
Source: MITEI

(Ton CO<sub>2</sub>/100 MWh Useful Energy)

Space conditioning and hot water heating systems have a broad range of end use and FFC efficiencies, and the geographic attributes of heating and cooling demands, and how electricity is generated can dramatically impact overall energy consumption and CO<sub>2</sub> emissions. Table 5.3 puts this information together. For 100 MWh of “Useful Energy Demand” — heating or cooling delivered inside the building — the table shows how much retail (site) and primary (source) energy was needed, as well as how much total CO<sub>2</sub> was emitted. This information is shown at both the national level and for select NERC regions where emissions are high or low, and there are large heating or cooling seasons.

The results identify the dangers of a “one size fits all” approach. Even moving to generic FFC efficiency and emissions metrics hides important differences. For CO<sub>2</sub> emissions, gas-fired furnaces and air-source heat pumps have roughly equivalent CO<sub>2</sub> emissions using national averages. When we look at higher emissions NERC regions such as the Southwest Power Pool (SPP), which covers parts of Kansas, Oklahoma, Texas and neighboring states, the electric-fueled options have substantially higher CO<sub>2</sub> emissions. Even ground-source heat pumps (with higher COP efficiencies) result in higher CO<sub>2</sub> emissions than the direct use of natural gas in regions where electric sector CO<sub>2</sub> emissions are high,

such as the Midwest Reliability Organization (MRO). Conversely, in regions where electric power comes from cleaner sources, including natural gas, like the Northeast Power Coordinating Council (NPCC), heat pump systems have better CO<sub>2</sub> emissions rates than the direct use of natural gas — although air-source heat pumps may not be applicable throughout the entire Northeast.

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#### **FINDING**

**Use of equipment-based FFC efficiency and national average energy demand and CO<sub>2</sub> emissions metrics alone are not sufficient to inform policy makers and consumers of the comparative cost and environmental benefits of competing appliances and building energy systems.**

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#### **RECOMMENDATION**

**More detailed and targeted approaches are needed to develop combined cost- and emissions-effective strategies for meeting future energy and emissions goals on a local and regional basis. State and Federal agencies should collaborate with the building industry and equipment manufacturers to provide clear and accurate information to consumers.**

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The findings regarding FFC efficiency, the comparative duty-cycles of space conditioning and other technologies, plus the CO<sub>2</sub> burdens of different fuels including regional differences in power generation, identify the need to develop more tailored energy policies for transforming the Residential sector, and by extension, all buildings. This includes total building energy performance and not just FFC efficiencies, cost-effectiveness and the emissions-effectiveness of space conditioning and hot water systems. For policy makers, this

should also include local and regional building stock trends, including building retrofits and new construction.

The efficiencies for the best heating, cooling and hot water technologies are already very high, so thermodynamically we cannot expect much improvement. Therefore, policies affecting RD&D in this area would reasonably focus on manufacturing cost-reductions and local capacity building for “plug-and-play” installation of new systems in both retrofit and new build applications. As mentioned above, this also needs a public education and awareness component focusing on how well various technologies match local conditions, as well as the development of well-trained local practitioners able to specify, install and maintain cost- and emission-effective building energy systems.

#### **DEMAND FOR NATURAL GAS AS A TRANSPORTATION FUEL**

The Transportation sector poses a dual challenge in a carbon-constrained future. First, the Transportation sector is responsible for about a third of CO<sub>2</sub> emissions from the U.S. economy. Second, the Transportation sector is currently almost wholly dependent on oil as a transportation fuel, making it very challenging to reduce those emissions to any significant extent. The concentration of resources in the Middle East, and the large balance of payment deficit created by about 12 million barrels per day (bpd) of U.S. oil imports conspire to make oil use in the Transportation sector a major energy security problem as well. In this section of the chapter, we look at how these two challenges might be tackled, to both reduce the oil dependency of transportation in the U.S. and to reduce the CO<sub>2</sub> emissions that go with it.

Natural gas is garnering attention for its potential to address these challenges in an economically attractive way. Natural gas produces significantly less CO<sub>2</sub> than oil when

combusted. It is also an abundant domestic resource with a price that, on an energy equivalent basis, is substantially lower than that of oil. Consequently, there is the possibility for substantial energy security and environmental benefits to be gained by the penetration of natural gas into the Transportation sector. About 2 Tcf of natural gas per year — slightly less than 10% of current U.S. consumption — could displace approximately 1 million bpd — about 5% of current U.S. consumption.

