Clean Energy

2008 Summary Annual Report
and Form 10-K

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

We have a broad customer base serving over 320 fleets in the refuse, transit, ports, shuttle, taxi, trucking, airport and municipal fleet markets, fueling more than 15,000 vehicles at 176 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 designed to expand to 340,000 LNG gallons per day as demand increases.

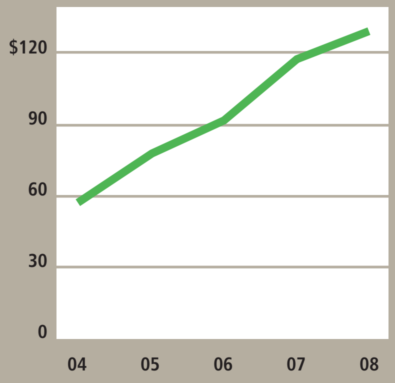
We also own and operate a landfill gas facility in Dallas, Texas that produces renewable biomethane gas for delivery in the nation's gas pipeline network that can be used as a renewable fuel. Our plant is one of the largest active biomethane gas producers in the United States.

The United States has enough natural gas to last over 115 years at current levels, and we are discovering more every year. Every vehicle that runs on natural gas reduces our dependence on imported oil.

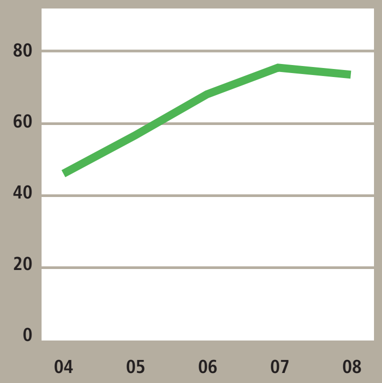
Natural gas is cleaner, cheaper and an All-American resource, making it the best alternative to gasoline and diesel for transportation. And we're making it happen.

Nasdaq: CLNE
www.cleanenergyfuels.com

Revenue **($millions)**



Volume of gas delivered — CNG & LNG **(millions of gallons)**



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

On the cover: The Clean Energy California LNG Plant in Boron, California, with its 1.8 million gallon storage tank, capable of holding 1.5 million usable gallons, produced and delivered its first loads of liquefied natural gas to customers in November 2008.

Clean Energy provides the critical connection for the use of natural gas as a fuel for transportation.

> Natural gas is produced in and delivered across North America through pipelines that reach nearly every populated area.
>
> We purchase natural gas from the pipelines, and compress it at our stations to deliver CNG for light- medium- and heavy-duty vehicles, including transit buses, refuse vehicles and trucks for goods movement.
>
> We also purchase natural gas from pipelines and liquefy it as LNG at our production plants or purchase LNG from others and deliver it for other medium- and heavy-duty vehicles, such as transit buses, refuse trucks, and class-8 trucks for goods movement at ports and in regional markets.

An oil-dependent America imports nearly 70% of the petroleum it uses, which results in exporting hundreds of billions of dollars yearly to other countries, some hostile to our interests. Transportation is the largest consumer of petroleum in the United States, accounting for nearly two-thirds of its use. Petroleum products, particularly diesel, pollute heavily. The cost of petroleum rose rapidly during portions of 2008, threatening the United States economy. Ultimately, we all believe it will rise again. Our dependence on petroleum is dangerous and needs to change.

How can we change?

America produces about 85% of the natural gas we use with another 12% coming from Canada — which means only 3% is from outside North America. Our natural gas supplies are domestic, secure and abundant. Natural gas is 80% hydrogen and inherently low in carbon. A heavy-duty truck running on natural gas (CNG or LNG) produces up to six times less NOx emissions and up to 21% fewer greenhouse gas emissions compared to diesel and, using biomethane, greenhouse gas reductions can reach approximately 88%. In light-duty natural gas vehicles, greenhouse gas emissions are reduced by up to 30% compared to gasoline. And natural gas for transportation costs less than gasoline or diesel, saving money daily for vehicle and fleet owners.

Natural Gas — the Green Standard for Transportation Fuel.

To Our Shareholders

2008 was momentous in every way, moving from drastic highs and lows in petroleum and fuel prices, economic momentum and business and consumer confidence.

In 2009, the world has changed, but our fuel has not.

Natural gas fuel for transportation is still All-American, abundant and cleaner and cheaper than diesel or gasoline.

That is why we believe our company will prevail and grow.

We are the leader in the industry and largest provider of natural gas for transportation in North America.

In 2008, we delivered 73.5 million gallon equivalents of CNG and LNG natural gas fuel (including volumes sold to industrial users and biomethane produced at our landfill gas processing plant). We ended the year owning or servicing 176 stations fueling over 320 fleet customers operating approximately 15,000 vehicles across North America. We completed 28 station upgrades or new stations during 2008. We have a capital budget of $31.6 million in 2009 to build additional stations. We are also pursuing numerous other projects.

Revenue in 2008 was $129.5 million and at year-end total assets were $290.4 million, with $22.9 million in long-term debt. Our 2008 10-K provides additional financial information that you should read.

The good news is that high-fuel-use fleets of heavy-duty vehicles — our primary market — are converting to natural gas fuel in increasing numbers. They recognize that lower gasoline and diesel prices at the beginning of 2009 are not likely sustainable once world demand for petroleum recovers. Fuel diversity is critical for these fleets.

Transit fleets have long been users of natural gas fuel, both CNG and LNG. Even with the advent of hybrid electric buses, natural gas fuel still makes the most sense as an alternative to diesel. About 33% of the nation's transit fleets use natural gas fuel and about 22% of new buses on order are natural gas-powered. There are about 58,000 natural gas buses in service overall.

In 2008, we obtained contracts or expanded agreements with transit agencies in Southern California, Las Vegas, Akron, Phoenix and El Paso, among others.

Refuse fleets have been converting to natural gas in large numbers in California for some time, due largely to the environmental benefits. Now with more favorable economics through lower natural gas fuel prices and incentives for vehicle purchases, refuse fleets are beginning to convert across the country. There are about 200,000 refuse trucks in service nationwide.

In 2008, we obtained contracts or

Clean Energy LNG tanker trucks load at our Clean Energy California LNG Plant to deliver fuel throughout Southern California and the Southwest.

In 2008, the first increment of class-8 LNG trucks began fueling daily at the Clean Energy Carson LNG station.

New LNG trucks are used to transport containers throughout the Ports of Los Angeles and Long Beach as part of the Ports' Clean Truck Program.

extended agreements with refuse fleets or municipalities in Glendale, Burbank, Sacramento, Fresno and Los Angeles, California; Brookhaven, New York; and central New Jersey, among others.

Airport-related fleets are an important market for Clean Energy for fueling taxis, passenger shuttles, airport buses, hotel and rental car shuttles, and airport fleets.

In 2008, we obtained contracts or extended agreements in College Park, GA, adjacent to Atlanta's Hartsfield-Jackson International Airport, Oakland International Airport and Will Rogers World Airport, and now are growing operations at 19 of the nation's airport complexes.

Trucking fleets for goods movement are beginning to convert to natural gas now that there are several makes and models of Class-8 vehicles available from major manufacturers such as Kenworth, Freightliner and Peterbilt. The Ports of Los Angeles and Long Beach in Southern California have mandated the retirement or conversion of more than 16,000 old diesel trucks in favor of new diesel and alternative fuel (natural gas) trucks. There are about 2.7 million Class-8 trucks on the road across the country.

In 2008, we began fueling the first wave of trucks at the Southern California ports and began construction of our second dedicated LNG truck station there, which will be the largest LNG truck fueling station in the world. Several more stations are planned for the region.

To provide the LNG fuel for the anticipated demand by port and regional trucking in the Southwest region, we completed The Clean Energy California LNG Plant in Boron, California in November 2008 and began delivering fuel to our first station at the ports as well as to other customers. The plant is designed to produce 160,000 LNG gallons per day initially, with the ability to increase production to 240,000 LNG gallons per day as deliveries grow.

The pace of port truck deployment is uncertain due to a slowing in goods movement from the recession. Yet we believe the port authorities are sticking to their plans. Also on the legislative front, we believe that President Obama, his Chief-of-Staff Emanuel, and leading legislators all are looking more favorably on natural gas for transportation as a means to reduce the nation's dependence on imported oil as well as benefit the environment. Our message is getting through better than ever.

Perhaps the biggest reason why natural gas for transportation is better known than ever is the singular effort during 2008 of

Transit fleets around the country are expanding natural gas vehicle use, including large articulated buses for high-volume demands.

Municipalities large and small are increasingly mandating the use of alternative fuel vehicles for taxis to lower emissions and to benefit their local environments.

