CLEAN ENERGY FUELS CORP.

2009 Summary Annual Report
and Form 10-K

Clean Energy®

Clean Energy is the leading provider of natural gas (CNG and LNG) for transportation in North America.

We have a broad customer base serving over 390 fleets in the refuse, transit, port, shuttle, taxi, trucking, airport and municipal fleet markets, fueling more than 17,800 vehicles daily at over 200 strategic locations across the United States, Canada and Peru.

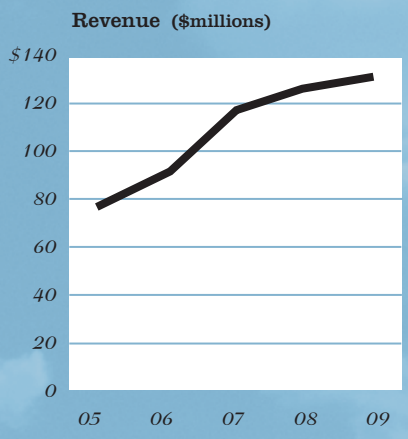
Clean Energy owns and operates two LNG production plants: one in Willis, Texas and one in Boron, California, with combined capacity of 260,000 LNG gallons per day and the capability to expand to 340,000 LNG gallons per day as demand increases.

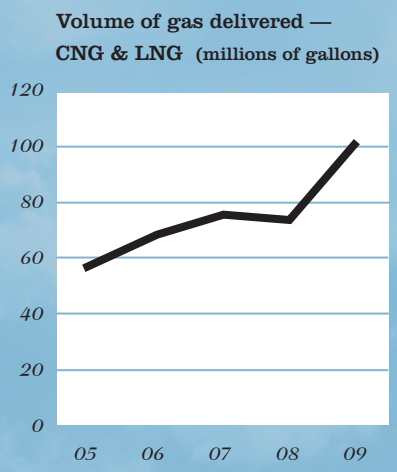
We own and operate a landfill gas facility in Dallas, Texas that produces renewable biomethane gas for delivery to the nation's gas pipeline network that can be used as a renewable fuel.

Clean Energy also owns BAF Technologies, Inc. of Dallas, Texas, a leading provider of natural gas vehicle systems and conversions for taxis, limousines, vans, pick-up trucks and shuttle buses.

Natural gas is cleaner, cheaper and an all-American resource, making it a compelling alternative to gasoline and diesel for transportation.

Nasdaq: CLNE
www.cleanenergyfuels.com





Please review the company's Annual Report on Form 10-K filed with the Securities and Exchange Commission for information on the Company's 2009 results of operations and financial position.

On the cover: Clean Energy, in 2009, opened the world's largest public LNG truck fueling station to serve the Ports of Los Angeles and Long Beach and to act as one of the hubs of the new Southwest LNG Trucking Corridor for regional trucking.

Clean Energy®

While oil costs less than at its peak, over 60% is still imported, threatening our national energy security. Natural gas fuel is abundant and nearly all-American. Recent discoveries have expanded domestic natural gas supplies to last for an estimated 120 years. ••• Natural gas fuel is cleaner than diesel or gasoline, producing over 23% lower greenhouse gas emissions, and is cheaper than gasoline or diesel. ••• Increasingly, vehicle fleets across the country, including taxi, transit, refuse, goods movement and regional trucking fleets, are switching to natural gas fuel for transportation. Today, over 200 Clean Energy fueling stations operate in 20 states, including 23 airports, serving numerous fleets of all types and over 5,200 transit buses. ••• Natural gas is delivered across North America through pipelines that reach nearly every populated area. ••• We purchase natural gas and compress it at our stations to deliver CNG. We liquefy natural gas at our two production plants or purchase it from our suppliers to deliver as LNG. We also produce biomethane, a renewable gas, and deliver it to the pipeline. ••• We provide the connection for the use of natural gas fuel for transportation. ••• In 2010, through our subsidiary, BAF, a small-volume manufacturer acquired in late 2009, we also provide natural gas vehicles for light- and medium-duty fleet markets. ••• It's clear in 2010 — natural gas fuel is here and Clean Energy is the leading provider nationwide. •••

TO OUR SHAREHOLDERS

IN 2009, we surpassed the 100-million-gallon mark for the volume of CNG and LNG delivered. At year-end, we operated 196 CNG and LNG stations fueling more than 390 fleet customers with approximately 17,800 vehicles, as well as numerous individual customers through public access at our stations. We completed 29 new stations or station upgrade projects during the year.

Revenue in 2009 totaled $131.5 million and at year-end total assets were $355.8 million, with $9.8 million in long-term debt. Our 2009 10-K in the following pages provides detailed financial information.

2009 saw steady growth at Clean Energy as well as in our industry. Traditional fleet markets for natural gas vehicles, such as refuse, expanded nationwide, and new fleet markets, such as heavy-duty trucking for goods movement, emerged with widening fleet-owner acceptance. With lower gasoline and diesel prices at the beginning of 2009 not likely sustainable once world demand for petroleum recovers, fuel diversity becomes critical for these fleets now.

KEY TRENDS IN 2009 focused on two major market segments for Clean Energy: refuse and regional trucking.

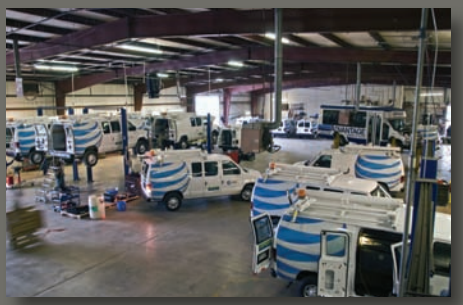
In refuse, or waste hauling, the conversion to natural gas fuel that started in Southern California with the aid of the South Coast Air Quality Management District's initiative to clean the air moved nationwide. Our station in Smithtown, New York commissioned in 2007 represented the first municipal deployment of natural gas-fueled trucks outside California. In 2009, we served customers in 11 states as fleet implementations ranged from Washington and Idaho in the West to Florida and New Jersey in the East. Refuse trucks are a prime example of the benefits of natural gas fuel. In cities and towns with natural gas refuse trucks, the air quality is improved due to lower emissions. Fuel savings as high as $12,000 per vehicle per year pay back the incremental cost of the trucks in short order and significantly reduce waste hauling expenses for communities over the 10-year life of the trucks. There are about 180,000 refuse trucks operating in municipal and private fleets in the United States.

In trucking, the arrival of robust, class-8 LNG-powered trucks from several manufacturers made regional trucking fleets a reality for shippers and fleet owners. This was prompted

The McCommas Landfill in Dallas, Texas produces biomethane, a low-carbon renewable gas, for delivery into the pipeline. Clean Energy is developing its landfill biomethane business nationwide.

Clean Energy began fueling buses in 2009 for the Los Angeles County Metropolitan Transportation Authority, the largest natural gas fleet in the country. Natural gas buses comprise 32% of all transit buses in the United States.

Clean Energy plans to serve goods movement by region, and through corridors connecting regions
Step 1: Serve local/regional trucking hubs.
Step 2: Serve corridors that connect the hubs.



Vans, buses and trucks for AT&T and other customers fill BAF's headquarters production facility in Dallas, Texas as they are upfitted for natural gas fuel use.

Converting waste hauling to natural gas fuel began wide implementation in 2009 with municipal and private fleets switching to gain the benefits of lower emissions and costs.

largely by the effects of the Clean Air Action Plan and Clean Truck Program, adopted by the Ports of Los Angeles and Long Beach, mandating wholesale changeover of thousands of trucks serving the ports to cleaner vehicles, including LNG trucks, thus providing a real market for manufacturers. The ports also provided a test bed for fleet owners and shippers to evaluate the efficiency, performance and cost-effectiveness of new LNG trucks. In June 2009, we opened the world's largest public LNG truck fueling station (pictured on the cover) to serve the new fleets at the ports. Now we are in the process of developing the fueling infrastructure for the Southwest LNG Truck Fueling Corridor to serve the needs of goods movement shippers throughout the region. Currently, there are close to three million Class-8 trucks on the road across the country.

TRANSIT FLEETS are long-term users of natural gas fuel, which still makes the most sense as an alternative to diesel. About 32% of the nation's transit fleets use natural gas fuel and we fuel over 5,200 buses daily. Last year, we added transit fueling contracts in Los Angeles, CA, Washington, DC and Boston, MA, among other cities.

OTHER KEY MARKET SEGMENTS for natural gas fuel grew as well. These include taxi and limousine fleets in cities like San Francisco, CA and Las Vegas, NV, airport multi-fleet fueling stations in Oklahoma City, OK, Austin, TX and Ontario, CA, and airport-related parking shuttle fleets at Dallas-Fort Worth, TX, Houston, TX and Las Vegas, NV.

In Fall 2009, with demand growing for natural gas vehicles and American vehicle manufacturers not responding, we acquired BAF Technologies, Inc., the leading provider of natural gas vehicle systems and conversions in the United States. BAF provides natural gas vehicle conversions, alternative fuel systems, application engineering, service and warranty support and research and development for taxis, limousines, vans, pick-up trucks and shuttle buses.

AT&T announced it would deploy approximately 8,000 natural gas vehicles in the next five years and awarded BAF the initial 600 Ford E-Series converted CNG vans, which were completed in December 2009. Through March, 2010, AT&T has awarded BAF an additional 1,389 CNG van conversions.

This new momentum in natural gas vehicle adoption is due, in part, to the continuing efforts by our co-founder and director, Boone Pickens and his Pickens Plan Campaign. The Pickens Plan was primarily responsible for the proposed NAT GAS Act now in Congress. If passed, the Act will provide a tremendous impetus to further development and deployment of natural gas vehicles in fleets of all sizes across the country.

GOVERNMENT SUPPORT during 2009 included the award of $38.6 million by the U.S. Department of Energy in stimulus grants to customers and government agency partners of Clean Energy to offset the incremental cost of more than 800 new clean-burning natural gas-powered taxis, shuttle buses, refuse trucks and heavy-duty trucks. The awards also opened new markets in several states by helping to defray the cost of building 12 new natural gas fueling stations. Overall, Clean Energy obtained over $97 million in grant awards in 2009 for us and our customers.

To help fund current and anticipated growth, we completed a successful follow-on offering of common stock in mid-2009 with aggregate net proceeds of approximately $73.2 million.

Overall, we believe 2010 may be a year of substantive growth if current trends of natural gas vehicle acceptance, adoption and deployment continue.

Clean Energy is now a company with 229 employees and 10 sales offices across the country, doing its best to see that the trend toward using clean, domestically-produced natural gas continues and that it remains the leading provider of natural gas fuel in America's future.

We thank our employees and management team for their continuing hard work in building our company, and particularly, our Board of Directors for their wise oversight and support.

ANDREW J. LITTLEFAIR
President and CEO

Airport-related vehicle fleets such as taxis, shuttles, buses and airport service vehicles increasingly use natural gas fuel, as at the Dallas-Ft. Worth Airport.

Co-founders Andrew Littlefair and Boone Pickens preview the new MV-1, a purpose-built natural gas vehicle for the taxi and paratransit markets coming to market in late 2010. The taxi and airport-related markets for natural gas fueling are large and growing.

Robust, clean, economical class-8 LNG-fueled trucks for goods movement are being deployed nationwide in 2010 and Clean Energy is committed to helping provide the fueling infrastructure for the regional and national trucking corridors.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-33480

CLEAN ENERGY FUELS CORP.

(Exact name of registrant as specified in its charter)

Delaware	**33-0968580**
(State or other jurisdiction of incorporation)	(IRS Employer Identification No.)

3020 Old Ranch Parkway, Suite 400, Seal Beach CA 90740
(Address of principal executive offices, including zip code)

(562) 493-2804
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	The NASDAQ Global Market

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2009, the last business day of the registrant's second fiscal quarter, was approximately $248,793,320 (based on the closing price reported on such date by The NASDAQ Global Market of the registrant's common stock). Shares of common stock held by officers and directors and holders of 10% or more of the outstanding common stock have been excluded from the calculation of this amount because such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 8, 2010, the number of outstanding shares of the registrant's common stock was 60,005,872.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for the 2010 Annual Meeting of Stockholders are incorporated herein by reference in Part III of this annual report on Form 10-K to the extent stated herein.

CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements in this annual report on Form 10-K may constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based upon our current assumptions, expectations and beliefs concerning future developments and their potential effect on our business. In some cases, you can identify forward-looking statements by the following words: "may," "will," "could," "would," "should," "expect," "intend," "plan," "anticipate," "believe," "approximately," "estimate," "predict," "project," "potential," "continue," "ongoing," or the negative of these terms or other comparable terminology, although the absence of these words does not necessarily mean that a statement is not forward-looking. We believe that the statements in this annual report on Form 10-K that we make regarding the following subject matters are forward-looking by their nature:

- our ability to capture a substantial share of the significant anticipated growth in the market for natural gas as a vehicle fuel and to enhance our leadership position as that market expands;
- passage of government legislation and regulation providing incentives, including vehicle and fuel credits, for natural gas vehicle production and purchases and fuel use;
- plans to expand our station network and business with existing customers and to win business with new customers;
- potential acquisitions of natural gas reserves, rights to natural gas production, and complementary businesses in the natural gas and biomethane fueling infrastructure, services and production industries;
- entering the business of leasing natural gas vehicles and financing additional purchases of natural gas vehicles by our customers;
- the success and expansion of our business of producing and selling biomethane derived from landfill gas;
- the success of our business of selling converted natural gas vehicles;
- our ability to successfully manage and integrate the operations of, and to implement effective controls and procedures over financial reporting at, BAF Technologies, Inc., our recently acquired, wholly owned subsidiary;
- estimated payments to BAF shareholders in future years pursuant to the terms of the stock purchase agreement;
- anticipated revenue from continued sales by BAF to AT&T;
- expanding our sales in the regional trucking, ports, public transit, refuse hauling and airport markets;
- expanding our business into international markets;
- plans to expand our sales and marketing team and to hire sales experts to focus on targeted metropolitan areas and markets;
- our ability to capitalize on the cost advantages of natural gas as a vehicle fuel;
- plans to build additional natural gas fueling stations both under and not under contract;
- plans to participate in state and federal grant programs;
- plans to seek long-term LNG and CNG station construction, maintenance and fuel sales contracts with governmental bodies;

- growth in demand for LNG in the regional trucking and other fleet markets;
- expansion of our California LNG plant;
- anticipated downtime at our DCE facility in 2010 and the availability of greenhouse gas emission reduction credits as a result of DCE's landfill gas operations;
- our ability to use our low temperature, high pressure fuels expertise and to leverage our existing natural gas infrastructure to enter the hydrogen fuels market and supply hydrogen/natural gas blends;
- developments and trends and opportunities for growth in the natural gas and fleet vehicle markets, including increased transition from diesel and gasoline powered vehicles to natural gas vehicles;
- impact of a significant increase in use of natural gas as a vehicle fuel on overall demand for natural gas supplies;
- estimated increases in costs for diesel engines and natural gas vehicles to meet federal 2010 emission standards;
- more stringent emissions requirements continuing to make natural gas vehicles an attractive alternative to traditional gasoline and diesel powered vehicles;
- impact of more stringent ozone standards on the number of nonattainment areas in the U.S.;
- availability and performance of natural gas vehicles in our principal markets;
- anticipated federal and state certification of additional natural gas vehicle models in 2010;
- expanded use of natural gas vehicles at and sales of our fuel to trucks operating at the Los Angeles and Long Beach seaports and plans to model LNG truck deployment programs at other ports based on experiences at these seaports;
- future supply, demand, use and prices of fossil and alternative fuels, including crude oil, gasoline, diesel, natural gas, biodiesel, ethanol, electricity, and hydrogen;
- prices for gasoline and diesel continuing to be higher than the price of natural gas as a vehicle fuel;
- estimated incremental costs, annual fuel usage, fuel costs, and annual fuel cost savings for vehicles using natural gas instead of gasoline or diesel;
- impact of environmental regulations and pressures on oil supply on the cost of crude oil, gasoline, diesel and diesel engines;
- impact of environmental regulations on the use of natural gas as a vehicle fuel;
- impact of general economic trends and budget deficits faced by many government entities on our business;
- the availability of tax incentives and grant programs that provide incentives for using natural gas as a vehicle fuel or purchasing natural gas vehicles;
- reinstatement or extension of the Volumetric Excise Tax Credit;
- extension of the alternative fuel vehicle tax credit beyond December 31, 2010;
- passage of the NAT GAS Act or similar legislation and the impact on our business;
- projected capital expenditures, project development costs and related funding requirements;

- plans to retain all future earnings to finance future growth and general corporate purposes;
- future margins on fuel sales;
- estimated costs to cover the increased price of natural gas above the inherent prices embedded in our customers' fixed price and price cap contracts;
- plans to purchase futures contracts and to continue offering fixed price sales requirement contracts as appropriate and consistent with our revised natural gas hedging policy;
- ability to qualify all futures contracts as cash flow hedges;
- our LNG liquefaction plant in California enabling us to supply our operations in California, Arizona and other western U.S. markets more economically;
- costs associated with remaining in compliance with government regulations and laws;
- our ability to obtain waivers for breach of covenants;
- future asset retirement costs;
- future impairments of goodwill balances; and
- access to equity capital and debt financing options, including, but not limited to, equipment financing, sale of convertible promissory notes or commercial bank financing.

The preceding list is not intended to be an exhaustive list of all of our forward-looking statements. Although the forward-looking statements in this annual report on Form 10-K reflect our good faith judgment, based on currently available information, they involve known and unknown risks, uncertainties and other factors that may cause our actual results or our industry's actual results, levels of activity, performance, or achievements to be materially different from any future results, levels of activity, performance, or achievements expressed or implied by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in the "Risk Factors" contained in this annual report on Form 10-K. As a result of these factors, we cannot assure you that the forward-looking statements in this annual report on Form 10-K will prove to be accurate. Except as required by law, we undertake no obligation to update publicly any forward-looking statements for any reason after the date we file this annual Report on Form 10-K with the Securities and Exchange Commission, or to conform these statements to actual results or to changes in our expectations. You should, however, review the factors and risks we describe in the reports we will file from time to time with the Securities and Exchange Commission after the date we file this annual report on Form 10-K.

PART I

Item 1. Business.

Overview

We are the leading provider of natural gas as an alternative fuel for vehicle fleets in the United States and Canada, based on the number of stations operated and the amount of gasoline gallon equivalents of compressed natural gas ("CNG") and liquefied natural gas ("LNG") delivered. We offer a comprehensive solution to enable our customers to run their fleets on natural gas, often with limited upfront expense to the customer. We design, build, finance and operate fueling stations and supply our customers with CNG and LNG. We also produce renewable biomethane, which can be used as vehicle fuel, through our landfill gas joint venture. We also provide natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles through our wholly owned subsidiary, BAF Technologies, Inc. In addition, we help our customers acquire and finance natural gas vehicles and obtain local, state and federal clean air rebates and incentives. CNG and LNG are cheaper than gasoline and diesel vehicle fuel, and are well suited for use by vehicle fleets that consume high volumes of fuel, refuel at centralized locations, and are increasingly required to reduce emissions. According to the U.S. Department of Energy's Energy Information Administration (EIA), the amount of natural gas consumed in the United States for vehicle use more than doubled between 2000 and 2009. We believe we are positioned to capture a substantial share of the growth in the use of natural gas as a vehicle fuel in the United States given our leading market share and the comprehensive solutions we offer.

We sell natural gas vehicle fuels in the form of both CNG and LNG. CNG is generally used in automobiles, light to medium-duty vehicles and refuse trucks and transit buses as an alternative to gasoline and diesel. CNG is produced from natural gas that is supplied by local utilities to CNG vehicle fueling stations, where it is compressed and dispensed into vehicles in gaseous form. LNG is generally used in trucks and other medium to heavy duty vehicles as an alternative to diesel, typically where a vehicle must carry a greater volume of fuel. LNG is natural gas that is super cooled at a liquefaction facility to −162 degrees Celsius (−260 degrees Fahrenheit) until it condenses into a liquid, which takes up about 1/600th of its original volume as a gas. We deliver LNG to fueling stations via our fleet of 58 tanker trailers. At the stations, LNG is typically stored in above ground containers until dispensed into vehicles in liquid form.

We serve fleet vehicle operators in a variety of markets, including public transit, refuse hauling, airports, taxis, seaports, and regional trucking. We believe these fleet markets will continue to present a high growth opportunity for natural gas vehicle fuels. We generate revenues primarily by delivering CNG and LNG and to a lesser extent by building CNG and LNG fueling stations, selling renewable biomethane produced by our landfill gas joint venture, natural gas vehicle conversions and financing vehicle acquisitions by our customers. We serve over 390 fleet customers operating over 17,790 natural gas vehicles. We own, operate or supply 196 natural gas fueling stations in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, Washington, and Wyoming, within the United States, and in British Columbia and Ontario within Canada. In April 2008, we opened our first compressed natural gas station in Lima, Peru through the Company's joint venture, Clean Energy del Peru. In August 2008, we acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE owns a facility that collects, processes and sells renewable biomethane collected from a landfill in Dallas, Texas. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles.

We own and operate an LNG liquefaction plant near Houston, Texas, which we call the Pickens Plant, capable of producing up to 35 million gallons of LNG per year. We also own an LNG liquefaction plant in Boron, California, capable of producing 60 million gallons of LNG per year, with the ability to expand production up to 90 million gallons of LNG per year.

The Market for Vehicle Fuels

According to the EIA's Annual Energy Outlook 2010 Early Release (December 14, 2009), the United States consumed an estimated 172 billion gallons of gasoline and diesel in 2009, and demand is expected to grow at an annual rate of 0.5% to 191 billion gallons by 2030. These projections are lower than previously reported, but reflect the future impact of new federal regulations regarding fuel economy for vehicles. Gasoline and diesel comprise the vast majority of vehicle fuel consumed in the United States, while CNG, LNG and other alternative fuels represent less than 3% of this consumption, according to the EIA. Alternative fuels, as defined by the U.S. Department of Energy ("DOE"), include natural gas, ethanol, propane, hydrogen, biodiesel, electricity and methanol.

Through the summer of 2008, domestic prices for gasoline and diesel fuel increased significantly, largely as a result of higher crude oil prices in the global market and limited refining capacity. Crude oil prices were affected by increased demand from developing economies such as China and India, global political issues, weather related supply disruptions and other factors. In 2008, many industry analysts believed that crude oil producers would continue to face challenges to find and produce crude oil reserves in quantities sufficient to meet growing global demand and that the costs of finding crude oil would increase. Contrary to that belief, however, the global recession in 2008 through 2009 brought about a collapse of world oil prices. We believe that once world economic growth resumes, pressures on oil supply will force oil, gasoline, and diesel prices higher. Prices for oil and gasoline increased during 2009 as the global credit crisis eased and economic activity stabilized.

Lower oil, gasoline and diesel prices reduce the magnitude of the immediate market opportunity for alternative fuels created by very high oil, gasoline and diesel prices. However, increasingly stringent federal, state and local air quality regulations, a desire to lower greenhouse gas emissions and regulations mandating low carbon fuels continue to develop, and the need for fuel diversity continues to represent an opportunity for alternative fuel vehicles in the United States and Canada. Natural gas as an alternative fuel has been more widely used for many years in other parts of the world such as in Europe and Latin America, based on the number of natural gas vehicles in operation in those regions. The March 2010 edition of the Gas Vehicles Report estimates that there are more than 100,000 natural gas vehicles in the United States compared to approximately 11.2 million worldwide.

Natural Gas as an Alternative Fuel for Vehicles

We believe that natural gas is an attractive alternative to gasoline and diesel for vehicle fuel in the United States and Canada because it is cheaper and cleaner than gasoline or diesel. In addition, almost all natural gas consumed in the United States and Canada is produced from U.S. and Canadian sources. According to the EIA, in 2009 there were approximately 300 million gasoline gallon equivalents of natural gas consumed in the United States for vehicle use, which is more than double the amount consumed in 2000. The Clean Vehicle Education Foundation estimates that there are over 1,100 natural gas fueling stations in the United States.

Natural gas vehicles use internal combustion engines similar to those used in gasoline or diesel powered vehicles. A natural gas vehicle uses airtight storage cylinders to hold CNG or LNG, specially designed fuel lines to deliver natural gas to the engine, and an engine tuned to run on natural gas. Natural gas fuels have higher octane content than gasoline or diesel, and the acceleration and other performance characteristics of natural gas vehicles are similar to those of gasoline or diesel powered vehicles of the same weight and engine class. Natural gas vehicles, whether they run on CNG or LNG,

are refueled using a hose and nozzle that makes an airtight seal with the vehicle's gas tank. For heavy duty vehicles, spark ignited natural gas vehicles operate more quietly than diesel powered vehicles. Several municipalities are encouraging the use of natural gas trucks because of their quieter operation in urban settings.

Almost any make or model passenger car, truck, bus or other vehicle is capable of being manufactured or modified to run on natural gas. In other countries, numerous makes and models of vehicles are produced from the factory to run on natural gas. However, in North America, only a limited number of models of natural gas vehicles are available. Only Honda offers a factory built natural gas passenger vehicle for sale in North America, a version of its Civic 4-door Sedan called the GX. A limited number of other passenger vehicles, vans and light duty trucks are available through small volume manufacturers, such as our wholly owned subsidiary, BAF Technologies, Inc. These small volume manufacturers offer model vehicles made by major automobile manufacturers that they have modified to use natural gas and have been certified to meet federal and state emissions and safety standards. Several GM and Ford models are now certified, including the Ford Crown Victoria, Ford E Series Van, Ford F Series Truck, and GM vehicles that include pickups, vans, cargo vans, and trucks. We anticipate additional models will be certified in 2010. Modifications involve removing the gasoline fuel system and replacing it with a compressed natural gas fuel storage system and an associated computer controlled fuel management system for the engine.

Heavy duty natural gas vehicles are manufactured by traditional original equipment manufacturers. These manufacturers offer some of their standard model vehicles with natural gas engines and components, which they make or purchase from engine manufacturers. Cummins Westport Inc., a joint venture of Cummins Inc. and Westport Innovations Inc., and Westport Innovations Inc. (on its own), manufacture natural gas engines for medium and heavy duty fleet applications, including transit buses, class 8 trucks, refuse trucks, delivery trucks and street sweepers.

In 2009, several engine manufacturers initiated new engine development programs that may eventually lead to a greater selection of natural gas engines for wider applications in the future.

Natural Gas Medium and Heavy Duty Vehicle Manufacturers

Medium and heavy duty natural gas vehicle manufacturers include:

Trucks

- Altec
- Autocar
- American LaFrance
- Crane Carrier Company
- Freightliner
- Kenworth
- McNeilus
- Peterbilt
- Volvo

Shuttles and Buses

- BAF Technologies (vans and shuttles)

- Blue Bird (school buses)
- Complete Coach Works (shuttles)
- El Dorado National (shuttles and transit buses)
- New Flyer (transit buses)
- North American Bus Industries, Inc. (transit buses)
- Orion Bus Industries (transit buses)
- Thomas Built Buses (school buses)

Specialty

- Allianz Madvac (street sweepers and specialty sweepers and vacuums)
- Capacity (yard hostler trucks for port drayage)
- Elgin (street sweepers)
- Tymco (street sweepers)

Benefits of Natural Gas Fuel

Less Expensive. Based on EIA data, since 2004, CNG and LNG have been significantly less expensive than gasoline and diesel. For example, in 2009, the average retail CNG price we charged in California, our most significant market, was $0.54 less per gasoline gallon equivalent than the average California regular unleaded gasoline price of $2.68 per gallon according to the EIA. In addition, CNG and LNG are also currently cheaper than the three other most widely available alternative fuels, propane, ethanol blends and biodiesel, as reported by the DOE on a gallon-equivalent basis.

Tax incentives have historically enhanced the cost-effectiveness of CNG and LNG. From October 1, 2006 through December 31, 2009, a U.S. federal excise tax credit of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG sold for vehicle use was available to sellers of the fuel. A U.S. federal income tax credit is also available to offset 50% to 80% of the incremental cost of purchasing new or converted natural gas vehicles. The fuel credit expired December 31, 2009. The vehicle credit is scheduled to expire on December 31, 2010, unless otherwise extended. Legislation has been introduced in Congress that would reinstate and extend the fuel tax credit, extend and increase the natural gas vehicle credit and potentially provide other incentives for the purchase of natural gas vehicles, including HR 1835, the New Alternative Transportation to Give Americans Solutions Act "NAT GAS Act." More than 130 members of Congress have indicated support for the NAT GAS Act; however, the legislative process is inherently uncertain and we do not know if or when any of the legislation providing for reinstatement, extension or new incentives for natural gas fuel or vehicles will be passed.

We believe that diesel fuel will become more expensive over the next several years as refineries must meet additional stringent federal standards regarding the content of sulfur in diesel. Additionally, all diesel engine manufacturers will have to comply with the more stringent 2010 EPA standards this year, which will increase the cost of diesel engines.

The chart below shows our average pump prices in California for CNG relative to California retail regular gasoline and diesel prices on a gasoline gallon equivalent basis for the periods indicated. CNG and LNG powered vehicles produce roughly the same miles per gallon as compared to gasoline or diesel powered vehicles.

Average California Retail Prices

(per gasoline gallon equivalent)(1)

	Year Ended December 31,		
	2007	2008	2009
California retail gasoline(2)	$ 3.08	$ 3.51	$ 2.68
California retail diesel(2)(3)	2.81	3.53	2.34
California CNG—Clean Energy	2.43	2.67	2.14
CNG discount to gasoline	$(0.65)	$(0.84)	$(0.54)
CNG discount to diesel	(0.38)	(0.86)	(0.20)

(1) Industry analysts typically use the gasoline gallon equivalent method in an effort to provide a normalized or "apples to apples" comparison of the relative cost of CNG compared to gasoline and diesel. Using this method, the cost of CNG is presented based on the amount of CNG required to generate the same amount of energy, measured in British Thermal Units, or BTUs, as a gallon of gasoline.

(2) Retail gasoline and diesel prices from the EIA.

(3) Converted to gasoline gallon equivalents assuming 125,000 BTU and 139,000 BTU per gallon of gasoline and diesel, respectively.

The following chart shows the estimated annual fuel cost savings that may be achieved by the natural gas vehicle.

Representative Annual Per Vehicle Fuel Cost Savings by Fleet Market for California Based on Average Fuel Prices During 2009

Market	Fuel	Estimated annual fuel usage (gallons)(1)(2)	Cost of fuel CNG or LNG vs. gasoline or diesel (gallons)(1)(3)		Estimated annual fuel cost savings
Taxi	CNG or Gasoline	5,000	$2.14(4)	vs. $2.68(4)	$ 2,700
Shuttle van	CNG or Gasoline	7,500	$2.14(4)	vs. $2.68(4)	$ 4,050
Municipal transit bus (CNG)	CNG or Diesel	16,680	$1.39(5)	vs. $1.81(6)	$ 7,006
Refuse truck (CNG)	CNG or Diesel	11,120	$1.29(5)(7)	vs. $2.34(6)	$11,676
Municipal transit Bus (LNG)	LNG or Diesel	16,680	$1.52(5)	vs. $1.81(6)	$ 4,837
Refuse truck (LNG)	LNG or Diesel	11,120	$1.43(7)(5)	vs. $2.34(6)	$10,119

(1) CNG and LNG volumes are stated on a gasoline gallon equivalent basis. Industry analysts typically use the gasoline gallon equivalent method in an effort to provide a normalized or "apples to apples" comparison of the relative cost of CNG compared to gasoline and diesel. Using this method, the cost of each fuel is presented based on the same amount of energy, measured in BTUs, as a gallon of gasoline.

(2) Average fleet vehicle usage estimated by us based on experience with our customers. Estimated usage for a taxi is based on a "single-shift" driving program.

(3) Fuel prices for municipal transit buses are lower compared to refuse trucks because fuel for municipal buses is not subject to fuel excise taxes.

(4) CNG retail pricing is based on average Clean Energy retail station pricing in California during 2009. Gasoline retail pricing is based on California average retail gasoline prices during 2009 as reported by EIA.

(5) CNG and LNG prices based on average prices paid by representative Clean Energy California fleet customers in 2009.

(6) Diesel price based on EIA reported average diesel price in California in 2009.

(7) Excludes California Board of Equalization taxes of $0.0875 per gasoline gallons equivalent on CNG vehicles and $0.06 per gallon on LNG vehicles, as these customers typically buy an annual permit of $168.00 per truck over 12,000 GVW that allows them to opt out of this tax.

Cleaner. Use of CNG and LNG as a vehicle fuel creates less pollution than use of gasoline or diesel, based on data from South Coast Air Quality Management District studies. On-road mobile source emissions reductions are becoming increasingly important because many urban areas have failed to meet federal air quality standards. This failure has led to the need for more stringent governmental air pollution control regulations.

The table below shows an example of emissions reductions for the 2010 Honda Civic GX versus its gasoline powered counterpart. Comparisons are based on information submitted to the EPA by the manufacturer.

		Test & Certified maximum grams per mile			
Model	**Fuel**	**NOx Test Data**	**NOx Cert Level**	**NMOG Test Data**	**NMOG Cert Level**
2010 Honda Civic	CNG	0.002	0.010	0.002	0.002
2010 Honda Civic	Gasoline	0.014	0.040	0.030	0.043
Emission Reduction		***86%***	***75%***	***93%***	***95%***

In 2007, new federal emissions requirements became effective for medium and heavy duty engines, and more stringent requirements went into effect in 2010. These requirements limit the levels of specified emissions from new vehicle engines manufactured in or after these years, and will likely result in cost increases for both acquiring and operating diesel vehicles. In order to comply with these standards, 2007 and later diesel engine models have employed significant new emissions control technologies such as advanced NOx and particulate matter (PM) traps and exhaust gas recirculation systems, which have resulted in increases to the cost of medium and heavy duty diesel vehicles. According to industry sources, the purchase price of a 2007 and later heavy duty diesel vehicle that meets the 2007 diesel emission standards increased by an average of $10,000 per vehicle. The 2007 and newer diesel vehicles require the use of ultra-low sulfur diesel fuel in order to meet the standards, which we believe will also increase the cost of operating and maintaining medium and heavy duty diesel vehicles. Additionally, we expect the cost of medium and heavy duty diesel vehicles to increase during 2010 and beyond when and as they must meet the federal 2010 emission standards. The 2010 standards to date have required diesel vehicles to use additional emission control technologies, which may include the use of selective catalytic reduction (SCR) strategies that require urea. Manufacturers claim that the addition of SCR technology, while being more expensive, could provide a slight improvement in engine efficiency. We expect these additional controls, along with urea, will generally increase the cost to own and operate diesel vehicles. While the only natural gas engine designed for Class 8 trucks currently available in North America (the Westport HPDI) is not currently certified by the EPA for 2010 emission standards, and cannot be sold until the EPA certification is obtained, we anticipate that the certification will be issued during the first half of 2010. Most 2007 and later model year natural gas engines can achieve the 2010 standards by using an available catalytic converter with an approximate cost of $4,000 to $6,000.

South Coast Air Quality Management District completed a study that compared emissions levels of natural gas and other alternative fuels to those of existing pre-2007 diesel engines. The results, shown in the chart below, demonstrate that natural gas vehicle fuels produce significantly lower emissions than biodiesel, ethanol blends and diesel technologies. The figures show the percentage reduction in NOx and PM compared to emissions from standard diesel engines. Little or no data on the performance of 2010 diesel engines is currently available for analysis.