We explore this opportunity in two ways: direct use of compressed natural gas (CNG) and liquefied natural gas (LNG) in vehicles; and indirect use through conversion of natural gas to liquid fuels. The attraction of the indirect pathway is the potential to capitalize on the large-scale liquid fuel infrastructure in place and to use current vehicles or vehicles very similar to those on the road today.

### Global Natural Gas Vehicle Market<sup>32</sup>

There are approximately 11 million natural gas vehicles (NGV) on the road worldwide of which more than 99.9% are operated on CNG, the rest being LNG-powered trucks. CNG vehicles are a small fraction, on the order of 1%, of the close to 900 million vehicles on the road worldwide. The NGV world market is predominately comprised of light-duty vehicles consisting of cars and light trucks (95%), with a smaller number of buses (3%) and trucks (2%). The majority of the light-duty NGVs are bi-fuel vehicles with the ability to operate on CNG or gasoline.

The largest light-duty NGV markets are found in Asia (Pakistan and Iran) and South America (Argentina and Brazil), where government policies support the use of NGVs. Natural gas capable vehicles constitute around 20% of the vehicles in Argentina and 70% in Pakistan.

Europe has about one million CNG vehicles whereas there are only approximately 100,000 light-duty CNG vehicles in the U.S.

### CNG-Powered Vehicles

CNG-powered vehicles use spark-ignition engines that are basically the same as those used in gasoline-powered vehicles. They can be factory-produced or aftermarket conversions of gasoline vehicles. The CNG is stored in high-pressure tanks (e.g., at 3,000 psi) to obtain sufficient energy density (fuel energy per volume). Even with storage at high pressure, the range of a CNG vehicle for a given tank size is only about one-quarter that of gasoline. Use of CNG requires a new fueling infrastructure that would require substantial additional investment.

Because of the lower carbon/hydrogen ratio of methane relative to gasoline, the CO<sub>2</sub> emissions from the combustion of natural gas are approximately 75% of those of gasoline for a given amount of energy production. Thus, on an energy basis at the point of use, the CO<sub>2</sub> emissions are reduced by around 25% relative to the use of gasoline for the same engine efficiency. On a life-cycle basis this advantage is reduced because the GHG emissions in production and distribution, including methane leakage, are greater for natural gas than for oil products, as discussed in Appendix 1A.<sup>33</sup>

The CNG vehicle market segments in the U.S. that are likely to offer an attractive payback period in the near term involve high mileage use. These include short-range, heavy-duty vehicles (e.g., urban buses, delivery trucks) and high mileage light-duty vehicles, primarily fleet vehicles (such as taxis, business and government vehicles). These two market segments presently have a total potential (assuming 100% penetration in these segments) of

2.5 Tcf/year — equivalent to 1.3 million bpd. Short-range, heavy-duty vehicles are particularly attractive for CNG because they operate with low mileage per gallon, resulting in substantial fuel cost savings.

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**FINDING**

**At present gasoline-CNG fuel price spreads, U.S. heavy-duty vehicles used for short-range operation (buses, garbage trucks, delivery trucks) have attractive payback times (around three years or less).**

**Payback times for U.S. light-duty vehicles are attractive provided they are used in high-mileage operation (generally in fleets) and have a sufficiently low incremental cost — a representative number is around \$5,000 for a payback time of three years or less. This condition is presently not met.**

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Although CNG is substantially cheaper than gasoline on an energy basis, its use requires significant additional upfront vehicle costs. Thus, a key factor in CNG vehicle market penetration is a sufficiently short time to compensate the higher cost of a CNG vehicle with lower-priced natural gas. In the U.S., incremental costs are high, particularly for

aftermarket conversions. The only factory-produced CNG vehicle in the U.S. is the Honda GX, which presently has an incremental cost relative to an equivalent gasoline vehicle of about \$7,000, and may be compared to the premium of about \$3,700 for the European VW Passat TSI Eco-fuel. The Honda GX offers only natural gas operation and, thereby, has received a tax subsidy not given to factory-produced vehicles providing bi-fuel operation. In contrast, VW Eco-fuel and Fiat vehicles produced in Europe do offer bi-fuel operation, increasing flexibility, which is crucial for non-fleet users.