Refuse fleets across the country are converting to natural gas vehicle use because they are cleaner, quieter and less costly to fuel. New to natural gas in 2008 is South County Sanitary Company in San Luis Obispo, California, a division of Waste Connections.

our co-founder, T. Boone Pickens, promoting The Pickens Plan. Beginning in July, he dedicated substantial personal funds and a significant amount of his time to telling the country, during a critical election period, what he believes: that in order to ensure our prosperity, our nation must significantly reduce imported oil consumption and the draining of American dollars by employing our own domestic natural resources, including solar power and wind for generating electricity and natural gas for transportation. His efforts almost singlehandedly created a national debate on energy in America and changed minds. He is continuing his campaign in 2009. Now we need to ensure that the new awareness is put into action through governmental support and industry practice.

In 2008 we also made a significant investment in clean renewable energy by acquiring 70% of the McCommas Bluff landfill gas operation in Dallas, Texas. There we produce biomethane gas and sell that gas into the pipeline system as a renewable fuel. Our landfill gas operations create significant reductions in greenhouse gas emissions through methane capture and displacement of fossil fuel in the pipeline system, further proving that natural gas is a renewable, sustainable, clean and permanent part of meeting our nation's energy needs. During the year, we also made an investment in a new, purpose-built car by the Vehicle Products Group that will provide a tailored natural gas vehicle for taxi and paratransit use, two key markets for Clean Energy.

We have taken many significant actions in recent months to sustain and strengthen Clean Energy's operations. These range from raising approximately $32.5 million last fall to invest in the growth of our business to tightening our operations and cutting costs.

Although the timing of natural gas fuel market development is uncertain, we believe its time is coming.

We thank our management team and staff for their exceptional work in building our company, and recognize our Board of Directors for their counsel and direct support.

Andrew J. Littlefair
President and CEO

Clean Energy's new LNG truck fueling station under construction at the Ports of Long Beach and Los Angeles is the largest LNG truck fueling station in the world.

Clean Energy Co-Founder Boone Pickens testified before Congress in summer 2008 as part of his campaign, The Pickens Plan. It aims to get the United States to adopt a meaningful energy policy that will lower dependence on imported oil and include extensive use of solar power and wind power for electricity and natural gas for transportation.

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, 2008

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 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, 2008, the last business day of the registrant's second fiscal quarter, was approximately $255,242,215 (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 12, 2009, the number of outstanding shares of the registrant's common stock was 50,238,212.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for the 2009 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;
- plans to expand 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 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;
- 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;
- plans to build additional natural gas fueling stations both under and not under contract, and the scheduled April 2009 opening of the second Long Beach seaport fueling station;
- our obligation to provide funding to the Vehicle Production Group, LLC, a company that is developing natural gas paratransit vehicles and taxis;
- expansion of our California LNG plant;
- 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 in the natural gas and fleet vehicle markets, including increased transition from diesel and gasoline powered vehicles to natural gas vehicles;
- estimated increases in costs for diesel engine 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;
- anticipated federal and state certification of additional natural gas vehicle models in 2009;
- expanded use of natural gas vehicles at and sales of our fuel to trucks operating at the Los Angeles and Long Beach 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 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;
- the availability of tax incentives and grant programs that provide incentives for using natural gas as a vehicle fuel;
- our continued receipt of the Volumetric Excise Tax Credit;
- projected capital expenditures, project development costs and related funding requirements;
- plans to retain all future earnings to finance future growth and general corporate purposes;
- 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;
- our LNG liquefaction plant in California enabling us to supply our operations in California and Arizona 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; 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 industries' 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, 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. 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, 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 2008. 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 and selling renewable biomethane produced by our landfill gas joint-venture. We serve over 320 fleet customers operating over 15,000 natural gas vehicles. We own, operate or supply 176 natural gas fueling stations in Arizona, California, Colorado, Maryland, Massachusetts, Nevada, New Mexico, New York, Texas, Washington, Georgia, Wyoming, and Ohio, within the United States, and in British Columbia and Ontario within Canada. In April 2008, we opened the 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.

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 that produced its first load of LNG in November of 2008 and is 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, the United States consumed an estimated 175 billion gallons of gasoline and diesel in 2006, and demand is expected to grow at an annual rate of 1.4% to 250 billion gallons by 2030. Gasoline and diesel comprise the vast majority of vehicle fuel currently 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 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. Going into 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 has brought about a collapse of world oil prices. We, along with a number of expert market commentators, believe that once world economic growth resumes, pressures on oil supply will force oil, gasoline, and diesel prices higher.

The current low oil, gasoline and diesel prices have reduced the immediate market opportunity for alternative fuels that existed with high oil, gasoline, and diesel prices. However, increasingly stringent federal, state and local air quality regulations, and the emphasis on greenhouse gas reductions and low carbon fuels continue to represent an opportunity for alternative vehicle fuels 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 Gas Vehicles Report estimates that there are approximately 100,000 natural gas vehicles in the United States compared to approximately 10 million worldwide as of February 2009.

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 2006 there were approximately 300 million gasoline gallon equivalents of natural gas consumed in the United States for vehicle use, which is nearly double the amount consumed in 2000. The Clean Vehicle Education Foundation estimates that there are over 1,000 natural gas fueling stations in the United States.

Natural gas vehicles use internal combustion engines similar to those used in gasoline or diesel powered engines. 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, natural gas vehicles operate more quietly than diesel powered vehicles. Several municipalities are encouraging natural gas trucks because of their quieter operation in urban settings.

Almost any current 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 and light-duty trucks are available through small volume manufacturers. These manufacturers offer current model vehicles made by others that they have modified to use natural gas and which 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 Van, Ford F Series Truck, and GM 6 liter and 8.1 liter vehicles that include pickups, vans, cargo vans, and trucks. We anticipate additional models will be certified in 2009. Modifications involve removing the gasoline storage and fuel delivery system and replacing it with high pressure fuel storage cylinders and fuel delivery lines.

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.

Natural Gas Medium and Heavy-Duty Vehicle Manufacturers

Medium and heavy-duty natural gas vehicles manufactured by traditional original equipment manufactures include:

Trucks

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

Shuttles and Buses

- Blue Bird (school buses)
- 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)
- Tymco (street sweepers)

Benefits of Natural Gas Fuel

Less Expensive. Based on EIA data, since 2004 CNG and LNG have become increasingly less expensive than gasoline and diesel. For example, in 2008 the average retail CNG price we charged in California, our most significant market, was $0.84 less per gasoline gallon equivalent than the average California regular unleaded gasoline price of $3.51 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 also enhance the cost-effectiveness of CNG and LNG. Since October 1, 2006, 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 has been 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 and the vehicle credit are scheduled to expire on December 31, 2009 and December 31, 2010, respectively, unless otherwise extended.

We believe that diesel fuel will become more expensive over the next several years as refineries must meet additional stringent federal sulfur diesel standards by 2010. Additionally, 2007 and later diesel engine models must meet 2007 federal heavy-duty engine emission standards as well as more restrictive standards in 2010, which will require significant modification costs.

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 comparable to gasoline or diesel powered vehicles.

Average California Retail Prices

(per gasoline gallon equivalent)(1)

	Year Ended December 31,		
	2006	2007	2008
California retail gasoline(2)	$ 2.83	$ 3.08	$ 3.51
California retail diesel(2)(3)	2.76	2.81	3.53
California CNG—Clean Energy	2.16	2.43	2.67
CNG discount to gasoline	$(0.67)	$(0.65)	$(0.84)
CNG discount to diesel	(0.60)	(0.38)	(0.86)

(1) Industry analysts typically use the 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 2008

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	$2.67(4)	vs. $3.51(4)	$ 4,200
Shuttle van	CNG or Gasoline	7,500	$2.67(4)	vs. $3.51(4)	$ 6,300
Municipal transit bus (CNG)	CNG or Diesel	16,680	$1.85(5)	vs. $2.58(6)	$12,176
Refuse truck (CNG)	CNG or Diesel	11,120	$1.89(5)(7)	vs. $3.53(6)	$18,237
Municipal transit Bus (LNG)	LNG or Diesel	16,680	$1.82(8)	vs. $2.58(6)	$12,677
Refuse truck (LNG)	LNG or Diesel	11,120	$2.22(7)(8)	vs. $3.53(6)	$14,567

(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 2008. Gasoline retail pricing is based on California average retail gasoline prices during 2008 as reported by EIA.

(5) CNG prices based on average prices paid by Clean Energy's California fleet customers in 2008.

(6) Diesel price based on EIA reported average diesel price in California in 2008.

(7) Excludes California Board of Equalization taxes of $0.0875 per GGE 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.

(8) LNG prices based on wholesale pricing adjusted for taxes and excluding infrastructure costs, which are typically paid by a third party.

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.