Proven Commercially Alternative Fuels and Diesel Technologies

Technology	NOx reduction	PM reduction
Natural gas	≥30-50%	>85%
Diesel emulsions	10-15%	50-65%
Biodiesel (B20)	−5%-0%	15-20%
Ethanol blends	2-6%	35-40%
Oxidation catalysts for diesel engines	0-3%	~20%
NOx/PM traps for diesel engines	0%	>85%
Low-sulfur diesel	Minimal	~20%

Source: South Coast Air Quality Management District—2009

In September 2006, California Governor Arnold Schwarzenegger signed AB 32—the Global Warming Solutions Act of 2006—into law, which calls for a cap on greenhouse-gas emissions throughout California and a statewide reduction to 1990 levels by the year 2020, and an additional 80% reduction below 1990 levels by 2050. To achieve the state's greenhouse gas reductions for mobile sources, the California Air Resources Board in 2007 identified an "early action item" under AB 32 called the Low Carbon Fuel Standard that requires a 10% carbon reduction in gasoline and diesel fuels sold in the State of California by 2020 and therefore encourages other low carbon transportation fuels to enter the marketplace by allowing them to generate carbon credits that can be sold to noncompliant regulated parties starting January 1, 2011. Under this regulation that was adopted in 2009, CNG, LNG and biomethane are identified as "compliant fuels" through 2020 as their carbon benefits have been verified to far exceed the regulation's 2020 goal of a 10% reduction. Further, the California Air Resources Board is also developing a cap and trade program that is expected to be adopted in November 2011 with a start date of January 1, 2012. Under this proposed regulatory action, California Air Resources Board staff are considering the possibility of allowing carbon credits generated under the Low Carbon Fuel Standard to be traded into the larger cap and trade program as early as 2012, as opposed to their original recommendation of 2015. This will allow fuel providers that generate credits to sell such credits beyond the Low Carbon Fuel Standard's regulated parties to the broader California cap and trade program, and potentially to other cap and trade markets under development, such as the Western Climate Initiative.

The Western Climate Initiative is made up of seven western U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec) with intent of forming a regional cap and trade market. Eleven Northeast and Mid-West U.S. states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania and Vermont) have already formed the Regional Greenhouse Gas Initiative to help combat climate change. Both efforts aim to implement market-based programs to reduce global warming pollution from stationary and mobile sources. We believe that the adoption of regional cap and trade programs can lead other states to adopt their own Low Carbon Fuel Standards. For example, each governor representing the eleven states that make up the Regional Greenhouse Gas Initiative have signed a memorandum of understanding to develop their own Low Carbon Fuel Standard by year 2012. Additional regulations that could stimulate growth in our market include AB 118, which Governor Schwarzenegger signed into

law in 2007 and that provides approximately $210 million per year for seven years to fund alternative fuel programs, including CNG, LNG and biogas, aimed at reducing greenhouse-gas emissions and improving air quality; and AB 1007, the State Alternative Fuels Plan (that was adopted by the California Energy Commission in 2007) establishes a goal of displacing 26% of California's petroleum fuel use by 2022 with alternative fuels, including natural gas.

Transportation accounts for more than 41% of California's annual greenhouse-gas emissions, according to the California Air Resources Board. As set forth in a report by TIAX, LLC, on a full life-cycle ("well to wheels") analysis, natural gas as a vehicle fuel results in greenhouse-gas reductions of up to 30% for light duty vehicles and up to 23% for medium and heavy duty vehicles.

Biomethane use is also a means to reduce greenhouse gas emissions. Biomethane is natural gas produced from waste streams such as landfills, animal waste "lagoons" and sewage processing plants. A recent full lifecycle analysis performed by the California Air Resources Board estimates that use of biomethane generated from landfills as a vehicle fuel can reduce greenhouse-gas emissions up to 88% as compared to gasoline. According to The American Biogas Alliance, biomethane can be liquefied or injected into a pipeline and is compatible with existing natural gas fueling infrastructure. Additionally, according to a 1998 DOE study, biomethane available from these sources could offset over ten billion gallons of petroleum fuel per year. Further, in February 2010, the U.S. Environmental Protection Agency finalized the Renewable Fuel Standard Phase 2 that we believe will provide incentives for biomethane production and use in the transportation sector.

Safety. As reported by NGV America, CNG and LNG are safer than gasoline and diesel because they dissipate into the air when spilled or in the event of a vehicle accident. When released, CNG and LNG are also less combustible than gasoline or diesel because they ignite only at relatively higher temperatures. The fuel tanks and systems used in natural gas vehicles are subjected to a number of federally required safety tests, such as fire, cycling tests, environmental hazard tests, burst pressures, and crash testing, according to the U.S. Department of Transportation National Highway Traffic Safety Administration. CNG and LNG are generally stored in above ground tanks and therefore are not likely to contaminate soil or groundwater.

Domestic supply. In 2009, the United States consumed 18.7 million barrels of crude oil per day, of which 42% was supplied from the United States and Canada and 58% was imported from other countries, according to the EIA. By comparison, the EIA estimates that 98% of the natural gas consumed in the United States in 2009 was supplied from the United States and Canada, making it less vulnerable to foreign supply disruption. In addition, the EIA estimates that less than 1% of the estimated 22.8 trillion cubic feet of natural gas consumed in the United States in 2009 was used for vehicle fuel. We believe that a significant increase in use of natural gas as a vehicle fuel would not materially impact the overall demand for natural gas supplies.

Analysts believe that there is a significant worldwide supply of natural gas relative to crude oil. According to the 2009 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2008 natural gas production was 44% greater than the ratio of proven crude oil reserves to 2008 crude oil production. This analysis suggests significantly greater long term availability of natural gas than crude oil based on current consumption.

On June 18, 2009, the Potential Gas Committee released its report on the natural gas resource base in the U.S. The report states that the United States possesses a total resource base of 1,836 trillion cubic feet (Tcf). This is the highest resource evaluation in the Committee's 44 year history. Another study published by Navigant Consulting in 2008, and further updated in 2009, defined the recoverable natural gas resources at 2,247 Tcf, or 118 years at current consumption levels.

Business Strategy

Our goal is to capitalize on the anticipated growth in the consumption of natural gas as a vehicle fuel and to enhance our leadership position as that market expands. To achieve these goals, we are pursuing the following strategies:

Focus on high-volume fleet customers. We will continue to target fleet customers such as public transit, refuse haulers and regional trucking companies, as well as vehicle fleets that serve airports and seaports. We believe these are ideal customers because they are high-volume users of vehicle fuel and can be served by a centralized fueling infrastructure. We have recently focused on seaports because they are among the biggest air polluters and many are under increasing regulatory pressure to reduce emissions. In November 2006, two of the nation's largest seaports, the Ports of Los Angeles and Long Beach (Ports), adopted the San Pedro Bay Clean Air Action Plan, which calls for the retrofit or replacement of trucks serving those ports with trucks that run on cleaner technology, such as LNG trucks. In November 2007, the Ports voted for a progressive ban of trucks that do not meet the 2007 emission standards from operating at the Ports. The ban began on October 1, 2008 and continues through January 1, 2012, when all trucks servicing the Ports must at least meet the EPA 2007 diesel emission standards. In December 2007, the Ports approved a cargo fee of $35 per loaded twenty-foot equivalent cargo container entering or leaving any terminal by truck, which they began collecting on February 18, 2009. LNG trucks are exempt from the cargo fees.

In December 2007, we opened the first fueling station in the port area to fuel LNG-powered trucks. In July 2009, we opened the second fueling station in the Port of Long Beach area to fuel LNG-powered trucks. In addition, we have selected other potential fueling station sites for development that would be capable of providing LNG fueling for the trucks servicing the Ports. We intend to model LNG truck deployment programs at other ports based on our experience in providing LNG fuel at the Ports of Los Angeles and Long Beach.

Capitalize on the cost savings of natural gas. We will continue to capitalize on the cost advantage of natural gas as a vehicle fuel. We educate fleet operators on the advantages of natural gas fuels, which include the cost savings relative to gasoline and diesel and the emission reductions that are achieved by switching from gasoline and diesel to natural gas fuel. We also educate fleet operators about various tax incentives and grants, including tax incentives and grants that reduce the purchase price of natural gas vehicles, which we believe accelerates the adoption of natural gas vehicles.

Leverage first mover advantage. We plan to continue to capitalize on our initial presence in a number of growing markets for CNG and LNG, such as public transit, refuse hauling, seaports, and airports, where there is increasing regulatory pressure to reduce emissions and where natural gas vehicles are already used in fleets. We plan to expand our business with existing customers as they continue to replace diesel and gasoline powered vehicles with natural gas vehicles. We intend to use our knowledge and reputation in these markets to win business with new customers.

Optimize LNG supply advantage. The supply of LNG in the United States and Canada is limited. We believe that increasing our LNG supply will enable us to increase sales to existing customers and to secure new customers. We use our LNG supply relationships and strategically located LNG production capacity to give us a competitive advantage. In addition to our own LNG liquefaction plants in Texas and California, we have relationships with five LNG supply plants in the western United States. Our LNG liquefaction plant in California will enhance our ability to serve California, Arizona and other western U.S. markets and will help us to optimize the allocation of LNG supply we sell to our customers. Also, in October 2007, we entered into an LNG sales agreement with Spectrum Energy Services, LLC ("SES"), whereby we will purchase, on a take-or-pay basis over a term of 10 years, 16 million gallons of LNG per year from a plant constructed by SES in Ehrenberg, Arizona, which is near the California border and that we anticipate will commence commercial operations in March,

2010. In the future, we may also acquire natural gas reserves or rights to natural gas production to supply our LNG plants.

Develop Renewable Biomethane Production Capabilities. Through our Dallas Clean Energy, LLC ("DCE") joint venture, we are producing from a landfill renewable pipeline quality biomethane, which can be used to generate renewable electricity and as a renewable low carbon fuel. Use of biomethane as CNG vehicle fuel can reduce greenhouse gas emissions by up to 88% as compared to gasoline. By developing biomethane production capabilities, we are able to offer customers renewable, low-carbon fuel options.

Bridge to hydrogen. With the goal of reducing U.S. dependence on foreign energy sources and lowering vehicle emissions, the federal government has launched several initiatives in the last few years that are dedicated to making practical and cost-effective hydrogen fuel cell vehicles widely available by 2020. The most cost-effective approach to produce hydrogen in the near term is to reform hydrogen from natural gas, according to Hydrogen.gov, the U.S. federal government's source of information on hydrogen fuels; and natural gas fueling stations are being considered by government agencies for use in the production of hydrogen for vehicles. In addition, natural gas vehicle fuel suppliers' expertise in working with fuels at very low temperatures or high pressure will be useful in a hydrogen-based transportation system because hydrogen is dispensed either in super-cooled liquid form (similar to LNG) or compressed gas form (similar to CNG). Even before wide scale hydrogen production for vehicle fuels goes into effect, natural gas fuel suppliers may begin supplying hydrogen/CNG blends or HCNG (i.e., 20% hydrogen, 80% CNG), which the DOE has found to reduce NOx emissions by an additional 50% versus pure CNG. During 2008, in collaboration with General Motors "GM", we installed a hydrogen fueling station adjacent to the Los Angeles International Airport as part of GM's Project Driveway fuel cell field test program.

In addition, as part of the Canadian Hydrogen Highway initiative, we are participating, together with a coalition of partners, in a program known as the Integrated Waste Hydrogen Utilization Project ("IWHUP"). The goal of the project is to take hydrogen from a process waste stream that is being vented to the atmosphere, purify it, and then transport it to a refueling station for use in vehicles. In furtherance of this program, we leveraged our design and engineering expertise with CNG fueling stations to build an integrated CNG/hydrogen "HCNG" dispenser. This dispenser is capable of providing 100% natural gas, 100% hydrogen or any blended combination of the two fuels with more precise mixing than was achieved previously. The station at which this dispenser is located provides CNG daily to approximately 70 buses and HCNG to four buses that are involved in the IWHUP demonstration project. We believe our construction and operation of this modified station demonstrates our ability to leverage existing natural gas infrastructure to introduce hydrogen fuel to customers.

Operations

Our revenue principally comes from delivering (by selling and providing station operating and maintenance services) CNG and LNG fuel to our customers. To a lesser extent, we generate revenues by designing and constructing fueling stations and selling or leasing those stations to our customers and selling biomethane gas through our interest in DCE (commencing in August 2008). Substantially all of our operating and maintenance revenues are generated from CNG stations, as owners of LNG stations tend to operate and maintain their own stations. Substantially all of our station sale and leasing revenues have been generated from CNG stations. In 2006, we began providing vehicle finance services to our customers. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF") and began providing natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. Each of these activities are discussed below.

Natural gas for CNG stations. We obtain natural gas for CNG stations from local utilities or brokers under standard arrangements which provide that we purchase natural gas at a published rate or negotiated prices. The natural gas is delivered via pipelines owned by local utilities to fueling stations where it is cleaned, compressed, stored and dispensed into vehicles on site. In some cases, we receive special rates from local utilities because of our status as a supplier of CNG for transportation.

LNG production and purchase. We obtain LNG from our own plants as well as through purchases from five suppliers in the western United States. Combining these sources provides important flexibility and helps to create a reliable supply for our LNG customers. We own and operate LNG liquefaction plants near Houston, Texas and Boron, California, which we call the Pickens Plant and California LNG Plant, respectively. The Pickens Plant has the capacity to produce 35 million gallons of LNG per year and also includes tanker trailer loading facilities and a 1.0 million gallon storage tank that can hold up to 840,000 usable gallons. Additionally, the LNG liquefaction plant in California (which produced its first load of LNG in November 2008), is capable of producing 60 million gallons of LNG per year (with expansion potential to produce 90 million LNG gallons per year) and will enable us to supply our operations in California and Arizona more economically as our supply source will be closer to our customers' locations. This plant has tanker trailer loading facilities similar to the Pickens Plant and a 1.8 million gallon storage tank that can hold up to 1.5 million usable gallons.

As of December 31, 2009, we had outstanding purchase contracts with various third-party LNG suppliers in the western United States. For the year ended December 31, 2009, of the LNG we sold, we purchased 26% from these suppliers and the balance was produced at our Pickens Plant and California LNG Plant. One of our LNG supply contracts contains "take-or-pay" provisions that require that we purchase specified minimum volumes of LNG at index-based prices or pay for the amounts that we do not purchase. We anticipate that our "take or pay" obligation to a second LNG supplier will commence in the first quarter of 2010 when the supplier's LNG plant commences commercial operations. If we need additional LNG and it is available from these suppliers, we generally may purchase it from them, typically at the market price for natural gas plus a liquefaction fee. To date, we have taken and sold the required amounts under our take-or-pay contracts.

We have a fleet of 58 tanker trailers that we use to transfer LNG from our third-party suppliers and production plants to individual fueling stations. We typically own the tanker trailers and we contract with third parties to provide tractors and drivers. Each LNG tanker trailer is capable of carrying 10,000 gallons of LNG. To optimize our distribution network, we use an automated tracking system that enables us to monitor the location of a tanker trailer at any time, as well as an automated fueling station tank-monitoring system that enables us to efficiently schedule the refilling of each station, which helps ensure that our customers have sufficient fuel to operate their fleets.

Operations and maintenance. Typically, we perform operations and maintenance services for CNG stations, which are either owned by us or our customers. Although we may from time to time own or operate and maintain LNG stations, LNG stations are most often owned and maintained by our customers and supplied by us. Most of the CNG and LNG stations that we maintain or supply are monitored from our centralized operations center, facilitating increased reliability and safety, as well as lower operating costs. This monitoring helps us to ensure the timely delivery of fuel and to respond rapidly to any technical difficulties that may arise. In addition, we have an automated billing system that enables us to track our customers' usage and bill them efficiently. As of December 31, 2009, we had an operations team of 77 employees, including 46 full-time employees dedicated to performing preventative maintenance and available to respond to service requests in 19 states and in Canada.

Our station network. As of December 31, 2009, we owned, operated or supplied 196 fueling stations for our customers in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, Washington, Wyoming, and Canada. Of these 196 stations, we owned 136 of the stations, and

our customers owned the other 60 stations. The breakdown of the services we perform for these stations is set forth below.

	As of December 31, 2009		
	CNG fueling stations	LNG fueling stations	Total stations
Operated, maintained and supplied by Clean Energy	111	6	117
Supplied by Clean Energy, operated and maintained by customer	0	26	26
Operated and maintained by Clean Energy, supplied by customer	52	1	53
Total	163	33	196

For the month of December 2009, 29 of the stations listed in the table above delivered in excess of 100,000 gasoline gallon equivalents, and 38 stations delivered in excess of 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents). Of the 29 stations delivering greater than 100,000 gasoline gallon equivalents per month, 22 relate to transit customers, three relate to airport locations, two relate to public stations, one relates to a refuse customer and one relates to an industrial customer. Of the 38 stations delivering greater than 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents), 12 relate to refuse customers, 11 relate to transit customers, 10 relate to airport locations, four relate to public stations and one relates to an industrial customer. In general, stations delivering higher volumes are more cost effective and perform better financially due to operating efficiencies obtained by the spreading of a station's fixed costs over a larger revenue base. With respect to station performance by geographic region, stations located in busy metropolitan areas, particularly near airports, experience higher traffic and deliver higher volumes compared to stations located in areas that are less densely populated.

Station construction and engineering. We have built 95 natural gas fueling stations, either serving as general contractor or supervising qualified third-party contractors, for ourselves or our customers. We acquired the additional stations we own that we did not build through acquisition of assets or businesses. We use a combination of custom designed and off-the-shelf equipment to build fueling stations. Equipment for a CNG station typically consists of dryers, compressors, dispensers and storage tanks (which hold a relatively small buffer amount of fuel). Equipment for an LNG station typically consists of storage tanks that hold 10,000 to 25,000 gallons of LNG, plus related dispensing equipment.

A number of our CNG fueling stations have separate public access areas for retail customers, which have the look, feel and fill rates of a traditional gasoline fueling station. Our CNG dispensers are designed to fuel at five to six gasoline gallon equivalents per minute, which is comparable to a traditional gasoline fueling dispenser. Our LNG dispensers are designed to fuel at 40 diesel gallon equivalents per minute, similar to a diesel fueling dispenser. LNG dispensing requires special training and protective equipment because of the extreme low temperatures of LNG.

Landfill gas. In August of 2008, we acquired 70% of the outstanding membership interests of DCE. DCE owns a facility that collects, processes and sells renewable, pipeline-quality biomethane at the McCommas Bluff landfill located in Dallas, Texas. During 2009, we generated approximately $7.9 million in revenues from sales of biomethane by DCE, which represents 100% of DCE's revenue which is included on a consolidated basis in our financial statements.

Vehicle conversion. On October 1, 2009, we acquired 100% of BAF Technologies, Inc., a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles. During the quarter-ended December 31, 2009, we generated approximately $6.9 million in revenues from BAF's operations, which is included on a consolidated basis in our financial statements.

Sales and Marketing

We have sales representatives in all of our major operating territories, including Los Angeles, San Francisco, San Diego, Phoenix region, Boston region, New York, Denver, Dallas, Atlanta, New Jersey, Seattle, New Mexico, Chicago, Florida, Virginia, Minnesota, Kentucky, and Toronto. At December 31, 2009, we had 44 employees in sales and marketing, including three employees of BAF. As our business grows and we enter new markets over the next several years, we intend to continue expanding our sales and marketing team, primarily by adding specialized sales experts to focus on fleet market opportunities in targeted metropolitan areas where we do not yet have a strong presence. We market primarily through our direct sales force, attendance at trade shows and participation in industry conferences and events. Our sales and marketing group works closely with federal, state and local government agencies to educate them on the value of natural gas as a vehicle fuel and to keep abreast of proposed and newly adopted regulations that affect the industry. Several of our U.S. sales offices are located in "nonattainment" areas, or near-non-attainment areas, under the Federal Clean Air Act, where government regulations are more likely to mandate vehicle pollution controls.

Customer Vehicle Financing

We provide, or help our customers obtain, financing to acquire natural gas vehicles or convert their vehicles to operate on natural gas. In 2006, we began to loan to certain qualifying customers an average of 75%, and on occasion up to 100%, of the up-front capital needed to purchase natural gas vehicles or convert existing vehicles to use natural gas. To ensure the availability of vehicles for our customers, we may also purchase natural gas vehicles or components of natural gas vehicles in anticipation of customer requirements. We also use our in-house grant specialists to help secure government grants, tax rebates and related incentives for ourselves and our customers, which can be a challenging process. Our specialists have secured over $212.3 million in federal and state funding for ourselves and our customers since 1998. This expertise is important to our customers, as natural gas vehicle fleet operators have access to an increasing number of grants and other incentives to help defray a significant portion of the incremental costs of purchasing natural gas vehicles. As of December 31, 2009, we have not generated significant revenue from financing activities.

Customers and Key Markets

We have over 390 fleet customers operating approximately 17,790 vehicles, including approximately 5,260 transit buses, 1,520 taxis, 990 shuttles and 1,700 refuse trucks. We target customers in a variety of markets, such as airports, public transit, refuse, seaports, regional trucking, taxis and government fleets. From 2006 through 2009, approximately 64% of our revenues were derived from contracts with governmental entities such as municipal transit fleets. We do not depend on a single customer or a few customers, the loss of which would have a material adverse effect on us.

- *Airports*—Many U.S. airports face emissions challenges and are under regulatory directives and political pressure to reduce pollution, particularly as part of any expansion plans. Many of these airports already have adopted various strategies to address tailpipe emissions, including rental car and hotel shuttle consolidation. In order to reduce emissions levels further, many airports require or encourage service vehicle operators to switch their fleets to natural gas, including airport delivery fleets, door-to-door and parking shuttles and taxis. To assist in this effort, airports are contracting with service providers to design, build and operate natural gas fueling stations in strategic locations on their property. Airports we serve include Albuquerque, Atlanta Hartsfield-Jackson International, Austin-Bergstrom International, Baltimore-Washington International, Burbank, Dallas-Ft. Worth International, Love Field (Dallas), Long Beach, Denver International, LaGuardia (New York), Los Angeles International, Oakland International, Palm Springs, Phoenix Sky Harbor International, San Francisco International, Santa Ana/John Wayne, San Diego International, SeaTac International (Seattle), and Tucson International. At

these airports, our representative customers include taxi and van fleets, as well as parking and car rental shuttles.

- *Transit agencies*—According to the American Public Transportation Association, there are over 65,000 municipal transit buses operating in the United States. In many areas, increasingly stringent emissions standards have limited the fueling options available to public transit operators. For example, the South Coast Air Quality Management District in California has adopted an Air Toxic Control Plan designed to encourage the use of alternative fuel buses. Eligible buses include hybrid gasoline electric buses (which typically cost $165,000 more than a traditional gasoline or diesel powered bus, or natural gas powered buses (which typically cost $35,000 more than a traditional gasoline or diesel powered bus, a significant portion of which can be recaptured through tax credits). Some public transit authorities also allow hybrid diesel electric buses (which typically cost $200,000 more than a traditional gasoline or diesel powered bus). The cost comparison data in this paragraph are from Hybridcenter.org, a project of the Union of Concerned Scientists. Transit agencies have been early adopters of natural gas vehicles, with almost 32% of all buses in the United States operating on LNG, CNG or CNG blends, according to the American Public Transportation Agency 2009 Public Transportation Factbook. Our representative public transit customers include Dallas Area Rapid Transit, Santa Monica Big Blue Bus, Los Angeles Metropolitan Transit Authority, Boston Metropolitan Transit Development Agency, Metropolitan Transit System of San Diego, Phoenix Transit, Tempe Transit, Foothill Transit (California), Santa Cruz Metropolitan, Orange County Transit Authority, Regional Transit Commission of Nevada, Regional Transit Authority (Ohio) and Washington Metropolitan Area Transit Authority (DC and Virginia).

- *Refuse haulers*—According to INFORM, there are nearly 200,000 trucks in the United States, consuming approximately two billion gallons of fuel per year, that collect and haul refuse and recyclables from collection points to landfills and recycling facilities. Many refuse haulers are facing pressure from the municipalities they serve to reduce emissions. We estimate there are approximately 2,700 natural gas powered refuse hauling vehicles operating in the United States on CNG and LNG. Our representative refuse hauler customers include national accounts such as Waste Management, Republic Services and Waste Connections, as well as private waste haulers in eleven different states such as CleanScapes (Seattle), Choice Waste (FL), Recology (Formerly Norcal Waste), South San Francisco Scavenger, Burrtec (CA), Central Jersey Waste and Garofalo V & Sons (NY) among others. We also provide vehicle fueling services to municipal refuse fleets including fleets in Los Angeles, Fresno, Sacramento, Burbank, Dallas, San Antonio and on Long Island, New York among other locations.

- *Seaports*—Seaports are typically large polluters because of emissions from cargo ships, trains, yard hostlers and trucks. Many seaports must reduce emissions levels in connection with any expansion efforts. A practical solution for reducing port emissions is to adopt policies that require alternative fuel vehicles in the seaport that have lower emissions than gasoline or diesel, such as natural gas. Such policies include requiring conversion to alternative fueling systems for regional trucking fleets that transport containers from the seaport to local distribution centers, as well as the yard hostlers that move containers around the shipyard. In November 2006, two of the nation's largest seaports, the Ports of Los Angeles and Long Beach (the "Ports"), adopted the San Pedro Clean Air Action Plan, which calls for the retrofit or replacement of trucks serving those ports so that they run on cleaner technology, such as LNG. In November 2007, the Ports introduced a progressive ban, beginning October 1, 2008, that will remove by 2012 all diesel trucks that do not meet 2007 emission standards. In December 2007, the Ports approved a $35 per twenty-foot container unit cargo fee that the Ports began collecting February 18, 2009. LNG trucks are exempt from the cargo fees.

In December 2007, we opened the first fueling station in the port area to fuel these LNG-powered trucks, and in July 2009 we opened a second port LNG fueling station at the Port of Long Beach. In addition, we have contracted to develop several other station sites to provide LNG fuel to the trucks servicing the Ports and operating in Southern California regional trucking.

- *Regional trucking*—According to the EPA, the average tractor-trailer uses over 11,500 gallons of fuel per year. Most of these trucks run on diesel fuel, which is becoming less desirable as emissions standards become increasingly more stringent. For regional fleets that can use centralized refueling facilities, LNG is a more cost-effective fuel alternative that enables trucking companies to meet the evolving emissions standards. Our representative regional trucking customers include the Dallas and Houston distribution centers of Sysco Food Services, a wholesale distributor of food products, the Houston distribution center of H.E. Butt Grocery Company, and Trimac USA of Houston.
- *Taxis*—According to the Automotive Fleet Factbook, there were approximately 162,000 taxis operating in the United States in 2005. We believe that less than 2% of these vehicles were natural gas vehicles. Because taxi fleets travel many miles and can refuel at a central location, we believe they are excellent candidates to use CNG. Natural gas vehicles provide taxi fleets a convenient way to reduce operating costs. We serve approximately 1,520 taxis in Southern California, the San Francisco Bay Area, New York City, Phoenix, Tucson and Seattle.
- *Government fleets*—According to the Federal Highway Administration, or FHA, in 2008, there were over 4.5 million government fleet vehicles in operation in the United States, including those operated by federal, state and municipal entities. In California and Texas, for example, according to the FHA, there were over 629,000 and 493,000 government vehicles, respectively. As government regulations on pollution continue to become more stringent, government agencies are evaluating ways to make their fleets cleaner and run more economically. Under the federal Energy Policy Act of 1992, 75% of new light-duty vehicles purchased by federal fleet operators are required to run on alternative fuels. Our representative government fleet customers include the California Department of Transportation (Los Angeles and Orange County), State of New York, City of Denver, City and County of Los Angeles, City of San Antonio, Town of Smithtown, City and County of San Francisco, City and County of Dallas and City of Phoenix.

Tax Incentives and Grant Programs

U.S. federal and state government tax incentives and grant programs are available to help fleet operators reduce the cost of acquiring and operating a natural gas vehicle fleet. Incentives are typically available to offset the cost of acquiring natural gas vehicles or converting vehicles to use natural gas, constructing natural gas fueling stations and selling CNG or LNG. The vehicle and fuel tax rebates and credits are key incentives designed to enhance the cost-effectiveness of CNG and LNG as vehicle fuels throughout the United States and are described below.

Fuel credits. Under the Volumetric Excise Tax Credit ("VETC") for alternative fuels, sellers of CNG or LNG were entitled to receive a credit of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG sold for vehicle fuel use after September 30, 2006 and before January 1, 2010. Based on the service relationship we have with our customers, either we or our customers were able to claim the credit. These tax credits for CNG and LNG lowered the cost of natural gas vehicle fuels to sellers, and the savings could be passed on to the customer if the seller elected to do so. These credits expired on December 31, 2009.

Vehicle credits. Effective January 1, 2006, a federal income tax credit became available to taxpayers for 50% of the incremental cost associated with purchasing a new vehicle that operates only

on natural gas or another alternative fuel (as compared to the cost of the same vehicle using a gasoline or diesel fuel motor) or a vehicle converted to that form of alternative fuel. The credit is increased to 80% of the incremental cost if the vehicle is certified as meeting the most stringent applicable emission standard for the vehicle under the Federal Clean Air Act or under California law (other than zero emission standards). The amount of the credit is subject to the following maximums: $4,000 if the vehicle purchased weighs 8,500 pounds or less, $8,000 if the vehicle purchased weighs more than 8,500 pounds but 14,000 pounds or less, $20,000 if the vehicle purchased weighs more than 14,000 pounds but 26,000 pounds or less, and $32,000 if the vehicle purchased weighs more than 26,000 pounds. For a taxpayer to be eligible for the credit, the vehicle must be acquired by the taxpayer for use or lease predominantly within the United States and not for resale, and the original use of the vehicle must commence with the taxpayer; or the taxpayer must sell the vehicle (which cannot be subject to a lease) to a tax-exempt entity (including the United States, any state and any political subdivision thereof), that places the vehicle into first use and disclose to that entity the amount of the allowable credit. The credit for any year is limited to the taxpayer's regular income tax liability for the year, subject in some cases to certain carryback and carryforward provisions. This federal income tax credit is in effect for vehicles purchased before January 1, 2011.

Legislation has been introduced in Congress that would reinstate and extend the fuel tax credit, extend and increase the natural gas vehicle credit and potentially provide other incentives for the purchase of natural gas vehicles, including HR 1835, the New Alternative Transportation to Give Americans Solutions Act ("NAT GAS Act"). More than 130 members of Congress have indicated support for the NAT GAS Act; however, the legislative process is inherently uncertain and therefore we do not know if or when any of the legislation providing for reinstatement, extension or new incentives for natural gas fuel or vehicles will be passed.

Grant programs

We apply for and help our customers apply for grant programs available for fleets in several of the states in which we operate including California, New York, and Texas. These programs provide funding for natural gas vehicle purchases, station construction and natural gas fueling infrastructure and include the following:

Mobile Source Air Pollution Reduction Review Committee—The Mobile Source Air Pollution Reduction Review Committee, or MSRC, is a Southern California program that funds projects that reduce air pollution from motor vehicles within the South Coast Air Quality Management District in Southern California. The South Coast Air Quality Management District is a geographic region defined in state regulations to include all of Los Angeles and Orange Counties, and portions of Riverside and San Bernardino counties. The MSRC derives funding from a portion of the California Department of Motor Vehicles $4 per vehicle surcharge on an estimated 12.5 million vehicles operating in the South Coast District. For 2009, the surcharge is anticipated to result in approximately $14 million in funding and support for a variety of clean air programs, including grants to purchase natural gas vehicles and fueling station infrastructure. The MSRC has a yearly work program designed to fund projects that reduce air pollution from motor vehicles.

California Carl Moyer Program—The Carl Moyer Memorial Air Quality Standards Attainment Program, or Carl Moyer Program, was initiated in California in 1998 to reduce emissions from heavy duty, diesel-powered vehicles and other mobile sources. The Carl Moyer Program provides matching grants to private companies and public agencies in California to fund efforts to clean up emissions from their heavy duty engines through retrofitting, repowering or replacing them with newer and cleaner versions. Based on actual receipts from the prior fiscal year, the California Air Resources Board "CARB" anticipates $76.5 million in funding for the twelve months constituting their fiscal year 2009/2010. CARB allocated $34.3 million to the South Coast Air Quality Management District under SB1107 for the implementation of its 2010 Carl Moyer Program.

Qualifying projects included those that reduce emissions from heavy duty on and off-road equipment, such as trucks over 14,000 pounds gross vehicle weight and off-road equipment such as construction equipment and airport ground support equipment.

Texas Emissions Reduction Plan—The Texas Emissions Reduction Plan is a comprehensive set of clean air incentive programs, including vehicle programs, designed to improve air quality in Texas. The Texas Commission on Environmental Quality administers grants under these programs. The grants are used to help reduce air pollution in Texas ozone "nonattainment" areas and in certain other near-non-attainment areas in the state and are often targeted towards reducing emissions from diesel equipment. Last year, $137.5 million was made available for programs to purchase and convert vehicles to low emission vehicles. As of March 8, 2010, the funding allocations for the current fiscal year have not been released although we anticipate a similar funding level.

U.S. Department of Energy Petroleum Reduction Technologies Projects for the Transportation Sector—This DOE program is administered through the DOE Clean Cities affiliates throughout the country. Approximately $3.8 million is available in 2010 for alternative fuel vehicle deployment and infrastructure projects. We anticipate pursuing funding opportunities with our customers to assist with the purchase of vehicles and construction of fueling infrastructure. We also prepared and partnered on grant applications under the 2009 Clean Cities and DOE ARRA (stimulus) program that resulted in potential customers receiving funding in the aggregate amount of $38.6 million to offset the capital costs of 12 potential natural gas fueling stations and the incremental costs of 822 potential natural gas vehicles. After the initial awards were made, we secured an additional $1.87 million to offset the incremental costs of 78 additional natural gas vehicles. Certain projects, which were awarded grant funds under the Clean Cities program, may require a competitive bid process, all of which we are pursuing. We are expanding our memberships in additional Clean Cities groups throughout the country for areas that did not successfully secure funding in 2009.

U.S. Environmental Protection Agency ("EPA") National Clean Diesel Funding Assistance Program—This national program provides funding to reduce emissions from existing diesel engines through a variety of strategies, including the use of alternative fuels. Total combined funds available for 2009 and 2010 is $120 million in total program dollars. A portion of this funding goes to individual states to support transportation air quality programs at that level. We expect to participate in regional funding programs which are administered through the EPA's seven regional offices.

Competition

The market for vehicular fuels is highly competitive. The biggest competition for CNG, LNG and other alternative fuels is gasoline and diesel, the production, distribution and sale of which are dominated by large integrated oil companies. The vast majority of vehicles in the United States and Canada are powered by gasoline or diesel.

Within the United States, we believe our largest competitors for CNG sales are: Trillium USA/Pinnacle CNG, a privately held provider of CNG fuel infrastructure and fueling services, which we believe focuses primarily on transit fleets in California, Arizona and New York and Pacific Gas and Electric, which operates public access CNG stations in Northern California. Within the U.S. LNG market, we believe our largest competitors are Applied LNG Technology, which is wholly owned by PNG Ventures, Inc., a publicly traded company, and Prometheus Energy, each of which distributes LNG in the western United States. We have identified no significant competitors in Canada for CNG or LNG vehicle fuel sales.

We own, operate or supply 196 CNG and LNG fueling stations. We operate 163 CNG fueling stations, which we estimate is approximately four times the number of CNG fueling stations as our next largest competitor. We believe we are the only company in the United States or Canada that provides both CNG and LNG on a significant scale, and we operate in more states and provinces than any of our competitors.

Potential entrants to the market for natural gas vehicle fuels include the large integrated oil companies, other retail gasoline marketers and natural gas utility companies. The integrated oil companies produce and sell crude oil and natural gas, and they refine crude oil into gasoline and diesel. They and other retail gasoline marketers own and franchise retail stations that sell gasoline and diesel fuel. Integrated oil companies and other established fueling companies sell CNG at a number of their vehicle fueling stations that sell gasoline and diesel in international markets. Natural gas utility companies own and operate the local pipeline infrastructure that supplies natural gas to retail, commercial and industrial customers and some utilities also sell CNG fuel at public access stations.

It is possible that any of these competitors, and other competitors who may enter the market in the future, may create product and service offerings that compete with ours. Many of these companies have far greater financial and other resources and name recognition than we have. Entry by these companies into the market for natural gas vehicle fuels may reduce our profit margins, limit our customer base and restrict our expansion opportunities.

Other alternative fuels compete with natural gas in the retail market and may compete in the fleet market in the future. We believe there is room for all providers of alternative fuels in the vehicle fuels market. Suppliers of ethanol, biodiesel and hydrogen, as well as providers of hybrid and electric vehicles, may compete with us for fleet customers in our target markets. Many of these companies benefit, as we do, from U.S. state and federal government incentives that allow them to provide fuel more inexpensively than gasoline or diesel.

Background on Clean Air Regulation

The Federal Clean Air Act provides a comprehensive framework for air quality regulation in the United States. Many of the federal, state and local air pollution control programs regulating vehicles and stationary sources have their basis in Title I or Title II of the Federal Clean Air Act.