Aftermarket conversions are available for a wide range of U.S. cars and light trucks, and provide bi-fuel operation. However, costs are approximately \$10,000 per vehicle, with firms carrying out the conversions pointing to U.S. EPA certification procedures for the high expense. In contrast, conversions are being provided for around \$2,500 per vehicle in Singapore.

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**FINDING**

**Experience in other countries indicates the potential for substantial reduction of incremental costs for U.S. factory and aftermarket converted CNG vehicles.**

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**Table 5.4 Illustrative Payback Times in Years for CNG Light-Duty Vehicles for Average and High Mileage Use, Low and High Incremental Vehicle Cost and Fuel Price Spread between Gasoline and CNG on a Gallon of Gasoline Equivalent (gge) Basis. Assumes 30 miles per gallon.**

|                   |                  | 12,000 mile per year |          | 35,000 miles per year |          |
|-------------------|------------------|----------------------|----------|-----------------------|----------|
|                   |                  | \$3,000              | \$10,000 | \$3,000               | \$10,000 |
| Fuel Price Spread | Incremental Cost |                      |          |                       |          |
|                   | \$0.50/gge       | 15                   | 50       | 5.2                   | 17       |
|                   | \$1.50/gge       | 5                    | 17       | 1.8                   | 5.9      |

Source: MITEI

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Table 5.4 illustrates the effects of various factors on payback time for light-duty vehicles. The fuel price spread of \$1.50/gge shown in the table would be associated with a \$3.00/gallon pump price for gasoline and residential gas at the consumer level of \$12/MMBtu.<sup>34</sup> Payback time is the incremental cost divided by the yearly fuel cost savings. Studies have shown that payback times of around three years or less are needed for substantial market penetration.<sup>35</sup> For the representative high-mileage use case of 35,000 miles/year, a three-year payback time could be obtained with a U.S. price spread of \$1.50/gge and an incremental vehicle cost of around \$5,300.

For present CNG vehicle costs and U.S. fuel price spreads the payback times are generally unattractive for the average mileage use (12,000 miles/year) market segment for light-duty vehicles; this market segment represents over 90% of light-duty vehicle fuel use. Reduction of the incremental cost to below \$1,800 along with \$1.50/gge fuel price spread would be needed for a three-year payback time. The rate of penetration of average mileage CNG vehicles, even if economic, will depend on the provision of an adequate public refueling infrastructure, though home refueling of CNG vehicles could augment public facilities.

Table 5.4 does not include the effect of a penalty on carbon emissions or a subsidy. For the illustrative case in the table, the use of CNG rather than gasoline reduces CO<sub>2</sub> emissions at the vehicle by about 1 ton/year for the average mileage (12,000 miles/year) light-duty vehicle. Even for a CO<sub>2</sub> price as high as \$100/ton, the impact on payback time is small.

If the gasoline-CNG price spread were to increase beyond the present level, the payback time for the average mileage CNG vehicle could decline and support greater penetration in this large market segment. A significant increase in the spread could occur either through an increased oil-natural gas price spread, a very

high CO<sub>2</sub> price and/or availability of natural gas for CNG vehicles at lower than residential rates. Using optimistic cost estimates for CNG vehicles, the carbon policy scenario explored in Chapter 3 projects a 20% penetration into the private vehicle fleet by 2040 to 2050. Recently enacted state low-carbon fuel standards (e.g., California) might provide additional motivation for the market penetration of NGVs.

Evolutionary technology could increase the fuel efficiency of bi-fuel engines by 25% to 30%, providing an efficiency level comparable to a diesel engine.<sup>36,37</sup> This could increase the value of natural gas in reducing oil dependence and GHG generation. Higher efficiency, natural gas-powered, spark-ignition engines also have the potential to reduce the cost and increase the power of LNG-powered trucks.

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## RECOMMENDATION

**The U.S. should consider revision to its current policies related to CNG vehicles, including how aftermarket CNG conversions are certified, with a view to reducing upfront costs and facilitating bi-fuel CNG-gasoline capability.**

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### LNG-Powered Long-Haul Trucks

LNG is being pursued as a fuel for truck applications, particularly long-haul trucking, because for a given tank size, it can provide a range of close to two and half times that of CNG, and around 60% of that of diesel fuel. On vehicle, LNG is stored at very low temperature (-162°C) in a double-walled tank with a vacuum between the walls to provide thermal insulation. Over time, the LNG warms, the methane gas boils and eventually a pressure relief valve must be opened if the tank is not refilled within a relatively limited period of time (about a week). This feature constrains the use of LNG to vehicles that have regular

frequent refills. LNG is in limited use in the U.S. in drayage trucks in the ports of Long Beach and Los Angeles and in garbage trucks in several cities.