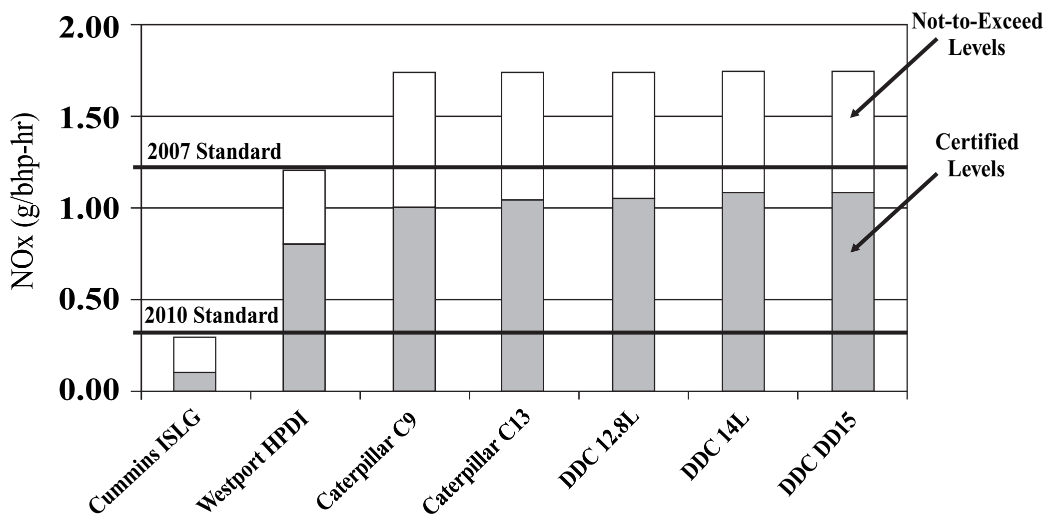
The table below shows an example of emissions reductions for the 2008 Honda Civic GX versus its gasoline powered counterpart. Comparisons are based on information submitted to the EPA by the manufacturer.

Model	Fuel	Certified maximum grams per mile NOx	PM
2008 Honda Civic	Gasoline	0.040	0.010
2008 Honda Civic	CNG	0.010	0.005
Emission Reduction		***75%***	***50%***

In 2007, new federal emissions requirements became effective for medium and heavy-duty engines, and more stringent requirements go 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 in 2010 when they must meet the federal 2010 emission standards. The 2010 standards will require diesel vehicles to use additional emission control technologies, which may include the use of selective catalytic reduction strategies that require urea. We expect these additional controls will generally result in lower performance and increase the cost to own and operate diesel vehicles.

By comparison, the "certified" levels (or the emission levels the vehicles test to) for all 2007 medium and heavy-duty natural gas engines satisfy the federal 2007 emission standards, and one natural gas engine model has already been certified to meet the 2010 standards. The chart below shows the results of comparison tests, published by the South Coast Air Quality Management District, of a sample of natural gas engines (the first two engines in the chart on the left), and diesel engines (the remainder of the engines in the chart below on the right) against the federal emission standards applicable for 2007 and 2010. The chart only shows the NOx standards as the PM standards are identical for 2007 and 2010. The chart demonstrates that all of the diesel engines certified to meet the 2007 standard have "not-to-exceed" levels (values that limit the amount an engine can emit as it deteriorates over time) that actually exceed the 2007 federal emission NOx standard. In addition, both natural gas engines do not exceed the 2007 standard. Finally, 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.

2008 On-Road Heavy-Duty Engines
(As of January 25, 2008)



In addition to the South Coast Air Quality Management District's study of emissions above, the agency also 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.

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 item" under AB 32 called the Low Carbon Fuel Standard that requires a 10% carbon reduction in all transportation fuels sold in the State of California by 2020. Under this draft regulation, LNG, CNG and biomethane are identified as "compliant fuels" through 2020. In October 2007, Governor Schwarzenegger signed into law AB 118, which 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. Additionally, 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 and eleven Eastern U.S. states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania and Vermont) 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.

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.

Further, in October 2007, the California Energy Commission adopted the AB 1007 State Alternative Fuels Plan that establishes goals of displacing 26% of California's petroleum fuel use by 2022 with alternative fuels, including natural gas.

Biomethane 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.

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 and gunfire tests, pressure extremes 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 2008, the United States consumed 19.5 million barrels of crude oil per day, of which 38% was supplied from the United States and Canada and 62% 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 2008 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 23.0 trillion cubic feet of natural gas consumed in the United States in 2008 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 2008 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2007 natural gas production was 45% greater than the ratio of proven crude oil reserves to 2007 crude oil production. This analysis suggests significantly greater longer term availability of natural gas than crude oil based on current consumption.

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 approximately 16,000 trucks serving those ports so that they run on cleaner technology. 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, beginning June 1, 2008. Due to challenges by the Federal Maritime Commission, the collection of the cargo fee was delayed and the Ports did not begin charging the fee until February 18, 2009. The Ports estimate the cargo fees will generate approximately $1.6 billion to help fund replacement trucks as the ban goes into effect. On February 19, 2008, the Port of Long Beach Commission added a provision to their plan that targets no less than 50% of the trucks at its port that are financed through the container fee will run on alternative fuels proven to be cleaner than diesel, such as LNG.

In December 2007, we opened the first fueling station in the port area to fuel LNG-powered trucks, and have been selected by the Port of Long Beach to design, construct and operate an additional station on Port property. This second station is under construction and is scheduled to open in April 2009. 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.

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 lower engine maintenance costs and longer engine life of natural gas engines. We also educate fleet operators on various tax incentives and grants, including tax incentives and grants that reduce the purchase price of natural gas vehicles, which we believe will accelerate 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 to be constructed by SES in Ehrenberg, Arizona, which is near the California border. 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 currently producing renewable pipeline quality biomethane from a landfill 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.

Expand internationally. We plan to expand our operations internationally in strategic locations where we believe potential fleet customers are ready to adopt natural gas as a vehicle fuel. For example, in April 2008, we opened our first compressed natural gas station in Lima, Peru through a joint venture, Clean Energy del Peru, which serves taxi fleets as well as industrial customers by transporting CNG from the station in "tube trailers", which are tractor trailers that consist of clusters of CNG tanks, to the customer's location.

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 (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 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. Each of these activities are discussed below.

Natural gas for CNG stations. We obtain natural gas for CNG stations from local utilities 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 compressed 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 up to 60 million gallons of LNG per year (with expansion potential to produce up to 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, 2008, we had outstanding purchase contracts with various third-party LNG suppliers in the western United States. For the year ended December 31, 2008, of the LNG we sold, we purchased 62% from these suppliers and the balance was produced at our Pickens Plant and California LNG Plant. Two of our LNG supply contracts contain "take-or-pay" provisions which 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 third LNG supplier will commence in the second quarter of 2009 when the supplier's LNG plant, which is under construction, is anticipated to be completed. 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 these 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 efficiently. As of December 31, 2008, we had an operations team of 64 employees, including 35 full-time employees dedicated to performing preventative maintenance and available to responding to service requests in 14 states and in Canada.

Our station network. As of December 31, 2008, we owned, operated or supplied 176 fueling stations for our customers in Arizona, California, Colorado, Maryland, Massachusetts, Nevada, New Mexico, New York, Texas, Washington, Georgia, Wyoming, Ohio, and Canada. Of these 176 stations, we owned 122 of the stations, and our customers owned the other 54 stations. The breakdown of the services we perform for these stations is set forth below.

	As of December 31, 2008		
	CNG fueling stations	LNG fueling stations	Total stations
Operated, maintained and supplied by Clean Energy	98	6	104
Supplied by Clean Energy, operated and maintained by customer	1	25	26
Operated and maintained by Clean Energy, supplied by customer	46	0	46
Total	145	31	176

For the month of December 2008, 16 of the stations listed in the table above delivered in excess of 100,000 gasoline gallon equivalents, and 40 stations delivered in excess of 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents). Of the 16 stations delivering greater than 100,000 gasoline gallon equivalents per month, 13 relate to transit customers, two relate to airport locations and one relates to a refuse customer. Of the 40 stations delivering greater than 25,000 gasoline gallon equivalents (but less than 100,000 gasoline gallon equivalents), 12 relate to airport locations, 11 relate to refuse customers, 11 relate to transit customers, five 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 78 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 2008, we generated approximately $1.8 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.

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, and Toronto. At December 31, 2008, we had 39 employees in sales and marketing. 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 60% 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. 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 $114.9 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, 2008, we have not generated significant revenue from financing activities.

To ensure the availability of vehicles for our customers, we may purchase natural gas vehicles or components of natural gas vehicles in anticipation of customer requirements. For example, we agreed to make cash deposits with Inland Kenworth, Inc. (Inland) to fund the acquisition from Kenworth Truck Company of up to 100 diesel tractors so that they could be converted to LNG tractors. The converted tractors were sold to fleet customers servicing the Ports of Los Angeles and Long Beach. We have also advanced funds to Westport Innovations Inc. to facilitate the production of LNG fuel systems for installation in the diesel tractors referenced above.