Title I of the Federal Clean Air Act charges the EPA with establishing uniform National Ambient Air Quality Standards for criteria air pollutants anticipated to endanger public health and welfare. States in turn have the primary responsibility under the Federal Clean Air Act for achieving these standards. If any area within a state fails to meet these standards for a criteria air pollutant, the state must develop an implementation plan and local agencies must develop air quality management plans for achieving these standards. Many state programs regulating stationary source emissions, vehicle pollution or mobile sources of pollution are developed as part of a state implementation plan. For mobile sources, two criteria pollutants in particular are of concern: ozone and particulate matter. Many of the nation's metropolitan areas are in "nonattainment" status for one or both of these criteria air pollutants. As components of state implementation plans, individual states have also adopted diesel fuel standards intended to reduce NOx and particulate matter emissions. Texas and California have both adopted low-NOx diesel programs. Additionally, many state implementation plans and some quality management plans include vehicle fleet requirements specifying the use of low emission or alternative fuels in government vehicles. Finally, the U.S. Environmental Protection Agency under the Obama Administration has signaled that it wishes to strengthen tropospheric ozone standards (i.e. smog) to the levels recommended originally under the Bush Administration. Such a move would potentially increase the number of nonattainment areas throughout the country.

Title II of the Federal Clean Air Act authorizes the EPA to establish emission standards for vehicles and engines. Diesel fueled heavy duty trucks and buses have recently accounted for substantial portions of NOx and particulate matter emissions from mobile sources, and diesel emissions have received significant attention from environmental groups and state agencies. In 2001, the EPA finalized its Heavy Duty Highway Rule, also known as the 2007 Highway Rule. The 2007 Highway Rule seeks to limit emissions from diesel fueled trucks and buses on two fronts: new tailpipe standards requiring significantly reduced NOx and particulate matter emissions for new heavy duty diesel engines, and new

standards requiring refiners to produce low sulfur diesel fuels that will enable more extensive use of advanced pollution control technologies on diesel engines.

The 2007 Highway Rule's tailpipe standards, which will apply to new diesel engines, take effect in 2007 and 2010. Specifically, new particulate matter standards took effect in the model year 2007 and new NOx standards will be phased in between 2007 and 2010. The rule's fuel standards call for a shift by U.S. refiners and importers from low sulfur diesel, with a sulfur content of 500 parts per million (ppm), to ultra low sulfur diesel, with a sulfur content of 15 ppm. The rule, which will effect a transition to ultra low sulfur diesel between 2006 and 2010, required refiners to begin producing ultra low sulfur diesel fuels on June 1, 2006.

Although the majority of state air pollution control regulations are components of state implementation plans developed pursuant to Title I of the Federal Clean Air Act, states are not precluded from developing their own air pollution control programs under state law. For example, the California Air Resources Board and the South Coast Air Quality Management District have promulgated a series of airborne toxic control measures under California state law, several of which are directed toward reducing emissions from diesel fueled engines.

Although the federal government has not adopted any laws that comprehensively regulate greenhouse gas emissions, the EPA is developing regulations that would regulate these pollutants under the Clean Air Act. In addition, in 2006, the State of California adopted a comprehensive law designed to reduce greenhouse gas emissions in the state. As discussed above, this statute and the regulations developed to implement its requirements will affect the operation of stationary and mobile sources and may require reformulation of fuels to lower their carbon "footprint."

Government Regulation and Environmental Matters

Certain aspects of our operations are subject to regulation under federal, state, local and foreign laws. If we were to violate these laws or if the laws or enforcement proceedings were to change, it could have a material adverse effect on our business, financial condition and results of operations.

Regulations that significantly impact our operations are described below.

- *CNG and LNG stations*—To construct a CNG or LNG fueling station, we must obtain a facility permit from the local fire department and either we or a third party contractor must be licensed as a general engineering contractor. The installation of each CNG and LNG fueling station must be in accordance with federal, state and local regulations pertaining to station design, environmental health, accidental release prevention, above-ground storage tanks, hazardous waste and hazardous materials. We are also required to register with certain state agencies as a retailer/wholesaler of CNG and LNG.
- *Transfer of LNG*—Federal Safety Standards require each transfer of LNG to be conducted in accordance with specific written safety procedures. These procedures must be located at each place of transfer and must include provisions for personnel to be in constant attendance during all LNG transfer operations.
- *LNG liquefaction plants*—To build and operate LNG liquefaction plants, we must apply for facility permits or licenses to address many factors, including storm water or wastewater discharges, waste handling and air emissions related to production activities or equipment operations. The construction of LNG plants must also be approved by local planning boards and fire departments.
- *Financing*—State agencies generally require the registration of finance lenders. For example, in California, pursuant to the California Finance Lenders Law, one of our subsidiaries is a registered finance lender with the California Department of Corporations.

- *Vehicle Conversion*—Vehicles that are converted to run on natural gas and sold by BAF are subject to EPA emission requirements and certifications, federal vehicle safety regulations and, in some cases, such as California, state emission requirements and certifications.

We believe we are in substantial compliance with environmental laws and regulations and other known regulatory requirements. Compliance with these regulations has not had a material effect on our capital expenditures, earnings or competitive position. It is possible that more stringent environmental laws and regulations may be imposed in the future, such as more rigorous air emissions requirements or proposals to make waste materials subject to more stringent and costly handling, disposal and clean-up requirements and regulations of greenhouse gas emissions from our LNG plants or stations. Accordingly, new laws or regulations or amendments to existing laws or regulations might require us to undertake significant capital expenditures, which may have a material adverse effect on our business, consolidated financial condition, results of operations and cash flows.

Employees

As of December 31, 2009, we employed 229 people, of whom 51 were in sales and marketing (including our grants department), 145 were in operations and engineering and vehicle production, and 33 were in finance and administration. We have not experienced any work stoppages and none of our employees is subject to collective bargaining agreements. We believe that our employee relations are good.

Financial Information about Segments and Geographic Areas

We operate our business in one reportable segment. For information about our revenues from external customers, operating income (loss) and long-lived assets broken down by geographic area, see note 12 to our consolidated financial statements.

Additional Information

Our web site is located at www.cleanenergyfuels.com. We make available free of charge on our web site our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. The reference to our website is intended to be an inactive textual reference and the contents of our website are not intended to be incorporated into this report.

Item 1A. Risk Factors.

We have a history of losses and may incur additional losses in the future.

In 2007, 2008 and 2009 we incurred pre-tax losses of $7.7 million, $44.3 million, and $33.4 million, respectively. Our loss for 2008 includes $18.6 million in expenses associated with our support for Proposition 10, the California Alternative Fuel Vehicles and Renewable Energy ballot initiative and our loss for 2009 includes $17.4 million of derivative losses related to marking to market the value of our Series I warrants. During 2007, 2008 and 2009, our losses were substantially decreased by our receipt of approximately $17.0 million, $17.2 million and $15.5 million of revenue from federal fuel tax credits; however the law providing for the fuel tax credits expired on December 31, 2009 and has not been extended. In order to execute our strategy and improve our financial performance, we must continue to invest in developing the natural gas vehicle fuel market and offer our customers compelling natural gas fuel prices. If our natural gas sales activities and station operations do not achieve or maintain profitability that can be sustained in the absence of federal fuel tax credits, our business will suffer and the price of our common stock may drop. In addition, if the price of our common stock increases

during future periods when our Series I warrants are outstanding, we may be required to recognize material losses based on the valuation of the outstanding Series I warrants.

A material portion of our historical revenues are associated with a federal fuel excise tax credit that expired on December 31, 2009.

The federal excise tax credit of $0.50 per gasoline gallon equivalent of CNG and liquid gallon of LNG sold for vehicle fuel use, which began on October 1, 2006, expired December 31, 2009. Based on the service relationship we have with our customers, either we or our customers were able to claim the credit. In 2007, 2008 and 2009, we recorded approximately $17.0 million, $17.2 million and $15.5 million of revenue, respectively, related to fuel tax credits, representing approximately 14.5%, 13.7% and 11.8%, respectively, of our total revenue during the periods. If the fuel tax credit is not reinstated during 2010 or extended to future periods, our revenue during 2010 and any such future periods will be materially reduced and our financial performance will suffer. Analysts that write research on our company may also reduce their ratings or make negative adjustments to their future expectations of our financial performance if the fuel excise tax credit is not reinstated or extended to future periods, which may also result in a decrease in the price of our common stock.

In the event that the NAT GAS Act passes, we may need to raise debt or equity capital to fund capital expenditures included in our 2010 capital budget.

Our capital expenditure budget for 2010 anticipates substantial capital investment in the event that federal legislation providing incentives for the production and use of natural gas vehicles known as the NAT GAS Act, or HR 1835 (the New Alternative Transportation to Give Americans Solutions Act), is successfully passed into law. If this legislation or other similar federal legislation providing substantial incentives for the sale and use of natural gas vehicles is passed, we anticipate that will need to raise capital to make the capital investments required to build the natural gas fueling infrastructure to meet anticipated demand. Our 2010 capital plan, assuming the passage of the NAT GAS Act or legislation providing for similar incentives, anticipates $86.3 million of capital expenditures during 2010, and as of December 31, 2009, we have $67.1 million in cash and $20.0 million in credit available under our line of credit from PlainsCapitalBank. If the NAT GAS Act is passed into law and we are unable to raise sufficient capital to make the investments called for under our 2010 capital budget, our ability to increase revenues through growth in customers and sales will be reduced and competitors may be successful in capturing growth in the natural gas fueling business that is incentivized by the NAT GAS Act.

We may need to raise debt or equity capital to fund unanticipated expenses, capital expenditures, mergers and acquisitions or strategic investments.

If the NAT GAS Act is not passed into law, we may nevertheless be required to raise debt or equity capital to fund unanticipated expenses, capital expenditures, mergers, acquisitions or strategic investments. Equity or debt financing options may not be available on terms favorable to us or at all, particularly if there are no effective federal incentives supporting the growth of the natural gas fueling business. Additional sales of our common stock or securities convertible into our common stock will dilute existing stockholders and may result in a decline in our stock price. We may also pursue debt financing options including, but not limited to, equipment financing, the sale of convertible promissory notes or commercial bank financing. Recent economic turmoil and severe lack of liquidity in the debt capital markets and volatility and rapidly falling prices in the equity capital markets have severely and adversely affected capital raising opportunities. If we are unable to obtain debt or equity financing in amounts sufficient to fund any unanticipated expenses, capital expenditures, mergers, acquisitions or strategic investments, we will be forced to suspend or curtail these capital expenditures or postpone or

delay potential acquisitions or other strategic transactions, which could harm our business, results of operations, and future prospects.

Our growth depends in part on tax and related government incentives for clean burning fuels and alternative fuel vehicles. A reduction in these incentives or the failure to pass new legislation with new incentive programs will increase the cost of natural gas fuel and vehicles for our customers and will significantly reduce our revenue.

Our business depends in part on tax credits, rebates and similar federal, state and local government incentives that promote the use of natural gas as a vehicle fuel in the United States. The federal fuel excise tax credit for the sale of natural gas fuel expired on December 31, 2009 and the federal income tax credit that is available to offset 50% to 80% of the incremental cost of purchasing new or converted natural gas vehicles is scheduled to expire on December 31, 2010, and if these tax credits are not extended, it will have a detrimental effect on the natural gas vehicle industry, including sales at our wholly owned subsidiary, BAF Technologies, Inc., and adversely affect our results of operations and financial performance. Our business plan and the ability of our business to successfully grow depends in part on the reinstatement and extension of the federal fuel excise tax credit for natural gas vehicle fuel, the extension of the federal income tax credit for the purchase of natural gas vehicles and the passage of legislation providing for additional incentives for the sale and use of natural gas vehicles, such as the NAT GAS Act. If existing federal incentives are not reinstated or extended and if new incentive programs like the NAT GAS Act are not passed, fewer natural gas vehicles will be sold and used and our revenue and financial performance will be adversely affected. In addition, if grant funds are no longer available under existing government programs for the purchase and construction of natural gas vehicles and stations, the purchase of or conversion to natural gas vehicles and station construction could slow and our business and results of operations will be adversely affected. Continued reduction in tax revenues associated with high unemployment rates, economic recession or slow-down could result in a significant reduction in funds available for government grants that support vehicle conversion and station construction, which could impair our ability to grow our business.

Automobile and engine manufacturers produce very few originally manufactured natural gas vehicles and engines for the U.S. and Canadian markets, which may restrict our sales.

Limited availability of natural gas vehicles restricts their wide scale introduction and narrows our potential customer base. Original equipment manufacturers produce a small number of natural gas engines and vehicles, and they may not make adequate investments to expand their natural gas engine and vehicle product lines. For the North American market, there is only one major automobile manufacturer that makes natural gas powered passenger vehicles, and major manufacturers of medium and heavy duty vehicles produce only a narrow range and number of natural gas vehicles. In addition, the only natural gas vehicle engine designed for Class 8 trucks available in North America is not certified by the EPA for 2010 emission standards, and therefore cannot be sold until the EPA certification is obtained. The technology utilized in some of the heavy duty vehicles that run on LNG is also relatively new and has not been previously deployed or used in large numbers of vehicles. As a result, these vehicles may require servicing and further technology refinements to address performance issues that may occur as vehicles are deployed in large numbers and are operated under strenuous conditions. If potential heavy duty LNG truck purchasers are not satisfied with truck performance, the existing Class 8 natural gas engines are not 2010 certified or additional heavy duty truck engine manufacturers do not enter the market for LNG engines, it may delay, impair, or eliminate the growth of our LNG fueling business, which would impair our financial performance. Further, North American car and truck manufacturers are facing significant economic challenges that may make it difficult or impossible for them to introduce new natural gas vehicles in the North American market or continue to manufacture and support the limited number of available natural gas vehicles. Due to the limited

supply of natural gas vehicles, our ability to promote natural gas vehicles and our natural gas fuel sales may be restricted, even if there is demand.

Decreases in the price of oil, gasoline and diesel fuel without similar decreases in the price of natural gas may slow the growth of our business and negatively impact our financial results.

Prices for oil, gasoline and diesel fuel have declined substantially from the recent high prices reached in the summer of 2008. The price of a barrel of crude oil has declined from a high of $148.35 per barrel reached on July 11, 2008 to a price of $79.36 per barrel on December 31, 2009. Average retail prices for ultra low sulfur diesel fuel in California have declined from a high of $5.03 in May and June 2008 to $2.90 per gallon at December 31, 2009, and average retail prices for gasoline in California have declined from a high of $4.59 per gallon in June 2008 to $2.93 per gallon at December 31, 2009. The decrease in the price of diesel and gasoline, in particular, has resulted in reduced interest in alternative fuels such as LNG and CNG. Decreased interest in alternative fuels will slow the growth of our business. In addition, to the extent that we price our CNG and LNG fuel at a discount to these reduced diesel or gasoline prices in an effort to attract new and retain existing customers, our profit margin on fuel sales may be harmed and our financial results negatively impacted. Our retail prices for LNG fuel in California decreased from $3.70 per diesel gallon equivalent in June and July of 2008 to $2.20 per diesel gallon equivalent at December 31, 2009, and our retail prices for CNG fuel sold in the Los Angeles Basin decreased from a high of $3.30 per gasoline gallon equivalent in July of 2008 to $2.50 per gasoline gallon equivalent at December 31, 2009. Lower fuel prices for CNG and LNG as a result of lower natural gas commodity prices also will reduce our revenues.

If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline and diesel, potential fleet customers will have less incentive to purchase natural gas vehicles, which would decrease demand for CNG and LNG and limit our growth.

Natural gas vehicles cost more than comparable gasoline or diesel powered vehicles because converting a vehicle to use natural gas adds to its base cost. If the prices of CNG and LNG do not remain sufficiently below the prices of gasoline or diesel, fleet operators may be unable to recover the additional costs of acquiring or converting to natural gas vehicles in a timely manner, and they may choose not to use natural gas vehicles. Our ability to offer CNG and LNG fuel to our customers at lower prices than gasoline and diesel depends in part on natural gas prices remaining lower, on an energy equivalent basis, than oil prices. If the price of oil declines and the price of natural gas increases, it will make it more difficult for us to offer our customers discounted prices for CNG and LNG as compared to gasoline and diesel prices and maintain an acceptable margin on our sales. Recent and significant volatility in oil and gasoline prices demonstrate that it is difficult to predict future transportation fuel costs. In addition, any new regulations imposed on natural gas extraction in the United States, particularly on extraction of natural gas from shale formations, could increase the costs of domestic gas production or make it unprofitable to produce natural gas in the United States, which could lead to substantial increases in the price of natural gas. Reduced prices for gasoline and diesel fuel and continuing uncertainty about fuel prices, combined with higher costs for natural gas and natural gas vehicles, may cause potential customers to delay or reject converting their fleets to run on natural gas. In that event, our sales of natural gas fuel and vehicles would be slowed and our business would suffer.

The volatility of natural gas prices could adversely impact the adoption of CNG and LNG vehicle fuel and our business.

In the recent past, the price of natural gas has been volatile, and this volatility may continue. From the end of 1999 through the end of 2009, the price for natural gas, based on the NYMEX daily futures data, ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. As of March 1, 2010, the

NYMEX index price for natural gas was $4.81 per Mcf. Increased natural gas prices affect the cost to us of natural gas and will adversely impact our operating margins in cases where we have committed to sell natural gas at a fixed price without an effective futures contract in place that fully mitigates the price risk or where we otherwise cannot pass on the increased costs to our customers. In addition, higher natural gas prices may cause CNG and LNG to cost as much as or more than gasoline and diesel generally, which would adversely impact the adoption of CNG and LNG as a vehicle fuel. Conversely, lower natural gas prices reduce our revenues due to the fact that in a significant amount of our customer agreements the commodity cost is passed through to the customer. Among the factors that can cause price fluctuations in natural gas prices are changes in domestic and foreign supplies of natural gas, domestic storage levels, crude oil prices, the price difference between crude oil and natural gas, price and availability of alternative fuels, weather conditions, level of consumer demand, economic conditions, price of foreign natural gas imports, and domestic and foreign governmental regulations and political conditions. In particular, there have been recent legislative efforts to place new regulatory requirements on the production of natural gas by hydraulic fracturing of shale gas reservoirs. Hydraulic fracturing of shale gas reservoirs has resulted in a substantial increase in the proven natural gas reserves in the United States, and any change in regulations that makes it substantially more expensive or unprofitable to produce natural gas through hydraulic fracturing could lead to increased natural gas prices. The recent economic recession and increased domestic natural gas supplies have contributed to significant declines in the price of natural gas since the summer of 2008.

Our growth depends in part on environmental regulations and programs mandating the use of cleaner burning fuels, and modification or repeal of these regulations may adversely impact our business.

Our business depends in part on environmental regulations and programs in the United States that promote or mandate the use of cleaner burning fuels, including natural gas for vehicles. In particular, the Ports of Los Angeles and Long Beach have adopted the San Pedro Bay Ports Clean Air Action Plan, which outlines a Clean Trucks Program that calls for the replacement of drayage trucks with trucks that meet certain clean truck standards. Industry participants with a vested interest in gasoline and diesel, many of which have substantially greater resources than we do, invest significant time and money in an effort to influence environmental regulations in ways that delay or repeal requirements for cleaner vehicle emissions. Further, an economic recession may result in the delay, amendment or waiver of environmental regulations or the Clean Trucks Program due to the perception that they impose increased costs on the transportation industry that cannot be absorbed in a contracting economy. For example, the Clean Trucks Program formerly called for the replacement of a set number of drayage trucks with "clean" trucks, but due to economic conditions and other factors, the Clean Trucks Program no longer calls for any specific number of "clean" truck replacements. In addition, many of the clean trucks that have been deployed have been clean diesel trucks which are generally less expensive than LNG trucks. There have also been recent ballot initiatives commenced in the State of California and political support for postponing or delaying California's implementation of AB 32, which is intended to reduce greenhouse gas emissions. CNG, LNG and biomethane vehicle fuel all produce fewer greenhouse gases than gasoline or diesel fuel and the delay or repeal of AB 32, and in particular California's low-carbon fuel standard, could reduce the appeal of natural gas fuel for our customers and reduce our revenue. The delay, repeal or modification of federal or state regulations or programs that encourage the use of cleaner vehicles, and in particular the Clean Trucks Program outlined in the San Pedro Bay Ports Clean Air Action Plan, could also have a detrimental effect on the U.S. natural gas vehicle industry, which, in turn, could slow our growth and adversely affect our business.

The use of natural gas as a vehicle fuel may not become sufficiently accepted for us to expand our business.

To expand our business, we must develop new fleet customers and obtain and fulfill CNG and LNG fueling contracts from these customers. We cannot guarantee that we will be able to develop

these customers or obtain these fueling contracts. Whether we will be able to expand our customer base will depend on a number of factors, including the level of acceptance and availability of natural gas vehicles, the growth in our target markets of fueling station infrastructure that supports CNG and LNG sales and our ability to supply CNG and LNG at competitive prices. The decline in oil, diesel and gasoline prices from the levels they reached during the summer of 2008 has resulted in decreased interest in alternative fuels like CNG and LNG. In addition, the disruption in the capital markets that began in 2008 has reduced the availability of debt financing to support the purchase of CNG and LNG vehicles and investment in CNG and LNG infrastructure. If our potential customers are unable to access credit to purchase natural gas vehicles, it may make it difficult or impossible for them to invest in natural gas vehicle fleets, which would impair the ability of our business to grow.

We cannot be certain that we will be successful in managing or integrating our recently acquired subsidiary, BAF Technologies, Inc., with our existing operations.

On October 1, 2009, we closed our acquisition of 100% of the equity interests of BAF Technologies, Inc., which is now our wholly owned subsidiary. BAF provides natural gas vehicle conversions, alternative fuel systems, application engineering, service and warranty support and research and development services. Historically, BAF has suffered net operating losses and required outside financing to support its ongoing business. Our ability to realize benefits from the acquisition depends on our ability to improve BAF's financial performance in comparison to its historical financial results. Our management team has limited experience managing a vehicle conversion company and BAF represents a new product offering for our company. The successful management and integration of BAF's operations will present significant challenges, including realizing economies of scale and integrating internal financial and operational systems. We cannot assure you that we will realize any anticipated benefits or will successfully integrate any of the acquired operations with our existing operations. In addition, the BAF operations do not have the disclosure controls and procedures or internal controls over financial reporting that are as thorough or effective as those required for public companies. Although we intend to implement appropriate controls and procedures as we integrate the BAF operations, we cannot provide assurance as to the effectiveness of BAF's disclosure controls and procedures or internal controls over financial reporting until we have fully integrated them.

Failure to comply with the terms of our Credit Agreement with PlainsCapital Bank could impair our rights in DCE and other secured property.

In August 2008, we acquired a 70% interest in DCE, which manages a biomethane production facility at the McCommas Bluff landfill in Dallas, Texas and holds a lease to the associated landfill gas development rights. We borrowed $18 million from PlainsCapital Bank ("PCB") to fund the acquisition and obtained a $12 million line of credit from PCB to pay certain costs and expenses of the acquisition and finance capital improvements of the gas processing plant through a loan made by us to DCE. We have used $12.0 million of the line of credit from PCB and the outstanding balance was $10.0 million as of December 31, 2009. In October, 2009, we repaid the $18 million loan that we used to fund the acquisition of DCE and amended the Credit Agreement to obtain a $20 million line of credit from PlainsCapital Bank to finance capital expenditures and working capital for our operations and for other general business purposes. As of the date of filing of this Form 10-K for the period ending December 31, 2009, we had not borrowed any money under the $20 million line of credit. To secure our obligations under the Credit Agreement, we granted PCB a security interest in 45 of our LNG tanker trailers, certain accounts receivable and inventory, and our note receivable from, and our membership interests in DCE. Our Credit Agreement with PCB requires that we comply with certain covenants. One of the covenants requires that we maintain accounts receivable balances from certain subsidiaries above $8 million at each quarter-end during the term. To the extent natural gas prices fall, which would result in decreased revenues, or our volumes sold decline, we could violate this covenant. Also, beginning with the quarter ending June 30, 2009, we are required to maintain a specific minimum

debt service ratio. Should our operating results not materialize as planned, we could violate this covenant. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant a waiver, all of the obligations under the Credit Agreement will become immediately due and payable and $2.5 million of our funds held by PCB would be applied to the balance due on the PCB loans. We also would be unable to use the $20 million PCB line of credit if this were to occur.

The infrastructure to support gasoline and diesel consumption is vastly more developed than the infrastructure for natural gas vehicle fuels.

Gasoline and diesel fueling stations and service infrastructure are widely available in the United States. For natural gas vehicle fuels to achieve more widespread use in the United States and Canada, they will require a promotional and educational effort and the development and supply of more natural gas vehicles and fueling stations. This will require significant continued effort by us, as well as government and clean air groups, and we may face resistance from oil companies and other vehicle fuel companies. A prolonged economic recession and continued disruption in the capital markets may make it difficult or impossible to obtain financing to expand the natural gas vehicle fueling infrastructure and impair our ability to grow our business. There is no assurance natural gas will ever achieve the level of acceptance as a vehicle fuel necessary for us to expand our business significantly.

Conversion of vehicles to run on natural gas is time-consuming and expensive and may limit the growth of our sales.

Conversion of vehicle engines from gasoline or diesel to natural gas is performed by only a small number of vehicle conversion suppliers (including our wholly owned subsidiary, BAF Technologies, Inc.) that must meet stringent safety and engine emissions certification standards. The engine certification process is time consuming and expensive and raises vehicle costs. In addition, conversion of vehicle engines from gasoline or diesel to natural gas may result in vehicle performance issues or increased maintenance costs that could discourage our potential customers from purchasing converted vehicles that run on natural gas and impair the financial performance of our recently acquired subsidiary, BAF. Without an increase in vehicle conversion options, reduced vehicle conversion costs and improved vehicle conversion performance, our sales of natural gas vehicle fuel and converted natural gas vehicles (through our recently acquired subsidiary BAF) may be restricted and our revenue will be reduced both by less demand for natural gas vehicle fuel and less demand for converted natural gas vehicles.

A majority of our sales of CNG vehicles are to one customer. If this customer does not continue to purchase CNG vehicles, then revenue at our wholly owned subsidiary, BAF, will decline and our financial results will be impaired.

During 2009, our wholly owned subsidiary, BAF Technologies, Inc., derived approximately 63% of its revenue from AT&T. During 2010, BAF anticipates that a similar percentage of its revenue will also be derived from sales to AT&T. AT&T is not required to purchase any conversion kits under its agreement with BAF and the agreement and all purchase orders submitted by AT&T under the agreement may be cancelled by AT&T at any time for any reason. If AT&T does not continue to order and pay for CNG conversion kits produced by BAF, then BAF's sales revenue will substantially decline and our financial performance may suffer.

If there are advances in other alternative vehicle fuels or technologies, or if there are improvements in gasoline, diesel or hybrid engines, demand for natural gas vehicles may decline and our business may suffer.

Technological advances in the production, delivery and use of alternative fuels that are, or are perceived to be, cleaner, more cost-effective or more readily available than CNG or LNG have the potential to slow adoption of natural gas vehicles. Advances in gasoline and diesel engine technology, especially hybrids, may offer a cleaner, more cost-effective option and make fleet customers less likely to convert their fleets to natural gas. Technological advances related to ethanol or biodiesel, which are increasingly used as an additive to, or substitute for, gasoline and diesel fuel, may slow the need to diversify fuels and affect the growth of the natural gas vehicle market. In addition, a prototype heavy duty electric truck model was recently introduced at the ports of Los Angeles and Long Beach. Use of electric heavy duty trucks or the perception that electric heavy duty trucks may soon be widely available and provide satisfactory performance in heavy duty applications may reduce demand for heavy duty LNG trucks. In addition, hydrogen and other alternative fuels in experimental or developmental stages may eventually offer a cleaner, more cost-effective alternative to gasoline and diesel than natural gas. Advances in technology that slow the growth of or conversion to natural gas vehicles, or which otherwise reduce demand for natural gas as a vehicle fuel, will have an adverse effect on our business. Failure of natural gas vehicle technology to advance at a sufficient pace may also limit its adoption and our ability to compete with other alternative fuels and alternative fuel vehicles.

Our ability to supply LNG to new and existing customers is restricted by limited production of LNG and by our ability to source LNG without interruption and near our target markets.

Production of LNG in the United States is fragmented. LNG is produced at a variety of smaller natural gas plants around the United States, as well as at larger plants. It may become difficult for us to obtain additional LNG without interruption and near our current or target markets at competitive prices. If our LNG liquefaction plants, or any of those from which we purchase LNG, are damaged by severe weather, earthquake or other natural disaster, or otherwise experience prolonged downtime, our LNG supply will be restricted. If we are unable to supply enough of our own LNG or purchase it from third parties to meet existing customer demand, we may be liable to our customers for penalties. Our growth plans, if successful, will require substantial growth in the available LNG supply across the United States, and if this supply is unavailable, it will necessarily constrain our ability to grow the market for LNG fuel including supplying LNG fuel to heavy duty truck consumers. An LNG supply interruption or LNG demand that exceeds available supply will also limit our ability to expand LNG sales to new customers and could disrupt our relationship with existing customers, which would hinder our growth. Furthermore, because transportation of LNG is relatively expensive, if we are required to supply LNG to our customers from distant locations and cannot push these costs on to our customers, our operating margins will decrease on those sales due to our increased transportation costs.

LNG supply purchase commitments may exceed demand causing our costs to increase and impact LNG sales margins.

Two of our LNG supply agreements have a take or pay commitment and our California LNG liquefaction plant has land lease and other fixed operating costs regardless of production and sales levels. The take or pay commitments, one of which we anticipate will commence in March 2010 when the supplier's LNG plant commences operations, require us to pay for the LNG that we have agreed to purchase irrespective of whether we can sell the LNG to our own customers. Should the market demand for LNG decline or if we lose significant LNG customers or if demand under any existing or any future LNG supply contract does not maintain its volume levels or grow, overall operating and supply costs may increase as a percentage of revenue and negatively impact our margins.

One of our third-party LNG suppliers may cancel its supply contract with us on short notice or increase its LNG prices, which would hinder our ability to meet customer demand and increase our costs.

Under certain circumstances, Williams Gas Processing Company ("Williams") may terminate our LNG supply contract with them on short notice. Williams may also significantly increase the price of LNG we purchase upon 24 hours' notice if their costs to produce LNG increases, and we may be required to reimburse them for certain other expenses. Our contract with Williams, which supplied 32% of the LNG we sold for the year ended December 31, 2007, 29% for the year ended December 31, 2008, and 14% for the year ended December 31, 2009, expires on June 30, 2011. Furthermore, there are a limited number of LNG suppliers in or near the areas where our LNG customers are located. It may be difficult to replace an LNG supplier, and we may be unable to obtain alternate suppliers at acceptable prices, in a timely manner or at all. If significant supply interruptions occur, our ability to meet customer demand will be impaired, customers may cancel orders and we may be subject to supply interruption penalties. If we are subject to LNG price increases, our operating margins may be impaired and we may be forced to sell LNG at a loss under our LNG supply contracts.

If we are unable to obtain natural gas in the amounts needed on a timely basis or at reasonable prices, we could experience an interruption of CNG or LNG deliveries or increases in CNG or LNG costs, either of which could have an adverse effect on our business.

Some regions of the United States and Canada depend heavily on natural gas supplies coming from particular fields or pipelines. Interruptions in field production or in pipeline capacity could reduce the availability of natural gas or possibly create a supply imbalance that increases natural gas prices. We have in the past experienced LNG supply disruptions due to severe weather in the Gulf of Mexico and plant outages. If there are interruptions in field production, insufficient pipeline capacity, equipment failure on liquefaction production or delivery delays, we may experience supply stoppages which could result in our inability to fulfill delivery commitments. This could result in our being liable for contractual damages and daily penalties or otherwise adversely affect our business.

Oil companies and natural gas utilities, which have far greater resources and brand awareness than we have, may expand into the natural gas fuel market, which could harm our business and prospects.

There are numerous potential competitors who could enter the market for CNG and LNG vehicle fuels. Many of these potential entrants, such as integrated oil companies and natural gas utilities, have far greater resources and brand awareness than we have. If the use of natural gas vehicles and demand for natural gas vehicle fuel increases, these companies may find it more attractive to enter the market for natural gas vehicle fuels and we may experience increased pricing pressure, reduced operating margins and fewer expansion opportunities.

If we do not have effective futures contracts in place, increases in natural gas prices may cause us to lose money.

From 2005 to 2008, we sold and delivered approximately 30% of our total gasoline gallon equivalents of CNG and LNG under contracts that provided a fixed price or a price cap to our customers over terms typically ranging from one to three years, and in some cases up to five years. At any given time, however, the market price of natural gas may rise and our obligations to sell fuel under fixed price contracts may be at prices lower than our fuel purchase or production price if we do not have effective futures contracts in place. This circumstance has in the past and may again in the future compel us to sell fuel at a loss, which would adversely affect our results of operations and financial condition. Commencing with the adoption of our revised natural gas hedging policy in February 2007, our policy has been to purchase futures contracts to hedge our exposure to variability related to our fixed price contracts. Such contracts, however, may not be available or we may not have sufficient

financial resources to secure such contracts. In addition, under our hedging policy, we may reduce or remove futures contracts we have in place related to these contracts if such disposition is approved in advance by our board of directors and derivative committee. If we are not economically hedged with respect to our fixed price contracts, we will lose money in connection with those contracts during periods in which natural gas prices increase above the prices of natural gas included in our customers' contracts. As of December 31, 2009, we were economically hedged with respect to all four of our fixed price contracts with our customers.

Our futures contracts may not be as effective as we intend.

Our purchase of futures contracts can result in substantial losses under various circumstances, including if we do not accurately estimate the volume requirements under our fixed price customer contracts when determining the volumes included in the futures contracts we purchase, or we are required to purchase a futures contract in connection with a bid proposal and ultimately we are not awarded the entire contract or our customer does not fully perform its obligations under the awarded contract. We also could incur significant losses if a counterparty does not perform its obligations under the applicable futures arrangement, the futures arrangement is economically imperfect or ineffective, or our futures policies and procedures are not properly followed or do not work as planned. Furthermore, we cannot assure that the steps we take to monitor our futures activities will detect and prevent violations of our risk management policies and procedures.

A decline in the value of our futures contracts may result in margin calls that would adversely impact our liquidity.

We are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Payments we make to satisfy margin calls will reduce our cash reserves, adversely impact our liquidity and may also adversely impact our ability to expand our business. Moreover, if we are unable to satisfy the margin calls related to our futures contracts, our broker may sell these contracts to restore the margin requirement at a substantial loss to us. At December 31, 2009, we had $2.9 million on deposit related to our futures contracts.

If our futures contracts do not qualify for hedge accounting, our net income and stockholders' equity will fluctuate more significantly from quarter to quarter based on fluctuations in the market value of our futures contracts.

We account for our futures activities under the relevant derivative accounting guidance, which requires us to value our futures contracts at fair market value in our financial statements. Our futures contracts historically have not qualified for hedge accounting, and therefore we have recorded any changes in the fair market value of these contracts directly in our consolidated statements of operations in the line item "derivative (gains) losses" along with any realized gains or losses during the period. Currently, we attempt to qualify all of our futures contracts for hedge accounting under the relevant derivative accounting guidance, but there can be no assurances that we will be successful in doing so. At December 31, 2009, all of our futures contracts qualified for hedge accounting. To the extent that all or some of our futures contracts do not qualify for hedge accounting, we could incur significant increases and decreases in our net income and stockholders' equity in the future based on fluctuations in the market value of our futures contracts from quarter to quarter. For example, related to our natural gas futures contracts, we experienced a derivative gain of $33.1 million and $5.7 million for the three months ended September 30, 2005 and June 30, 2008, respectively, and experienced derivative losses of $19.9 million, $0.3 million, $65.0 million, $13.7 million, $6.0 million and $0.3 million for the

three months ended December 31, 2005, March 31, 2006, September 30, 2006, December 31, 2006, September 30, 2008 and December 31, 2008, respectively. We had no derivative gains or losses related to our natural gas futures contracts for the three months ended June 30, 2006, March 31, 2007, June 30, 2007, September 30, 2007, December 31, 2007, March 31, 2008, March 31, 2009, June 30, 2009, September 30, 2009 and December 31, 2009. Any negative fluctuations may cause our stock price to decline due to our failure to meet or exceed the expectations of securities analysts or investors.