The GHG advantage of LNG is lower than CNG because of the energy loss in liquefaction and methane emissions in fueling and operation. A representative GHG emission reduction relative to diesel for the same engine efficiency is 10% to 15%. As with the CNG-gasoline comparison noted earlier in the chapter, this modest GHG advantage would be substantially reduced or possibly eliminated if stated on a life-cycle basis including the fugitive emissions of methane in production and distribution. Of course, the oil displacement benefits remain.

The current incremental cost of an LNG long-haul truck is around \$70,000. Even if the payback time is acceptable (it is about four years at late 2010 natural gas and oil prices), this high incremental cost can be an impediment to market penetration. An additional factor is that the resale value, particularly in the international market where many used trucks are sold, is likely to be substantially reduced. Another challenge may be assuring that reliability will not be adversely affected by operational issues related to cryogenic fuel storage in a tank with vacuum thermal insulation (manufacturing issues, a collision or extended use may reduce the ability of the tank to store LNG cryogenically). If the integrity of the vacuum is compromised and LNG warms, methane gas boils off, increasing pressure in the tank. The relief valve is used to vent the boiled-off methane and cool the remaining methane. A further challenge is the need for a new fueling infrastructure that is more expensive and complex than the diesel fueling infrastructure.

The American Trucking Association, representing concerns of the user community, has stated that natural gas-powered trucks are currently

not a viable solution for most long-haul trucking operations for these technical reasons and because of the concern that the high cost of LNG fueling infrastructure will limit competition in the on-road LNG fuel supply.<sup>38</sup> LNG-powered trucks may also face competition from other alternatives to diesel fuel, such as methanol, as discussed in the next section.

Industry is working on reducing the incremental cost and improving operational features related to the use of a cryogenically stored fuel. It is likely that a significant cost reduction can be made, particularly in the cost of the engine. In addition, use of LNG-powered, long-haul trucks is significantly less challenging in the growing area of transporting goods between company-owned hubs. These hubs could have their own LNG fueling stations. This is a modest market segment which presently accounts for less than 20% of long-haul diesel fuel consumption. It has a market potential (100% market penetration) of less than 0.8 Tcf per year. With increased use of hubs in long-distance trucking and reduced range requirements, there may be opportunities for use of CNG as well as LNG. These opportunities could be enhanced by bi-fuel capability with gasoline as a range extender.

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#### FINDING

**The deployment of LNG-powered, long-haul trucks presently faces operational limitations due to the use of onboard fuel storage at very low temperature (-162 C°); the need for a new fueling infrastructure that ensures competitive pricing; a high incremental cost; and a likely lower resale value particularly in the important international market. These challenges are mitigated by use in the relatively modest market of hub-to-hub transport.**

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## Conversion to Liquid Fuels

Another route for natural gas penetration into transportation markets could be through conversion into a (room temperature) liquid fuel that could be blended with (or replace) current liquid fuels (diesel, gasoline and ethanol). As illustrated in Figure 5.9, a range of liquid fuels can be produced from natural gas by thermochemical conversion to a synthesis gas followed by catalytic conversion to the liquid fuel. These fuels include methanol, ethanol, mixed alcohols (methanol, ethanol and others), and diesel. Methanol can in turn be converted into gasoline or into dimethyl ether (DME), a clean-burning fuel for diesel engines.

The choices among these multiple pathways to liquid fuels depend on several criteria involving engine requirements and fueling infrastructure. Diesel and gasoline are drop-in fuels with regard to current engine technology and fueling infrastructure, but require more processing from natural gas feedstock than other routes, such as methanol production, making the conversion less efficient and more costly.