Customers and Key Markets

We have over 320 fleet customers operating approximately 15,000 vehicles, including approximately 3,400 transit buses, 1,500 taxis, 800 shuttles and 1,400 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 2008, approximately two-thirds of our revenues were derived from contracts with governmental entities. 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 problems 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, 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, SeaTac International (Seattle), and Tucson. 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 83,000 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 according to the Union of Concerned Scientists, an environmental watchdog group) 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 33% of all buses in the United States operating on LNG, CNG or CNG blends, according to the American Public Transportation Agency 2008 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 and Regional Transit Authority (Ohio).

- *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 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 3,000 natural gas powered refuse hauling vehicles operating in the United States on CNG and LNG. Our representative refuse hauler customers include a portion of the California-based operations of Waste Management and Allied Waste, as well as Waste Connections and NORCAL Waste Systems, and the cities of Bakersfield, Fresno, Los Angeles, Tulare, San Antonio, and Sacramento.

- *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 use land-based vehicles accessing the seaport use alternative fuels such as natural gas. Such policies require 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 approximately 16,000 trucks serving those ports so that they run on cleaner technology. 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, which the Ports estimate will generate approximately $1.6 billion to help fund replacement trucks. In February 2008, the Port of Long Beach Commission approved a provision in their plan calling for no less than 50% of the trucks at their port that are financed through the container fee will run on alternative fuels proven to be cleaner than diesel, such as LNG.

In December 2007, we opened the first fueling station in the port area to fuel these LNG-powered trucks, and have been selected by the Port of Long Beach to design, construct and operate an additional station on Port property. This second station is currently under construction and is scheduled to open in April 2009. 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.

- *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, they are excellent candidates to use CNG. Natural gas vehicles provide taxi fleets a convenient way to reduce operating costs. We serve approximately 1,500 taxis in Southern California, the San Francisco Bay Area, New York City, Phoenix, Tucson and Seattle. In March 2008, San Francisco Mayor Gavin Newsom signed legislation that will enable the purchase of more alternative-fuel taxi cabs for use in San Francisco.
- *Government fleets*—According to the Federal Highway Administration, or FHA, in 2007, there were over four 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 615,000 and 494,000 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.

Under the Volumetric Excise Tax Credit ("VETC") for alternative fuels, sellers of CNG or LNG are 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 are able to claim the credit. During this period, we may offset a portion of the $0.50 credit against the federal excise tax paid by our customers of $0.183 per gasoline gallon equivalent of CNG sold or $0.243 per gallon of LNG sold, which was increased to these amounts as part of the same legislation. By comparison, the legislation does not provide any offsetting refund to the federal excise tax of $0.183 per gallon of gasoline or $0.243 per gallon of diesel fuel sold, which tax rates the legislation did not change. These tax credits for CNG and LNG lower the cost of natural gas vehicle fuels to sellers, and the savings can be passed on to the customer if the seller elects to do so. These credits are scheduled to expire on December 31, 2009, unless otherwise extended.

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.

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 includes 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 (SCAQMD) 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. The California Air Resources Board (CARB) allocated $34.4 million to the South Coast Air Quality Management District under SB1107 for the implementation of its 2009 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 (TCEQ) 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. In 2008, $137.5 million was made available for programs to purchase and convert vehicles to low emission vehicles.

U.S. Department of Energy (DOE) 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 2009 for alternative fuel vehicle deployment and infrastructure projects. In partnership with our customers, we anticipate pursuing funding opportunities to assist with the purchase of vehicles and construction of fueling infrastructure.

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 funds available for 2009 are estimated to be $50 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 Exterran Holdings, Inc. (formerly Hanover Compressor Company), a large publicly traded international provider of natural gas compressors and related equipment, which we believe focuses its CNG vehicle fuel business primarily on transit fleets in California, Maryland, Massachusetts and Washington D.C. These companies are significant competitors in the market for transit fleets.

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 whom distributes LNG in the western United States. We have identified no significant competitors in Canada for CNG or LNG sales.

We own, operate or supply 176 CNG and LNG fueling stations. We operate 145 CNG fueling stations, which we estimate is approximately four times the number of CNG fueling stations as our next largest competitor. We further estimate that in 2005 we supplied approximately twice the amount of natural gas for vehicular use as our next largest competitor. In addition, 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. In international markets, including to a limited extent in Canada, integrated oil companies and other established fueling companies sell CNG at a number of their vehicle fueling stations that sell gasoline and diesel. Natural gas utility companies own and operate the local pipeline infrastructure that supplies natural gas to retail, commercial and industrial customers.

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. However, 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 have their basis in Title I or Title II of the Federal Clean Air Act.

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.

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 vehicle pollution or mobile sources of pollution are developed as part of a state implementation plan for achieving these standards for two criteria pollutants in particular: 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 optional 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.

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.

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.

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. 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, 2008, we employed 140 people, of whom 39 were in sales and marketing, 72 were in operations and engineering, and 29 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 (1) our revenues from external customers, measures of profits and losses and total assets, and (2) our revenues from external customers 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 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 2006, 2007 and 2008 we incurred pre-tax losses of $89.8 million, $7.7 million, and $40.7 million, respectively. Our loss for 2006 includes $79.0 million in derivative losses and 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. During 2007 and 2008, our losses were substantially decreased by our receipt of approximately $17.0 million and $20.8 million of revenue from federal fuel tax credits and the law providing for the fuel tax credits is scheduled to expire December 31, 2009. 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.

We may need to raise debt or equity capital to fund increased capital expenditures beyond those included in our 2009 capital budget or for any potential acquisitions, and an inability to access the capital markets may impair our ability to invest in our business.

We anticipate that, in order to fund additional capital projects beyond those included in our current 2009 capital expenditure program or to provide resources for potential acquisition activity, we may need to pursue additional equity financing options, which may not be available on terms favorable to us or at all. Our 2009 capital plan anticipates $31.6 million of capital expenditures and no amounts for acquisitions. 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 additional capital expenditures or unanticipated expenses, 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. In addition, we have committed to provide up to $6.2 million in additional funding during 2009 to the Vehicle Production Group LLC, a company planning to manufacture CNG taxi and paratransit vehicles. If we do not have sufficient funds to fund our capital commitment to the Vehicle Production Group, we may lose our investment of $4.6 million that has been made through December 31, 2008.

Decreases in the price of oil, gasoline and diesel fuel may slow the growth of our business and negatively impact our financial results.

Prices for oil, gasoline and diesel fuel have declined rapidly since the summer of 2008. The price for a barrel of crude oil has declined from a high of $148.35 per barrel reached on July 11, 2008 to a price of $38.00 per barrel on December 31, 2008. Average retail prices for ultra low sulfur diesel fuel in California have declined from a high of $5.03 in May and June of 2008 to $2.24 per gallon at December 31, 2008 and average retail prices for gasoline in California have declined from a high of $4.59 per gallon in June of 2008 to $1.81 per gallon at December 31, 2008. 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 $2.00 per diesel gallon equivalent at December 31, 2008 and our retail prices for CNG fuel sold in the Los Angeles Basin decreased from a high of $3.20 per gasoline gallon equivalent in July of 2008 to a low of $1.30 per gasoline gallon equivalent at December 31, 2008. Lower fuel prices for CNG and LNG 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 or convert their fleets to natural gas, 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. Recent and extreme volatility in oil and gasoline prices demonstrate that it is difficult to predict future transportation fuel costs. The decline in the price of oil, diesel fuel and gasoline has reduced the economic advantages that our existing or potential customers may realize by using less expensive CNG or LNG fuel as an alternative to gasoline or diesel. The reduced prices for gasoline and diesel fuel and continuing uncertainty about fuel prices, combined with higher costs for natural gas vehicles, may cause potential customers to delay or reject converting their fleets to run on natural gas. In that event, our growth 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 2008, the price for natural gas, based on the New York Mercantile Exchange (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, 2009, the NYMEX index price for natural gas was $4.07 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 a futures contract or with an ineffective futures contract that does not fully mitigate 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, including revenue generated by sales of biomethane through our 70% interest in our landfill gas joint-venture. Low prices for natural gas may prevent us from selling the biomethane produced at our landfill gas processing plant at prices that exceed our operating and production costs, which has and may continue to result in financial losses. 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. The recent economic recession has resulted in significant and rapid declines in the price of natural gas.