Compliance with potential greenhouse gas regulations affecting our LNG plants or fueling stations may prove costly and negatively affect our financial performance.

California has adopted legislation, AB 32, or the Global Warming Solutions Act, which calls for a cap on greenhouse gas emissions throughout California and a statewide reduction to 1990 levels by 2020, and an additional 80% reduction below 1990 levels by 2050. Seven western U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec) formed the Western Climate Initiative to help combat climate change. Other states and the federal government are considering passing measures to regulate and reduce greenhouse gas emissions. Any of these regulations, when and if implemented, may regulate the greenhouse gas emissions produced by our LNG production plants in California and Texas or our LNG and CNG fueling stations and require that we obtain emissions credits or invest in costly emissions prevention technology. We cannot currently estimate the potential costs associated with federal or state regulation of greenhouse gas emissions from our LNG plants or LNG and CNG stations, and these unknown costs are not contemplated in the financial terms of our customer agreements. These unanticipated costs may have a negative impact on our financial performance and may impair our ability to fulfill customer contracts at an operating profit.

Natural gas fueling operations and vehicle conversions entail inherent safety and environmental risks that may result in substantial liability to us.

Natural gas fueling operations and vehicle conversions entail inherent risks, including equipment defects, malfunctions and failures and natural disasters, which could result in uncontrollable flows of natural gas, fires, explosions and other damages. For example, operation of LNG pumps requires special training and protective equipment because of the extreme low temperatures of LNG. LNG tanker trailers have also in the past been, and may in the future be, involved in accidents that result in explosions, fires and other damage. Improper refueling of LNG vehicles can result in venting of methane gas, which is a potent greenhouse gas, and LNG related methane emissions may in the future be regulated by the EPA or by state regulations. Additionally, CNG fuel tanks, if damaged or improperly maintained, may rupture and the contents of the tank may rapidly decompress and result in death or injury. In 2007, a driver of a CNG van in Los Angeles was killed when the previously damaged tanks he was fueling ruptured. These risks may expose us to liability for personal injury, wrongful death, property damage, pollution and other environmental damage. We may incur substantial liability and cost if damages are not covered by insurance or are in excess of policy limits.

Our business is heavily concentrated in the western United States, particularly in California and Arizona. Continuing economic downturns in these regions could adversely affect our business.

Our operations to date have been concentrated in California and Arizona. For the years ended December 31, 2007, 2008 and 2009, sales in California accounted for 40%, 45% and 49% respectively, and sales in Arizona accounted for 20%, 14% and 10%, respectively, of the total amount of gallons we delivered. A decline in the economy in these areas could slow the rate of adoption of natural gas vehicles, reduce fuel consumption or reduce the availability of government grants, any of which could negatively affect our growth.

We provide financing to fleet customers for natural gas vehicles, which exposes our business to credit risks.

We loan to certain qualifying customers on average 75%, and occasionally up to 100%, of the purchase price of natural gas vehicles. We may also lease vehicles to customers in the future. There are risks associated with providing financing or leasing that could cause us to lose money. Some of these risks include: most of the equipment financed consists of vehicles, which are mobile and easily damaged, lost or stolen, there is a risk the borrower may default on payments, we may not be able to bill properly or track payments in adequate fashion to sustain growth of this service, and the amount of capital available to us is limited and may not allow us to make loans required by customers. Some of our customers, such as taxi owners, may depend on the CNG vehicles that we finance or lease to them as their sole source of income, which may make it difficult for us to recover the collateral in a bankruptcy proceeding. The continued disruption in the credit markets may further reduce the amount of capital available to us and an economic recession or continued economic contraction may increase the rate of default by borrowers, leading to an increase in losses on our loan portfolio. As of December 31, 2009, we had $3.6 million outstanding in loans provided to customers to finance natural gas vehicle purchases.

We may incur losses and use working capital if we are unable to place with customers the natural gas vehicles that we or our business partners order from manufacturers.

To ensure availability for our customers, from time to time we enter into binding purchase agreements for natural gas vehicles when there is a production lead time. Although we attempt to arrange for customers to purchase the vehicles before delivery to us, we may be unable to locate purchasers on a timely basis and consequently may need to take delivery of and title to the vehicles. These purchases would adversely affect our cash reserves until such time as we can sell the vehicles to our customers, and we may be forced to sell the vehicles at a loss. At December 31, 2009, we had $0.6 million in aggregate deposits outstanding on natural gas vehicles.

We have significant contracts with federal, state and local government entities that are subject to unique risks.

We have existing, and will continue to seek, long-term LNG and CNG station construction, maintenance and fuel sales contracts with various federal, state and local governmental bodies, which accounted for approximately 64% of our yearly revenues from 2006 through 2009. In May 2009, we spent $5.6 million to acquire four new CNG operation and maintenance contracts with government agencies. In addition to our normal business risks, our contracts with these government entities are often subject to unique risks, some of which are beyond our control. Long-term government contracts and related orders are subject to cancellation if appropriations for subsequent performance periods are not made. The termination of funding for a government program supporting any of our CNG or LNG operations could result in a loss of anticipated future revenues attributable to that program, which could have a negative impact on our operations. In addition, government entities with whom we contract are often able to modify, curtail or terminate contracts with us without prior notice at their convenience, and are only liable for payment for work done and commitments made at the time of termination. Modification, curtailment or termination of significant contracts could have a material adverse effect on our results of operations and financial condition. In particular, if any of the contracts we recently acquired are terminated, we may be unable to recover our investment in acquiring the contracts. Further, many governmental entities are experiencing significant budget deficits as a result of the economic recession, which has and may continue to reduce or curtail their ability to fund natural gas fuel programs, purchase natural gas vehicles or provide public transportation and services, which would harm our business.

Our business is subject to a variety of governmental regulations that may restrict our business and may result in costs and penalties.

We are subject to a variety of federal, state and local laws and regulations relating to the environment, health and safety, labor and employment and taxation, among others. These laws and regulations are complex, change frequently and have tended to become more stringent over time. Failure to comply with these laws and regulations may result in a variety of administrative, civil and criminal enforcement measures, including assessment of monetary penalties and the imposition of remedial requirements. From time to time, as part of the regular overall evaluation of our operations, including newly acquired operations, we may be subject to compliance audits by regulatory authorities. In addition, any failure to comply with regulations related to the government procurement process at the federal, state or local level or restrictions on political activities and lobbying may result in administrative or financial penalties including being barred from providing services to governmental entities, which accounted for approximately 64% of our yearly revenues from 2006 through 2009.

In connection with our LNG liquefaction activities and the landfill gas processing facility operated by DCE, we need or may need to apply for additional facility permits or licenses to address storm water or wastewater discharges, waste handling, and air emissions related to production activities or equipment operations. This may subject us to permitting conditions that may be onerous or costly. Compliance with laws and regulations and enforcement policies by regulatory agencies could require us to make material expenditures, which may distract our officers, directors and employees from the operation of our business.

Operational issues, permitting and other factors at DCE's landfill gas processing facility may adversely affect both DCE's ability to supply biomethane and our operating results.

In August 2008, we acquired our 70% interest in DCE. In April 2009, DCE entered into a 15-year gas sale agreement with Shell for the sale to Shell of specified levels of biomethane produced by DCE's landfill gas processing facility. There is, however, no guarantee that DCE will be able to produce or sell up to the maximum volumes called for under the agreement. DCE's ability to produce such volumes of biomethane depends on a number of factors beyond DCE's control, including, but not limited to, the availability and composition of the landfill gas that is collected, successful permitting, the impact of operation of the landfill by the City of Dallas and the reliability of the processing facility's critical equipment. The DCE facility is subject to periods of reduced production or non-production due to upgrades, maintenance, repairs and other factors. For example, as part of an operational upgrade in March 2009, the facility was shut down for approximately one month. More recently, on June 12, 2009, the facility was taken offline for repairs that were completed on July 2, 2009. We anticipate that the facility will incur additional downtime related to replacing the gas driven compression with electric driven compression during 2010. Future operational upgrades or complications in the operations of the facility could require additional shutdowns, and accordingly, DCE's revenues may fluctuate from quarter to quarter.

Our quarterly results of operations have not been predictable in the past and have fluctuated significantly and may not be predictable and may fluctuate in the future.

Our quarterly results of operations have historically experienced significant fluctuations. Our net losses were approximately $0.9 million, $3.6 million, $1.5 million, $2.9 million, $5.4 million, $3.2 million, $12.1 million, $23.7 million, $6.5 million, $6.4 million, $18.5 million and $1.9 million for the three months ended March 31, 2007, June 30, 2007, September 30, 2007, December 31, 2007, March 31, 2008, June 30, 2008, September 30, 2008, December 31, 2008, March 31, 2009, June 30, 2009, September 30, 2009 and December 31, 2009, respectively. Our quarterly results may fluctuate significantly as a result of a variety of factors, many of which are beyond our control. In particular, if our stock price increases or decreases in future periods during which our Series I warrants are

outstanding, we may be required to recognize corresponding losses or gains related to the valuation of the Series I warrants that could materially impact our results of operations. If our quarterly results of operations fall below the expectations of securities analysts or investors, the price of our common stock could decline substantially. Fluctuations in our quarterly results of operations may be due to a number of factors, including, but not limited to, our ability to increase sales to existing customers and attract new customers, the addition or loss of large customers, construction cost overruns, downtime at our facilities (including the recent shutdowns in March and June 2009 of DCE's landfill gas processing facility), the amount and timing of operating costs, unanticipated expenses, capital expenditures related to the maintenance and expansion of our business, operations and infrastructure, changes in the price of natural gas, changes in the prices of CNG and LNG relative to gasoline and diesel, changes in our pricing policies or those of our competitors, fluctuation in the value of our outstanding Series I warrants or natural gas futures contracts, the costs related to the acquisition of assets or businesses, regulatory changes, and geopolitical events such as war, threat of war or terrorist actions. Investors in our stock should not rely on the results of one quarter as an indication of future performance as our quarterly revenues and results of operations may vary significantly in the future. Therefore, period-to-period comparisons of our operating results may not be meaningful.

The future price of our common stock or the offering price of our common stock in future offerings could result in a reduction of the exercise price of our Series I warrants and result in dilution of our common stock.

We issued Series I warrants to purchase up to 3,314,394 shares of our common stock in connection with our registered direct offering completed in November 2008. These warrants contain provisions that require an adjustment in the exercise price of the Series I warrants in the event that we price any offering of common stock at a price below the current exercise price, which is $12.68 per share after our follow-on equity offering we completed on July 1, 2009.

In addition, on November 3, 2010, the exercise price per share of the Series I warrants could be reduced if the then current market price of our common stock is sufficiently less than the then exercise price for the Series I warrants. In such an instance, the exercise price would reset to 120% of the then current market price of our common stock so long as such resulting price is less than the exercise price. If the Series I warrants are exercised, it would be dilutive to our stockholders by increasing the number of shares of our common stock outstanding, which would reduce our earnings per share.

Sales of outstanding shares of our stock into the market in the future could cause the market price of our stock to drop significantly, even if our business is doing well.

If our stockholders sell, or indicate an intention to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline. At December 31, 2009, 59,840,151 shares of our common stock were outstanding. The 11,500,000 shares sold in our initial public offering, the 4,419,192 shares of common stock and the 3,314,394 shares of common stock subject to outstanding warrants sold in our registered direct offering that closed on November 3, 2008, and the 9,430,000 shares of our common stock sold in our common stock offering that closed July 1, 2009 are freely tradable without restriction or further registration under federal securities laws unless purchased by our affiliates. Shares held by non-affiliates for more than six months may generally be sold without restriction, other than a current public information requirement, and may be sold freely without any restrictions after one year. All other outstanding shares of common stock may be sold under Rule 144 under the Securities Act, subject to applicable restrictions.

In addition, as of December 31, 2009, there were 10,348,188 shares underlying outstanding options and 18,314,394 shares underlying outstanding warrants (including the 3,314,394 Series I warrant shares sold in our registered direct offering which closed on November 3, 2008). All shares subject to outstanding options and warrants are eligible for sale in the public market to the extent permitted by

the provisions of various option and warrant agreements and Rule 144. If these additional shares are sold, or if it is perceived that they will be sold in the public market, the trading price of our stock could decline.

Further, as of December 31, 2009, 16,539,720 shares of our stock held by our co-founder and board member T. Boone Pickens are subject to a pledge agreement with a bank. Should the bank be forced to sell the shares subject to the pledge, the trading price of our stock could also decline. As previously reported on our Form 8-K filed on September 22, 2009, a number of our directors and executive officers have entered into Rule 10b5-1 Sales Plans with a broker to sell shares of our common stock that may be acquired upon the exercise of stock options. All sales of common stock under the plans will be reported through appropriate filings with the SEC.

A significant portion of our stock is beneficially owned by a single stockholder whose interests may differ from yours and who will be able to exert significant influence over our corporate decisions, including a change of control.

As of December 31, 2009, Boone Pickens and affiliates (including Madeleine Pickens, his wife) owned in the aggregate 34% of our outstanding shares of common stock and beneficially owned in the aggregate approximately 47% of the outstanding shares of our common stock, inclusive of the 15,000,000 shares underlying a warrant held by Mr. Pickens. As a result, Mr. Pickens will be able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers, acquisitions or other extraordinary transactions. Mr. Pickens may have interests that differ from yours and may vote in a way with which you disagree and which may be adverse to your interests. This concentration of ownership may have the effect of delaying, preventing or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their stock as part of a sale of our company, and might ultimately affect the market price of our stock. Conversely, this concentration may facilitate a change in control at a time when you and other investors may prefer not to sell.

Item 1B. Unresolved Staff Comments.

We have not received written comments from the SEC staff more than 180 days before the end of our 2009 fiscal year.

Item 2. Properties.

Our corporate headquarters are located at 3020 Old Ranch Parkway, Suite 400, Seal Beach, CA 90740, where we occupy approximately 29,881 square feet. Our monthly rental payments for these offices are approximately $77,000. Our office lease expires on January 31, 2015. We believe our existing facilities are adequate for our current needs.

We also lease facilities for our satellite sales and service offices in Concord, Denver, Dallas, Houston, Vancouver, and Phoenix, and our monthly rent payments for such facilities are approximately $18,000 per month in the aggregate.

The BAF Technologies Inc. headquarters are located in Dallas, TX, where they occupy approximately 81,699 square feet and our monthly rental payment is approximately $10,000. The lease expires April 30, 2012.

We own and operate the Pickens Plant located in Willis, Texas, approximately 50 miles north of Houston. We own approximately 24 acres on which the plant is situated, along with approximately 34 acres surrounding the plant.

We own an LNG liquefaction plant in Boron, California, approximately 125 miles from Los Angeles. In November 2006, we entered into a ground lease for the 36 acres on which this plant is

situated. The lease is for an initial term of 30 years, beginning on the date that the plant commences full operations, and requires annual base rent payments of $230,000 per year, plus up to $130,000 per year for each 30,000,000 gallons of production capacity utilized, subject to future adjustment based on consumer price index changes. We began paying rent on December 1, 2008. For 2009, we recorded rent expense of approximately $1.1 million, which includes royalty payments to the landlord for each gallon of LNG produced at the facility as well as for certain other services that the landlord provided.

We lease or license the land upon which we construct, operate and maintain some of our CNG and LNG fueling stations for our customers. We often own the equipment and fixtures that comprise the CNG fueling stations, and in some cases, LNG stations. The ground leases or licenses for our stations typically have a term of 10 years and require payments of a fixed amount or a variable amount based on the number of gallons sold at the site during the period. As of December 31, 2009, we leased or licensed the land for approximately 69 stations, and for the year ended December 31, 2009, paid a total of approximately $1.5 million in rent under the station ground leases and licenses.

Item 3. Legal Proceedings.

We are party to various legal actions that have arisen in the ordinary course of our business. During the course of our operations, we are also subject to audit by tax authorities for varying periods in various federal, state, local, and foreign tax jurisdictions. Disputes have and may continue to arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that we may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon our consolidated financial position or results of operations. However, we believe that the ultimate resolution of such actions will not have a material adverse effect on our consolidated financial position, results of operations, or liquidity.

Item 4. Submission of Matters to a Vote of Security Holders.

None

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information

Our common stock has been quoted on the Nasdaq Global Market under the symbol "CLNE" since May 25, 2007. Prior to that time, there was no public market for our stock. Set forth below are the high and low sales prices as reported by Nasdaq for our common stock for the periods indicated.

	Sales Prices	
	High	Low
Fiscal Year 2008		
First Quarter 2008	$16.84	$11.75
Second Quarter 2008	$15.47	$10.15
Third Quarter 2008	$19.95	$10.33
Fourth Quarter 2008	$14.70	$ 3.23
Fiscal Year 2009		
First Quarter 2009	$ 7.61	$ 4.62
Second Quarter 2009	$10.25	$ 5.89
Third Quarter 2009	$15.18	$ 7.81
Fourth Quarter 2009	$16.57	$10.95

Holders

There were approximately 73 stockholders of record as of March 8, 2010. We believe there are approximately 47,475 stockholders of our common stock held in street name.

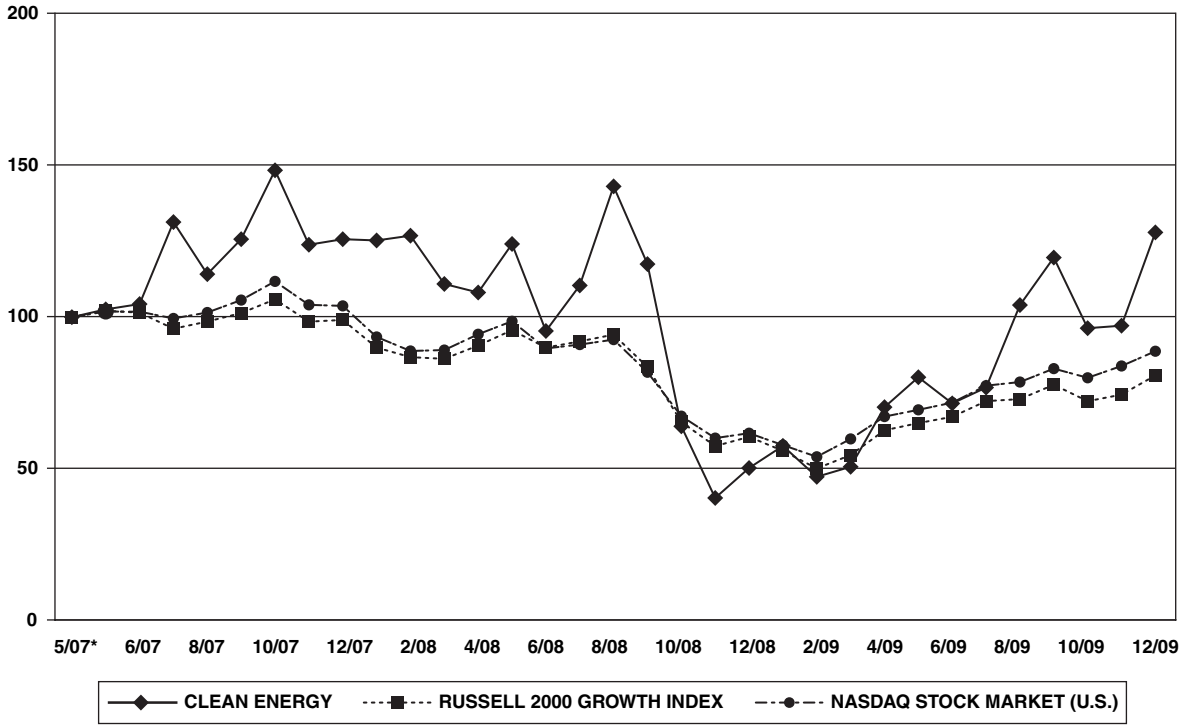
Dividend Policy

We have not paid any dividends to date and do not anticipate paying any dividends on our common stock in the foreseeable future. We anticipate that all future earnings will be retained to finance future growth.

Performance Graph

This performance graph shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), or incorporated by reference into any filing of Clean Energy Fuels Corp. under the Securities Act, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

The following graph shows a comparison from May 25, 2007 (the date our common stock commenced trading on The Nasdaq Global Market) through December 31, 2009 of the cumulative total return for our common stock, the Nasdaq Global Market Index, and the Russell 2000 Growth Index. We chose to include the Russell 2000 Growth Index as a comparable index due to the lack of a comparable industry index or peer group. We are the only actively-traded public company whose only line of business is to sell natural gas as a vehicle fuel. Such returns are based on historical results and are not intended to suggest future performance. Data for the Nasdaq Global Market Index and the Russell 2000 Growth Index assumes reinvestment of dividends.



* Assumes $100 was invested on May 25, 2007 in our common stock, the Nasdaq Global Market Index, and the Russell 2000 Growth Index. The Nasdaq Global Market Index and the Russell 2000 Growth Index results include reinvestment of dividends.

Item 6. Selected Financial Data.

You should read the following selected historical consolidated financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and the notes elsewhere in this Form 10-K.

The consolidated statements of operations data for the years ended December 31, 2007, 2008 and 2009 and the consolidated balance sheet data at December 31, 2008 and 2009 are derived from our audited consolidated financial statements in this Form 10-K. The consolidated statements of operations data for the years ended December 31, 2005 and 2006, and the consolidated balance sheet data at December 31, 2005, 2006 and 2007 are derived from our audited consolidated financial statements that are not included in this Form 10-K. The historical results are not necessarily indicative of the results to be expected in any future period.

	Year Ended December 31,				
	2005	2006	2007	2008	2009
Statement of Operations Data:					
Total Revenues(1)	$ 77,955,083	$ 91,547,316	$117,716,233	$125,866,533	$131,503,277
Operating expenses:					
Costs of sales	72,004,077	74,047,901	85,660,329	98,767,585	82,920,867
Derivative (gains) losses(2):					
Futures contracts	(44,067,744)	78,994,947	—	611,175	—
Series I warrant valuation	—	—	—	—	17,366,754
Loss on extinguishment of derivative liability	—	2,142,095	—	—	—
Selling, general and administrative(3)	17,108,425	20,860,181	35,933,694	62,415,554	47,509,662
Depreciation and amortization	3,948,544	5,765,001	7,107,942	9,623,672	16,991,695
Total operating expenses:	48,993,302	181,810,125	128,701,965	171,417,986	164,788,978
Operating income (loss)	28,961,781	(90,262,809)	(10,985,732)	(45,551,453)	(33,285,701)
Interest income (expense), net	59,780	746,339	3,505,597	1,630,436	(31,989)
Other (expense), net	(140,921)	(255,479)	(192,347)	(169,159)	(310,570)
Equity in gains (losses) of equity method investee	—	—	—	(188,186)	243,962
Income (loss) before income taxes	28,880,640	(89,771,949)	(7,672,482)	(44,278,362)	(33,384,298)
Income tax (expense) benefit	(11,623,053)	12,271,208	(1,221,880)	(289,141)	(303,501)
Net income (loss)	17,257,587	(77,500,741)	(8,894,362)	(44,567,503)	(33,687,799)
Minority interest in net income	—	—	—	104,829	439,098
Net income (loss) attributable to Clean Energy Fuels Corp	$ 17,257,587	$ (77,500,741)	$ (8,894,362)	$ (44,462,674)	$ (33,248,701)

	Year Ended December 31,				
	2005	2006	2007	2008	2009
Basic earnings (loss) per share	$ 0.76	$ (2.45)	$ (0.22)	$ (0.98)	$ (0.60)
Fully diluted earnings (loss) per share	$ 0.75	$ (2.45)	$ (0.22)	$ (0.98)	$ (0.60)
Weighted average common shares outstanding:					
Basic	22,602,033	31,676,399	40,258,440	45,367,991	55,021,961
Diluted	23,191,674	31,676,399	40,258,440	45,367,991	55,021,961

(1) Revenues include the following amounts:

	Year Ended December 31,				
	2005	2006	2007	2008	2009
Fuel tax credits (VETC)	$0	$3,810,109	$17,046,412	$17,197,265	$15,534,650

(2) 2006 amount includes $78,712,599 of losses on certain derivative contracts. The contracts were assumed by our largest stockholder, Boone Pickens, on December 28, 2006. 2009 amount represents Series I warrant valuation.

(3) 2008 amount includes $18.6 million of expenses to support Proposition 10 on the California ballot in November 2008.

	December 31,				
	2005	2006	2007	2008	2009
Balance Sheet Data:					
Cash and cash equivalents	$ 28,763,445	$ 937,445	$ 67,937,602	$ 36,284,431	$ 67,086,965
Restricted cash	—	—	—	2,500,000	2,500,000
Short-term investments	—	—	12,479,684	—	—
Working capital	27,426,766	44,811,284	119,480,877	47,337,938	78,798,814
Total assets	128,613,650	136,932,636	249,024,944	290,374,400	355,798,573
Long-term debt, inclusive of current portion	5,100,256	282,396	224,897	25,083,802	12,220,668
Stockholders' equity	93,489,868	122,915,857	230,932,474	233,776,603	277,189,341

	Year Ended December 31,		
	2007	2008	2009
Key Operating Data:			
Gasoline gallon equivalents delivered (in millions):			
CNG	48.0	47.6	67.9
Biomethane	—	2.0	6.4
LNG	27.3	23.9	26.7
Total	75.3	73.5	101.0

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The discussion in this section contains forward-looking statements. These statements relate to future events or our future financial performance. We have attempted to identify forward-looking statements by terminology such as "anticipate," "believe," "can," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potential," "predict," "should," "would" or "will" or the negative of these terms or other comparable terminology, but their absence does not mean that a statement is not forward-looking. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, which could cause our actual results to differ from those projected in any forward-looking statements we make. See "Risk Factors" in Part I, Item 1A of this report for a discussion of some of these risks and uncertainties. This discussion should be read with our financial statements and related notes included elsewhere in this report.

We provide natural gas solutions for vehicle fleets primarily in the United States and Canada. In April 2008, we opened our first CNG station in Lima, Peru, through our joint venture, Clean Energy del Peru. Our primary business activity is selling CNG and LNG vehicle fuels and providing operations and maintenance services to our customers. We also build fueling stations and help our customers acquire and finance natural gas vehicles and obtain local, state and federal clean air financial and tax incentives. Our customers include fleet operators in a variety of markets, such as public transit, refuse hauling, airports, taxis and regional trucking. In August 2008, we acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE owns a facility that collects, processes and sells renewable biomethane at the McCommas Bluff landfill located in Dallas, Texas. On October 1, 2009, we acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support, and research and development for natural gas vehicles.

Overview

This overview discusses matters on which our management primarily focuses in evaluating our financial condition and operating performance.

Sources of revenue. We generate the vast majority of our revenue from selling CNG and LNG and providing operations and maintenance services to our customers. The balance of our revenue is provided by designing and constructing natural gas fueling stations, financing our customers' natural gas vehicle purchases, sales of pipeline quality biomethane produced by our DCE joint venture and, beginning in the fourth quarter of 2009, sales of natural gas vehicles through our wholly owned subsidiary, BAF.

Key operating data. In evaluating our operating performance, our management focuses primarily on: (1) the amount of CNG and LNG gasoline gallon equivalents delivered (which we define as (i) the volume of gasoline gallon equivalents we sell to our customers, plus (ii) the volume of gasoline gallon equivalents dispensed to our customers at stations where we provide O&M services but do not directly sell the CNG or LNG, plus (iii) our proportionate share of the gasoline gallon equivalents sold as CNG by our joint venture in Peru, plus (iv) our proportionate share of the gasoline gallon equivalents of biomethane produced and sold as pipeline quality natural gas by DCE), (2) our gross margin (which we define as revenue minus cost of sales), and (3) net income (loss). The following table, which you should

read in conjunction with our consolidated financial statements and notes contained elsewhere in this Form 10-K, presents our key operating data for the years ended December 31, 2007, 2008 and 2009:

Gasoline gallon equivalents delivered

	Year Ended December 31,		
(in millions)	**2007**	**2008**	**2009**
CNG	48.0	47.6	67.9
Biomethane	—	2.0	6.4
LNG	27.3	23.9	26.7
Total	75.3	73.5	101.0
Operating data			
Gross margin	$32,055,904	$ 27,098,948	$ 48,582,410
Net loss	(8,894,362)	(44,462,674)	(33,248,701)

Key trends in 2007, 2008 and 2009. According to the U.S. Energy Information Administration, demand for natural gas fuels in the United States increased by approximately 29% during the period January 1, 2007 through December 31, 2009. We believe this growth in demand was attributable primarily to the rising prices of gasoline and diesel relative to CNG and LNG during these periods and increasingly stringent environmental regulations affecting vehicle fleets.

The number of fueling stations we served grew from 147 at December 31, 2004 to 196 at December 31, 2009 (a 33.3% increase). Included in this number are all of the CNG and LNG fueling stations we own, maintain or with which we have a fueling supply contract. The amount of CNG and LNG gasoline gallon equivalents we delivered from 2005 to 2009 increased by 77.8%. The increase in gasoline gallon equivalents delivered, contributed to increased revenues during these periods. Our cost of sales also increased during these periods, which was attributable primarily to increased costs related to delivering more CNG and LNG to our customers and the increased price of natural gas.

During 2009, we also experienced reduced margins in certain markets, particularly in the municipal transit and refuse sector. The reduction in margins is primarily a result of increased competition and sales agreements with larger entities that have greater pricing leverage. In addition, during 2009, we acquired four compressed natural gas operations and maintenance services contracts with municipal transit agencies that have significant volume but smaller margins than we typically maintain on our fuel sales. As a result, the overall average margin on our fuel sales across our business decreased during 2009. We believe that our margins on fuel sales will improve in the future to the extent we are successful in growing our retail CNG and LNG fueling operations, which is where we earn our highest margin, relative to our lower-margin operations, such as municipal transit.

During 2009, prices for oil, gasoline, diesel fuel and natural gas generally increased. Oil increased from a low of $41.68 per barrel on January 30, 2009 to a price of $79.36 per barrel on December 31, 2009. In California, average retail prices for gasoline have increased from a low of $1.87 per gallon in January 2009 to $2.93 per gallon at December 31, 2009, and average retail prices for diesel fuel have increased from a low of $2.05 per diesel gallon in March 2009 to $2.90 per diesel gallon at December 31, 2009. To the extent that we continue to try to price LNG and CNG at a discount to diesel and gasoline prices in an effort to attract new and retain existing customers, our revenue and profit margin on fuel sales may be lower than they were during 2008 when gasoline and diesel were at substantially higher prices. In addition, the volatility in natural gas prices has a direct impact on our revenue. The NYMEX price for natural gas increased from a low of $2.84 per MMbtu in September 2009 to $4.49 per MMbtu at December 31, 2009. The average retail sales price of our CNG fuel sold in the Los Angeles metropolitan area increased from $2.00 for the month of January 2009 to $2.50 for the month of December 2009.

Recent developments. On October 1, 2009, we purchased all the outstanding shares of BAF Technologies, Inc. ("BAF") under a stock purchase agreement. We paid an upfront purchase price of $8.5 million to acquire BAF. Pursuant to the terms of the agreement, the purchase price was reduced by the amount of BAF's outstanding debt which was repaid in full at closing. Due to the fact that we held approximately $3.8 million of BAF's outstanding debt, including interest, we paid a net amount of approximately $4.7 million in cash to acquire BAF at the closing. BAF shareholders will be able to earn additional consideration if BAF achieves certain gross profit targets in fiscal 2010 and 2011. The additional consideration will be determined as a percentage of gross profit based on a sliding scale that increases at certain gross profit levels, subject to achieving a minimum gross profit target and capped by a maximum additional payment amount. For 2010, the shareholders of BAF will receive between one and twenty-six percent of gross profit of BAF as additional consideration if BAF achieves $8 million or more in gross profit, up to a maximum of $11 million in additional consideration (which would be payable if BAF achieved approximately $42.3 million in gross profit in 2010). For 2011, the shareholders of BAF will receive between one and twenty-one percent of gross profit of BAF as additional consideration if BAF achieves $8.5 million or more in gross profit, up to a maximum of $11 million in additional consideration (which would be payable if BAF achieved approximately $52.4 million in gross profit in 2011). The contingent consideration was valued at $3.1 million on the acquisition date, and based on the accounting literature for business combinations that became effective for new acquisitions for the Company on January 1, 2009, the Company will adjust this liability each reporting period, with a corresponding gain or loss reflected in the statement of operations, based on changes in the fair value of the obligation.

Founded in 1992, BAF provides natural gas vehicle conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles ("NGV"). BAF's vehicle conversions include taxis, limousines, vans, pick-up trucks and shuttle buses. BAF has certified NGVs under both EPA and California Air Resources Board ("CARB") standards achieving Super Ultra Low Emission Vehicle emissions. Following AT&T's announcement in March 2008 of their intent to deploy more than 15,000 alternative-fuel vehicles over the next five years, approximately 8,000 of which are expected to be NGVs, BAF was awarded a purchase order to provide to AT&T the initial 600 Ford E-Series converted CNG vans in 2009 and has subsequently received purchase orders for 1,389 CNG vans for the first three quarters of 2010.

Anticipated future trends. Despite the recent volatility in energy prices, we anticipate that, over the long term, the prices for gasoline and diesel will continue to be higher than the price of natural gas as a vehicle fuel, and more stringent emissions requirements will continue to make natural gas vehicles an attractive alternative to traditional gasoline and diesel powered vehicles. Our belief that natural gas will continue, over the long term, to be a cheaper vehicle fuel than gasoline or diesel is based in part on the growth in U.S. natural gas production. A 2008 Navigant Consulting, Inc. study indicates that as a result of new unconventional gas shale discoveries from 22 basins in the U.S., maximum estimates of total recoverable domestic reserves from producers have increased to equal 118 years of U.S. production at 2007 producing rates. The study indicated a mean level of reserves equal to 88 years of supply at 2007 production levels. According to the report, shale gas production growth from only the major six shale plays in the U.S., plus the Marcellus shale, could become 27 billion cubic feet per day and as high as 39 billion cubic feet per day by 2015. Navigant has also indicated that development of the shale resources base has resulted in a substantial current surplus of gas supply compared to demand of as much as 11 billion cubic feet per day. These current surplus levels are 18% of annual average historical U.S. consumption levels of approximately 20 Tcf per year; providing sufficient gas supply to meet the requirements of all existing markets and to meet new market requirements. Based on analyst reports, we believe that there is a significant worldwide supply of natural gas relative to crude oil as well. According to the 2009 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2008 natural gas production was 44% greater than the ratio of

proven crude oil reserves to 2008 crude oil production. This analysis suggests significantly greater longer term availability of natural gas than crude oil based on current consumption.

We believe there will be significant growth in the consumption of natural gas as a vehicle fuel among vehicle fleets, and our goal is to capitalize on this trend and enhance our leadership position as this market expands. We have built natural gas fueling stations, and plan to build additional natural gas fueling stations, that will provide LNG to fleet vehicles at the Ports of Los Angeles and Long Beach. We also anticipate expanding our sales of CNG and LNG in the other markets in which we operate, including public transit, regional trucking, refuse hauling and airports. Consistent with the anticipated growth of our business, we also expect that our operating costs and capital expenditures will increase, primarily from the anticipated expansion of our station network as well as the logistics of delivering more CNG and LNG to our customers. Additionally, we have and will continue to increase our sales and marketing team and other necessary personnel as we seek to expand our existing markets and enter new markets, which will also result in increased costs.

The disruption in the capital markets that began during 2008 and has continued into 2009 has made it more difficult for new customers to finance or invest in natural gas vehicle acquisitions or natural gas fueling stations. Continuing economic contraction and reduced economic activity may reduce our opportunities to attract new fleet customers. Many governmental entities, which during 2006 through 2009 represented approximately 64% of our revenues, are experiencing significant budget deficits as a result of the economic recession and have been and may continue to be unable to invest in new natural gas vehicles for their transit or refuse fleets or may be compelled to reduce public transportation and services, which would negatively affect our business.

Sources of liquidity and anticipated capital expenditures. Liquidity is the ability to meet present and future financial obligations either through operating cash flows, the sale or maturity of existing assets, or by the acquisition of additional funds through capital management. Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities.