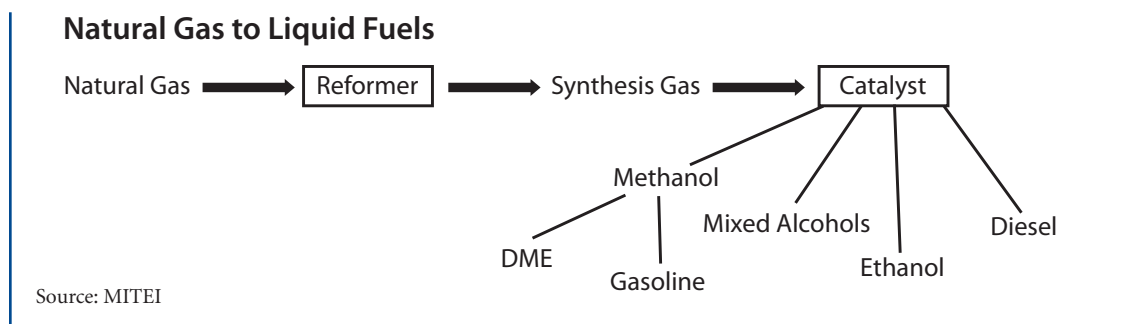
Methanol is less costly for conversion, but requires modest changes to engines (it is more corrosive than gasoline) and the fueling infrastructure (methanol and ethanol are hydroscopic) that has been developed for a petroleum-based system. DME requires moderate pressure for storage as a liquid (similar

to propane). Overall system optimizations are needed to guide choices.

Our detailed analysis is for natural gas conversion to methanol. There is considerable experience for both conversion to methanol and for use of methanol in vehicles (including high-performance Indy 500 cars). The efficiency of conversion of natural gas into methanol, mixed alcohols and DME is considerably higher than that for the conversion of natural gas into diesel and gasoline.

Among the processes shown in Figure 5.9, the one that has been operated at large industrial scale over a long period, with well-established costs, is methane-to-methanol conversion, mainly as a feedstock for chemical production.<sup>39</sup> Methanol is an alcohol that can be used like ethanol in mixtures with gasoline in spark-ignition engines and can be employed in heavy-duty as well as light-duty vehicles. With the energy loss during conversion of natural gas to methanol taken into account, the well-to-wheels CO<sub>2</sub> emissions from using natural gas derived methanol is slightly lower than gasoline.<sup>40</sup> GHG emissions could be somewhat higher than gasoline if methane emissions are included. The production cost of natural gas conversion to diesel fuel is projected to be around 30% higher than methanol on an energy-equivalent basis. In addition, GHG emissions would be increased by more than 50% relative to natural gas derived methanol.

**Figure 5.9 Conversion of Natural Gas to Liquid Fuels**



Methanol used in the U.S. is mainly imported from the Caribbean and South America, at comparable prices over the period 2005 to 2010 to gasoline on an energy-equivalent basis. With deployment of new plants, using existing technology, methanol could be produced from U.S. natural gas at a cost less than U.S. gasoline price in 2010 of around \$2.30/gallon (excluding the tax). Table 5.5 shows an illustrative projection of methanol production costs. It is based on a 67% energy conversion efficiency of natural gas into methanol and a contribution of amortized capital and operating costs of \$0.50/gge of methanol production.<sup>41,42</sup> Under these assumptions, the spread between gasoline price and methanol cost is around \$1/gge. The cost advantage of methanol at the fueling station is reduced by around \$0.10/gge due to higher cost per unit energy of transporting methanol to fueling stations. The production cost of methanol at this assumed natural gas price would be lower than the cost of corn-based ethanol by more than \$1.00/gge.<sup>43</sup>

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#### FINDING

**With deployment of plants using current technology, on an energy-equivalent basis, methanol could be produced from U.S. natural gas at a lower cost than gasoline at current oil prices.**

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Methanol can be used in spark-ignition engines, with very low emissions of NOx and other pollutants through use of state-of-the-art,

three-way catalytic converters. It has a high-octane number that enables high-efficiency engine operation. Methanol has the disadvantage of being able to provide only around half of the range of gasoline for a given tank size, which would be mitigated by methanol-gasoline mixtures.

Methanol use was demonstrated in the U.S. in the early 1990s, in some 15,000 vehicles. Interest waned in the mid-1990s, however, due to falling oil prices and the ascendancy of ethanol in low-concentration blends, driven by strong political support from the farm states. In addition, aversion to methanol may have developed from its association with MTBE (Methyl Tertiary Butyl Ether), an additive to gasoline that contaminated ground water from leaks in underground tanks and that, unlike methanol, produced an unpleasant taste in water at very low concentrations. The toxicity of methanol is similar to gasoline. Methanol is soluble in water and is biodegradable.<sup>44</sup>