Failure to comply with the terms of our Credit Agreement with PlainsCapital Bank could impair our rights in Dallas Clean Energy, LLC ("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 $18.0 million from PlainsCapital Bank to fund the acquisition and obtained a $12 million line of credit from PlainsCapital 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 $7.9 million of the line of credit from PlainsCapital Bank as of March 13, 2009. To secure our obligations under the Credit Agreement, we granted PlainsCapital Bank a security interest in 45 of our LNG tanker trailers, certain accounts receivable and inventory, our note receivable from, and our membership interests in, DCE. If we default on the Credit Agreement or otherwise fail to comply with any of the negative or affirmative covenants of the Credit Agreement, PlainsCapital Bank may declare all of the obligations and indebtedness under the Credit Agreement (and related documents) due and payable. In addition, reduction in our accounts receivable balances at certain of our subsidiaries due to decreased natural gas prices may result in violation of one of our debt covenants under our credit agreement with PlainsCapital Bank, as is further described in "Liquidity and Capital Resources." In such a scenario, we may lose our right, title, and interest in the property that secures such obligations and indebtedness.

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 16,000 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. In addition, the Federal Maritime Commission has filed a lawsuit to block parts of the Clean Trucks Program as anticompetitive and the American Trucking Association has also filed suit to challenge specific concession requirements in the Clean Trucks Program, either of which may delay the program's implementation. 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. 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 have a detrimental effect on the U.S. natural gas vehicle industry, which, in turn, could slow our growth and adversely affect our business.

Our growth depends in part on tax and related government incentives for clean burning fuels. A reduction in these incentives would increase the cost of natural gas fuel and vehicles for our customers and could 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 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, is scheduled to expire December 31, 2009. Based on the service relationship we have with our customers, either we or our customers are able to claim the credit. In 2007 and 2008, we recorded $17.0 million and $20.8 million of revenue, respectively, related to fuel tax credits, representing approximately 14.5% and 16.1%, respectively, of our total revenue during the period. The failure to extend the federal excise tax credit for natural gas, or the repeal of federal or state tax credits for the purchase of natural gas vehicles or natural gas fueling equipment, could have a detrimental effect on the natural gas vehicle industry, which, in turn, could adversely affect our business and results of operations. In addition, if grant funds were no longer available under existing government programs, the purchase of or conversion to natural gas vehicles and station construction could slow and our business and results of operations could be adversely affected. Any reduction in tax revenues associated with an economic recession or slow-down could result in a significant reduction in funds available for government grants that support vehicle conversion and station construction and impair our ability to grow 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 recent and rapid decline in oil, diesel and gasoline prices has resulted in decreased interest in alternative fuels like CNG and LNG. In addition, recent disruption in the capital markets has severely reduced the availability of debt financing to support the purchase of CNG and LNG vehicles and investment in the 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 our ability to grow our business.

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 fuel 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.

A decline in the demand for vehicular natural gas would reduce our revenue and negatively affect our ability to sustain our revenue growth.

We derive our revenue primarily from sales of CNG and LNG as a fuel for fleet vehicles, and we expect this trend will continue. A downturn in demand for CNG and LNG would adversely affect our revenue and ability to sustain and grow our operations. Circumstances that could cause a drop in demand for CNG and LNG vehicle fuel are described in other risk factors and include a reduction in supply of natural gas, changes in governmental incentives, the development of other alternative fuels and technologies, continued economic contraction, prolonged disruption in the capital markets, lower prices for competing fuels such as diesel and gasoline and any sustained increase in the price of natural gas relative to gasoline and diesel.

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. Currently, 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 automobile manufacturer that makes natural gas powered passenger vehicles, and manufacturers of medium and heavy-duty vehicles produce only a narrow range and number of natural gas vehicles. 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 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, it may delay or impair the growth of our LNG fueling business. 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 sales may be restricted, even if there is demand.

There are a small number of companies that convert vehicles to operate on natural gas, which may restrict our sales.

Conversion of vehicle engines from gasoline or diesel to natural gas is performed by only a small number of vehicle conversion suppliers 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 which could discourage our potential customers from purchasing converted vehicles that run on natural gas. Without an increase in vehicle conversion options, vehicle choices for fleet use will remain limited and our sales may be restricted, even if there is demand.

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 ability to compete with other alternative fuels.

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 where it is a byproduct of their primary natural gas production. 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 experiences 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. An LNG supply interruption would also limit our ability to expand LNG sales to new 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, our operating margins will decrease on those sales.

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

Some of our LNG supply agreements have take or pay commitments and the new California LNG liquefaction plant has land lease and other fixed operating costs regardless of production and sales levels. Should the market demand for LNG decline 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 and negatively impact our margins.

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

Two third-party LNG suppliers, Williams Gas Processing Company and ExxonMobil Corporation, supplied approximately 47% of the LNG we sold for the year ended December 31, 2007 and supplied 49% of the LNG we sold for the year ended December 31, 2008. Our contracts with these LNG suppliers generally may be terminated by the supplier on short notice. In addition, under certain circumstances, Williams Gas Processing Company may significantly increase the price of LNG we purchase upon 24 hours' notice if Williams' costs to produce LNG increases, and we may be required to reimburse Williams for certain other expenses. Williams Gas Processing Company supplied 32% of the LNG we sold for the year ended December 31, 2007 and 29% for the year ended December 31, 2008, and our contract with Williams expires on June 30, 2011. Our contract with ExxonMobil Corporation, which supplied 15% of the LNG we sold for the year ended December 31, 2007 and 20% for the year ended December 31, 2008, expires on March 31, 2009. 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, pipeline capacity, equipment failure, liquefaction production or delivery, 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 as 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 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.

We are in the process of commencing operations at a new LNG liquefaction plant, which could cost more to operate than we estimate and divert resources and management attention.

We are in the initial stages of operating our LNG liquefaction plant in California, which began producing LNG in November 2008. The implementation and operation of any plant of this nature has inherent risks. Permitting, environmental issues, lack of materials and lack of human resources, among other factors, could complicate our ability to operate the LNG liquefaction plant and affect the operation of the plant. The new facility could also present increased financial exposure through start-up delays, repairs and incomplete production capability. If the new plant has higher than expected operating costs and is not able to produce expected amounts of LNG, we may be forced to sell LNG at a price below production costs and we may lose money. Additionally, if the quality of LNG produced at the plant does not meet contractual specifications, our customers may not be required to purchase it, which would harm our business.

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, we expect to purchase futures contracts to hedge our exposure to variability related to our fixed price contracts. However, such contracts may not be available or we may not have sufficient financial resources to secure such contacts. 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, 2008, we were economically hedged with respect to two of our fixed price contracts with our customers. Based on natural gas prices as of December 31, 2008, we anticipate we will incur between $70,000 and $85,000 of costs to cover the increased price of natural gas above the inherent price of natural gas embedded in our customers' fixed price and price cap contracts where we are not economically hedged over the duration of the contracts. We expect the majority of these costs will be incurred from January 1, 2009 through December 31, 2009.

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 or price cap 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, 2008, we had $1.1 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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended (SFAS 133), 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. In the future, we will attempt to qualify all of our futures contracts for hedge accounting under SFAS 133, but there can be no assurances that we will be successful in doing so. At December 31, 2008, we had two futures contracts that did qualify 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, 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 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 for the three months ended June 30, 2006, March 31, 2007, June 30, 2007, September 30, 2007, December 31, 2007 and March 31, 2008. 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 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 stations and require that we obtain emissions credits or invest in costly emissions prevention technology. We can not 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 operations entail inherent safety and environmental risks that may result in substantial liability to us.

Natural gas operations 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. 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 recently damaged tanks he was fueling exploded. 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 year ended December 31, 2007 and the year ended December 31, 2008, sales in California accounted for 40% and 45% respectively, and sales in Arizona accounted for 20% and 14%, respectively, of the total amount of gallons we delivered. A continuing 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 60% 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 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, 2008 we had $5.6 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, 2008, we had $7.6 million in aggregate deposits outstanding on natural gas vehicles which are described below.

In July 2006, we entered into an agreement with Inland Kenworth, Inc. (Inland) pursuant to which we agreed to deposit certain amounts with Inland, as security for a guarantee, to fund the acquisition by Kenworth Truck Company (Kenworth) of 100 LNG trucks. At December 31, 2008, we had outstanding $3.2 million of deposits under this agreement. We also entered into two deposit agreements with Westport in 2007 to facilitate the production of LNG fuel systems for installation in the tractors purchased by Inland. At December 31, 2008, we had outstanding a total of $3.0 million on deposits made to Westport under these agreements. Repayment of these deposits will occur incrementally upon the sale of the converted tractors to customers; however, to the extent an LNG fuel system incorporated into a tractor is not sold within 24 months of the effective date of the applicable deposit agreement (or such other time period as is agreed by both us and Westport), Westport is not obligated to repay any of the deposit with respect to such LNG fuel systems. In addition, we have approximately $1.4 million on deposit at December 31, 2008 to secure the availability of 57 Honda Civic natural gas vehicles

If we are unable to attract, retain and motivate our executives and other key personnel, our business would be harmed.