Our current business plan, assuming that the NAT GAS Act or comparable legislation is passed into law, calls for approximately $86.3 million in capital expenditures in 2010, primarily related to construction of new fueling stations. We will have to raise capital to fund this business plan if the NAT GAS Act or similar legislation is passed into law providing incentives for the use of natural gas fuel and purchase of natural gas vehicles that lead to rapid growth in our business. If the NAT GAS Act or similar legislation is not passed or any available incentives do not lead to rapid growth in our business, we anticipate that we will build fewer fueling stations and our capital expenditures may be materially less than $86.3 million. We may also elect to invest additional amounts in expansion of our California LNG plant, expansion of our DCE landfill gas processing plant, or for other acquisitions or investments in companies or assets in the natural gas fueling infrastructure, services and production industries. We will need to raise additional capital as necessary to fund expansion of our California LNG plant or DCE landfill gas plant, acquisitions or other capital expenditures or investments that we cannot fund through available cash, our line of credit from PlainsCapital Bank, or cash generated by operations. The timing and necessity of any future capital raise will depend primarily on our rate of new station construction, which will be affected by any federal legislation that may provide incentives for natural gas vehicle purchases and fuel use, any decision to expand our California LNG plant or DCE gas processing plant and potential merger or acquisition activity. For more information, see "Liquidity and Capital Resources" below. Due to the continuing disruption in the capital markets, we may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, expand our California LNG plant or DCE gas processing plant, develop natural gas fueling infrastructure and invest in strategic transactions or acquisitions and reduce our ability to grow our business and generate increased revenues.

Business risks and uncertainties. Our business and prospects are exposed to numerous risks and uncertainties. For more information, see "Risk Factors" in Part I, Item 1A.

Operations

We generate revenues principally by selling CNG and LNG and providing operations and maintenance services to our vehicle fleet customers. For the year ended December 31, 2009, CNG and biomethane (together) represented 74% and LNG represented 26% of our natural gas sales (on a gasoline gallon equivalent basis). To a lesser extent, we generate revenues by designing and constructing fueling stations and selling or leasing those stations to our customers. We also generate material revenues through sales of biomethane produced by our joint venture subsidiary DCE, and beginning in the fourth quarter of 2009, sales of natural gas vehicles by our wholly owned subsidiary BAF. Substantially all of our operating and maintenance revenues are generated from CNG stations, as owners of LNG stations tend to operate and maintain their own stations. Substantially all of our station sale and leasing revenues have been generated from CNG stations.

CNG Sales

We sell CNG through fueling stations located on our customers' properties and through our network of public access fueling stations. At these CNG fueling stations, we procure natural gas from local utilities or brokers under standard, floating-rate arrangements and then compress and dispense it into our customers' vehicles. Our CNG sales are made primarily through contracts with our fleet customers. Under these contracts, pricing is determined primarily on an index plus basis, which is calculated by adding a margin to the local index or utility price for natural gas. CNG sales revenues based on an index plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We sell a small amount of CNG under fixed price contracts and also provide price caps to certain customers on their index plus pricing arrangements. Effective January 1, 2007, we ceased offering price cap contracts to our customers, but we will continue to perform our obligations under price cap contracts we entered into before January 1, 2007. We will continue to offer fixed price contracts as appropriate and consistent with our natural gas hedging policy that was revised in May 2008. Our fleet customers typically are billed monthly based on the volume of CNG sold at a station. The remainder of our CNG sales are on a per fill up basis at prices we set at the pump based on prevailing market conditions. These customers typically pay using a credit card at the station. In April 2008, we opened our first CNG station in Lima, Peru through our joint venture Clean Energy del Peru.

LNG Sales

We sell substantially all of our LNG to fleet customers, who typically own and operate their fueling stations. We also sell LNG to customers at our two public LNG stations and for non-vehicle use. We procure LNG from third party producers and also produce LNG at our liquefaction plants in Texas and California. For LNG that we purchase from third-parties, we may enter into "take or pay" contracts that require us to purchase minimum volumes of LNG at index-based rates. We deliver LNG via our fleet of 58 tanker trailers to fueling stations, where it is stored and dispensed in liquid form into vehicles. We sell LNG principally through supply contracts that are priced on either a fixed price or index plus basis. LNG sales revenues based on an index plus methodology increase or decrease as a result of an increase or decrease in the price of natural gas. We also provided price caps to certain customers on the index component of their index plus pricing arrangement for certain contracts we entered into on or prior to December 31, 2006. Effective January 1, 2007, we ceased offering price cap contracts to our customers, but we will continue to perform our obligations under price cap contracts we entered into before January 1, 2007, including a one year renewal period beginning April 1, 2010 that one of our customers is entitled to exercise. This renewal period, if exercised, would obligate us to sell the customer approximately 2.1 million LNG gallons subject to a price cap of $7.50 per MMbtu on

the Southern California Gas Company Index. We will continue to offer fixed price contracts as appropriate and consistent with our natural gas hedging policy that was revised in May 2008. Our LNG contracts provide that we charge our customers periodically based on the volume of LNG supplied.

Government Incentives

From October 1, 2006 through December 31, 2009, we received a federal fuel tax credit ("VETC") of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG that we sold as vehicle fuel. Based on the service relationship with our customers, either we or our customers were able to claim the credit. We recorded these tax credits as revenues in our consolidated statements of operations as the credits are fully refundable and do not need to offset tax liabilities to be received. As such, the credits are not deemed income tax credits under the accounting guidance applicable to income taxes. In addition, we believe the credits are properly recorded as revenue because we often incorporate the tax credits into our pricing with our customers, thereby lowering the actual price per gallon we charge them. The tax credit expired on December 31, 2009. If the tax credit is not reinstated or extended, our revenue in future periods will be materially reduced and our ability to attract new customers, or retain old customers, may also be reduced.

Operation and Maintenance

We generate a portion of our revenue from operation and maintenance agreements for CNG fueling stations where we do not supply the fuel. We refer to this portion of our business as "O&M." At these fueling stations, the customer contracts directly with a local broker or utility to purchase natural gas. For O&M services, we do not sell the fuel itself, but generally charge a per-gallon fee based on the volume of fuel dispensed at the station. We include the volume of fuel dispensed at the stations at which we provide O&M services in our calculation of aggregate gallon equivalents sold.

Station Construction

We generate a small portion of our revenue from designing and constructing fueling stations and selling or leasing the stations to our customers. For these projects, we act as general contractor or supervise qualified third party contractors. We charge construction fees or lease rates based on the size and complexity of the project.

Vehicle Acquisition and Finance

In 2006, we commenced offering vehicle finance services for some of our customers' purchases of natural gas vehicles or the conversion of their existing gasoline or diesel powered vehicles to operate on natural gas. We loan to certain qualifying customers on average 75%, and on occasion up to 100%, of the purchase price of their natural gas vehicles. We may also lease vehicles in the future. Where appropriate, we apply for and receive state and federal incentives associated with natural gas vehicle purchases and pass these benefits through to our customers. We may also secure vehicles to place with customers or pay deposits with respect to such vehicles prior to receiving a firm order from our customers, which we may be required to purchase if our customer fails to purchase the vehicle as anticipated. Through December 31, 2009, we have not generated significant revenue from vehicle finance activities.

Landfill Gas

In August 2008, we acquired 70% of the outstanding membership interests of DCE for a purchase price of $19.6 million including transaction costs. DCE owns a facility that collects, processes and sells biomethane from the McCommas Bluff landfill located in Dallas, Texas. From the acquisition date through December 31, 2008, and for the year ended December 31, 2009, DCE generated approximately

$1.8 million and $7.9 million, respectively, in revenue from sales of biomethane, all of which is included in our consolidated statements of operations.

On April 3, 2009, DCE entered into a fifteen year gas sale agreement with Shell Energy North America (US), L.P. ("Shell") for the sale by DCE to Shell of biomethane produced by DCE's landfill gas processing facility.

DCE retains the right to reserve from the gas sale agreement up to 500 MMBtus per day of biomethane for sale as a vehicle fuel. To the extent that DCE produces volumes of biomethane in excess of the volumes sold under the agreement with Shell, DCE will either attempt to sell such volumes at then-prevailing market prices or seek to enter into another gas sale agreement in the future. There is no guarantee that DCE will produce or be able to sell up to the maximum volumes called for under the agreement, and DCE's ability to produce such volumes of biomethane is dependent on a number of factors beyond DCE's control including, but not limited to, the availability and composition of the landfill gas that is collected, the impact on DCE's operations of the operation of the landfill by the City of Dallas and the reliability of the processing plant's critical equipment.

The sale price for the gas under the agreement with Shell is fixed and increases in 2010 and 2011. The sale price for the gas represents a substantial premium to the current prevailing prices for natural gas at March 8, 2010.

Under the terms of the agreement, DCE has retained the rights to any available greenhouse gas emission reduction credits that may be generated through the operation of the landfill gas collection and processing facility, provided that DCE must supply Shell with a sufficient number of such credits to enable the end-user of the gas to meet applicable "net-zero" emissions requirements under the relevant renewable portfolio standard with respect to use of the biomethane in power generation. DCE is in the preliminary stages of assessing whether greenhouse gas emission reduction credits will be generated or available for sale as a result of the landfill gas collection and pipeline quality biomethane production. Given the complex and changing standards and requirements in the market for greenhouse gas emission reduction credits, there can be no guarantee that any greenhouse gas emission credits will be generated or available for sale as a result of DCE's landfill gas operations.

The gas sale agreement is terminable by either party on 30 days' written notice if the California Energy Commission makes a written determination or adopts a ruling or regulation after the date of the agreement that the biomethane sold under the agreement will, from the date of such ruling or regulation, no longer qualify as a California Renewable Portfolio Standard eligible fuel. In addition, Shell has the right to terminate the agreement upon 30 days' written notice if the volumes of biomethane produced and delivered, calculated monthly on a rolling two-year average, are less than an annual average of 630,720 MMBtu per year (or 2,083 MMBtu per day).

Vehicle Conversion

On September 23, 2009, we agreed to purchase all of the outstanding shares of BAF Technologies, Inc. Founded in 1992, BAF provides natural gas vehicle conversions, alternative fuel systems, application engineering, service and warranty support and research and development. BAF's vehicle conversions include taxis, limousines, vans, pick-up trucks and shuttle buses. BAF utilizes advanced natural gas system integration technology and has certified NGVs under both EPA and CARB standards achieving Super Ultra Low Emission Vehicle emissions. We generate revenues through the sale of natural gas vehicles that have been converted to run on natural gas by BAF. The majority of BAF's revenue during 2009 was derived from sales of converted natural gas service vans to AT&T. BAF contributed approximately $6.9 million to our revenue during 2009.

Volatility of Earnings and Cash Flows

Our earnings and cash flows historically have fluctuated significantly from period to period based on our futures activities, as all but a few of our futures contracts have not historically qualified for hedge accounting under the relative derivative accounting guidance. We have therefore recorded any changes in the fair market value of these contracts that did not qualify for hedge accounting directly in our statements of operations in the line item derivative (gains) losses along with any realized gains or losses generated during the period. For example, we experienced derivative gains of $5.7 million for the three months ended June 30, 2008, and derivative losses of $6.0 million and $0.3 million for the three months ended September 30, 2008 and December 31, 2008, respectively. We had no derivative gains or losses for the three months ended March 31, 2007, June 30, 2007, September 30, 2007, December 31, 2007, March 31, 2008, March 31, 2009, June 30, 2009, September 30, 2009 and December 31, 2009 related to our futures contracts. In accordance with our natural gas hedging policy, we plan to structure all subsequent futures contracts as cash flow hedges under the applicable derivative accounting guidance, but we cannot be certain that they will qualify. See "Risk Management Activities" below. If the futures contracts do not qualify for hedge accounting, we could incur significant increases or decreases in our earnings based on fluctuations in the market value of the contracts from period to period.

Additionally, we are required to maintain a margin account to cover losses related to our natural gas futures contracts. Futures contracts are valued daily, and if our contracts are in loss positions at the end of a trading day, our broker will transfer the amount of the losses from our margin account to a clearinghouse. If at any time the funds in our margin account drop below a specified maintenance level, our broker will issue a margin call that requires us to restore the balance. Consequently, these payments could significantly impact our cash balances. At December 31, 2009, we had $2.9 million on deposit in margin accounts.

The decrease in the value of our futures positions and any required margin deposits on our futures contracts that are in a loss position could significantly impact our financial condition in the future.

Volatility of Earnings Related to Series I Warrants

Beginning January 1, 2009, under new accounting guidance, we are required to record the change in the fair market value of our Series I warrants in our financial statements. We recognized a loss (gain) of $0.2 million, $2.2 million, $15.4 million and ($0.4) million related to recording the fair market value changes of our Series I warrants in the quarters ended March 31, 2009, June 30, 2009, September 30, 2009 and December 31, 2009, respectively (see note 20 to our consolidated financial statements contained elsewhere herein). Our earnings or loss per share may be materially impacted by future gains or losses we are required to take as a result of valuing our Series I warrants.

Debt Compliance

Our credit agreement with PlainsCapital Bank ("PCB") ("Credit Agreement") requires us to comply with certain covenants. We may not incur indebtedness or liens except as permitted by the Credit Agreement, or declare or pay dividends. We must maintain, on a quarterly basis, minimum liquidity of not less than $6.0 million, accounts receivable balances, as defined, of not less than $8.0 million, consolidated net worth, as defined, of not less than $150.0 million, and a debt to equity ratio, as defined, of not more than 0.3 to 1. Beginning in the quarter ended June 30, 2009, we must also maintain a specific minimum debt service ratio at each quarter end. Effective in the fourth quarter of 2008, we established a lock-box arrangement with PCB subject to the Credit Agreement. Funds received from our customers are remitted to the lock-box and then deposited to a PCB bank account. The remitted funds are not used to pay-down the balance of the credit agreement. One of the events of default is the occurrence of a "material adverse change," which is a subjective acceleration clause.

Based on the relevant accounting guidance, we have classified our debt pursuant to the Credit Agreement as short-term or long-term, as appropriate, and we believe an event of default is more than remote but not more likely than not. If we default on the Credit Agreement, all of the obligations under the Credit Agreement will become immediately due and payable and all funds received in our lockbox held by PCB, plus $2.5 million we have deposited with PCB in a payment reserve account, will be applied to the balance due on the Credit Agreement. One of our bank covenants is a requirement to maintain accounts receivable balances from certain subsidiaries above $8.0 million at each quarter-end. To the extent natural gas prices continue to fall, which a significant portion of our revenues are derived from, or our volumes decline, we could violate this covenant in the future. Beginning with the quarter ended June 30, 2009, we are required to maintain a specific minimum debt service ratio. To the extent our operating results do not materialize as planned, we could violate this covenant in the future. In the event we violate either of these covenants, we would seek a waiver from the bank. We were in compliance with all of our covenants at December 31, 2009.

Risk Management Activities

Historically, a significant portion of our natural gas fuel sales have been covered by contracts to sell LNG or CNG to our customers at a fixed price or a variable index based price subject to a cap. These contracts expose us to the risk that the price of natural gas may increase above the natural gas cost component included in the price at which we are committed to sell gas to our customers. We account for sales of natural gas under these contracts as described below in "Critical Accounting Policies—Fixed Price and Price Cap Sales Contracts."

In an effort to mitigate the volatility of our earnings related to our futures contracts and to reduce our risk related to fixed price sales contracts, our board of directors revisited our risk management policies and procedures and adopted a revised natural gas hedging policy in February 2007, which was amended effective May 29, 2008, and restricts our ability to purchase natural gas futures contracts and offer fixed price sales contracts to our customers. Unless otherwise agreed in advance by the board of directors and the derivative committee, we will conduct our futures activities and enter into fixed price sales contracts only in accordance with the natural gas hedging policy, a complete copy of which was filed as Exhibit 99.1 to our Form 8-K filed with the SEC on June 20, 2008. Pursuant to the policy, we only purchase futures contracts to hedge our exposure to variability in expected future cash flows related to a particular fixed price contract or bid. Subject to the conditions set forth in the policy, we purchase futures contracts in quantities reasonably expected to hedge effectively our exposure to cash flow variability related to such fixed price sales contracts entered into after the date of the policy. The summary of the policy described above does not purport to be complete and is qualified in its entirety by reference to the copy of the policy previously filed.

Due to the restrictions of our revised hedging policy, we expect to offer fewer fixed price sales contracts to our customers. If we do offer a fixed price sales contract, we anticipate including a price component that would cover our increased costs as well as a return on our estimated cash requirements over the duration of the underlying futures contracts. The amount of this price component will vary based on the anticipated volume and the natural gas price component to be covered under the fixed price sales contracts.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations is based upon our financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of financial statements requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, revenue and expenses, and disclosures of contingent assets and liabilities as of the date of the financial statements. On a periodic basis, we evaluate our estimates, including those related to revenue recognition, accounts receivable

reserves, notes receivable reserves, derivative values, income taxes, and the market value of equity instruments granted as stock-based compensation. We use historical experience, market quotes, and other assumptions as the basis for making estimates. Actual results could differ from those estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements.

Revenue Recognition

We recognize revenue on our gas sales and for our O&M services in accordance with Generally Accepted Accounting Principles ("GAAP"), which require that four basic criteria must be met before revenue can be recognized: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred and title and the risks and rewards of ownership have been transferred to the customer or services have been rendered; (3) the price is fixed or determinable; and (4) collectability is reasonably assured. Applying these factors, we typically recognize revenue from the sale of natural gas at the time fuel is dispensed or, in the case of LNG sales agreements, delivered to the customer's storage facility. We recognize revenue from operation and maintenance agreements as we provide the O&M services.

In certain transactions with our customers, we agree to provide multiple products or services, including construction of and either leasing or sale of a station, providing operations and maintenance to the station, and sale of fuel to the customer. We evaluate the separability of revenues for deliverables based on current accounting guidance, which provides a framework for establishing whether or not a particular arrangement with a customer has one or more deliverables. To the extent we have adequate objective evidence of the values of separate deliverable items under a contract, we allocate the revenue from the contract on a relative fair value basis at the inception of the arrangement. During 2007, 2008 and 2009, we did not have objective evidence for our multi-deliverable contracts, which generally resulted in the deferral of revenue until future services are performed. If the arrangement contains a lease, we use the existing evidence of fair value to separate the lease from the other deliverables.

We account for our leasing activities in accordance with current accounting guidance. Our existing station leases are sales-type leases, giving rise to profit at the delivery of the leased station. Unearned revenue is amortized into income over the life of the lease using the effective interest method. For those arrangements, we recognize gas sales and operations and maintenance service revenues as earned from the customer on a volume-delivered basis.

We recognize revenue on fueling station construction projects where we sell the station to the customer using the completed contract method. We recognize revenue on biomethane sales and vehicle sales when we transfer title of the gas or vehicle to our customer.

Natural Gas Derivative Activities

Current accounting guidance for our derivative instruments, specifically our natural gas futures contracts, require the recognition of all derivatives as either assets or liabilities in the consolidated balance sheet and the measurement of those instruments at fair value to the extent they qualify for hedge accounting. Our derivatives did not qualify for hedge accounting for the years ended December 31, 2006, and we did not have any derivative activities in 2007. During 2008, we had some futures contracts that qualified for hedge accounting and some that did not. During 2009, we had five contracts that did qualify for hedge accounting. As such, changes in the fair value of the derivatives were recorded directly to our consolidated statements of operations for the futures contracts that did not qualify for hedge accounting during these periods. We determine the fair value of our derivatives at the end of each reporting period based on quoted market prices from the NYMEX discounted to reflect the time value of money for contracts related to future periods.

The counter-party to the Company's derivative transactions is a high credit quality counterparty; however, the Company is subject to counterparty credit risk to the extent the counterparty to the derivatives is unable to meet its settlement commitments. The Company manages this credit risk by minimizing the number and size of its derivative contracts. The Company actively monitors the creditworthiness of its counterparties and records valuation adjustments against the derivative assets to reflect counterparty risk, if necessary. The counter-party is also exposed to credit risk of the Company, which requires the Company to provide cash deposits as collateral.

The Company marks to market its open futures positions at the end of each period and records the net unrealized gain or loss during the period in derivative (gains) losses in the consolidated statements of operations or in accumulated other comprehensive income in the consolidated balance sheets in accordance with the relevant accounting guidance. The Company recorded unrealized gains of approximately $0.8 million in accumulated other comprehensive income in the year ended December 31, 2009 related to its futures contracts. The fair value of the Company's futures contracts of approximately $159,000 at December 31, 2009, of which an asset of $442,000 is included in prepaid expenses and other current assets for the short-term amount, and $283,000 is included as a liability in other long-term liabilities for the long-term amount on the Company's consolidated balance sheet at December 31, 2009. The Company's ineffectiveness related to its futures contracts in the year ended December 31, 2009 was insignificant. In 2009, the Company recognized cost of sales of $1.8 million in the accompanying consolidated statement of operations related to its futures contracts that were settled during year.

The following table presents the notional amounts and weighted average fixed prices per gasoline gallon equivalent of the Company's natural gas futures contracts as of December 31, 2009:

	Gallons	Weighted Average Price Per Gasoline Gallon Equivalent
2010	12,040,000	$0.76
2011	11,600,000	$0.82
2012	5,160,000	$0.81
January to May, 2013	300,000	$0.81

Fixed Price and Price Cap Sales Contracts Without an Underlying Futures Contract

From time to time, the Company enters into contracts with various customers, primarily municipalities, to sell LNG or CNG at fixed prices, and prior to January 1, 2007, the Company also from time-to-time entered into contracts to sell LNG or CNG at prices subject to a price cap. Effective January 1, 2007, the Company no longer offers contracts with a price cap to its customers. The contracts generally range from two to five years. The most significant cost component of LNG and CNG is the price of natural gas. Through June 2008, we also may or may not have had a futures contract in place to economically offset the price of natural gas we were selling to our customers on a fixed priced basis. For any futures contracts that were in place related to these contracts, they did not qualify for hedge accounting and they may have been sold and subsequently reestablished over the term of the customer contract.

As part of determining the fixed price or price cap in the contracts, the Company works with its customers to determine their future usage over the contract term. The Company's fixed price and price cap customers, however, do not agree to purchase a minimum amount of volume or guarantee their volume of purchases. There is not an explicit volume in the contract as the Company agrees to sell its customers volumes on an "as needed" basis, also known as a "requirements contract." The volume required under these contracts varies each month, and is not subject to any minimum commitments.

For U.S. generally accepted accounting purposes, there is not a "notional amount," which is one of the required conditions for a transaction to be a derivative pursuant to the authoritative guidance.

The Company's sales agreements that fix the price or cap the price of LNG or CNG that it sells to its customers are, for accounting purposes, firm commitments, and U.S. generally accepted accounting principles do not require or allow the Company to record a loss until the delivery of the gas and corresponding sale of the product occurs. When the Company enters into these fixed price or price cap contracts with its customers, the price is set based on the prevailing index price of natural gas at that time. The index price of natural gas, however, constantly changes, and a difference between the fixed price of the natural gas included in the customer's contract price and the corresponding index price of natural gas typically occurs after the Company enters into the sales contract (with the price of natural gas having historically increased).

Prior to June 2008, from an accounting perspective, during periods of rising natural gas prices, the Company's futures contracts related to these transactions have generally been marked-to-market through the recognition of a derivative asset and a corresponding derivative gain in its statements of operations. However, because the Company's contracts to sell LNG or CNG to its customers at fixed prices or an index-based price that is subject to a fixed price cap are not derivatives for purposes of U.S. generally accepted accounting principles, a liability or a corresponding loss has not been recognized in the Company's statements of operations during these periods of rising natural gas prices for the future commitments under these contracts. As a result, for these situations, the Company's statements of operations do not reflect its firm commitments to deliver LNG or CNG at prices that are below, and in some cases, substantially below, the prevailing market price of natural gas (and therefore LNG or CNG).

Income Taxes

We compute income taxes under the asset and liability method. This method requires the recognition of deferred tax assets and liabilities for temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. The impact on deferred taxes of changes in tax rates and laws, if any, are applied to the years during which temporary differences are expected to be settled and are reflected in the consolidated financial statements in the period of enactment. We record a valuation allowance against any deferred tax assets when management determines it is more likely than not that the assets will not be realized. When evaluating the need for a valuation analysis, we use estimates involving a high degree of judgment including projected future income and the amounts and estimated timing of the reversal of any deferred tax liabilities.

Stock-Based Compensation

The Company accounts for its share based compensation transactions using a fair-value method and recognizes the expense in the statements of operations. We use the Black-Scholes option pricing model to value our options, which requires that we make assumptions concerning the market price of our stock, our stock price volatility, our projected dividends, and the risk free inherent rate applicable to the relevant period.

Impairment of Goodwill and Long-lived Assets

We assess our goodwill for impairment at least annually (or more frequently if there is an indicator of impairment) based on current accounting guidance for Goodwill and Other Intangible Assets. An initial assessment of impairment is made by comparing the fair value of the operations with goodwill, which in our case is the U.S. operations and BAF, to the book value of these operations. When assessing fair value, we look at our projected future cash flows and our market capitalization for the respective operations. To the extent our projected future cash flows do not materialized as planned or

our market capitalization goes down, which could occur during the current economic contraction, we may be forced to take an impairment charge in future periods. Our goodwill balance at December 31, 2009 was $21.6 million. If the fair value is less than the book value, an impairment is indicated and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. We performed our annual tests of goodwill as of December 31, 2007, 2008 and 2009 and there was no impairment indicated.

The Company has two reporting units with goodwill, BAF and its U.S. operations. BAF was acquired on October 1, 2009, so the fair market value of its goodwill of approximately $0.7 million approximates its book value as of December 31, 2009. The remaining goodwill is associated with the Company's U.S. operations, and the fair value of the Company's U.S. operations greatly exceeds its book value. Management would not expect there to be any impairment of its goodwill at its U.S. operations in the foreseeable future unless there is a dramatic decrease in the price of the Company's common stock or a very significant adverse event that severely impacted the Company's U.S. business.

Recently Issued Accounting Pronouncements

See Note 1(d) to our consolidated financial statements.

Results of Operations

Fiscal Year Ended December 31, 2009 Compared to Fiscal Year Ended December 31, 2008

Revenue. Revenue increased by $5.6 million to $131.5 million in the year ended December 31, 2009, from $125.9 million in the year ended December 31, 2008. A portion of this increase was the result of an increase in the number of gallons delivered from 73.5 million gasoline gallon equivalents to 101.0 million gasoline gallon equivalents. Revenue also increased by $6.9 million from sales of natural gas conversion equipment and vehicles by BAF, which we acquired on October 1, 2009, and $5.6 million in increased station construction revenue between periods. The increase in volume was primarily from an increase in CNG sales of 20.3 million gallons and an increase in biomethane sales (our 70% share of the biomethane sales of DCE) of 4.4 million gallons. The acquisition of four compressed natural gas operations and maintenance services contracts in May and June, eight new refuse customers, and one new transit customer together accounted for 17.5 million gallons of the CNG volume increase. The volume growth from our joint venture in Peru and from existing refuse and transit customers contributed to the remaining CNG volume increase. We believe that the biomethane sales increase was primarily attributable to our investment in new wells and the capital upgrades to the processing plant that we completed in the first quarter of 2009. We also experienced an increase of 2.8 million gallons in LNG volume between periods, which was primarily due to the volume growth from our port trucking customers. These increases were offset by the decrease in our effective price per gallon charged between periods. Our effective price per gallon was $1.00 in the year ended December 31, 2009, which represents a $0.45 per gallon decrease from $1.45 in the year ended December 31, 2008. This decrease is primarily due to the decreased price of natural gas in 2009, upon which a significant portion of our revenues are based. In the majority of our contracts, natural gas commodity prices are a direct pass-through to our customer or the customer pays for the natural gas commodity themselves. Revenue attributable to VETC also decreased between periods as we recorded $15.5 million of revenue related to fuel tax credits in 2009, compared to $17.2 million in 2008 due to the fact that a few of our customers began collecting the credit that we had previously collected.

Cost of sales. Cost of sales decreased by $15.9 million to $82.9 million in the year ended December 31, 2009, from $98.8 million in the year ended December 31, 2008. Our cost of sales primarily decreased between periods as a result of our effective cost per gallon declining by $0.62 per gallon to $0.71 in 2009, primarily due to the decreased price of natural gas in 2009. Offsetting this decrease was a $19.5 million increase in costs related to delivering more volume between periods together with $4.7 million of costs related to BAF's vehicle sales, which we began to recognize on October 1, 2009 when we acquired the company. We also experienced a $5.2 million increase in station construction costs between periods.

Derivative losses. Derivative losses increased by $16.8 million to $17.4 million in the year ended December 31, 2009, from $0.6 million in the year ended December 31, 2008. The 2009 amount represents the impact of our mark-to-market accounting for our Series I warrants (see note 20 to our consolidated financial statements contained elsewhere herein). The 2008 amount represents a loss we recognized in the year ended December 31, 2008 with respect to the sale of certain futures contracts we purchased in conjunction with the portion of a fixed priced bid on an LNG supply contract.

Selling, general and administrative. Selling, general and administrative expenses decreased by $14.9 million to $47.5 million in the year ended December 31, 2009, from $62.4 million in the year ended December 31, 2008. Our marketing expenses decreased $20.5 million between periods primarily because we did not incur certain advertising costs related to the Ports of Los Angeles and Long Beach and to support the Clean Alternative Fuels Act in California in 2009 as we did in 2008. Our bad debt expense decreased $1.4 million between periods due to a reversal of our BAF loan loss provision in the third quarter of 2009. Our professional service fees decreased $1.0 million between periods primarily due to reduced legal, audit and consulting services. These decreases were offset by $3.3 million increase in stock option expense between periods, primarily due to the expensing of options granted to our employees in December 2008 and January 2009, and an increase of $2.4 million in bonus expense between periods due to higher anticipated payouts in 2009. There was also an increase of $2.2 million in salaries and benefits between periods primarily related to the hiring of additional employees. Our employee headcount increased from 140 at December 31, 2008 to 229 at December 31, 2009.

Depreciation and amortization. Depreciation and amortization increased by $7.4 million to $17.0 million in the year ended December 31, 2009, from $9.6 million in the year ended December 31, 2008. This increase was primarily due to additional depreciation expense in the year ended December 31, 2009 related to increased property and equipment balances between periods, including our expanded station network and our California LNG plant. Our December 31, 2009 amortization amount also includes amortization of the City of Dallas landfill gas lease that we acquired in connection with our acquisition of DCE on August 15, 2008 and amortization of the intangible assets we obtained in connection with our acquisition of the operation and maintenance contracts we acquired during the second quarter of 2009 and BAF in the fourth quarter of 2009.

Interest income (expense), net. Interest income (expense), net, decreased by $1.7 million to $32,000 of expense for the year ended December 31, 2009. This decrease was primarily the result of an increase in interest expense in the year ended December 31, 2009 related to debt we incurred with PCB to acquire our 70% interest in DCE on August 15, 2008.

Other income (expense), net. Other income (expense), net, increased by $141,000 to $311,000 of expense for the year ended December 31, 2009. This increase was primarily related to the write-off of certain non-recoverable station costs in the year ended December 31, 2009 that did not occur in the year ended December 31, 2008.

Income (loss) from equity method investment. During 2009, we recorded equity income of $244,000 related to our 49% interest in our Peruvian joint venture, and in 2008, we recorded a loss of $188,000 related to our interest.

Loss (income) of noncontrolling interest. During the year ended December 31, 2009, we recorded $439,000 for the noncontrolling interest in the net loss of DCE. The noncontrolling interest represents the 30% interest of our joint venture partner. In 2008, we recorded $105,000 for the non-controlling interest in the net loss of DCE.

Fiscal Year Ended December 31, 2008 Compared to Fiscal Year Ended December 31, 2007

Revenue. Revenue increased by $8.2 million to $125.9 million in the year ended December 31, 2008, from $117.7 million in the year ended December 31, 2007. This increase was primarily the result of an increase in our average price per gallon between periods. Our effective price per gallon was $1.45 in the year ended December 31, 2008, which represents a $0.18 per gallon increase from $1.27 in the year ended December 31, 2007 due to the increased price of natural gas in 2008. Revenue also increased between periods as we recorded $17.2 million of revenue related to fuel tax credits in 2008 compared to $17.0 million in 2007. These increases were offset by the decrease in the number of gallons delivered between periods from 75.3 million gasoline gallon equivalents to 73.5 million gasoline gallon equivalents. The decrease in volume was primarily in LNG volume related to the loss of a portion of the City of Phoenix LNG supply contract. Offsetting The LNG volume decrease was 2.0 million gallons of biomethane sales in 2008, which represents our 70% share of the biomethane sales of DCE after the acquisition date of August 15, 2008. We also experienced a decrease between periods of $3.2 million in station construction revenue.

Cost of sales. Cost of sales increased by $13.1 million to $98.8 million in the year ended December 31, 2008, from $85.7 million in the year ended December 31, 2007. Our cost of sales primarily increased between periods as our effective cost per gallon rose to $1.33 in 2008, which represents a $0.25 per gallon increase over 2007 due to the increased price of natural gas in 2008. Offsetting the increase in our effective cost per gallon was a decrease in station construction costs of $2.8 million between periods and a decrease in costs related to delivering less CNG and LNG between periods.

Derivative losses. We incurred derivative losses of $0.6 million in the year ended December 31, 2008, primarily related to losses recorded on certain futures contracts we purchased in conjunction with the portion of a fixed price bid on an LNG supply contract that we were not awarded. We incurred no derivative gains or losses during the year ended December 31, 2007 because we did not own any derivative instruments during this period.

Selling, general and administrative. Selling, general and administrative expenses increased by $26.5 million to $62.4 million in the year ended December 31, 2008, from $35.9 million in the year ended December 31, 2007. The increase was primarily related to $18.6 million in expenses we incurred to support Proposition 10 (Clean Alternative Fuels Act) on the California ballot in November 2008. Our stock option expense accounted for $3.4 million of the increase between periods primarily due to options issued in 2008 for new employees and from stock options we granted to our employees in December 2007. There was also an increase of $0.5 million in salaries and benefits between periods primarily related to the hiring of additional employees. Our employee headcount increased from 121 at December 31, 2007 to 140 at December 31, 2008. Our professional service fees increased $2.1 million between periods primarily for legal, audit and consulting services related to our status as a public company. Our business insurance costs also increased $0.4 million between periods, primarily due to premium increases in our directors and officers insurance between periods. In addition, our travel and entertainment expenses increased $0.4 million between periods, primarily due to increased travel related to our sales team.

Depreciation and amortization. Depreciation and amortization increased by $2.5 million to $9.6 million in the year ended December 31, 2008, from $7.1 million in the year ended December 31, 2007. This increase was primarily related to additional depreciation expense in 2008 related to

increased property and equipment balances between periods, primarily related to our expanded station network and the California LNG plant. Our 2008 amount also includes amortization of the City of Dallas landfill gas lease that we acquired in connection with our acquisition of DCE on August 15, 2008.

Interest income, net. Interest income, net, decreased by $1.9 million from $3.5 million in the year ended December 31, 2007, to $1.6 million for the year ended December 31, 2008. This decrease was primarily the result of a decrease in interest income in 2008 due to lower average cash balances on hand during the year ended December 31, 2008 as compared to the year ended December 31, 2007, which included higher cash balances associated with the proceeds received from our initial public offering in May 2007.

Other expense, net. Other expense, net, was essentially the same between years.

Equity in losses of equity method investee. During 2008, we recorded losses of $188,000 related to our 49% interest in our Peruvian joint venture.

Non controlling interest in net income. During the year ended December 31, 2008, we recorded $0.1 million for the non controlling interest in the net loss of DCE. The non controlling interest represents the 30% interest of our joint venture partner. The results of DCE's operations have been included in the consolidated financial statements since August 15, 2008, the date of acquisition.

Seasonality and Inflation

To some extent, we experience seasonality in our results of operations. Natural gas vehicle fuel amounts consumed by some of our customers tends to be higher in summer months when buses and other fleet vehicles use more fuel to power their air conditioning systems. Natural gas commodity prices tend to be higher in the fall and winter months due to increased overall demand for natural gas for heating during these periods.

Since our inception, inflation has not significantly affected our operating results. However, costs for construction, repairs, maintenance, electricity and insurance are all subject to inflationary pressures and could affect our ability to maintain our stations adequately, build new stations, build new LNG plants and expand our existing facilities or materially increase our operating costs.