Methanol could be used in tri-flexible-fuel, light-duty (and heavy-duty) vehicles in a manner similar to present ethanol-gasoline flex fuel vehicles, with modest incremental vehicle cost. These tri-flex-fuel vehicles could be operated on a wide range of mixtures of methanol, ethanol and gasoline. For long-distance driving, gasoline could be used in the flex-fuel engine to maximize range. Present ethanol-gasoline flex-fuel vehicles in the U.S. are sold at the same price as their gasoline counterparts. Adding methanol capability to

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**Table 5.5 Illustrative Methanol Production Costs, Relative to Gasoline (excluding taxes) at \$2.30 per Gallon**

| Natural Gas Price | Methanol Production Cost, per gge | Cost Reduction Relative to Gasoline, per gge |
|-------------------|-----------------------------------|--|
| \$4/MMBtu         | \$1.30                            | \$1.00                                       |
| \$6/MMBtu         | \$1.60                            | \$0.70                                       |
| \$8/MMBtu         | \$2.00                            | \$0.30                                       |

Source: MITEI

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a factory 85% ethanol blend (E85) vehicle, to create tri-flex fuel capability, would require an air/fuel mixture control to accommodate an expanded fuel/air range with addition of an alcohol sensor and would result in an extra cost of \$100 to \$200, most likely at the lower end of that range with sufficient production.

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#### FINDING

**Methanol could be used in tri-flex-fuel light-duty vehicles with a modest incremental vehicle cost (likely to be \$100 to \$200 more than an ethanol-gasoline flex-fuel vehicle). It could also be used to power long-haul trucks in mixtures with gasoline, and could provide both vehicle and fuel cost savings. Barriers to methanol use include the lack of incentives for vehicle conversion and provision of distribution infrastructure.**

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Presently, no factory-produced flex-fuel vehicles in the U.S. are equipped for flex-fuel operation with methanol. Removing this barrier through the adoption of an open fuel standard is a key requirement for methanol use to be pursued on a level playing field. Open fuel standard legislation that has been under consideration would require automobile manufacturers to produce an increasing number of vehicles that could operate on a mix of the three fuels. Requiring this flex-fuel capability could be a cost-effective way to level the playing field for liquid fuels and increase opportunities for reducing oil dependence.

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#### RECOMMENDATION

**The U.S. government should implement an open fuel standard that requires automobile manufacturers to provide tri-flex-fuel operation in light-duty vehicles. It should also consider methanol fueling infrastructure subsidies similar to those given to the fueling infrastructure for ethanol.**

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Methanol can be used as a fuel for heavy-duty vehicles in a range of mixtures with gasoline. Use of methanol as an alternative to diesel for heavy-duty vehicles is now possible by use of turbocharged spark-ignition engines operating at high compression ratio and high levels of turbo pressure boosting. These engines can provide comparable or possibly better efficiency than diesel engines along with comparable or greater torque, at lower vehicle cost and with lower emissions and more power.<sup>45</sup> An illustrative comparison for a methanol-gasoline mixture of 70% methanol vs. diesel for a long-haul truck suggests a vehicle cost saving of more than \$10,000 (from less expensive exhaust treatment and a less costly fuel-injection system) and a fuel saving of some \$5,200/year.<sup>46</sup>

Use of methanol as a transportation fuel faces a number of challenges. They include the financial risk for private investment in U.S. methanol production plants: the demand for methanol as a transportation fuel could be reduced by a decline in oil prices and domestic natural gas prices are volatile. In addition, incentives are lacking for building methanol capability into vehicles and incurring the costs of additional infrastructure, such as pumps in fueling stations. It is likely that some form of government assistance would be necessary to facilitate this option at large scale.

In summary, while use of methanol as a transportation fuel has substantial cost and GHG advantages relative to other natural gas derived liquid fuels, it requires some infrastructure modification and faces substantial acceptance barriers. At sufficiently high oil prices, the drop-in fuel and acceptance advantages of natural gas derived gasoline may make it a better candidate than methanol. Natural gas derived diesel could also become economically attractive.