Our ability to manage and expand our business depends significantly on the skills and services of our management team, each of whom may terminate his or her service with us at any time and none of whom are subject to non-compete restrictions. We believe the loss of one or more members of our management team would harm our business because few people have comparable experience working in the natural gas vehicle industry or managing companies similar to ours. Moreover, we expect our operations to grow, and to do so, we will need to hire additional personnel in all areas of our business, particularly in sales and marketing. Competition for qualified personnel is intense, and we may be unable to attract or retain qualified personnel and expand our business as planned.

We may have difficulty managing our planned growth.

If our business grows as planned, our management team and our operational, financial and accounting systems will also need to be expanded. This expansion would result in increased expenses and may strain our resources. If we are unable to manage this growth, we may experience higher expenses, poor internal controls, employee attrition and customer dissatisfaction, any of which could harm our business. Additionally, we may find it difficult to maintain important aspects of our corporate culture, which could negatively affect our ability to retain and recruit personnel, and otherwise adversely affect our future success.

There are many risks associated with conducting operations in international markets.

We are in the process of expanding our operations outside of the United States and Canada. For example, in August 2007, we executed a joint venture agreement with Energy Gas del Peru pursuant to which we built and operate a natural gas fueling station in Lima, Peru. Changes in local economic or political conditions in foreign countries could have a material adverse effect on our business, consolidated financial condition, results of operations and cash flows. Additional risks inherent in our international business activities include the following: difficulties in managing international operations, including our ability to timely and cost effectively execute projects, unexpected changes in regulatory requirements, tariffs and other trade barriers that may restrict our ability to enter into new markets, governmental actions that result in the deprivation of contract rights, changes in political and economic conditions in the countries in which we operate, including civil uprisings, riots, kidnappings and terrorist acts, changes in foreign currency exchange rates, potentially adverse tax consequences, restrictions on repatriation of earnings or expropriation of property without fair compensation, difficulties in establishing new international offices and risks inherent in establishing new relationships in foreign countries, and the burden of complying with the various laws and regulations in the countries in which we operate.

Our future plans may involve expanding our business in international markets where we do not conduct business. The risks inherent in establishing new business ventures, especially in international markets where local customs, laws and business procedures present special challenges, may affect our ability to be successful in these ventures or avoid losses that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

If we are unable to adequately protect our intellectual property, our business could be harmed.

We protect our intellectual property through a combination of trademark laws, confidentiality procedures, contractual provisions and seeking patents, when appropriate. Nonetheless, our intellectual property rights may not be successfully asserted in the future or may be invalidated, circumvented or challenged. Enforcement of intellectual property rights against alleged infringers can sometimes lead to costly litigation and counterclaims. Our inability to protect our proprietary information could harm our business.

We have significant contracts with federal, state and local government entities, which 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 two-thirds of our revenues from 2006 through 2008. 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. Further, many governmental entities are experiencing significant budget deficits as a result of the economic recession, which may 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 two-thirds of our revenues from 2006 through 2008.

In connection with our LNG liquefaction activities and the landfill gas processing facility operated by our joint-venture subsidiary, Dallas Clean Energy, LLC, 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.

The requirements of being a public company, including the costs of complying with Section 404 of the Sarbanes-Oxley Act of 2002, may strain our resources and distract management.

As a public company, we are incurring significant legal, accounting and other expenses that we did not incur as a private company. The Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), as well as rules subsequently implemented by the Securities and Exchange Commission (SEC), NASDAQ and other stock exchanges, have required changes in corporate governance practices of public companies.

These rules and regulations have increased our legal and financial compliance costs and made some activities more time-consuming and costly. For example, as a result of becoming a public company, we have created additional board committees and have implemented a number of new corporate policies. In addition, we are incurring additional costs associated with our public company reporting. We also expect these new rules to make it more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage.

Ensuring that we have adequate financial and accounting controls to produce accurate financial statements on a timely basis is a costly and time-consuming effort that needs to be re-evaluated frequently. We are required to document and evaluate our internal controls in order to comply with Section 404 of the Sarbanes-Oxley Act, which requires management assessments of the effectiveness of our internal controls over financial reporting and a report by our independent registered public accounting firm addressing these internal controls. Both we and our independent registered public accounting firm will continue to test our internal controls in connection with the Section 404 requirements and, as part of that documentation and testing, identify areas for further attention and improvement. Maintaining, and if necessary, improving our internal controls will likely involve substantial costs and take significant time to complete, which may distract our officers, directors and employees from the operation of our business. These efforts may not ultimately be effective to maintain adequate internal controls. Our accounting and financial reporting department may not have all of the necessary resources to ensure that we will not have significant deficiencies or material weaknesses in our system of internal control over financial reporting. The effectiveness of our internal control over financial reporting may be limited by a variety of factors including: faulty human judgment and errors, omissions or mistakes, inappropriate management override of policies and procedures, and the possibility that any enhancements to disclosure controls and procedures may still not be adequate to assure timely and accurate financial information.

If we fail to maintain effective controls and procedures for financial reporting, we could be unable to provide timely and accurate financial information. In addition, investor perceptions that our internal controls are inadequate or that we are unable to produce accurate financial statements may negatively affect our stock price.

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 $0.9 million, $3.6 million, $1.5 million, $2.9 million, $5.4 million, $2.4 million $10.6 million and $22.4 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 and December 31, 2008, respectively. Our quarterly results may fluctuate significantly as a result of a variety of factors, many of which are beyond our control. 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 historically have primarily been attributable to our derivative gains and losses and, in the quarter ending December 31, 2008, our increased expense associated with our support of Proposition 10; but also may be due to a number of other 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, the amount and timing of operating costs and 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, 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 price of our common stock may be volatile as a result of market conditions unrelated to our company, and the value of your investment could decline.

The trading price of our common stock may fluctuate substantially due to factors in the market beyond our control. These fluctuations could cause you to lose all or part of your investment in our common stock. Factors that could cause fluctuations in the trading price of our common stock include: price and volume fluctuations in the overall stock market from time to time, actual or anticipated changes or fluctuations in our results of operations, actual or anticipated changes in the expectations of investors or securities analysts, actual or anticipated developments in our competitors' businesses or the competitive landscape generally, litigation involving us or our industry, domestic and international regulatory developments, general economic conditions and trends, widespread adoption of other alternative fuels and technologies, major catastrophic events or sales of large blocks of our stock. Since our initial public offering, which was completed in May 2007, the price of our common stock has ranged from an intra-day low of $3.23 to an intra-day high of $20.65 through March 13, 2009.

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, 2008, 50,238,212 shares of our common stock were outstanding. The 11,500,000 shares sold in our initial public offering in addition to 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 closed November 3, 2008, 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, 2008, there were 8,234,467 shares underlying outstanding options and 18,314,394 shares underlying outstanding warrants (including the 3,314,394 warrants sold in our registered direct offering which closed 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 March 3, 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.

If securities analysts stop publishing research or reports about our business, or if they downgrade our stock, the price of our stock could decline.

The trading market for our common stock relies in part on the research and reports that industry or financial analysts publish about us. We do not control these analysts. If one or more of the analysts who do cover us downgrade our stock, our stock price would likely decline. Further, if one or more of these analysts cease coverage of our company, we could lose visibility in the market, which in turn could cause our stock price to decline.

A majority 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, 2008, Boone Pickens and affiliates (including Madeleine Pickens, his wife) beneficially owned in the aggregate 54% of our outstanding 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 also 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.

Provisions in our certificate of incorporation and bylaws and Delaware law may discourage, delay or prevent a change of control of our company or changes in our management and, therefore, depress the trading price of our stock.

Our certificate of incorporation and bylaws contain provisions that could depress the trading price of our stock by acting to discourage, delay or prevent a change of control of our company or changes in our management that the stockholders of our company may deem advantageous. These provisions:

- authorize the issuance of “blank check” preferred stock that our board of directors could issue to increase the number of outstanding shares to discourage a takeover attempt,
- provide that a special meeting of stockholders may only be called by our board of directors or our chief executive officer,
- provide that the board of directors is expressly authorized to make, alter or repeal our bylaws, and
- establish advance notice requirements for nominations for elections to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Additionally, we are subject to Section 203 of the Delaware General Corporation Law, which generally prohibits a Delaware corporation from engaging in any of a broad range of business combinations with any “interested” stockholder for a period of three years following the date on which the stockholder became an “interested” stockholder and which may discourage, delay or prevent a change of control of our company.

Item 1B. Unresolved Staff Comments.

We have not received written comments from the SEC staff more than 180 days before the end of our 2008 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 $76,000. 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 Boston, Denver, Dallas, Vancouver, Toronto and Phoenix, and our monthly rent payments for such facilities are approximately $17,000 per month in the aggregate.

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 2008, we recorded rent expense of approximately $0.3 million, which includes amortization of our rent obligations during the construction period. In addition, we must also pay a royalty to the landlord for each gallon of LNG produced at the facility as well as for certain other services that the landlord will provide.