Liquidity and Capital Resources

Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities. In May 2007, we completed our initial public offering of 10,000,000 shares of common stock at a public offering price of $12.00 per share. Net cash proceeds from the initial public offering were approximately $108.5 million, after deducting underwriting discounts, commissions and offering expenses. On August 15, 2008, in connection with our acquisition of 70% of the membership interests of DCE, we entered into a credit agreement with PCB pursuant to which we borrowed $18.0 million under a term loan and an additional $12.0 million under a line of credit (see note 8 to the accompanying consolidated financial statements). On September 24, 2008, we sold 319,488 shares of our common stock at a price of $15.65 per share to Boone Pickens Interests, Ltd. for proceeds of approximately $5.0 million. On November 3, 2008, we sold 4,419,192 units of common stock and warrants for $7.92 per unit and we raised net proceeds of approximately $32.5 million after deducting offering costs. On July 1, 2009, we sold 9,430,000 shares of our common stock to third party investors and received net proceeds of $73.2 million. On October 7, 2009, we repaid the $18.0 million term loan with PCB and simultaneously amended the Credit Agreement to obtain a $20 million line of credit ("LOC"). The LOC expires August 15, 2010, but we have a one year renewal option we can exercise as long as we are not in default on the PCB debt facilities. As of December 31, 2009, we have not drawn

any loan amounts under the new LOC and we have an outstanding balance of $10 million on our original line of credit.

In addition to funding operations, our principal uses of cash have been, and are expected to be, the construction of new fueling stations, construction of LNG production facilities, the purchase of new LNG tanker trailers, investment in biomethane production, the financing of natural gas vehicles for our customers and general corporate purposes, including making deposits to support our derivative activities, geographic expansion (domestically and internationally), expanding our sales and marketing activities, support of legislative initiatives and for working capital for our expansion. We have also acquired and may continue to seek to acquire and invest in companies or assets in the natural gas and biomethane fueling infrastructure, services and production industries. We financed our operations in 2009 primarily through cash on hand and cash provided by operations.

At December 31, 2009, we had total cash and cash equivalents of $67.1 million, compared to $36.3 million at December 31, 2008.

Cash provided by operating activities was $13.3 million for the year ended December 31, 2009, compared to cash used in operating activities of $2.1 million for the year ended December 31, 2008. The increase in operating cash flow resulted primarily from improved operating results between periods of $37.9 million, of which $18.6 million is attributable to not incurring expenditures to support Proposition 10 that were incurred in 2008. This increase was offset by a decrease of $3.6 million of deposits on LNG trucks and a decrease of $13.9 million in collections of accounts and other receivables between periods. The remaining changes primarily resulted from changes in working capital balances, which were mostly due to timing differences related to the various cash flows between periods.

Cash used in investing activities was $43.4 million for the year ended December 31, 2009, compared to $92.3 million for the twelve months ended December 31, 2008. Our purchases of property and equipment were $30.5 million during 2009, compared to $78.0 million (which included expenditures for our California LNG plant) in 2008. Our cash used in acquisitions, net of cash acquired, was $10.4 million during 2009, compared to $19.3 million in 2008. We acquired four compressed natural gas operations and maintenance services contracts for $5.6 million during the second quarter of 2009 and in the fourth quarter of 2009 we purchased BAF Technologies, Inc. for total net cash consideration (after repayment of debt) of $4.7 million. In August of 2008 we purchased a 70% interest in DCE and our net cash outlay for the acquisition including transaction costs was approximately $19.3 million. We made investments during 2008 and 2009 totaling $4.4 million and $5.6 million, respectively, in the Vehicle Production Group, LLC, a company developing a CNG taxi and a paratransit vehicle. In June and July 2009, we sold certain customer vehicle loans to a bank for net proceeds of $3.0 million. In 2008, we purchased $45.2 million of short-term investments with our initial public offering proceeds, of which $57.7 million matured or were sold during the period. We did not have any short-term investments during 2009.

Cash provided by financing activities for the year ended December 31, 2009 was $60.9 million, compared to $62.7 million for the year ended December 31, 2008. Our cash proceeds from the issuance of equity instruments was $73.8 million during 2009, compared to $37.8 million in 2008. This increase is primarily due to the 9,430,000 shares of our common stock we sold to third party investors during the third quarter of 2009, through which we received net proceeds of $73.2 million. Our debt proceeds received were $7.2 million during 2009, compared to $22.8 million in 2008. In 2008, we borrowed $22.8 million to fund the acquisition of our interest in DCE and to fund other amounts and improvements related to the transaction. During 2009, we incurred additional borrowings of $7.2 million to fund further improvements by DCE as we lent the majority of the proceeds we received from PCB to DCE. Our repayments of capital lease obligations and long-term debt were $20.0 million during 2009, compared to $0.4 million in 2008. In October 2009, we repaid in full the Facility A loan

with PCB which had approximately $17.1 million outstanding at that time. In addition, we made scheduled principal payments of $2.5 million during the year.

Our financial position and liquidity are, and will be, influenced by a variety of factors, including our ability to generate cash flows from operations, deposits and margin calls on our futures positions, the level of any outstanding indebtedness and the interest we are obligated to pay on this indebtedness, our capital expenditure requirements (which consist primarily of station construction, LNG plant construction costs, DCE plant construction costs and the purchase of LNG tanker trailers and equipment) and any merger or acquisition activity.

Capital Expenditures

Our current business plan, assuming passage of the NAT GAS Act or comparable legislation providing incentives for natural gas vehicle purchases or fuel use, calls for approximately $86.3 million in capital expenditures in 2009, primarily related to construction of new fueling stations. We will have to raise capital to fund this business plan if the NAT GAS Act or similar legislation is passed into law providing incentives for natural gas fuel use and purchase of natural gas vehicles that leads to rapid growth in our business. If the NAT GAS Act or similar legislation is not passed, or the incentives do not lead to rapid growth in our business, we anticipate that we will build fewer fueling stations and our capital expenditures may be materially less than $86.3 million. Notwithstanding the outcome of any federal legislation that may lead to growth in our business, if we have significant unanticipated capital expenditures, investments, acquisitions or operating expenses, we may also seek to raise capital to fund such capital expenditures, investments, acquisitions or expenses. Due to the continuing disruption in the capital markets, we may not be able to raise capital on terms that are favorable to existing stockholders or at all. Any inability to raise capital may impair our ability to invest in new stations, develop natural gas fueling infrastructure, invest in our biomethane business, invest in strategic transactions or acquisitions and reduce our ability to generate increased revenues.

Our credit agreement with PCB requires that we comply with certain covenants, as detailed in footnote 8 of our consolidated financial statements contained elsewhere herein. One of the covenants requires that we maintain accounts receivable balances from certain subsidiaries above $8.0 million at each quarter-end during the term. To the extent natural gas prices fall, which would result in decreased revenues, or our volumes sold decline, we could violate this covenant. Also, beginning with the quarter ending June 30, 2009, we are required to maintain a debt service ratio, as defined, of 1.5 to 1. Should our operating results not materialize as planned, we could violate this covenant. If we were to violate a covenant, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant a waiver, all of the obligations under the credit agreement will become immediately due and payable and $2.5 million of our funds held by PCB would be applied to the balance due on the PCB loans. We also would be unable to use the $20 million PCB line of credit if this were to occur. We were in compliance with all of the covenants as of December 31, 2009.

Contractual Obligations

The following represents the scheduled maturities of our contractual obligations as of December 31, 2009:

	Payments Due by Period				
Contractual Obligations:	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt and capital lease obligations(a)	$14,125,883	$ 3,096,574	$ 4,625,669	$ 6,093,583	$ 310,057
Operating lease commitments(b)	15,757,965	2,095,914	3,774,229	3,430,848	6,456,974
"Take or pay" LNG purchase contracts(c)	26,440,426	4,543,688	7,114,350	6,116,850	8,665,538
Construction contracts(d)	13,969,431	13,969,431	0	0	0
Total	$70,293,705	$23,705,607	$15,514,248	$15,641,281	$15,432,569

(a) Consists of long-term debt and capital lease obligations to finance equipment purchases, including interest.

(b) Consists of various space and ground leases for our California LNG plant, offices and fueling stations as well as leases for equipment.

(c) The amounts in the table represent our estimates for our fixed LNG purchase commitments under two "take-or-pay" contracts. In October 2007, we entered into a 10-year contingent take-or-pay commitment for 45,000 LNG gallons per day from an LNG plant to be constructed in Arizona, which commitment is reflected in the table above because the obligation is contingent on the completion of construction of the LNG plant, which is anticipated to occur beginning in March 2010.

(d) Consists of our obligations to fund various fueling station construction projects, net of amounts funded through December 31, 2009, and excluding contractual commitments related to station sales contracts.

Off-Balance Sheet Arrangements

At December 31, 2009, we had the following off-balance sheet arrangements that had, or are reasonably likely to have, a material effect on our financial condition.

- outstanding surety bonds for construction contracts and general corporate purposes totaling $10.0 million,
- two take-or-pay contracts for the purchase of LNG,
- operating leases where we are the lessee,
- operating leases where we are the lessor and owner of the equipment, and
- firm commitments to sell CNG and LNG at fixed prices.

We provide surety bonds primarily for construction contracts in the ordinary course of business, as a form of guarantee. No liability has been recorded in connection with our surety bonds as we do not believe, based on historical experience and information currently available, that it is probable that any amounts will be required to be paid under these arrangements for which we will not be reimbursed.

We have entered into a contract, which expires in June 2011, with one vendor to purchase LNG that requires us to purchase minimum volumes. The minimum commitment under the contract is included in the table set forth under "Take-or-pay" LNG purchase contracts above. In October 2007,

we entered into a contingent take-or-pay contract from an LNG plant that is also included in the table above as it is anticipated to begin in March 2010 when the plant commences operations.

We have entered into operating lease arrangements for certain equipment and for our office and field operating locations in the ordinary course of business. The terms of our leases expire at various dates through 2016. Additionally, in November 2006, we entered into a ground lease for 36 acres in California on which we built our California LNG liquefaction plant. The lease is for an initial term of thirty years and requires payments of $230,000 per year, plus up to $130,000 per year for each 30 million gallons of production capacity utilized, subject to future adjustment based on consumer price index changes. We must also pay a royalty to the landlord for each gallon of LNG produced at the facility, as well as a fee for certain other services that the landlord will provide. Commercial operations began December 1, 2008, and the fixed payments for this lease are included in "Operating lease commitments" in the "Contractual Obligations" table set forth above.

We are also the lessor in various leases with our customers, whereby our customers lease from us certain stations and equipment that we own.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Risk We are subject to market risk with respect to our sales of natural gas, which has historically been subject to volatile market conditions. Our exposure to market risk is heightened when we have a fixed price or price cap sales contract with a customer that is not covered by a futures contract, or when we are otherwise unable to pass through natural gas price increases to customers. Natural gas prices and availability are affected by many factors, including weather conditions, overall economic conditions and foreign and domestic governmental regulation and relations.

Natural gas costs represented 60% of our cost of sales for 2008 and 42% (or 44% excluding BAF) of our cost of sales for 2009. Prices for natural gas over the nine-year period from December 31, 1999 through December 31, 2009, based on the NYMEX daily futures data, have ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At December 31, 2009, the NYMEX index price of natural gas was $4.49 per Mcf.

To reduce price risk caused by market fluctuations in natural gas, we may enter into exchange traded natural gas futures contracts. These arrangements also expose us to the risk of financial loss in situations where the other party to the contract defaults on its contract or there is a change in the expected differential between the underlying price in the contract and the actual price of natural gas we pay at the delivery point.

We account for these futures contracts in accordance with the accounting guidance on derivatives. The accounting under this guidance for changes in the fair value of a derivative depends upon whether it has been specified in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria must be met and appropriate documentation maintained. Our futures contracts did not qualify for hedge accounting under this guidance for the years ended December 31, 2005 and 2006, and we did not have any derivative activity in 2007. Consequently, any changes in the fair value of the derivatives during 2005 and 2006 were recorded directly to our consolidated statements of operations. In 2008, we had certain contracts that did not qualify for hedge accounting and we had two derivative contracts to hedge two fixed supply contracts that did qualify for hedge accounting. During the year ended December 31, 2009, we had five futures contracts that did qualify for hedge accounting.

The fair value of the futures contracts we use is based on quoted prices in active exchange traded or over the counter markets which are then discounted to reflect the time value of money for contracts applicable to future periods. The fair value of these futures contracts is continually subject to change due to market conditions. We did not have any futures contracts outstanding during the year ended

December 31, 2007. In an effort to mitigate the volatility in our earnings related to futures activities, in February 2007, our board of directors adopted a revised natural gas hedging policy which restricts our ability to purchase natural gas futures contracts and offer fixed price sales contracts to our customers. This policy was further revised by our board of directors in May 2008. We plan to structure prospective futures contracts so that they will be accounted for as cash flow hedges under this guidance, but we cannot be certain they will qualify. For more information, please read "—Risk Management Activities" above.

We have prepared a sensitivity analysis to estimate our exposure to market risk with respect to the futures contracts we hold as of December 31, 2009 to hedge the fixed price component of certain supply contracts. If the price of natural gas were to fluctuate (increase or decrease) by 10% from the price quoted on NYMEX on December 31, 2009 ($4.49 per Mcf), we could expect a corresponding fluctuation in the value of the contracts of approximately $1.6 million.

Quarterly Results of Operations

The following table sets forth the Company's quarterly consolidated statements of operations data for the eight quarters ended December 31, 2009. The information for each quarter is unaudited and the Company has prepared them on the same basis as the audited consolidated financial statements appearing elsewhere in this Form 10-K. This information includes all adjustments that management considers necessary for the fair presentation of such data. The quarterly data should be read together with the Company's consolidated financial statements and related notes appearing elsewhere in this Form 10-K. The results of operations for any one quarter are not necessarily indicative of results for any future period.

Quarterly Financial Data (Unaudited)

	For the Quarter Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Revenue:				
Product revenues	$28,960,706	$32,725,614	$ 31,935,485	$ 26,538,990
Service revenues	986,651	1,087,367	1,883,202	1,748,518
Total revenues	29,947,357	33,812,981	33,818,687	28,287,508
Operating expenses:				
Cost of sales:				
Product cost of sales	22,161,597	28,316,620	25,558,150	20,978,550
Service cost of sales	252,079	297,410	552,904	650,275
Derivative (gains) losses:				
Futures contracts	—	(5,706,981)	6,047,727	270,429
Series I warrant valuation	—	—	—	—
Selling, general and administrative	11,587,718	12,139,133	11,397,913	27,290,790
Depreciation and amortization	2,063,421	2,184,019	2,310,527	3,065,705
Total operating expenses	36,064,815	37,230,201	45,867,221	52,255,749
Operating loss	(6,117,458)	(3,417,220)	(12,048,534)	(23,968,241)
Interest income (expense), net	839,216	265,347	78,399	447,474
Other income (expense), net	38,356	1,622	(28,801)	(180,336)
Income (loss) from equity method investments	(145,046)	4,724	19,881	(67,745)
Loss before income taxes	(5,384,932)	(3,145,527)	(11,979,055)	(23,768,848)
Income tax expense	(43,767)	(56,203)	(99,171)	(90,000)
Net loss	(5,428,699)	(3,201,730)	(12,078,226	(23,858,848)
Loss (income) of noncontrolling interest	—	—	(13,920)	118,749
Net loss attributable to Clean Energy Fuels Corp.	$(5,428,699)	$(3,201,730)	$(12,092,146)	$(23,740,099)
Basic earnings (loss) per share	$ (0.12)	$ (0.07)	$ (0.27)	$ (0.49)
Fully diluted earnings (loss) per share	$ (0.12)	$ (0.07)	$ (0.27)	$ (0.49)

	For the Quarter Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Revenue:				
Product revenues	$28,382,281	$24,827,576	$ 26,290,638	$37,134,776
Service revenues	1,865,863	3,042,455	4,891,188	5,068,500
Total revenues	30,248,144	27,870,031	31,181,826	42,203,276
Operating expenses:				
Cost of sales:				
Product cost of sales	21,251,866	15,164,592	16,369,247	23,980,457
Service cost of sales	392,383	1,039,899	2,388,458	2,333,965
Derivative (gains) losses:				
Futures contracts	—	—	—	—
Series I warrant valuation	176,767	2,209,596	15,422,310	(441,919)
Selling, general and administrative	11,565,989	11,591,451	10,491,987	13,860,235
Depreciation and amortization	3,617,053	4,123,037	4,516,513	4,735,092
Total operating expenses	37,004,058	34,128,575	49,188,515	44,467,830
Operating loss	(6,755,914)	(6,258,544)	(18,006,689)	(2,264,554)
Interest income (expense), net	(32,538)	(59,538)	(276,110)	336,197
Other income (expense), net	(40,186)	(146,341)	(107,468)	(16,575)
Income (loss) from equity method investments	16,564	35,854	77,744	113,800
Loss before income taxes	(6,812,074)	(6,428,569)	(18,312,523)	(1,831,132)
Income tax expense	(67,887)	(72,963)	(68,352)	(94,299)
Net loss	(6,879,961)	(6,501,532)	(18,380,875)	(1,925,431)
Loss (income) of noncontrolling interest	385,914	124,766	(79,708)	8,126
Net loss attributable to Clean Energy Fuels Corp.	$(6,494,047)	$(6,376,766)	$(18,460,583)	$(1,917,305)
Basic earnings (loss) per share	$ (0.13)	$ (0.13)	$ (0.31)	$ (0.03)
Fully diluted earnings (loss) per share	$ (0.13)	$ (0.13)	$ (0.31)	$ (0.03)

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS/SCHEDULE

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Clean Energy Fuels Corp.:

We have audited the accompanying consolidated balance sheets of Clean Energy Fuels Corp. and subsidiaries (the Company) as of December 31, 2008 and 2009, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedule. We also have audited the Company's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these consolidated financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Clean Energy Fuels Corp. and subsidiaries as of December 31, 2008 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted

accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, Clean Energy Fuels Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As indicated in the accompanying *Management's Report on Internal Control Over Financial Reporting*, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of BAF Technologies, Inc., which constituted 4% of total assets as of December 31, 2009 and 5% of revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of BAF Technologies, Inc.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2009, the Company changed its method of accounting for business combinations.

/s/ KPMG LLP

Los Angeles, California
March 10, 2010

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Balance Sheets

	December 31,	
	2008	2009
Assets		
Current assets:		
Cash and cash equivalents	$ 36,284,431	$ 67,086,965
Restricted cash	2,500,000	2,500,000
Accounts receivable, net of allowance for doubtful accounts of $657,734 and $898,423 as of December 31, 2008 and December 31, 2009, respectively	10,530,638	16,339,730
Other receivables	12,995,507	8,862,213
Inventory, net	3,110,731	6,217,133
Deposits on LNG trucks	6,197,746	445,372
Prepaid expenses and other current assets	3,542,387	6,948,520
Total current assets	75,161,440	108,399,933
Land, property and equipment, net	160,593,665	172,182,436
Capital lease receivables	364,500	1,311,054
Notes receivable and other long-term assets	7,176,755	6,875,364
Investments in other entities	4,879,604	10,536,405
Goodwill	20,797,878	21,572,020
Intangible assets, net of accumulated amortization	21,400,558	34,921,361
Total assets	$ 290,374,400	$ 355,798,573
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$ 2,232,875	$ 2,439,263
Accounts payable	14,276,591	14,775,406
Accrued liabilities	10,253,454	9,695,443
Deferred revenue	1,060,582	2,691,007
Total current liabilities	27,823,502	29,601,119
Long-term debt and capital lease obligations, less current portion	22,850,927	9,781,425
Other long-term liabilities	2,297,446	36,039,864
Total liabilities	52,971,875	75,422,408
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.0001 par value. Authorized 1,000,000 shares; issued and outstanding no shares	—	—
Common stock, $0.0001 par value. Authorized 99,000,000 shares; issued and outstanding 50,238,212 shares and 59,840,151 shares at December 31, 2008 and December 31, 2009, respectively	5,024	5,984
Additional paid-in capital	346,466,999	424,580,895
Accumulated deficit	(113,549,257)	(149,410,111)
Accumulated other comprehensive income	853,837	2,012,573
Total stockholders' equity of Clean Energy Fuels Corp.	233,776,603	277,189,341
Noncontrolling interest in subsidiary	3,625,922	3,186,824
Total equity	237,402,525	280,376,165
Total liabilities and equity	$ 290,374,400	$ 355,798,573

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Operations

	Years Ended December 31,		
	2007	2008	2009
Revenue:			
Product revenues	$113,678,130	$120,160,795	$116,635,271
Service revenues	4,038,103	5,705,738	14,868,006
Total revenue	117,716,233	125,866,533	131,503,277
Operating expenses:			
Cost of sales:			
Product cost of sales	84,591,197	97,014,917	76,766,162
Service cost of sales	1,069,132	1,752,668	6,154,705
Derivative losses:			
Futures contracts	—	611,175	—
Series I warrant valuation	—	—	17,366,754
Selling, general and administrative	35,933,694	62,415,554	47,509,662
Depreciation and amortization	7,107,942	9,623,672	16,991,695
Total operating expenses	128,701,965	171,417,986	164,788,978
Operating loss	(10,985,732)	(45,551,453)	(33,285,701)
Interest income (expense), net	3,505,597	1,630,436	(31,989)
Other expense, net	(192,347)	(169,159)	(310,570)
Income (loss) from equity method investments	—	(188,186)	243,962
Loss before income taxes	(7,672,482)	(44,278,362)	(33,384,298)
Income tax expense	(1,221,880)	(289.141)	(303,501)
Net loss	(8,894,362)	(44,567,503)	(33,687,799)
Loss of noncontrolling interest	—	104,829	439,098
Net loss attributable to Clean Energy Fuels Corp.	$ (8,894,362)	$ (44,462,674)	$ (33,248,701)
Loss per share:			
Basic	$ (0.22)	$ (0.98)	$ (0.60)
Diluted	$ (0.22)	$ (0.98)	$ (0.60)
Weighted average common shares outstanding:			
Basic	40,258,440	45,367,991	55,021,961
Diluted	40,258,440	45,367,991	55,021,961

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss)

	Common stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Noncontrolling Interest in Subsidiary	Total Stockholders' Equity	Total Comprehensive Income (Loss)
	Shares	Amount						
Balance, December 31, 2006	34,192,161	$3,419	$181,678,861	$ (60,192,221)	$1,425,798	$ —	$122,915,857	$(77,498,686)
Issuance of common stock, net	10,000,000	1,000	108,520,933	—	—		108,521,933	
Issuance of common stock upon exercise of options	82,214	9	296,077	—	—		296,086	
Stock-based compensation	—	—	7,370,874	—	—		7,370,874	
Foreign currency translation adjustment	—	—	—	—	722,086		722,086	722,086
Net loss	—	—	—	(8,894,362)	—	—	(8,894,362)	(8,894,362)
Balance, December 31, 2007	44,274,375	4,428	297,866,745	(69,086,583)	2,147,884	—	230,932,474	(8,172,276)
Issuance of common stock upon exercise of options	87,414	9	350,613	—	—	—	350,622	
Issuance of common stock in exchange for services	2,984	—	30,000	—	—	—	30,000	
Issuance of common stock to Boone Pickens	319,488	32	4,999,956	—	—	—	4,999,988	
Issuance of common stock in Unit offering, net of offering costs (see note 9)	4,419,192	442	19,071,562	—	—	—	19,072,004	
Issuance of Series I warrant, net of offering costs (see note 9)	—	—	9,761,585	—	—	—	9,761,585	
Issuance of Series II warrants, net of offering costs (see note 9)	—	—	3,650,790	—	—	—	3,650,790	
Cashless exercise of Series II warrants (see note 9)	1,134,759	113	(113)	—	—	—	—	
Acquisition of 70% interests in DCE	—	—	—	—	—	3,625,922	3,625,922	
Stock-based compensation	—	—	10,735,861	—	—	—	10,735,861	
Net loss	—	—	—	(44,462,674)	—	—	(44,462,674)	(44,462,674)
Unrealized loss on futures contracts	—	—	—	—	(654,483)	—	(654,483)	(654,483)
Foreign currency translation adjustment	—	—	—	—	(639,564)	—	(639,564)	(639,564)
Balance, December 31, 2008	50,238,212	5,024	346,466,999	(113,549,257)	853,837	3,625,922	237,402,525	(45,756,721)
Issuance of common stock upon exercise of options	171,939	17	587,744	—	—	—	587,761	
Issuance of common stock, net of offering costs (see note 9)	9,430,000	943	73,216,848	—	—	—	73,217,791	
Adoption of FASB ASC 815, Series I warrants	—	—	(9,761,584)	(2,612,153)	—	—	(12,373,737)	
Stock-based compensation	—	—	14,070,888	—	—	—	14,070,888	
Net loss	—	—	—	(33,248,701)	—	(439,098)	(33,687,799)	(33,687,799)
Unrealized gain on futures contracts	—	—	—	—	813,638	—	813,638	813,638
Foreign currency translation adjustment	—	—	—	—	345,098	—	345,098	345,098
Balance, December 31, 2009	59,840,151	$5,984	$424,580,895	$(149,410,111)	$2,012,573	$3,186,824	$280,376,165	$(32,529,063)

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2007	2008	2009
Cash flows from operating activities:			
Net loss	$ (8,894,362)	$(44,567,503)	$(33,687,799)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation and amortization	7,107,942	9,623,672	16,991,695
Provision for doubtful accounts and notes	1,309,428	528,885	(783,269)
Loss on disposal of assets	237,783	170,781	422,521
Derivative (gain) loss	—	—	17,366,754
Stock option expense	7,370,874	10,735,861	14,070,888
Common stock issued in exchange for services	—	30,000	—
Changes in operating assets and liabilities, net of assets and liabilities acquired:			
Accounts and other receivables	13,313,304	11,224,221	(2,655,894)
Inventory	154,799	(706,841)	109,385
Capital lease receivables	649,000	399,000	857,426
Margin deposits on futures contracts	—	(1,114,227)	(2,117,594)
Return (deposits) on LNG trucks	(14,540,307)	9,318,181	5,752,425
Prepaid expenses and other assets	(1,942,715)	(3,800,121)	(2,155,366)
Accounts payable	1,556,817	445,361	925,541
Accrued expenses and other	778,543	5,636,827	(1,825,801)
Net cash provided by (used in) operating activities	7,101,106	(2,075,903)	13,270,912
Cash flows from investing activities:			
Purchases of property and equipment	(38,082,456)	(78,031,747)	(30,498,501)
Proceeds from sale of property and equipment	—	386,502	57,641
Proceeds from sale of loans receivable	—	—	3,026,073
Purchases of short-term investments	(19,339,799)	(45,230,061)	—
Maturity or sales of short-term investments	6,860,115	57,709,745	—
Initial note advance to DCE	—	(714,370)	—
Acquisitions, net of cash acquired	—	(19,274,948)	(10,362,312)
Investments in other entities	—	(4,616,283)	(5,633,717)
Restricted cash	—	(2,500,000)	—
Net cash used in investing activities	(50,562,140)	(92,271,162)	(43,410,816)
Cash flows from financing activities:			
Proceeds from Unit offering (see note 9)	—	32,484,379	—
Proceeds from issuance of common stock and exercise of stock options	110,518,690	5,350,610	73,805,552
Proceeds from long-term debt	—	22,828,425	7,159,571
Proceeds from capital leases	—	2,410,423	—
Repayment of capital lease obligations and long-term debt	(57,499)	(379,943)	(20,022,685)
Net cash provided by financing activities	110,461,191	62,693,894	60,942,438
Net increase (decrease) in cash	67,000,157	(31,653,171)	30,802,534
Cash, beginning of year	937,445	67,937,602	36,284,431
Cash, end of year	$ 67,937,602	$ 36,284,431	$ 67,086,965
Supplemental disclosure of cash flow information:			
Income taxes paid	$ 1,214,464	$ 149,219	$ 334,299
Interest paid, net of $0, $493,000 and $539,000 capitalized, respectively	$ 27,038	$ 449,187	$ 1,078,274

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

(a) The Company

Clean Energy Fuels Corp., together with its majority and wholly owned subsidiaries (hereinafter collectively referred to as "Clean Energy" or the "Company"), is engaged in the business of selling natural gas fueling solutions to its customers, primarily in the United States and Canada. Clean Energy was incorporated in April 2001. In June 2001, the Company acquired certain assets and interests of Pickens Fuel Corp. (a private company owned by Boone Pickens) and BCG eFuels, Inc. (owned by Terasen, Inc. ("Terasen") (formerly BC Gas, Inc.)), and Westport Innovations Inc. ("Westport Innovations") of Vancouver, British Columbia. For accounting purposes, BCG eFuels, Inc. was deemed the acquiring entity in the formation of the Company and was accounted for on a carryover cost basis. On December 31, 2002, the Company acquired all the outstanding membership interests of Blue Energy & Technologies, L.L.C. ("Blue Energy").

Clean Energy has a broad customer base in a variety of markets, including public transit, refuse, airports, and regional trucking. Clean Energy operates, maintains or supplies approximately 196 natural gas fueling locations in Arizona, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, Washington, and Wyoming within the United States, and in British Columbia and Ontario within Canada. The Company also generates revenue through operation and maintenance agreements with certain customers, through building and selling or leasing natural gas fueling stations to its customers, and through financing its customers' vehicle purchases. In April 2008, the Company opened its first compressed natural gas ("CNG") station in Lima, Peru through the Company's joint venture, Clean Energy del Peru. In August 2008, the Company acquired 70% of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE"). DCE owns a facility that collects, processes and sells renewable biomethane collected from a landfill in Dallas, Texas. On October 1, 2009, the Company acquired 100% of BAF Technologies, Inc. ("BAF"), a company that provides natural gas conversions, alternative fuel systems, application engineering, service and warranty support and research and development for natural gas vehicles.

(b) Principles of Consolidation

The consolidated financial statements include the financial statements of Clean Energy and its majority or wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results could differ from those estimates. Current economic conditions may require the use of additional estimates and these estimates may be subject to a greater degree of uncertainty as a result of the uncertain economy.

(1) Summary of Significant Accounting Policies (Continued)

(d) Impact of Recently Issued Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued new authoritative guidance on Accounting for Uncertainty in Income Taxes, which prescribed a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax provision taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The adoption of this revised guidance did not have a material impact on the Company's financial statements.

In December 2007, the FASB revised it existing guidance on business combinations by providing new accounting guidance and disclosure requirements for business combinations. The revised guidance is effective for business combinations which occur beginning in 2009. On October 1, 2009, the Company purchased BAF Technologies, Inc., and the purchase price included contingent considerations based on the performance of BAF Technologies, Inc. in 2010 and 2011. Under the prior guidance for accounting for business combinations, contingent consideration would have been recorded when earned by the counterparty. However, the new guidance requires management to establish the fair value of the contingent consideration on the closing date and then adjust the value through the statement of operations as the value of the obligation changes. The Company allocated $3.1 million to this contingent obligation on the purchase date as a result of applying the new guidance for this acquisition. See note 3 for additional details.

In December 2007, the FASB issued new authoritative guidance for Noncontrolling Interests in Consolidated Financial Statements. This new guidance requires presentation of non-controlling interests in consolidated subsidiaries separately within equity in the consolidated statements of financial position as well as the separate presentation within the consolidated statements of operations and comprehensive income (loss) attributable to the parent and noncontrolling interest. Accounting for changes in a parent's ownership interest will generally be at fair value, and if the parent retains control or significant influence of the subsidiary, any adjustments will be made through equity, while transactions where control changes occur will be accounted for through earnings. This new authoritative guidance was effective for the Company on January 1, 2009. As a result of adopting this guidance, the Company reclassified the minority interest of DCE to the stockholders' equity section of its consolidated balance sheet. References to minority interest in previous financial statements are now reflected as noncontrolling interest. The adoption of this statement did not have a material impact on the Company's consolidated financial position or results of operations.

In March 2008, the FASB issued new authoritative guidance on disclosures about derivative instruments and hedging activities. This guidance requires enhanced disclosures about the Company's derivative and hedging activities. The Company is required to provide enhanced disclosures about (a) how and why it uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for, and (c) how derivative instruments and related hedged items affect the Company's financial position, results of operations, and cash flows. The Company adopted this guidance as of January 1, 2009 and the adoption did not have a material impact on its consolidated financial statements.

In April 2008, the FASB issued its position on determination of the useful life of intangible assets by amending the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. Specifically, the FASB removed the

(1) Summary of Significant Accounting Policies (Continued)

requirement to consider whether an intangible asset can be renewed without substantial cost or material modifications to the existing terms and conditions, and instead, requires an entity to consider its own historical experience in renewing similar arrangements. The FASB also now requires expanded disclosure related to the determination of intangible asset useful lives. This requirement was effective for the Company on January 1, 2009. Adoption of this guidance did not have a material impact on the Company's consolidated financial statements.

In June 2008, the FASB reached a consensus on determining whether an instrument (or embedded feature) is indexed to an entity's own stock. The FASB concluded, among other things, that contingent and other adjustment features in equity-linked financial instruments are consistent with equity indexation if they are based on variables that would be inputs to a "plain vanilla" option or forward pricing model and they do not increase the contract's exposure to those variables. The Company's Series I warrants issued on October 28, 2008 are linked to the Company's own equity shares; however, the investor has protective pricing features commonly referred to as "*down-round*" protection, whereby the conversion price potentially resets if the common stock price of the Company declines after issuance. As a result of this guidance, effective January 1, 2009, the Company accounts for the Series I warrants as a derivative. The Company recorded a cumulative-effect adjustment of approximately $2.6 million to opening retained earnings and reclassed approximately $9.8 million from additional paid-in capital to long-term liabilities on the date of adopting this guidance, January 1, 2009. During 2009, the Company recorded charges of $17.4 million related to valuing the Series I warrants.

In April 2009, the FASB issued new authoritative guidance on determining fair value when the volume and level of activity for an asset or liability has significantly decreased. The guidance provides that when the volume and level of activity for the asset or liability have significantly decreased, that regardless of market conditions, the fair value measurement is an exit price concept. This guidance clarifies and includes additional factors to consider in determining whether there has been a significant decrease in market activity for an asset or liability and provides additional clarification on estimating fair value when the market activity for an asset or liability has declined significantly. The scope of this guidance does not include assets and liabilities measured under Level 1 inputs. The Company adopted this guidance on May 1, 2009 and its adoption did not have a material impact on the Company's consolidated financial statements.

In May 2009, the FASB issued new authoritative guidance on reporting subsequent events, which establishes general standards of accounting for and disclosures of events that occur after the balance sheet date, but before the financial statements are issued or are available to be issued. This guidance requires the disclosure of the date through which an entity has evaluated subsequent events, and is effective for interim and annual reporting periods ending after June 15, 2009. The Company adopted the new disclosure requirements on June 1, 2009 and its adoption did not have a material impact on the Company's consolidated financial statements.

In June 2009, the FASB issued new authoritative guidance on interim disclosures about fair value of financial instruments. This guidance requires publicly-traded companies to provide disclosures on the fair value of financial instruments in interim financial statements. The Company adopted the new disclosure requirements on July 1, 2009 and its adoption did not have a material impact on the Company's consolidated financial statements.

In July 2009, the FASB codified the accounting standards ("Codification"). The Codification will become the source of authoritative U.S. generally accepted accounting principles ("GAAP") recognized

(1) Summary of Significant Accounting Policies (Continued)

by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, the Codification superseded all then-existing, non-SEC accounting and reporting standards. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. This Statement was effective for the Company's consolidated financial statements issued for interim and annual periods ending after September 15, 2009. The Company adopted this guidance September 30, 2009 and its adoption did not have a material impact on the Company's consolidated financial statements.

In October 2009, the FASB issued new authoritative guidance on multi-deliverable revenue arrangements. This guidance establishes requirements that must be met for an entity to recognize revenue from the sale of a delivered item that is part of a multiple-element arrangement when other items have not yet been delivered. One of those current requirements is that there be objective and reliable evidence of the standalone selling price of the undelivered items, which must be supported by either vendor-specific objective evidence ("VSOE") or third party evidence ("TPE"). This guidance amends previous guidance by eliminating the requirement that all undelivered elements have VSOE or TPE before an entity can recognize the portion of an overall arrangement fee that is attributable to items that already have been delivered. In the absence of VSOE or TPE of the standalone selling price for one or more delivered or undelivered elements in a multiple-element arrangement, entities will be required to estimate the selling prices of those elements. The overall arrangement fee will be allocated to each element (both delivered and undelivered items) based on their relative selling prices, regardless of whether those selling prices are evidenced by VSOE or TPE or are based on the entity's estimated selling price. Application of the "residual method" of allocating an overall arrangement fee between delivered and undelivered elements will no longer be permitted under this new guidance. Additionally, the new guidance will require entities to disclose more information about their multiple-element revenue arrangements. This guidance is effective June 15, 2010 and the Company is currently evaluating the impact of this guidance on is consolidated financial statements.