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#### **FINDING**

**If the present oil to natural gas price spread is sustained, there will be materially increased opportunities for use of natural gas-based transportation fuels.**

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#### **FINDING**

**The potential for natural gas to reduce oil dependence could be increased by conversion into room temperature liquid fuels that can be stored at atmospheric pressure. Of these fuels, methanol is the only one that has been produced for a long period at large industrial scale. Methanol has the lowest cost and lowest GHG emissions, but requires some infrastructure modification and faces substantial acceptance challenges. Natural gas derived gasoline and diesel have the advantage of being drop-in fuels, but carry a higher conversion cost.**

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#### **RECOMMENDATION**

**The U.S. government should carry out a transparent comparative study of natural gas derived diesel, gasoline and methanol, and possibly natural gas derived ethanol, mixed alcohol and DME, with each other and with oil-derived fuels and biofuels. The study should include cost analysis, vehicle requirements, infrastructure requirements and health and environmental issues. It also should include discussion of R&D needs for more efficient and lower-cost production.**

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## NOTES

- <sup>1</sup>U.S. Energy Information Administration statistics refer to “Lease and Plant Fuel” as natural gas used in well, lease, or field operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas processing plants.
- <sup>2</sup>Data derived from the U.S. Energy Information Administration Manufacturing Energy Consumption Survey (MECS), which collects data on energy consumption by industry sector and end use. The MECS historically covers 80% to 90% of total industrial natural gas use. See <http://www.eia.doe.gov/emeu/mecs/contents.html>.
- <sup>3</sup>“Solutions from Shop Floor to Top Floor: Best Business Practices in Energy Efficiency,” prepared by William R. Prindle, ICF International, for the Pew Center on Global Climate Change, April 2010.
- <sup>4</sup>Energy Information Administration, Annual Energy Outlook 2011. Table A2. See <http://www.eia.doe.gov>.
- <sup>5</sup>AEO 2011, Table A6.
- <sup>6</sup>For details see Paltsev, S., et al. (2010), “The Future of U.S. Natural Gas Production, Use, and Trade”, MIT Joint Program on the Science and Policy of Global Change, Report No. 186, Cambridge, MA.
- <sup>7</sup>U.S. Energy Information Administration, 2008 Manufacturing Energy Consumption Survey.
- <sup>8</sup>Industrial boilers are rated in terms of heat input on the basis of MMBTU/hr.
- <sup>9</sup>Energy Efficiency in boilers is measured as AFUE or Average Fuel Use Efficiency.
- <sup>10</sup>The DOE Energy Efficiency Standards can be found at 10 CFR Part 431.
- <sup>11</sup>An overall guidebook is “Improving Process Heating System Performance: A Sourcebook for Industry,” published by the U.S. Department of Energy, Industrial Technologies Program and the Industrial Heating Equipment Association. DOE and industry groups also have co-authored a number of industry sector-specific reports on energy efficiency improvements.
- <sup>12</sup>Pew Center Report.
- <sup>13</sup>Pew Center Report, p80.
- <sup>14</sup>See “Energy Star” guides published by Lawrence Berkeley National Laboratory.
- <sup>15</sup>“Cutting Carbon and Making Money,” Chemical & Engineering News, Volume 88 Number 15, April 12, 2010.
- <sup>16</sup>“Ethylene from Methane,” Chemical and Engineering News, January 24, 2011.
- <sup>17</sup>This process is described more fully in the “Super Boiler White Paper,” which can be found at <http://www.cbboilers.com/superboiler>.
- <sup>18</sup>“Energy Research at DOE: Was It Worth It?” National Research Council, 2001, p32.
- <sup>19</sup>Reported in the U.S. Department of Energy, FY 2012 Congressional Budget, p 250.
- <sup>20</sup>U.S. Energy Information Administration, “Annual Energy Outlook 2011,” Table A2.
- <sup>21</sup>U.S. Environmental Protection Agency and the Combined Heat and Power Partnership, Catalog of CHP Technologies, 2008.
- <sup>22</sup>Tapia-Ahumada, Karen, “Understanding the Impact of Large-Scale Penetration of Micro Combined Heat and Power Technologies within Energy Systems,” PhD Thesis, Engineering Systems Division, Massachusetts Institute of Technology, 2011.
- <sup>23</sup>Tapia-Ahumada, Karen, “Are Distributed Technologies a Viable Alternative for Institutional Settings? Lessons from the MIT Cogeneration Plant,” M.Sc. Thesis, Engineering Systems Division, Massachusetts Institute of Technology, 2005.
- <sup>24</sup>See <http://www.districtenergy.org/us-district-energy-systems>.
- <sup>25</sup>See [http://www.powergenworldwide.com/index/display/articledisplay/1153798328/articles/cogeneration-and-on-site-power-production/volume-10/issue-6/features/the-district\\_energy.html](http://www.powergenworldwide.com/index/display/articledisplay/1153798328/articles/cogeneration-and-on-site-power-production/volume-10/issue-6/features/the-district_energy.html).
- <sup>26</sup>Tapia-Ahumada, 2011.
- <sup>27</sup>DOE/EIA Annual Energy Review 2009 [DOE/EIA-0384(2009) August 2010].
- <sup>28</sup>Natural Resources Canada, <http://oee.nrcan.gc.ca/publications/infosource/pub/home/heating-heat-pump/asheatpumps.cfm>.
- <sup>29</sup>Compiled from a variety of sources including the US DOE, EnergyStar, ACEEE, AHRI and others.
- <sup>30</sup>Source Energy and Emissions Factors for Building Energy Consumption, Gas Technology Institute, 2009.
- <sup>31</sup>Review of Site (Point-of-Use) and Full-Fuel-Cycle Measurement Approaches to DOE/EERE Building Appliance Energy-Efficiency Standards, National Research Council, 2009 – accessed via <http://www.nap.edu/catalog/12670.html>. Also, Federal Register Vol. 75, No. 161 Friday, August 20, 2010 – 10 CFR Part 431, Policy for Adopting Full-Fuel-Cycle Analyses Into Energy Conservation Standards Program.
- <sup>32</sup>The analysis of CNG and LNG in vehicles draws heavily on P.J. Murphy, “Natural Gas as a Transportation Fuel,” MS Thesis, MIT, June 2010.