We lease 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. The ground leases 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, 2008, we leased the land for approximately 64 stations and for the year ended December 31, 2008, paid a total of approximately $1.3 million in rent under the station ground leases.

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 2007		
Second Quarter 2007	$13.90	$11.40
Third Quarter 2007	$18.80	$10.81
Fourth Quarter 2007	$20.65	$12.55
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

Holders

There were approximately 76 stockholders of record as of March 12, 2009. We believe there are approximately 43,490 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.

Use of Proceeds

Our initial public offering of common stock was effected through a Registration Statement on Form S-1 (File No. 333-137124) that was declared effective by the Securities and Exchange Commission on May 24, 2007. On May 31, 2007, 10,000,000 shares of common stock were sold on our behalf at an initial public offering price of $12.00 per share (for aggregate gross offering proceeds of $120.0 million) managed by W.R. Hambrecht + Co., Simmons & Company International, Susquehanna Financial Group, LLLP, and NBF Securities (USA) Corp. In addition, on June 22, 2007, in connection with the exercise of the underwriters' over-allotment option, 1,500,000 additional shares of common stock were sold by selling stockholders at the initial public offering price of $12.00 per share (for aggregate gross offering proceeds of $18.0 million). We received no proceeds from the sale of shares by selling stockholders. The offering terminated following the closing of the over-allotment sale.

We paid to the underwriters underwriting discounts totaling approximately $7.0 million in connection with the offering. In addition, we incurred approximately $4.5 million of costs in connection with the offering, which when added to the underwriting discounts paid by us, amounts to total expenses of approximately $11.5 million. Thus, the net offering proceeds to us, after deducting underwriting discounts and offering expenses, were approximately $108.5 million. No offering expenses were paid directly or indirectly to any of our directors or officers (or their associates) or persons owning ten percent or more of any class of our equity securities or to any other affiliates.

Through December 31, 2008, we used the net proceeds from the offering as follows:

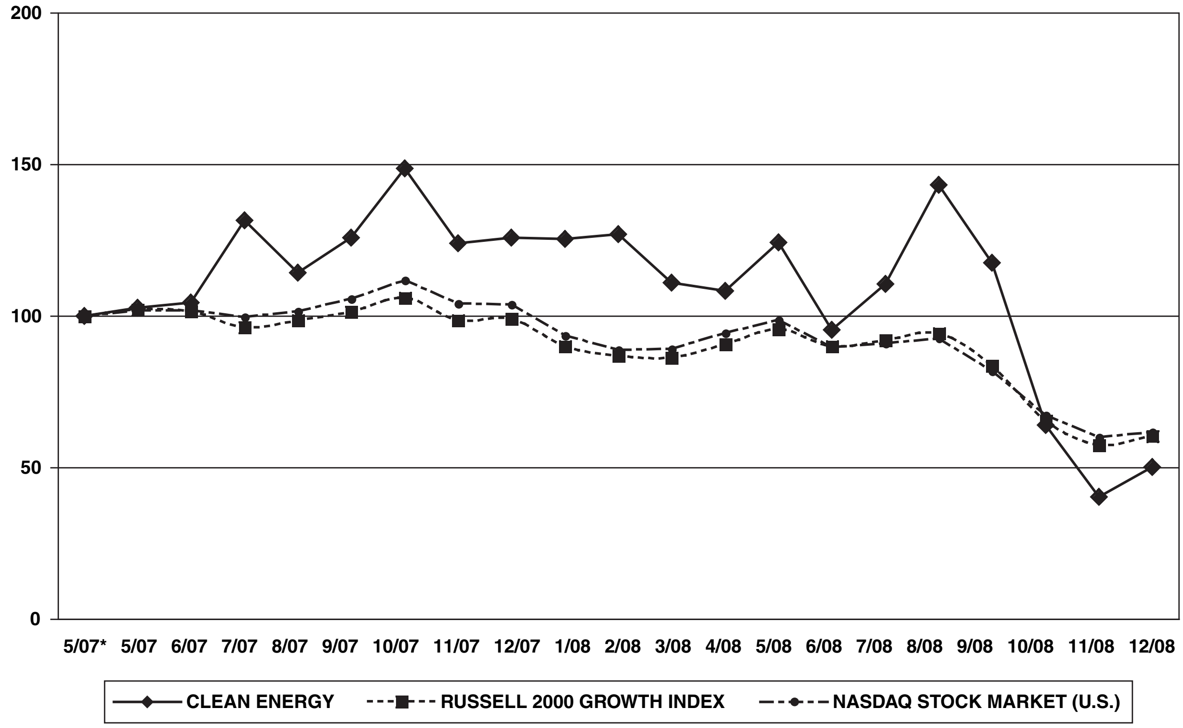
- construction of our LNG liquefaction plant in California ($65.6 million),
- construction and installation of CNG and LNG stations ($29.2 million),
- financing customer vehicle purchases ($5.8 million), and
- working capital ($7.9 million).

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) a warrant to purchase up to 0.2571 shares of Common Stock (the "Series II Warrant"). Our offering of common stock and warrants was effected through a Registration Statement on Form S-3 (File No. 333-152306) that was declared effective by the Securities and Exchange Commission on July 29, 2008. 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. As of December 31, 2008 all of the Series II Warrants have been exercised. The Company received approximately $32.5 million after deducting the placement agents' fees and other offering expenses. As of December 31, 2008, we have maintained the net proceeds from this offering as cash and cash equivalents.

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, 2008 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, 2006, 2007 and 2008 and the consolidated balance sheet data at December 31, 2007 and 2008 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, 2004 and 2005, and the consolidated balance sheet data at December 31, 2004, 2005 and 2006 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,				
	2004	2005	2006	2007	2008
Statement of Operations Data:					
Total Revenues[1]	$ 57,641,605	$ 77,955,083	$ 91,547,316	$117,716,233	$129,472,533
Operating expenses:					
Costs of sales	48,772,296	72,004,077	74,047,901	85,660,329	98,767,585
Derivative (gains) losses[2]	(10,572,349)	(44,067,744)	78,994,947	—	611,175
Loss on extinguishment of derivative liability	—	—	2,142,095	—	—
Selling, general and administrative[3]	11,112,878	17,108,425	20,860,181	35,933,694	62,415,554
Depreciation and amortization	3,810,419	3,948,544	5,765,001	7,107,942	9,623,672
Total operating expenses:	53,123,244	48,993,302	181,810,125	128,701,965	171,417,986
Operating income (loss)	4,518,361	28,961,781	(90,262,809)	(10,985,732)	(41,945,453)
Interest income (expense), net	(96,983)	59,780	746,339	3,505,597	1,630,436
Other (expense), net	(605,312)	(140,921)	(255,479)	(192,347)	(169,159)
Equity in gains (losses) of equity method investee	—	—	—	—	(188,186)
Income (loss) before income taxes	3,816,066	28,880,640	(89,771,949)	(7,672,482)	(40,672,362)
Income tax (expense) benefit	(1,686,825)	(11,623,053)	12,271,208	(1,221,880)	(289,141)
Minority interest in net income	—	—	—	—	104,829
Net income (loss)	$ 2,129,241	$ 17,257,587	$ (77,500,741)	$ (8,894,362)	$ (40,856,674)
Basic earnings (loss) per share	$ 0.11	$ 0.76	$ (2.45)	$ (0.22)	$ (0.90)
Fully diluted earnings (loss) per share	$ 0.11	$ 0.75	$ (2.45)	$ (0.22)	$ (0.90)
Weighted average common shares outstanding:					
Basic	18,949,636	22,602,033	31,676,399	40,258,440	45,367,991
Diluted	18,949,636	23,191,674	31,676,399	40,258,440	45,367,991

(1) Revenue includes the following amounts:

	Year Ended December 31,				
	2004	2005	2006	2007	2008
Fuel tax credits (VETC)	$ 0	$ 0	$ 3,810,109	$ 17,046,412	$ 20,803,265

(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. See note 13 to our consolidated financial statements.

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

	December 31,				
	2004	2005	2006	2007	2008
Balance Sheet Data:					
Cash and cash equivalents	$ 1,299,746	$ 28,763,445	$ 937,445	$ 67,937,602	$ 36,284,431
Restricted cash	—	—	—	—	2,500,000
Short-term investments	—	—	—	12,479,684	—
Working capital	8,375,627	27,426,766	44,811,284	119,480,877	50,943,938
Total assets	79,812,007	128,613,650	136,932,636	249,024,944	290,374,400
Long-term debt, inclusive of current portion	5,921,999	5,100,256	282,396	224,897	25,083,802
Stockholders' equity	62,063,424	93,489,868	122,915,857	230,932,474	237,382,603

	Year Ended December 31,		
	2006	2007	2008
Key Operating Data:			
Gasoline gallon equivalents delivered (in millions):			
CNG	41.9	48.0	47.6
Biomethane	—	—	2.0
LNG	26.5	27.3	23.9
Total	68.4	75.3	73.5

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.