(e) Foreign Currency Translation

In accordance with current accounting guidance, the Company uses the local currency as the functional currency of its foreign subsidiary. Accordingly, all assets and liabilities outside the United States are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date. Income and expense items are translated at the weighted average exchange rates prevailing during the period. Net foreign currency translation adjustments are recorded as accumulated other comprehensive income in stockholders' equity. The Company realized net foreign currency transaction exchange gains of $10,286, $8,766 and $1,597 in 2007, 2008 and 2009, respectively. The functional currency for the Company's subsidiary in Canada is the Canadian dollar.

The accompanying consolidated balance sheets include total assets of the Canadian subsidiary of $2,529,011 and $3,605,020 expressed in U.S. dollars, as of December 31, 2008 and 2009, respectively. Sales made by the Canadian subsidiary totaled $1,360,593, $1,020,040 and $957,121 in U.S. dollars for the years ended December 31, 2007, 2008 and 2009, respectively.

(1) Summary of Significant Accounting Policies (Continued)

(f) Cash and Cash Equivalents

The Company considers all highly liquid investments with maturities of three months or less on the date of acquisition to be cash equivalents.

(g) Short-Term Investments

Short-term investments, which are classified as "available for sale," generally consist of commercial paper and government and commercial debt securities with original maturity dates between three and six months. Short-term investments are marked-to-market at each period end with any unrealized gains or losses included in the consolidated balance sheets under the line item accumulated other comprehensive income. All of the short-term investments at December 31, 2007 matured or were sold during the year ended December 31, 2008.

(h) Inventories

Parts inventories are stated at the lower of cost or market on a first-in, first out basis for the parts to service the Company's fueling locations and for the parts used in the vehicle conversions at the Company's wholly owned subsidiary BAF. Management's estimate of market includes a provision for obsolete, slow moving, and unsaleable inventory based upon inventory on hand and forecasted demand. The Company also has LNG inventory related to its LNG liquefaction plants which it values at the lower of cost or market on a first-in, first-out basis. Inventories consisted of the following at December 31, 2008 and 2009:

	2008	2009
Station parts	2,086,165	2,959,995
Vehicle parts	—	2,390,842
LNG	1,024,566	866,296
Total	3,110,731	6,217,133

(i) Research and Development and Advertising

Research and development costs related to the design, development, and testing of new products, applications, and technologies are charged to expense as incurred. No research and development costs were incurred during the years ended December 31, 2007, 2008 and 2009.

Advertising costs are expensed as incurred. Advertising costs amounted to approximately $1,316,000, $985,000 and $932,000 for the years ended December 31, 2007, 2008 and 2009, respectively. For the year ended December 31, 2008, the Company also spent $18.6 million in support of Proposition 10 on the California ballot in November 2008.

(j) Property and Equipment

Property and equipment are recorded at cost. Depreciation and amortization are recognized over the estimated useful lives of the assets using the straight-line method. The estimated useful lives of depreciable assets are 20 years for LNG liquefaction plant assets, ten years for station equipment and LNG trailers, and three to seven years for all other depreciable assets. Leasehold improvements are

(1) Summary of Significant Accounting Policies (Continued)

amortized over the shorter of their estimated useful lives or lease terms. Periodically, the Company receives grant funding to assist in the financing of natural gas fueling station construction. The Company records the grant proceeds as a reduction of the cost of the respective asset. Total grant proceeds received were approximately $300,000, $384,000 and $325,000 for the years ended December 31, 2007, 2008 and 2009, respectively.

(k) Long-Lived Assets

The Company reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of long-lived assets to be held and used is measured by a comparison of the carrying amount of an asset to future net undiscounted cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or the fair value less costs to sell.

(l) Goodwill and Intangible Assets

Goodwill represents the excess of costs incurred over the fair value of the net assets of acquired businesses. Goodwill and intangible assets acquired in a purchase business combination and determined to have an indefinite useful life are not amortized, but instead are tested for impairment at least annually in accordance with current accounting guidance on *Goodwill and Other Intangible Assets*. When assessing fair value, the Company looks at its projected future cash flows and its market capitalization for its respective operations. To the extent the Company's projected future cash flows do not materialize as planned or its market capitalization goes down, the Company could be forced to take an impairment charge in future periods.

Intangible assets with estimable useful lives are amortized over their respective estimated useful lives and reviewed for impairment. Amortization expense for intangible assets was $35,491, $534,979 and $2,246,774 for the years ended December 31, 2007, 2008 and 2009, respectively. Estimated amortization expense for the five years succeeding the year ended December 31, 2009 is approximately $3.4 million, $3.0 million, $2.5 million, $2.5 million, and $2.5 million, respectively. Accumulated amortization at December 31, 2008 and 2009 was $1,264,425 and $3,511,199, respectively.

(m) Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred or becomes reasonably estimable and if there is a legal obligation to restore or remediate the property at the end of a lease term. All of the Company's fueling and storage equipment is located above-ground. The liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as the costs to restore the property, future inflation rates, and the adjusted risk free rate of interest. When the liability is initially recorded, the Company capitalizes the cost by increasing the related property and equipment balances. Over time, the liability is increased and expense is recognized for the change in present value, and the initial capitalized cost is depreciated over the useful life of the asset.

(1) Summary of Significant Accounting Policies (Continued)

The following table summarizes the activity of the asset retirement obligation, of which $411,060 and $835,053 is included in other long-term liabilities, with the remaining current portion included in accrued liabilities, at December 31, 2008 and 2009, respectively:

	2008	2009
Beginning balance	$224,455	$488,685
Liabilities incurred	267,524	393,451
Liabilities settled	(13,349)	(3,973)
Accretion expense	10,055	39,559
Ending balance	$488,685	$917,722

(n) Stock-Based Compensation

The Company accounts for its stock based compensation transactions using a fair value method. The Company recognizes compensation expense based on estimated grant-date fair values using the Black-Scholes option-pricing model.

(o) Revenue Recognition

Revenue from the sale of natural gas and from operations and maintenance agreements is recognized typically at the time fuel is dispensed or when the operations and maintenance services are provided.

In certain transactions with its customers, the Company agrees to provide multiple products or services, including construction of and either leasing or sale of a station, providing operations and maintenance to the station, and sale of fuel to the customer. The Company evaluates the separability of revenues for deliverables based on current accounting guidance, which provides a framework for establishing whether or not a particular arrangement with a customer has one or more deliverables. To the extent the Company has adequate objective evidence of the values of separate deliverable items under a contract, it allocates the revenue from the contract on a relative fair value basis at the inception of the arrangement. If the arrangement contains a lease, the Company uses the existing evidence of fair value to separate the lease from the other deliverables.

The Company accounts for its leasing activities in accordance with current accounting guidance. The Company's existing station leases are sales-type leases, giving rise to profit at the delivery of the leased station. Any remaining unearned revenue is amortized into income over the life of the lease using the effective interest method. For these arrangements, the Company recognizes gas sales and operations and maintenance service revenues as earned from the customer on a volume-delivered basis.

The Company has evaluated the relative fair values of the deliverables for three stations that it sold in 2007, two stations it sold in 2008 and three stations that it sold in 2009, and concluded that there is not sufficient objective evidence to separate those deliverables. The Company is recognizing profit on the sale of those stations over the respective lives of the associated contracts as the associated services are being performed. Additionally, the Company sold one station during 2007, two stations in 2008 and two stations in 2009 that were not part of a multi-deliverable contract and recognized the associated revenue and costs during the period.

(1) Summary of Significant Accounting Policies (Continued)

Revenue on construction contracts has been recognized using the completed contract method.

Revenue from the sale of biomethane and vehicles is recognized at the time title to the gas or vehicle passes to the customer.

(p) Income Taxes

The Company computes income taxes under the asset and liability method. This method requires the recognition of deferred tax assets and liabilities for temporary differences between the financial reporting basis and the tax basis of the Company's assets and liabilities. The impact on deferred taxes of changes in tax rates and laws, if any, is applied to the years during which temporary differences are expected to be settled and is reflected in the consolidated financial statements in the period of enactment. The Company records a valuation allowance against its deferred tax assets when management determines it is more likely than not that the assets will not be realized.

(q) Volumetric Excise Tax Credits (VETC)

The Company records its VETC credits as revenue in its consolidated statements of operations as the credits are fully refundable and do not need to offset income tax liabilities to be received. VETC revenues for 2007, 2008 and 2009 were $17.0 million, $17.2 million, and $15.5 million, respectively. The legislation providing for VETC expired on December 31, 2009.

(r) Concentration of Credit Risk

Credit is extended to all customers based on financial condition, and collateral is generally not required. Concentrations of credit risk with respect to trade receivables are limited because of the large number of customers comprising the Company's customer base and dispersion across many different industries and geographies.

The Company continuously monitors collections and payments from its customers and maintains a provision for estimated credit losses based upon its historical experience and any specific customer collection issues that it has identified. While such credit losses have historically been within the Company's expectations and the provisions established, the Company cannot guarantee that it will continue to experience the same credit loss rates that it has in the past.

(s) Derivative Financial Instruments

The Company, in an effort to manage its natural gas commodity price risk exposures related to certain contracts, utilizes derivative financial instruments. The Company, from time to time, enters into natural gas futures contracts that are over-the-counter swap transactions that convert its index-based gas supply arrangements to fixed price arrangements. The Company accounts for its derivative instruments in accordance with the authoritative guidance for derivative instruments and hedging activities, which requires the recognition of all derivatives as either assets or liabilities in the consolidated balance sheet and the measurement of those instruments at fair value. Historically, through June 30, 2008, the Company's derivative instruments have not qualified for hedge accounting under the authoritative guidance. On and after July 1, 2008, the Company entered into futures contracts that did qualify for hedge accounting. The Company's futures contracts at December 31, 3009 are being accounted for as cash flow hedges under the authoritative guidance and are being used to

(1) Summary of Significant Accounting Policies (Continued)

mitigate the Company's exposure to changes in the price of natural gas and not for speculative purposes. At December 31, 2009, all of the Company's futures contracts qualified for hedge accounting.

The counter-party to the Company's derivative transactions is a high credit quality counterparty; however, the Company is subject to counterparty credit risk to the extent the counterparty to the derivatives is unable to meet its settlement commitments. The Company manages this credit risk by minimizing the number and size of its derivative contracts. The Company actively monitors the creditworthiness of its counterparties and records valuation adjustments against the derivative assets to reflect counterparty risk, if necessary. The counter-party is also exposed to credit risk of the Company, which requires the Company to provide cash deposits as collateral.

(t) LNG Transportation Costs

The Company records the costs incurred to transport LNG to its customers in the line item cost of sales in the accompanying statements of operations.

(2) Derivative Transactions

The Company marks to market its open futures positions at the end of each period and records the net unrealized gain or loss during the period in derivative (gains) losses in the consolidated statements of operations or in accumulated other comprehensive income in the consolidated balance sheets in accordance with the guidance. The Company recorded unrealized gains of approximately $0.8 million in accumulated other comprehensive income in the year ended December 31, 2009 related to its futures contracts. The fair value of the Company's futures contracts of approximately $159,000 at December 31, 2009 is included in prepaid expenses and other current assets for the short-term amount (an asset of $442,000), and other long-term liabilities for the long-term amount (a liability of $283,000) on the Company's consolidated balance sheet at December 31, 2009. The Company's ineffectiveness related to its futures contracts in the year ended December 31, 2009 was insignificant. In 2009, the Company recognized cost of sales of $1.8 million in the accompanying consolidated statement of operations related to its futures contracts that were settled during year.

The Company is required to make certain deposits on its futures contracts, should any exist. At December 31, 2008, the Company had $1.1 million of margin deposits related to its futures contracts, all of which were classified as current. At December 31, 2009, the Company had $2.9 million of margin deposits related to its futures contracts, $1.7 million of which was classified as current as of December 31, 2009.

The following table presents the notional amounts and weighted average fixed prices per gasoline gallon equivalent of the Company's natural gas futures contracts as of December 31, 2009:

	Gallons	Weighted Average Price Per Gasoline Gallon Equivalent
2010	12,040,000	$0.76
2011	11,600,000	$0.82
2012	5,160,000	$0.81
January to May, 2013	300,000	$0.81

(2) Derivative Transactions (Continued)

The Company historically has relied on the advice of BP Capital when conducting its futures activities. BP Capital is an entity the principal of which is Boone Pickens, the Company's largest stockholder and one of its directors. Prior to June 2008, at the advice of BP Capital, the Company from time to time has liquidated and subsequently re-established its futures positions based on market conditions.

(3) Acquisitions

Landfill Operation

On August 15, 2008, the Company and Cambrian Energy McCommas Bluff LLC ("Cambrian") formed a joint venture to acquire all of the outstanding membership interests of DCE. DCE owns a facility that collects, processes and sells landfill gas at the McCommas Bluff landfill located in Dallas, Texas. This acquisition enables the Company to participate in the production of pipeline quality renewable biomethane which may be used as a vehicle fuel.

The Company paid an aggregate of $19.6 million, including transaction costs, to acquire a 70% interest in DCE. Also as part of the transaction, the Company granted DCE's minority investor an exclusive, non-assignable option to purchase from the Company up to and including a 19% membership interest in DCE. The exercise price of the option is $368,000 for each 1%, up to $6,992,000 for the total 19%. The option may be exercised as a whole or in part (but only in 1% increments) during the ten-year period commencing on the date which the loan made by the Company to DCE has been repaid in full.

The Company borrowed $18.0 million from PlainsCapital Bank ("PCB") to finance its acquisition of its membership interests in DCE. The Company also obtained a $12.0 million line of credit from PCB to finance capital improvements of the DCE processing facility pursuant to a loan made by the Company to DCE and to pay certain costs and expenses related to the acquisition and the PCB loan (see note 8).

The Company accounted for this acquisition in accordance with authoritative guidance for business combinations which requires the Company to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, measured at their fair values as of that date of acquisition. The following table summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed, net of Cambrian's non controlling interest, in the DCE acquisition:

Current assets	$ 1,129,389
Property, plant and equipment	1,821,770
Identifiable intangible assets	21,810,986
Total assets acquired	24,762,145
Current liabilities assumed	(1,480,770)
Non-controlling interest	(3,730,751)
Total purchase price	$19,550,624

Management allocated approximately $21.8 million to the identifiable intangible asset related to the fair value of DCE's landfill gas lease with the City of Dallas that was acquired with the acquisition.

(3) Acquisitions (Continued)

The fair value of the identifiable intangible asset will be amortized on a straight-line basis over the remaining life of the lease, approximately 16.5 years at the acquisition date.

The results of DCE's operations have been included in the Company's consolidated financial statements since August 15, 2008.

Operating and Maintenance Contracts

In May 2009, the Company acquired four compressed natural gas operations and maintenance services contracts for $5.6 million in cash. The Company recorded $0.5 million to tangible assets and $5.1 million of intangible assets related to customer relationships, which are being amortized over their expected lives of eight years. The results of operations of the acquired contracts are included in the Company's consolidated financial statements from their acquisition dates forward, which are May 2009 for two of the contracts and June 2009 for the remaining two contracts. In addition, as part of the acquisition, the Company became the custodian of certain customer-owned inventories that it is required to replenish when the contracts expire. The customer-owned inventory was valued on the Company's books at $986,000 with a corresponding balance of $986,000 recorded as a liability on the acquisition dates of the contracts.

Vehicle Conversion

On October 1, 2009, the Company purchased all the outstanding shares of BAF under a stock purchase agreement. The Company paid an aggregate of $8.5 million to acquire BAF. Pursuant to the terms of the agreement, the purchase price was reduced by the amount of BAF's outstanding debt which was repaid in full at closing. Due to the fact that approximately $3.8 million of BAF's outstanding debt, including interest, was held by Clean Energy, the Company paid a net amount of approximately $4.7 million in cash to acquire BAF at the closing. BAF shareholders will be able to earn additional consideration if BAF achieves certain gross profit targets in fiscal 2010 and 2011. The additional consideration will be determined as a percentage of gross profit based on a sliding scale that increases at certain gross profit levels, subject to achieving a minimum gross profit target and capped by a maximum additional payment amount. For 2010, the shareholders of BAF will receive between one and twenty-six percent of the gross profit of BAF as additional consideration if BAF achieves $8 million or more in gross profit, up to a maximum of $11 million in additional consideration (which maximum amount would be payable if BAF achieved approximately $42.3 million in gross profit in 2010). For 2011, the shareholders of BAF will receive between one and twenty-one percent of the gross profit of BAF as additional consideration if BAF achieves $8.5 million or more in gross profit, up to a maximum of $11 million in additional consideration (which maximum amount would be payable if BAF achieved approximately $52.4 million in gross profit in 2011).

The Company accounted for this acquisition in accordance with authoritative guidance for business combinations which requires the Company to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, measured at their fair values as of

(3) Acquisitions (Continued)

that date of acquisition. The following table summarizes the allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed:

Current assets	$ 4,820,188
Property, plant and equipment	157,624
Identifiable intangible assets	10,660,000
Goodwill	774,142
Total assets acquired	16,411,954
Current liabilities assumed	(4,844,672)
Contingent liability	(3,100,000)
Total purchase price	$ 8,467,282

Management allocated approximately $10.7 million of the purchase price to the identifiable intangible assets related to customer relationships, engine certifications and trademarks that were acquired with the acquisition. The fair value of the identifiable intangible assets will be amortized on a straightline basis over their estimated useful lives of 1.5 to 8 years. In addition, management allocated $774,142 to goodwill as part of the acquisition and recorded a contingent liability of $3.1 million related to the possible consideration owed to BAF shareholders if BAF achieves certain gross profit targets in 2010 and 2011. Under the accounting guidance the Company must follow for this acquisition, the Company is required to adjust the value of the contingent consideration for this acquisition through the statement of operations as the value of the obligation changes each reporting period.

The results of BAF's operations have been included in the Company's consolidated financial statements since October 1, 2009.

(4) Other Receivables

Other receivables at December 31, 2008 and 2009 consisted of the following:

	2008	2009
Loans to customers to finance vehicle purchases	$ 1,983,414	$1,179,356
Capital lease receivables	399,000	1,209,819
Advances to vehicle manufacturers	4,510,386	2,413,066
Fuel tax credits	5,511,908	2,626,551
Other	590,799	1,433,421
	$12,995,507	$8,862,213

(5) Land, Property and Equipment

Land, property and equipment at December 31, 2008 and 2009 are summarized as follows:

	2008	2009
Land	$ 472,616	$ 472,616
LNG liquefaction plants	88,366,069	91,830,640
Station equipment	57,994,315	83,935,092
LNG trailers	11,863,681	11,887,326
Other equipment	11,533,656	15,744,484
Construction in progress	22,439,115	14,190,917
	192,669,452	218,061,075
Less accumulated depreciation	(32,075,787)	(45,878,639)
	$160,593,665	$172,182,436

(6) Investment in Other Entities

Through December 31, 2009, the Company invested approximately $10.0 million in The Vehicle Production Group LLC ("VPG"), a company that is developing a natural gas vehicle made in the United States for taxi and paratransit use. The Company committed to fund up to $10.0 million in VPG from August 2008 through March 2010, and VPG may under certain circumstances make a capital call on investors which could require the Company to invest up to approximately $0.8 million in additional funds. The Company accounts for its investment in VPG under the cost method of accounting as the Company does not have the ability to exercise significant influence over VPG's operations.

(7) Accrued Liabilities

Accrued liabilities at December 31, 2008 and 2009 consisted of the following:

	2008	2009
Salaries and wages	$ 568,760	$2,555,849
Accrued gas purchases	777,086	627,710
Accrued refund of tax credits	3,606,000	—
Obligation under derivative liability	654,483	—
Accrued property and other taxes	1,705,469	2,383,707
Accrued professional fees	1,230,958	577,470
Accrued employee benefits	434,788	777,058
Accrued warranty liability	—	1,135,846
Other	1,275,910	1,637,803
	$10,253,454	$9,695,443

(8) Long-term Debt

In conjunction with the Company's acquisition of its 70% interest in DCE (see note 3) on August 15, 2008, the Company entered into a Credit Agreement with PCB. The Company borrowed $18.0 million (the "Facility A Loan") to finance the acquisition of its membership interests in DCE. The Company also obtained a $12.0 million line of credit from PCB to finance capital improvements of

(8) Long-term Debt (Continued)

the DCE processing facility and to pay certain costs and expenses related to the acquisition and the PCB loans (the "Facility B Loan"). As of December 31, 2009, the Company had an outstanding balance of $10.0 million under the Facility B Loan. On October 7, 2009, the Facility A Loan was repaid in full and converted into a line of credit (the "A Line of Credit") pursuant to an amendment to the Credit Agreement. The Company did not have any amounts outstanding under the A Line of Credit at December 31, 2009. Interest accrues daily on the amounts outstanding under the Credit Agreement at the greater of the prime rate of interest for the United States plus 0.50% per annum or 5.50% per annum. The principal amount of the Facility B Loan became due and payable in annual payments commencing on August 1, 2009, and continuing each anniversary date thereafter, with each such payment being in an amount equal to the lesser of twenty percent of the aggregate principal amount of the Facility B Loan then outstanding or $2,800,000. On August 15, 2013, the remaining amount of unpaid principal and interest under the Facility B Loan is due and payable. Any amounts outstanding under the A Line of Credit are due August 15, 2010, which the Company can extend for one year if it is not in defaut of the A Line of Credit. The Company paid a facility fee of $300,000 in connection with the Credit Agreement. As of December 31, 2009, the unamortized balance of the facility fee was $217,500. Amortization of the facility fee is recorded as additional interest expense in the consolidated statements of operations.

The Credit Agreement requires the Company to comply with certain covenants. The Company may not incur indebtedness or liens except as permitted by the Credit Agreement, or declare or pay dividends. The Company must maintain, on a quarterly basis, minimum liquidity of not less than $6.0 million, accounts receivable balances, as defined, of not less than $8.0 million, consolidated net worth, as defined, of not less than $150.0 million, and a debt to equity ratio, as defined, of not more than 0.3 to 1. Beginning in the quarter ended June 30, 2009, the Company must also maintain a specific minimum debt service ratio at each quarter end. Effective in the fourth quarter of 2008, the Company established a lock-box arrangement with PCB subject to the Credit Agreement. Funds from the Company's customers are remitted to the lock-box and then deposited to a PCB bank account. The remitted funds are not used to pay-down the balance of the Credit Agreement. However, if the Company defaults on the Credit Agreement, all of the obligations under the Credit Agreement will become immediately due and payable and all funds received in the Company's lock-box held by PCB will be applied to the balance due on the A Line of Credit and Facility B Loan. One of the events of default is the occurrence of a "material adverse change," which is a subjective acceleration clause. Based on the authoritative guidance for balance sheet classification of borrowings outstanding under revolving credit agreements that include both a subjective acceleration clause and a lock-box arrangement, the Company has classified its debt pursuant to the Credit Agreement as short-term or long-term as appropriate and believes an event of default is more than remote but not more likely than not. One of the Company's bank covenants is a requirement to maintain accounts receivable balances from certain subsidiaries above $8.0 million at each quarter end during the term. To the extent natural gas prices fall, which a significant portion of the Company's revenues are derived from, or the Company's volumes decline, the Company could violate this covenant in the future. Beginning with the quarter ended June 30, 2009, the Company is required to maintain a debt service ratio, as defined, of not less than 1.5 to 1. To the extent the Company's operating results do not materialize as anticipated, the Company could violate this covenant in the future. In the event the Company would violate either of these covenants, it would seek a waiver from the bank. The Company is in compliance with the covenants as of December 31, 2009. The Credit Agreement is secured by the Company's interest in, and note receivable from, DCE (described below), certain of the Company's accounts receivable and

(8) Long-term Debt (Continued)

inventory balances and 45 of the Company's LNG tanker trailers. The net book value of the collateral securing the PCB loans was approximately $52.2 million at December 31, 2009. The Company maintains $2.5 million in a payment reserve account at PCB. PCB may withdraw funds from the account to apply to the principal and interest payments due on the A Line of Credit or the Facility B Loan. Such amount is included as restricted cash in the Company's consolidated balance sheet at December 31, 2009.

As part of the transaction, the Company also entered into a Loan Agreement with DCE (the "DCE Loan") to provide secured financing of up to $14.0 million to DCE for future capital expenditures or other uses as agreed to by the Company in its sole discretion. As of December 31, 2009, the Company has approximately $8.5 million outstanding under the DCE Loan. Interest on the unpaid balance accrues at a rate of 12% per annum and became payable quarterly beginning on September 30, 2008. The principal amount of the loan is due and payable in annual payments commencing on August 1, 2009, and continuing each anniversary date thereafter, with each such payment being in an amount equal to the lesser of the aggregate principal amount of the DCE Loan then outstanding or $2,800,000. On August 1, 2013, the entire amount of unpaid principal and interest under the DCE Loan is due and payable. The principal and accrued interest balances as well as any interest income related to the DCE Loan are eliminated in the consolidated financial statements of the Company. Any event of default by DCE on the DCE Loan results in a cross-default of the Company's Credit Agreement with PCB. Events of default include failure to make payments when due, DCE's failure to perform under the provisions of its landfill lease with the City of Dallas, DCE's violation of a covenant under its operating agreement and other standard events of default.

Principal payments for the following periods under the Facility B Loan at December 31, 2009 are as follows:

	Facility B Loan
2010	$ 2,009,498
2011	1,607,599
2012	1,286,079
2013	5,144,316
Total	$10,047,492

(9) Stockholders' Equity

(a) Authorized Shares

The Company's certificate of incorporation authorizes the issuance of two classes of capital stock designated as common stock and preferred stock, each having $0.0001 par value per share. As of December 31, 2009, the Company was authorized to issue 100,000,000 shares, of which 99,000,000 shares are designated common stock and 1,000,000 shares are designated preferred stock.

Dividend Provisions

The Company did not declare nor pay any dividends during the years ended December 31, 2007, 2008 or 2009.

(9) Stockholders' Equity (Continued)

Voting Rights

Each holder of common stock has the right to one vote per share owned on matters presented for stockholder action.

(b) Issuance of Common Stock

On July 1, 2009, the Company closed a follow-on public offering of 9,430,000 shares of common stock at a price of $8.30 per share. The aggregate amount of common shares sold reflects the exercise in full by the underwriters of their option to purchase 1,230,000 additional shares of the Company's common stock to cover over-allotments. The Company received aggregate net proceeds of approximately $73.2 million, after deducting underwriting discounts and commissions and estimated offering expenses payable by the Company.

As a result of the follow-on public offering, the exercise price of the Company's Series I Warrants issued on October 28, 2008 was adjusted to $12.68 per share from $13.50 per share per the terms of the Series I warrant agreements.

(c) Issuance of Common Stock and Warrants in Unit Offering

On October 28, 2008, the Company entered into a Placement Agent Agreement (the "Placement Agent Agreement") relating to the sale and issuance by the Company to select investors of up to 4,419,192 units (the "Units"), with each Unit consisting of (i) one share of the Company's common stock, par value $0.0001 per share, (ii) a warrant to purchase 0.75 shares of Common Stock (the "Series I Warrant"), and (iii) one warrant to purchase up to 0.2571 shares of Common Stock (the "Series II Warrant"). The price of each Unit was $7.92 per Unit. The transaction closed on November 3, 2008, and the Company issued 4,419,192 shares of common stock, Series I Warrants to purchase up to 3,314,394 shares of Common Stock, and Series II Warrants to purchase up to 1,136,364 shares of Common Stock. The Company received approximately $32.5 million after deducting the placement agent's fees and other offering expenses related to the Unit sale.

The Series I Warrants became exercisable beginning six months from the date of issuance for a period of seven years from the date they become exercisable, and carry an exercise price of $12.68 per share. On the second anniversary of the issuance of the Series I warrants, the exercise price will reset to an exercise price equal to one-hundred twenty percent (120%) of the closing price of the Company's common stock on such first anniversary date. However, under the terms of the Series I warrants, no such reset adjustment will operate to increase the exercise price above the then current exercise price at the time of the second anniversary of the issuance of the Series I warrant.

The Series II Warrants became exercisable on November 5, 2008 upon the failure of the California Alternative Fuel Vehicles and Renewable Energy Act, or Proposition 10, in the California statewide election. The Series II Warrants were all exercised on a cashless basis at the exercise price of $0.01 per share, which resulted in the issuance of 1,134,759 shares of common stock to the Series II Warrant holders on November 12, 2008.

The proceeds of $32.5 million were allocated between the common stock, the Series I Warrants and the Series II Warrants. The Company allocated $19.1 million, $9.8 million and $3.6 million to the common stock, the Series I Warrants and the Series II Warrants, respectively. The Series I Warrant is an equity classified instrument as of and for the year ended December 31, 2008. However, based on the relevant accounting guidance, which became effective for the Company on January 1, 2009, the

(9) Stockholders' Equity (Continued)

Company now treats the Series I Warrants as a derivative and marks-to-market the change in the value of the derivative liability through the statement of operations. The Company recorded a cumulative-effect adjustment to opening retained earnings on January 1, 2009 for the change in the value of the instrument between the amount recorded in equity as of December 31, 2008 (which was the fair value on the issuance date of October 28, 2008), and the fair value of the instrument on January 1, 2009. For additional information about the Series I Warrants, see note 20.

(d) Stock Option Plans

In December 2002, the Company adopted its 2002 Stock Option Plan ("2002 Plan"). The board of directors determines eligibility, vesting schedules, and exercise prices for options granted under the 2002 Plan. Options generally have a term of ten years.

Under the 2002 Plan, eligible persons may be issued options for services rendered to the Company. Under the 2002 Plan, the purchase price per share for each option granted shall not be less than 100% of the fair market value of the Company's common stock on the date of such option grant; provided, however, that the purchase price per share of common stock issued to a 10% stockholder shall not be less than 110% of such fair market value on the date of such option grant. Options generally vest over a three-year period.

In December 2006, the Company adopted its 2006 Equity Incentive Plan ("2006 Plan"). The 2006 Plan was effective on May 24, 2007, the date the Company completed its initial public offering of common stock. Under the 2006 Plan, 6,390,500 shares of common stock were initially authorized for issuance, and on January 1, 2007, 2008 and 2009, this number was automatically increased by 1,000,000 shares at each date in accordance with the terms of the 2006 Plan. The 2002 Plan became unavailable for new awards upon the effectiveness of the 2006 Plan. If any outstanding option under the 2002 Plan expires or is cancelled, the shares allocable to the unexercised portion of that option will be added to the share reserve under the 2006 Plan and will be available for grant under the 2006 Plan. As of December 31, 2009, the Company had 10,890,500 shares reserved for issuance in total under the 2006 Plan. At December 31, 2009, the Company had 225,745 shares available for grant under the 2006 Plan.

(9) Stockholders' Equity (Continued)

Option activity for 2007, 2008, and 2009 was as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance, December 31, 2006	2,402,250	2.97		
Options exercised	4,266,500	12.85		
Options granted	(82,214)	3.60		
Options forfeited	(33,500)	12.00		
Balance, December 31, 2007	6,553,036	9.37		
Options granted	1,921,512	8.54		
Options exercised	(87,414)	4.01		
Options forfeited	(152,667)	14.07		
Balance, December 31, 2008	8,234,467	9.14		
Options granted	2,468,713	10.72		
Options exercised	(171,939)	3.42		
Options forfeited	(183,053)	10.91		
Balance, December 31, 2009	10,348,188	9.57	7.5	$60,829
Exercisable, December 31, 2009	6,256,774	8.99	6.5	$40,317

A summary of the Company's non-vested stock options as of December 31, 2009, and the changes during the year ended December 31, 2009, are presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested options at December 31, 2008	3,719,097	$6.09
Granted	2,468,713	7.07
Vested	(1,996,343)	6.42
Forfeited	(100,053)	5.86
Non-vested options at December 31, 2009	4,091,414	6.53

As of December 31, 2009, there was $26.7 million of total unrecognized compensation cost related to non-vested shares. That cost is expected to be recognized over a weighted average period of 2.5 years. The total fair value of shares vested during the year ended December 31, 2009 was $12.8 million.

All options granted in 2007, 2008 and 2009 were pursuant to the 2002 Plan and 2006 Plan, except for a special stock option for 25,000 shares of common stock granted at $3.86 per share to a consultant in May 2006, which vested in full upon the Company completing its initial public offering of its common stock. The fair value of this option award was estimated on the grant date using the Black-Scholes option-pricing model using an expected dividend yield of 0%, expected volatility of 60%, an expected life of two years, and a risk-free interest rate of 4.8%. The volatility amount was estimated

(9) Stockholders' Equity (Continued)

based on several comparable companies. The expected life was based on the Company's estimate of when the individual will exercise the option, and the risk free rate was based on the U.S. Treasury yield curve at the time of grant. The Company recorded approximately $53,000 of expense in 2006 related to this option and no other expense was recorded in 2006 as all the Company's previously issued options vested in 2005 or earlier.

All of the Company's unvested options issued prior to October 2005 vested in October 2005 when the Company experienced a change in control in accordance with the 2002 Plan. The Company plans to issue new shares to its employees upon the employee's exercise of their options. The intrinsic value of all options exercised during 2007, 2008 and 2009 was $1.0 million, $0.6 million and $1.7 million, respectively.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants during the year ended December 31, 2009:

Dividend yield	0.00%
Expected volatility	72.88%
Risk-free interest rate	2.37%
Expected life in years	6.00

The weighted average grant date fair value of options granted during 2009 using these assumptions was $7.07. The volatility amounts used during the year were estimated based on several comparable companies. The expected useful lives used during the year were based on the weighted average of the vesting periods averaged with the term of the respective options. The risk free rates used during the year were based on the U.S. Treasury yield curve at the time of grant. The Company recorded approximately $10,736,000 and $14,071,000 of stock option expense during the years ended December 31, 2008 and 2009, respectively. The Company did not record any tax benefit during the year ended December 31, 2009 related to its stock option expense.

(e) Boone Pickens Warrant Agreement

On December 28, 2006, the Company issued to Boone Pickens a five-year warrant to purchase 15,000,000 shares of the Company's common stock at an exercise price of $10.00 per share.

(10) Income Taxes

The components of income (loss) before income taxes for the years ended December 31, 2007, 2008, and 2009 are as follows:

	2007	2008	2009
U.S.	$(6,717,982)	$(42,997,399)	$(32,650,815)
Foreign	(954,500)	(1,176,134)	(294,385)
	$(7,672,482)	$(44,173,533)	$(32,945,200)

(10) Income Taxes (Continued)

The provision (benefit) for income taxes consists of the following:

	2007	2008	2009
Current:			
State	$ 536,970	$ 261,511	$ 303,501
Federal	684,910	27,630	—
Total current	1,221,880	289,141	303,501
Deferred:			
State	(380,091)	(1,242,348)	(756,067)
Federal	(2,026,323)	(5,931,561)	(4,502,481)
Foreign	(284,869)	(375,498)	724,829
Change in valuation allowance	2,691,283	7,549,407	4,533,719
Total deferred	—	—	—
Total	$ 1,221,880	$ 289,141	$ 303,501

Income tax expense (benefit) for the years ended December 31, 2007, 2008 and 2009 differs from the "expected" amount computed using the federal income tax rate of 34% as a result of the following:

	2007	2008	2009
Computed expected tax expense (benefit)	$(2,608,644)	$(13,792,961)	$(11,201,368)
State and local taxes, net of federal benefit	354,400	147,994	39,975
Nondeductible expenses	1,186,137	8,419,392	7,480,999
Other	(491,290)	(779,400)	(549,824)
Change in valuation allowance	2,781,277	6,294,116	4,533,719
Total tax expense (benefit)	$ 1,221,880	$ 289,141	$ 303,501

(10) Income Taxes (Continued)

Deferred tax assets and liabilities result from differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. The tax effect of temporary differences that give rise to deferred tax assets and liabilities as of December 31, 2008 and 2009 are as follows:

	2008	2009
Deferred tax assets:		
Accrued expenses	$ 975,440	$ 790,741
Sales-type leases	520,525	546,154
Alternative minimum tax and general business credits	2,150,524	3,195,261
Derivative loss	13,783,447	12,281,210
Stock option expense	4,635,342	8,230,893
Other	450,845	740,809
Net operating loss carryforwards	20,380,290	29,408,712
Total deferred tax assets	42,896,413	55,193,780
Less valuation allowance	(31,457,905)	(35,991,624)
Net deferred tax assets	11,438,508	19,202,156
Deferred tax liabilities:		
Depreciation and amortization—domestic	(11,438,508)	(17,674,978)
Depreciation and amortization—foreign	—	—
Partnership income	—	(1,527,178)
Total deferred tax liabilities	(11,438,508)	(19,202,156)
Net deferred tax assets (liabilities)	$ —	$ —

At December 31, 2009, the Company had federal and state net operating loss carryforwards of approximately $74.8 million and $67.9 million, respectively. The Company's federal net operating loss carryforward will expire beginning in 2026. The Company's state net operating loss carryforwards begin expiring in 2010. The Company also has a foreign net operating loss carryforward of approximately $2.0 million at December 31, 2009, which will expire beginning in 2010. Due to the change of ownership provisions of Internal Revenue Code Section 382, utilization of a portion of the Company's domestic net operating loss and tax credit carryforwards may be limited in future periods.