- <sup>33</sup>There is large range of uncertainty of the effect of methane emissions. Within this range of uncertainty the GHG reduction advantage of CNG relative to gasoline could be reduced from 25% to around 12%.
- <sup>34</sup>This interpretation assumes the CNG is not subject to transportation fuel taxes. If current taxes were imposed on an energy-equivalent basis these assumptions would lead to about a \$1.00/gge spread.
- <sup>35</sup>Yeh, S. "An Empirical Analysis on the Adoption of Alternative Fuel Vehicles: The Case of Natural Gas Vehicles," *Energy Policy*, 35(11):5865-5875, 2007.
- <sup>36</sup>"Optimized Use of E85 in a Turbocharged Direct Injection Engine," R.A. Stein, C.J. House and T.G. Leone, SAE paper 2009-01-1490, 2009.
- <sup>37</sup>L. Bromberg and D.R. Cohn, "Alcohol Fueled Heavy-Duty Vehicles Using Clean High Efficiency Engines," Society of Automotive Engineers Technical Paper, SAE 2010-01=2199.
- <sup>38</sup>American Trucking Association, Statement submitted to the U.S. Senate Committee on Energy and Natural Resources on the use of natural gas as a diesel fuel substitute, November 10, 2009.
- <sup>39</sup>Though volumes are small, methanol is in widespread use in windshield washer mixtures with water, with concentrations as high as 50%.
- <sup>40</sup>Pearson, R.J. et. al, "Extending the Supply of Alcohol fuels for Energy Security and Carbon Reduction," Society for Automotive Engineers (SAE) Paper 2009-01-2764, 2009.
- <sup>41</sup>M. A. Weiss et. al., "On the Road in 2020," MIT Energy Laboratory Report MIT EL-00-003, Oct. 2000, p. 2-6.
- <sup>42</sup>R. Abbott et al, "Evaluation of Ultra Clear Fuels From Natural Gas," Conoco Phillips, Nexant and Pennsylvania State University, final report for Department of Energy, 2006.
- <sup>43</sup>All these comparisons are dependent on the ultimate tax treatment of methanol fuel or various blends with gasoline. This calculation, which includes the tax, implicitly assumes tax treatment that is roughly equivalent on an energy basis.
- <sup>44</sup>L. Bromberg and W.K. Cheng, "Methanol as an Alternative Transportation Fuel for the US: Options for Sustainable and/or Energy Secure Transportation," MIT PSFC report PSFC-RR-10-12, 2010.
- <sup>45</sup>L. Bromberg and D.R. Cohn, "Alcohol Fueled Heavy-Duty Vehicles Using Clean High Efficiency Engines," Society of Automotive Engineers Technical Paper, SAE 2010-01=2199.
- <sup>46</sup>The calculation assumes 65,000 miles per year at 5 miles/gallon and a \$0.40 M70-diesel price spread (with \$5/MMBtu natural gas) and the same engine efficiency. M70 is 70% methanol and 30% gasoline by volume and has a range of around 0.6x the range of diesel for a given fuel tank size.