In assessing the realizability of the net deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers projected future taxable income and tax planning strategies in making this assessment. In 2007, 2008 and 2009, the Company provided a valuation allowance of $24,019,665, $31,457,905, and $35,991,624, respectively, to reduce the net deferred tax assets due to uncertainty surrounding the realizability of these assets. The net change in the valuation allowance for the years ended December 31, 2007, 2008, and 2009 was $2,691,283, $7,549,407, and $4,533,719, respectively, after adjustments between current and deferred taxes.

(10) Income Taxes (Continued)

On January 1, 2007, the Company adopted certain accounting guidance that clarifies the accounting for uncertain positions. This guidance requires that the Company recognizes the impact of a tax position in its financial statements if the position is more likely than not of being sustained upon examination, based on the technical merits of the position. The impact of the adoption of this guidance was immaterial to the Company's consolidated financial statements. The total amount of unrecognized tax benefits as of December 31, 2008 and 2009 were $369,000 and $100,000, respectively, which if recognized, would primarily affect the effective tax rate in future periods.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits for the years ended December 31, 2008 and 2009:

Unrecognized tax benefit—January 1, 2008	$ 369,000
Gross increases—tax positions in prior years	—
Unrecognized tax benefit—December 31, 2008	369,000
Gross (decreases)—tax positions in prior years	(269,000)
Unrecognized tax benefit—December 31, 2009	$ 100,000

Accounting guidance requires the Company to accrue interest and penalties where there is an underpayment of taxes based on the Company's best estimate of the amount ultimately to be paid. The Company's policy is to recognize interest accrued related to unrecognized tax benefits and penalties as income tax expense. During the years ended December 31, 2008 and 2009, the Company accrued $20,000 and $6,000 of interest, respectively. No penalties have been accrued by the Company.

The Company is subject to taxation in the United States and various states and foreign jurisdictions. The Company's tax years for 2005 through 2008 are subject to examination by various tax authorities. The Company is no longer subject to U.S. examination for years before 2005, and state examinations for years before 2005. The Company is currently under audit by the Internal Revenue Service for tax years 2005 through 2007.

A number of years may elapse before an uncertain tax position is finally resolved. It is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, but the Company believes that its reserves for income taxes reflect the most probable outcomes. The Company adjusts the reserve, as well as the related interest, in light of changing facts and circumstances. Settlement of any particular position would usually require the use of cash and result in the reduction of the related reserve, or there could be a change in the amount of the Company's net operating loss. The resolution of a matter would be recognized as an adjustment to the provision for income taxes and the effective tax rate in the period of resolution. As of December 31, 2009, it is possible that the Company's liability for uncertain tax positions will be reduced by as much as $100,000 during the year ended December 31, 2010 as a result of the settlement of tax positions with tax authorities and lapses of statutes of limitations.

(11) Commitments and Contingencies

Environmental Matters

The Company is subject to federal, state, local, and foreign environmental laws and regulations. The Company does not anticipate any expenditures to comply with such laws and regulations which

(11) Commitments and Contingencies (Continued)

would have a material impact on the Company's consolidated financial position, results of operations, or liquidity. The Company believes that its operations comply, in all material respects, with applicable federal, state, local and foreign environmental laws and regulations.

Litigation, Claims and Contingencies

The Company may become party to various legal actions that arise in the ordinary course of its business. During the course of its operations, the Company is also subject to audit by tax authorities for varying periods in various federal, state, local and foreign tax jurisdictions. Disputes may arise during the course of such audits as to facts and matters of law. It is impossible at this time to determine the ultimate liabilities that the Company may incur resulting from any lawsuits, claims and proceedings, audits, commitments, contingencies and related matters or the timing of these liabilities, if any. If these matters were to be ultimately resolved unfavorably, an outcome not currently anticipated, it is possible that such outcome could have a material adverse effect upon the Company's consolidated financial position or results of operations. However, the Company believes that the ultimate resolution of such actions will not have a material adverse affect on the Company's consolidated financial position, results of operations, or liquidity.

Operating Lease Commitments

The Company leases facilities, including the land for its LNG production plant in Boron, California, and certain equipment under noncancelable operating leases expiring at various dates through 2038. The following schedule represents the future minimum lease obligations for all noncancelable operating leases as of December 31, 2009:

Fiscal year:	
2010	$ 2,095,914
2011	1,965,485
2012	1,808,744
2013	1,723,723
2014	1,707,125
Thereafter	6,456,974
Total future minimum lease payments	$15,757,965

Rent expense, including variable rent, totaled $1,692,982, $2,218,690 and $5,182,603 for the years ended December 31, 2007, 2008 and 2009, respectively.

Take-or-Pay LNG Supply Contracts

At December 31, 2009, the Company has entered into one LNG supply contract at market prices that contains minimum take or pay provisions over the term of the contract. The contract contains fixed amounts the Company must pay for any shortfall below its minimum volume requirements and also contains a variable charge that is based on the price of natural gas at the beginning and end of the month where a shortfall occurs. The contract expires in June 2011. For the years ended December 31, 2007, 2008 and 2009, the Company paid approximately $10,100,054, $13,417,473 and $3,750,340, respectively, under take-or-pay supply contracts. At December 31, 2009, the fixed commitments under

(11) Commitments and Contingencies (Continued)

this contract totaled approximately $1,995,000 and $997,500, respectively, for the years ending December 31, 2010 and 2011, respectively.

Additionally, in October 2007, the Company entered into an LNG sales agreement with Spectrum Energy Services, LLC ("SES"), to purchase, on a take-or-pay basis over a term of ten years, 45,000 gallons per day of LNG from a plant to be constructed by SES in Ehrenberg, Arizona, which is near the California border. This obligation is anticipated to begin in March 2010. The contract expires in October 2017. At December 31, 2009, the fixed commitments under this contract totaled approximately $2,548,688 for the year ending December 31, 2010, $3,058,425 for each of the years ending December 31, 2011 through December 31, 2016, and $2,548,688 for the year ended December 31, 2017.

(12) Geographic Information

Several of the Company's functions, including marketing, engineering, and finance are performed at the corporate level. As a result, significant interdependence and overlap exists among the Company's geographic areas. Accordingly, revenue, operating income (loss), and long-lived assets shown for each geographic area may not be the amounts which would have been reported if the geographic areas were independent of one another. Revenue by geographic area is based on where fuel is dispensed.

	2007	2008	2009
Revenue:			
United States	$116,355,640	$124,846,493	$130,546,156
Canada	1,360,593	1,020,040	957,121
Total revenue	$117,716,233	$125,866,533	$131,503,277
Operating income (loss):			
United States	$(10,049,214)	$(44,424,926)	$(33,053,675)
Canada	(936,518)	(1,126,527)	(232,026)
Total operating income (loss)	$(10,985,732)	$(45,551,453)	$(33,285,701)
Long-lived assets:			
United States	$105,502,811	$205,624,423	$237,345,222
Canada	4,873,217	2,047,282	1,867,001
Total long-lived assets	$110,376,028	$207,671,705	$239,212,223

The Company's goodwill and intangible assets at December 31, 2007, 2008 and 2009 relate to its United States operations and its BAF operations.

(13) Related Party Transactions

In 2007, 2008 and 2009, under an advisory agreement, the Company paid $10,000 a month for energy market advice to BP Capital L.P. ("BP Capital"), which is owned by Boone Pickens, the largest stockholder and a director of the Company.

(14) 401(k) Plan

The Company has established a savings plan ("Savings Plan") which is qualified under Section 401(k) of the Internal Revenue Code. Eligible employees may elect to make contributions to the Savings Plan through salary deferrals of up to 20% of their base pay, subject to limitations. The Company may make discretionary contributions to the Savings Plan that are subject to limitations. For the years ended December 31, 2007, 2008 and 2009, the Company contributed approximately $289,000, $188,000, and $377,000 of matching contributions to the Savings Plan, respectively.

(15) Supplier Concentrations

During 2007, 2008, and 2009, the Company incurred approximately 14%, 13%, and 8%, respectively, of its natural gas expense related to its LNG sales from Williams Gas Processing Company pursuant to a floating rate purchase contract that includes minimum purchase commitments. In 2009, the Company incurred 20% of its natural gas expense related to its LNG sales from Coral Energy Resources, which supplies the Company's LNG plant in California. During 2007, 2008 and 2009, the Company incurred approximately 32%, 32%, and 28%, respectively, of its natural gas costs related to its CNG operations from the SoCal Gas Company and San Diego Gas and Electric. Any inability to obtain natural gas in the amounts needed on a timely basis or at commercially reasonable prices could result in interruption of gas deliveries or increases in gas costs, which could have a material adverse effect on the Company's business, financial condition, and results of operations until alternative sources could be developed at a reasonable cost.

(16) Capitalized Lease Obligation and Receivables

The Company leases equipment under capital leases with a weighted average interest rate of 7.3%. At December 31, 2009, future payments under these capital leases are as follows:

2010	571,918
2011	502,626
2012	488,768
2013	488,768
Thereafter	553,619
Total minimum lease payments	2,605,699
Less amount representing interest	(432,503)
Present value of future minimum lease payments	2,173,196
Less current portion	(429,765)
Capital lease obligations, less current portion	$1,743,431

The value of the equipment under capital lease as of December 31, 2009 is $2,943,269, with related accumulated amortization of $810,925.

The Company also leases certain fueling station equipment, including one of the assets leased above under capital lease, to certain customers under sales-type leases at a 10% interest rate. The leases are payable in varying monthly installments through February 2017.

(16) Capitalized Lease Obligation and Receivables (Continued)

At December 31, 2009, future receipts under these leases are as follows:

2010	$1,275,076
2011	318,804
2012	236,304
2013	219,804
2014	219,804
Thereafter	476,242
Total	2,746,034
Less amount representing interest	(252,467)
	$2,493,567

(17) Fair Value of Financial Instruments

The carrying amount and fair values of financial instruments, expressed in dollars, are as follows:

	December 31,			
	2008		2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Other receivables	11,012,093	10,785,955	7,157,656	7,157,656
Notes receivable	8,081,680	8,063,680	5,901,646	5,933,908
Long-term debt	22,512,003	22,512,003	10,047,491	10,047,491

As of December 31, 2008 and 2009, the carrying amounts of the Company's other current assets and current liabilities not included in the table above approximate fair value due to the short-term maturities of those instruments. The fair values of other receivables, notes receivable and long-term debt were determined by discounting the respective instrument's future cash flows by an interest rate commensurate with existing market rates at the time and the inherent risk of the respective instrument.

(18) Fixed Price and Price Cap Sales Contracts Without an Underlying Futures Contracts

From time to time, the Company enters into contracts with various customers, primarily municipalities, to sell LNG or CNG at fixed prices, and prior to January 1, 2007, the Company from time to time also entered into contracts to sell LNG or CNG at prices subject to a price cap. Effective January 1, 2007, the Company no longer offers contracts with a price cap to its customers. The contracts generally range from two to five years. The most significant cost component of LNG and CNG is the price of natural gas. Through June 2008, the Company also may or may not have had a futures contract in place to economically offset the price of natural gas it was selling to its customers on a fixed price basis. For any futures contracts that were in place related to these contracts, they did not qualify for hedge accounting and they may have been sold and subsequently reestablished over the term of the customer contract.

As part of determining the fixed price or price cap in the contracts, the Company works with its customers to determine their future usage over the contract term. However, the Company's fixed price and price cap customers do not agree to purchase a minimum amount of volume or guarantee their volume of purchases. There is not an explicit volume in the contract as the Company agrees to sell its

(18) Fixed Price and Price Cap Sales Contracts Without an Underlying Futures Contracts (Continued)

customers volumes on an "as needed" basis, also known as a "requirements contract." The volume required under these contracts varies each month, and is not subject to any minimum commitments. For U.S. generally accepted accounting purposes, there is not a "notional amount," which is one of the required conditions for a transaction to be a derivative pursuant to the authoritative guidance.

The Company's sales agreements that fix the price or cap the price of LNG or CNG that it sells to its customers are, for accounting purposes, firm commitments, and U.S. generally accepted accounting principles do not require or allow the Company to record a loss until the delivery of the gas and corresponding sale of the product occurs. When the Company enters into these fixed price or price cap contracts with its customers, the price is set based on the prevailing index price of natural gas at that time. However, the index price of natural gas constantly changes, and throughout the term of the contract, the fixed price of the natural gas included in the customer's contract price typically diverges from the corresponding index price of natural gas after the Company enters into the sales contract (with the price of natural gas having historically increased).

Prior to June 2008, from an accounting perspective, during periods of rising natural gas prices, the Company's futures contracts related to these transaction have generally been marked-to-market through the recognition of a derivative asset and a corresponding derivative gain in its statements of operations. However, because the Company's contracts to sell LNG or CNG to its customers at fixed prices or an index-based price that is subject to a fixed price cap are not derivatives for purposes of U.S. generally accepted accounting principles, a liability or a corresponding loss has not been recognized in the Company's statements of operations during these periods of rising natural gas prices for the future commitments under these contracts. As a result, for these situations, the Company's statements of operations do not reflect its firm commitments to deliver LNG or CNG at prices that are below, and in some cases, substantially below, the prevailing market price of natural gas (and therefore LNG or CNG).

(19) Earnings Per Share

Basic earnings per share is based upon the weighted average number of shares outstanding during each period. Diluted earnings per share reflects the impact of assumed exercise of dilutive stock options and warrants. The information required to compute basic and diluted earnings per share is as follows:

	2007	2008	2009
Basic:			
Weighted average number of common shares outstanding	40,258,440	45,367,991	55,021,961

Certain securities were excluded from the diluted earnings per share calculation in 2008 and 2009 as the inclusion of the securities would be anti-dilutive to the calculation. The amounts outstanding as of December 31, 2008 and 2009 for these instruments are as follows:

	2008	2009
Options	8,234,467	10,348,188
Warrants	18,314,394	18,314,394

(20) Fair Value Measurements

On January 1, 2008, the Company adopted the authoritative guidance for fair value measurements which defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measurements related to financial instruments. In December 2007, the FASB provided a one year deferral of this guidance for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. Accordingly, the Company adopted this guidance for non-financial assets and non-financial liabilities on January 1, 2009.

During 2009, the Company's financial instruments consisted of natural gas futures contracts, debt instruments, and its Series I warrants. The Company uses quoted forward price curves, discounted to reflect the time value of money, to value its natural gas futures contracts. The Company uses a Monte Carlo simulation model to value the Series I warrants, which requires the Company to make certain estimates including risk-free interest rates and the volatility of its stock price, among others. The Company's futures contracts are recorded in prepaid expenses and other current assets for the short-term asset amount, and long-term liabilities for the long-term liability amount, and the Series I warrants are recorded in other long-term liabilities in the accompanying consolidated balance sheet at December 31, 2009. The fair market value of the Company's debt instruments approximated their carrying values at December 31, 2009.

The following table reflects the fair value as defined by the authoritative guidance of the Company's natural gas futures contracts and Series I warrants at December 31, 2009:

	Balance at December 31, 2009	Quoted Prices In Active Markets for Identical Items (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Natural gas futures contracts (asset)	$ (159,155)	$—	$(159,155)	$ —
Series I warrants	$29,740,491	$—	$ —	$29,740,491

The Company's use of the Monte Carlo simulation model to value its Series I warrants requires management to estimate the expected volatility of the Company's stock price over the remaining term of the Series I warrants. The volatility estimate, along with the Company's period end stock price, are the two most significant variables in the determination of the value of the warrants. The Company considers a variety of market data with observable inputs when estimating the expected volatility. For example, the Company considers the historical volatilities of its competitors, the call option value of convertible bonds of certain peer group entities and the implied volatilities of its exchange traded stock options. The Company also uses the implied volatilities of its short-term (i.e. 3 to 9 month) traded options and extrapolates the data over the remaining term of the Series I warrants, which was approximately 5.8 years as of December 31, 2009. Given the extrapolation beyond the term of the short term exchange traded options is not based on observable market inputs for a significant portion of the remaining term of the warrants, the Series I warrants have been classified as a Level 3 fair value determination in the table above.

For the year ended December 31, 2009, the Company recorded a charge of $17,366,754 in the statement of operations associated with the Series I warrants.

(20) Fair Value Measurements (Continued)

The following table provides a reconciliation of the beginning and ending balances for the Series I warrants at fair value using significant unobservable inputs (Level 3) for the year ended December 31, 2009:

	Series I Warrants
Beginning Balance, January 1, 2009	$(12,373,737)
Total charges included in earnings for the period	(17,366,754)
Purchases	—
Sales	—
Transfers In/Out	—
Ending Balance, December 31, 2009	$(29,740,491)

(21) Subsequent Events

Subsequent events have been evaluated through March 10, 2010, the date of issuance of this report, and none were noted.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of disclosure controls and procedures.

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Based on management's evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2009, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting.

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

On October 1, 2009, the Company purchased BAF Technologies, Inc. In the fourth quarter, the Company began to integrate the acquisition into its internal control over financial reporting structure. As such, there have been changes during the quarter associated with the establishment of internal control over financial reporting with respect to BAF Technologies, Inc. As of December 31, 2009, BAF Technologies, Inc. has been excluded from management's report of internal control over financial reporting as described below.

There were no other changes in our internal control over financial reporting that occurred during the period covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our management assessed the effectiveness of our internal controls over financial reporting as of December 31, 2009. In making its assessment of the effectiveness of our internal controls over financial reporting, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework. Our management's evaluation excluded the natural gas vehicle conversion business of our wholly owned subsidiary, BAF Technologies, Inc., which we acquired on October 1, 2009. BAF contributed $6.9 million to our revenues during 2009. In accordance with the guidance issued by the SEC,

companies are allowed to excluded acquisitions from their assessment of internal controls over financial reporting during the first year subsequent to the acquisition. Based on these criteria, our management has concluded that, as of December 31, 2009, our internal control over financial reporting is effective. Our independent registered public accounting firm, KPMG LLP, has issued an audit report on our assessment of our internal control over financial reporting, which is included in Part II, Item 8 of this Form 10-K.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated by reference to the proxy statement for our 2010 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2009.

Item 11. Executive Compensation.

The information required by this item is incorporated by reference to the proxy statement for our 2010 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2009.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference to the proxy statement for our 2010 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2009.

Item 13. Certain Relationships and Related Transactions and Director Independence.

The information required by this item is incorporated by reference to the proxy statement for our 2010 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2009.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference to the proxy statement for our 2010 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2009.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a)(1) **Consolidated Financial Statements**.

The following documents are filed in Part II, Item 8 of this annual report on Form 10-K:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2008 and 2009

Consolidated Statements of Operations for the Years Ended December 31, 2007, 2008 and 2009

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2007, 2008 and 2009

Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2008 and 2009

Notes to Consolidated Financial Statements

(a)(2) **Financial Statement Schedules.**

The following financial statement schedule is filed as a part of this annual report on Form 10-K:

Schedule II: Valuation and Qualifying Accounts

All other schedules have been omitted as they are not required, not applicable, or the required information is otherwise included.

	Allowances for Doubtful Trade Receivables	Reserve for Excess and Obsolete Inventory	Allowance for Doubtful Notes Receivables
Balance at December 31, 2005	$ 446,812	$ 218,351	$ 0
Charges to operations	230,486	50,000	541,521
Deductions	(325,248)	(143,775)	0
Balance at December 31, 2006	352,050	124,576	541,521
Charges to operations	253,890	0	708,885
Deductions	(104,189)	0	0
Balance at December 31, 2007	501,751	124,576	1,250,406
Charges to operations	386,696	104,934	142,189
Deductions	(230,713)	(160,342)	0
Balance at December 31, 2008	657,734	69,168	1,392,595
Charges (benefit) to operations	335,112	215,581	(1,118,381)
Deductions	(94,423)	(179,663)	(58,427)
Balance at December 31, 2009	$ 898,423	$ 105,086	$ 215,787

(a)(3) **Exhibits.**

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
2.3	Purchase and Sale Agreement dated as of May 7, 2009 by and between Clean Energy and Exterran Energy Solutions, L.P.	Filed as Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-33480)	May 11, 2009
2.4	Stock Purchase Agreement dated September 23, 2009, by and among Clean Energy, a California corporation, BAF Technologies, Inc., a Kentucky corporation and All the Shareholders of BAF Technologies, Inc.	Filed as Exhibit 2.4 to the Current Report on Form 8-K (File No. 001-33480)	September 29, 2009
3.1	Restated Certificate of Incorporation	Filed as Exhibit 3.1 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
3.2	Amended and Restated Bylaws	Filed as Exhibit 3.2 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
4.1	Specimen Common Stock Certificate	Filed as Exhibit 4.1 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
4.2	Registration Rights Agreement dated December 31, 2002	Filed as Exhibit 4.2 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
4.3	Amendment No. 1 to Registration Rights Agreement, dated August 8, 2006	Filed as Exhibit 4.3 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
4.4	Amendment No. 2 to Registration Rights Agreement dated May 1, 2007 between the registrant and the shareholders named therein	Filed as Exhibit 4.4 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	May 4, 2007
4.5	Form of Warrant to Purchase Common Stock	Filed as Exhibit 4.5 to the Current Report on Form 8-K (File No. 001-33480)	October 29, 2008
4.6	Form of Warrant to Purchase Additional Shares of Common Stock	Filed as Exhibit 4.6 to the Current Report on Form 8-K (File No. 001-33480)	October 29, 2008

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.1	2002 Stock Option Plan, Amendment and Form of Stock Option Agreement+	Filed as Exhibit 10.1 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.2	Amended & Restated 2006 Equity Incentive Plan+	Filed as Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-33480)	May 15, 2009
10.3	Lease Agreement dated August 12, 1999 between the registrant and Bixby Office Park Associates, LLC	Filed as Exhibit 10.3 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.4	Form of Indemnification Agreement	Filed as Exhibit 10.4 to the Registration Statement on Form S-1, as amended (File No. 333-137124	March 27, 2007
10.6	Amended and Restated 2002 Stock Option Plan dated August 10, 2007+	Filed as Exhibit 99.1 to the Registration Statement on Form S-8 (File No. 333-145434)	August 14, 2007
10.7	Stock Option Agreement dated May 18, 2006 between the registrant and G. Michael Boswell+	Filed as Exhibit 99.3 to the Registration Statement on Form S-8 (File No. 333-145434)	August 14, 2007
10.8	2006 Equity Incentive Plan—Form of Notice of Stock Option Grant and Stock Option Agreement+	Filed as Exhibit 99.5 to the Registration Statement on Form S-8 (File No. 333-145434)	August 14, 2007
10.11	Buyer's Order and Purchase Agreement dated April 12, 2006 between the registrant and Inland Kenworth, Inc.	Filed as Exhibit 10.11 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.12	Stock Purchase and Buy-Sell Agreement dated February 1, 2006, among the registrant and the individuals and entities named therein	Filed as Exhibit 10.12 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.13	ISDA Master Agreement dated March 23, 2006, between the registrant and Sempra Energy Trading Corp.	Filed as Exhibit 10.13 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.14	ISDA Credit Support Annex dated March 23, 2006, between the registrant and Sempra Energy Trading Corp.	Filed as Exhibit 10.14 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.15	Trading Authorization dated March 23, 2006	Filed as Exhibit 10.15 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.16	Guarantee dated March 23, 2006, by Boone Pickens in favor of Sempra Energy Trading Corp.	Filed as Exhibit 10.16 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.17	Guarantee dated March 28, 2006, by Sempra Energy in favor of the registrant	Filed as Exhibit 10.17 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.20	Investment Advisory Agreement dated July 24, 2006, between the registrant and BP Capital LP	Filed as Exhibit 10.20 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.21	Purchase and Sale Agreement dated November 3, 2005 among Clean Energy Texas LNG, LLC and the sellers named therein†	Filed as Exhibit 10.21 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.25	Ground Lease dated November 3, 2006 among the registrant, Clean Energy Construction and U.S. Borax, Inc.†	Filed as Exhibit 10.25 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	May 24, 2007
10.26	Warrant to Purchase Common Shares dated December 28, 2006 issued by the registrant to Boone Pickens	Filed as Exhibit 10.26 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.27	Obligation Transfer and Securities Purchase Agreement dated December 28, 2006, between the registrant and Boone Pickens	Filed as Exhibit 10.27 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.30	Investment Advisory Agreement dated March 9, 2007 between the registrant and BP Capital LP	Filed as Exhibit 10.30 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.31	2006 Equity Incentive Plan—Form of Stock Award Agreement+	Filed as Exhibit 99.1 to the Current Report on Form 8-K (File No. 001-33480)	May 15, 2008
10.32	Subscription Agreement dated September 24, 2008 between the registrant and Boone Pickens Interests, Ltd.	Filed as Exhibit 99.1 to the Current Report on Form 8-K (File No. 001-33480)	September 25, 2008

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.33	LNG Sales Agreement dated October 17, 2007 between the registrant and Spectrum Energy Services, LLC†	Filed as Exhibit 10.2 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 2007
10.34	LNG Sales Agreement dated July 1, 2008 between the registrant and Williams Four Corners LLC+	Filed as Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 2008
10.35	Sixth Amendment to Lease Agreement dated August 1, 2008 among the registrant, Clean Energy and Bixby Office Park, LLC.	Filed as Exhibit 10.3 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 2008
10.36	Amendment No. 1 to Amended and Restated 2002 Stock Option Plan+	Filed as Exhibit 10.36 to the Annual Filing on Form 10-K (File No. 001-33480)	March 19, 2008
10.41	First Amendment to Base Contract for Sale and Purchase of Natural Gas dated November 7, 2008, between the registrant and Shell Energy North America (US), L.P.	Filed as Exhibit 10.4 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 2008
10.42	Guaranty dated November 7, 2008, by the registrant in favor of Shell Energy North America (US), L.P.	Filed as Exhibit 10.5 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 2008
10.43	Amended and Restated Employment Agreement dated December 31, 2008, between the registrant and Andrew J. Littlefair+	Filed as Exhibit 99.1 to the Current Report on Form 8-K (File No. 001-33480)	December 31, 2008
10.44	Amended and Restated Employment Agreement dated December 31, 2008, between the registrant and Richard R. Wheeler+	Filed as Exhibit 99.2 to the Current Report on Form 8-K (File No. 001-33480)	December 31, 2008
10.45	Amended and Restated Employment Agreement dated December 31, 2008, between the registrant and Mitchell W. Pratt+	Filed as Exhibit 99.3 to the Current Report on Form 8-K (File No. 001-33480)	December 31, 2008
10.46	Amended and Restated Employment Agreement dated December 31, 2008, between the registrant and James N. Harger+	Filed as Exhibit 99.4 to the Current Report on Form 8-K (File No. 001-33480)	December 31, 2008

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.47	Credit Agreement among the registrant Clean Energy and PlainsCapital Bank.	Filed as Exhibit 99.9 to the Current Report on Form 8-K (File No. 001-33480)	August 21, 2008
10.48	First Amendment to Credit Agreement among the registrant Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.47 to the Annual Filing on Form 10-K (File No. 001-33480)	March 16, 2009
10.49	Second Amendment to Credit Agreement among the registrant Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.48 to the Annual Filing on Form 10-K (File No. 001-33480)	March 16, 2009
10.50	Third Amendment to Credit Agreement among the registrant Clean Energy and PlainsCapital Bank.	Filed as Exhibit 10.49 to the Quarterly Report on Form 10-Q (File No. 001-33480)	May 11, 2009
10.51	Base Contract for Sale and Purchase of Natural Gas between Shell Energy North America (US), LP and Dallas Clean Energy, LLC.†	Filed as Exhibit 10.50 to the Quarterly Report on Form 10-Q (File No. 001-33480)	August 10, 2009
10.52	First Amendment to Loan Agreement among Clean Energy and Dallas Clean Energy, LLC.	Filed as Exhibit 10.51 to the Quarterly Report on Form 10-Q (File No. 001-33480)	August 10, 2009
10.53	Fourth Amendment to Credit Agreement among the registrant, Clean Energy and PlainsCapital Bank	Filed as Exhibit 10.52 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 9, 2009
10.54	Fleet Service Agreement between Bachman NGV, Inc. dba BAF Technologies and AT & T Services, Inc. dated February 22, 2008.*†		
10.55	Amendment No. 1 to the Fleet Service Agreement between Bachman NGV, Inc. dba BAF Technologies and AT & T Services, Inc. dated March 30, 2009.*†		
10.56	Employment Agreement dated February 17, 2010, between the registrant and Barclay Corbus+	Filed as Exhibit 99.1 to the Current Report on Form 8-K (File No. 001-33480)	February 18, 2010
21.1	Subsidiaries*		

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
23.1	Consent of Independent Registered Public Accounting Firm KPMG LLP*		
31.1	Certification of Andrew J. Littlefair, President and Chief Executive Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*		
31.2	Certification of Richard R. Wheeler, Chief Financial Officer, pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities and Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*		
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, executed by Andrew J. Littlefair, President and Chief Executive Officer, and Richard R. Wheeler, Chief Financial Officer.**		
99.1	Natural Gas Hedge Policy dated May 29, 2008	Filed as Exhibit 99.1 to the Quarterly Report on Form 10-Q (File No. 001-33480)	June 20, 2008

† Portions of this exhibit have been omitted pursuant to a request for confidential treatment and the non-public information has been filed separately with the SEC.

* Filed herewith.

** Furnished herewith.

+ Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CLEAN ENERGY FUELS CORP.

By: /s/ ANDREW J. LITTLEFAIR

Andrew J. Littlefair
President and Chief Executive Officer

Date: March 10, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ANDREW J. LITTLEFAIR Andrew J. Littlefair	President, Chief Executive Officer (Principal Executive Officer) and a Director	March 10, 2010
/s/ RICHARD R. WHEELER Richard R. Wheeler	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 10, 2010
/s/ WARREN I. MITCHELL Warren I. Mitchell	Chairman of the Board and Director	March 10, 2010
/s/ VINCENT C. TAORMINA Vincent C. Taormina	Director	March 10, 2010
/s/ JOHN S. HERRINGTON John S. Herrington	Director	March 10, 2010
/s/ JAMES C. MILLER III James C. Miller III	Director	March 10, 2010
/s/ BOONE PICKENS Boone Pickens	Director	March 10, 2010
/s/ KENNETH M. SOCHA Kenneth M. Socha	Director	March 10, 2010

Board of Directors

Warren I. Mitchell
Chairman of the Board
Former Chairman
Southern California Gas Company
May 2005

Andrew J. Littlefair
June 2001

T. Boone Pickens
Chairman
B.P. Capital, L.P.
June 2001

James C. Miller III
Former Director
U.S. Office of
Management and Budget
May 2006

John S. Herrington
Former U.S. Secretary
Department of Energy
November 2005

Kenneth M. Socha
Senior Managing Director
Perseus, L.L.C.
January 2003

Vincent C. Taormina
Former Chief Executive Officer
Taormina Industries, Inc.
April 2008

Year denotes year of appointment or election to the board of directors.

Management

Andrew J. Littlefair
President and Chief Executive Officer

Richard R. Wheeler
Chief Financial Officer

James N. Harger
Senior Vice President and
Chief Marketing Officer

Mitchell W. Pratt
Senior Vice President
Operations and Engineering,
Corporate Secretary

Barclay F. Corbus
Senior Vice President,
Strategic Development

Shareholder Information

For address changes, consolidation, lost or replacement certificates, contact:

Transfer Agent and Registrar
Computershare Trust Company
250 Royall Street
Canton, MA 02021
800.962.4284

Common Stock

Clean Energy Fuels Corp. is listed on NASDAQ. Ticker symbol: CLNE

At March 8, 2010, Clean Energy Fuels Corp. had approximately 73 stockholders of record and an estimated 47,475 stockholders held in street name, and 60,005,872 shares of common stock outstanding.

Annual Meeting

The Annual Meeting of Stockholders will be held at 9:00 a.m., Wednesday, May 26, 2010 at The Island Hotel, Newport Beach, California.

Auditors

KPMG LLP
Los Angeles, California

Investor Relations

562.493.7215

Corporate Headquarters

3020 Old Ranch Parkway, Suite 400
Seal Beach, California 90740
562.493.2804

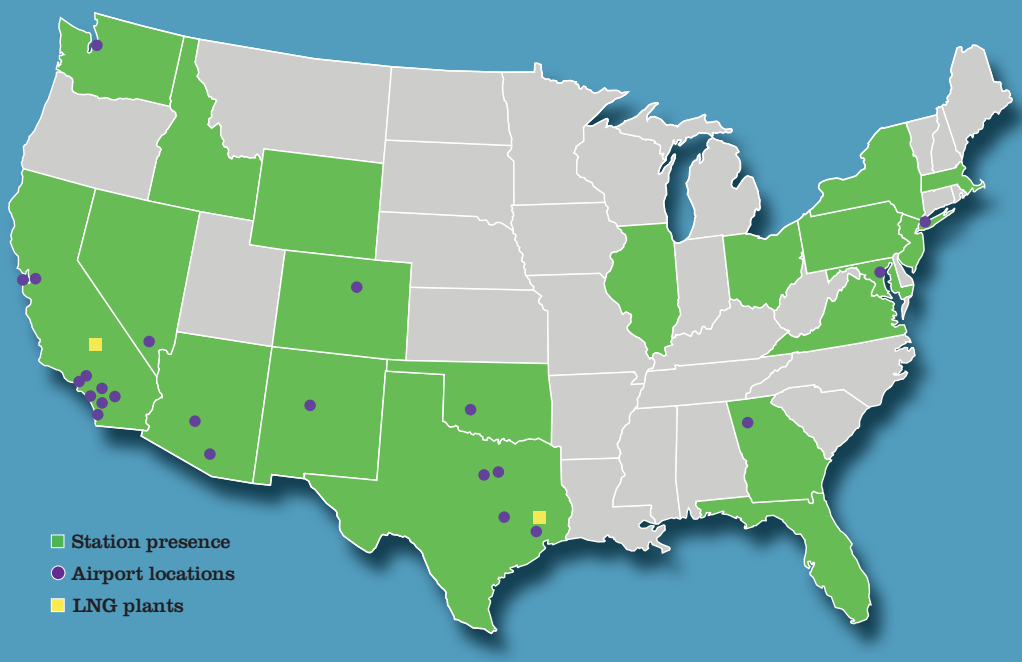
Web Site

www.cleanenergyfuels.com

NORTH AMERICA'S LEADER IN CLEAN TRANSPORTATION

Clean Energy is the leading provider of natural gas (CNG and LNG) for transportation in North America. It fuels more than 17,800 vehicles daily at over 200 strategic locations across the United States and Canada, including 23 of the nation's largest airport complexes. Clean Energy also owns and operates two LNG production plants: one in Willis, Texas and one in Boron, California.

In addition to its headquarters in Seal Beach, California, Clean Energy has sales and service offices in Arizona, Colorado, Florida, Georgia, Illinois, Maryland, Michigan, New Hampshire, New Jersey, New Mexico, New York, Texas, Virginia, Washington, D.C., and Vancouver B.C.



Clean Energy®

Clean Energy
3020 Old Ranch Parkway, Suite 400
Seal Beach, California 90740
562.493.2804
www.cleanenergyfuels.com