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 and sales of pipeline quality biomethane produced by our DCE joint venture.

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 revenue, (3) our earnings before interest, taxes, depreciation and amortization (EBITDA), and (4) 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, 2006, 2007 and 2008:

Gasoline gallon equivalents delivered (in millions)	Year Ended December 31, 2006	2007	2008
CNG	41.9	48.0	47.6
Biomethane	—	—	2.0
LNG	26.5	27.3	23.9
Total	68.4	75.3	73.5
Operating data			
Revenue	$ 91,547,316	$117,716,233	$129,472,533
EBITDA	(84,753,287)	(4,070,137)	(32,574,297)
Net loss	(77,500,741)	(8,894,362)	(40,856,674)

Key trends in 2006, 2007 and 2008. According to the U.S. Energy Information Administration, demand for natural gas fuels in the United States increased by approximately 25% during the period January 1, 2006 through December 31, 2008. 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 176 at December 31, 2008 (a 19.7% increase). Included in this number are all of the CNG and LNG fueling stations we own, maintain or have a fueling supply contract with. The amount of CNG and LNG gasoline gallon equivalents we delivered from 2005 to 2008 increased by 29.4%. The increase in gasoline gallon equivalents delivered, together with higher prices we charged our customers due to higher natural gas prices, 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 2008, prices for oil, gasoline, diesel fuel and natural gas experienced significant volatility and substantial price declines by the end of 2008. Oil declined from a high of $148 per barrel on July 11, 2008 to a price of $38 per barrel on December 31, 2008. In California, average retail prices for gasoline have declined from a high of $4.59 per gallon in June of 2008 to $1.81 per gallon at December 31, 2008 and average retail prices for diesel fuel have declined from a high of $5.03 per diesel gallon in May and June of 2008 to $2.24 per diesel gallon at December 31, 2008. To the extent that we continue to try to price LNG and CNG at a discount to these lower 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. In addition, the volatility in natural gas prices has a direct impact on our revenue. The NYMEX price for natural gas declined from over $13.00 per MMbtu in July 2008 to around $6.90 per MMbtu at the end of December 2008. Our sales revenue from biomethane produced by DCE, which from August 15, 2008 through December 31, 2008 was sold based on an index price for natural gas, has had a corresponding drop due to the lower natural gas prices. The average retail sales price of our CNG fuel sold in the Los Angeles metropolitan area declined from $3.20 for the month of July 2008 to $1.30 for the month of December 2008. Continuing declines in natural gas prices would lead to further revenue reduction and potentially lower profit margins on our fuel sales. In addition, reduction in our accounts receivable balances at certain of our subsidiaries due to decreased natural gas prices may result in violation of one of our debt covenants under our credit agreement with PlainsCapital Bank, as is further described in "Liquidity and Capital Resources" below.

Anticipated future trends. Despite the recent volatility and decline 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. Indications were that shale gas production growth from only the major six shale plays, plus Marcellus 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 making available gas supply to meet all existing markets and to meet new market requirements. Analysts believe that there is a significant worldwide supply of natural gas relative to crude oil as well. According to the 2008 BP Statistical Review of World Energy, on a global basis, the ratio of proven natural gas reserves to 2007 natural gas production was 45% greater than the ratio of proven crude oil reserves to 2007 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 a natural gas fueling station, 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, 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.

In addition, the economic recession that began during 2008 has resulted in decreased demand for vehicle fuel generally, which has reduced our sales of LNG and CNG fuel. 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. Continuing economic contraction and reduced economic activity may reduce our opportunities to attract new fleet customers. Many governmental entities, which during 2006 through 2008 represented approximately two-thirds or our revenues, are experiencing significant budget deficits as a result of the economic recession and may 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. 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. Historically, our principal sources of liquidity have been cash provided by operations, capital contributions from our stockholders, our cash and cash equivalents and, during the third and fourth quarters of fiscal 2006, a revolving line of credit with Boone Pickens, a director and our largest stockholder. The line of credit was used to fund margin requirements on certain derivative contracts and was terminated in December 2006. In connection with our acquisition of 70% of the membership interests in DCE, we entered into a credit agreement on August 15, 2008 with PlainsCapital Bank. We borrowed $18.0 million to finance the acquisition and entered into a $12.0 million line of credit from PlainsCapital Bank to provide capital to DCE, primarily for capital expenditures, and to pay certain costs and expenses of the acquisition and the loans. As of March 13, 2009 approximately $4.1 million is available under the line of credit from PlainsCapital Bank to provide further capital to DCE. On September 24, 2008, we sold 319,488 shares of our common stock at a purchase 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 shares of common stock and warrants exercisable for common stock to third-party investors and received net proceeds of approximately $32.5 million. See note 9 to the accompanying condensed consolidated financial statements for a discussion of the November 3, 2008 transaction and description of the outstanding warrants.

Our current business plan calls for approximately $31.6 million in capital expenditures in 2009, primarily related to construction of new fueling stations. In addition, we anticipate that during 2009 we will provide approximately $2.0 million for financing natural gas vehicle purchases by our customers and up to $6.2 million in funding that we may be required to provide to the Vehicle Production Group, LLC, a company that is developing CNG paratransit vehicles and taxis. We anticipate that we will fund any capital expenditures of DCE during 2009 through our line of credit from PlainsCapital Bank. We may also elect to invest additional amounts in expansion of our California LNG plant, station construction for new or existing customers that are not currently under contract, 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, additional station construction, acquisitions or other capital expenditures or investments which are not budgeted for in our 2009 business plan. If we do need to raise additional capital, the timing and necessity of any future capital raise will depend primarily on our rate of new station construction and any decision to expand our California LNG plant. 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, develop natural gas fueling infrastructure and invest in strategic transactions or acquisitions and reduce our ability to grow our business and generate increased revenues.

Volatility in operating results related to futures contracts. Historically, we have purchased futures contracts from time to time to help mitigate our exposure to natural gas price fluctuations in current periods and in future periods. Gains and losses related to our futures activities, which appear in the line item derivative (gains) losses in our consolidated financial statements, have materially impacted our results of operations in recent periods. For the years ended December 31, 2006, 2007 and 2008, derivative (gains) losses were $78,994,947, $0 and $611,175 respectively. For this reason and others, we caution investors that our past operating results may not be indicative of future results. For more information, please read "Volatility of Earnings and Cash Flows" and "Risk Management Activities" below.

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, 2008, CNG and biomethane (together) represented 68% and LNG represented 32% 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. 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.

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. We sell a small amount of CNG under fixed-price contracts and also provide price caps to certain customers on their index-plus pricing arrangement. 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 a small volume of LNG to customers 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 typically 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. 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 two one-year renewal periods beginning April 1, 2009 that one of our customers is entitled to should they choose to exercise such renewals. The renewal periods, if exercised, would obligate us to sell the customer approximately 2.1 million LNG gallons on an annual basis subject to a price cap of $7.50 per MMbtu on the SoCal Border Index for each renewal year. We will continue to offer fixed price contracts as appropriate and consistent with our revised natural gas hedging policy adopted 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 may receive a Volumetric Excise Tax Credit (VETC) of $0.50 per gasoline gallon equivalent of CNG and $0.50 per liquid gallon of LNG that we sell as vehicle fuel. Based on the service relationship we have with our customers, either we or our customers are able to claim the credit. We record 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 SFAS No. 109. 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. We expect the tax credit will continue to factor into the price we charge our customers for CNG and LNG in the future. The legislation that created this tax credit also increased the federal excise taxes on sales of CNG from $0.061 to $0.183 per gasoline gallon equivalent and on sales of LNG from $0.119 to $0.243 per LNG gallon. These new excise tax rates are approximately the same as those for gasoline and diesel fuel.

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 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 60% 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. As of December 31, 2008, 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, DCE generated approximately $1.8 million in revenue from sales of biomethane, all of which is included in our consolidated revenue total.

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 SFAS 133. See "Critical Accounting Policies—Derivative Activities" below. We have therefore recorded any changes in the fair market value of these contracts 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 $33.1 million and $5.7 million for the three months ended September 30, 2005 and June 30, 2008, and 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 for the three months ended June 30, 2006, March 31, 2007, June 30, 2007, September 30, 2007, December 31, 2007 and March 31, 2008. Commencing with the adoption of our natural gas hedging policy in May 2007, we plan to structure all subsequent futures contracts as cash flow hedges under SFAS No. 133, but we can not 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 contacts. 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, 2008, we had $1.1 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.

Debt Compliance

Our credit agreement with PlainsCapital Bank (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 minimum liquidity of not less than $6.0 million at each quarter end beginning December 31, 2008, maintain an accounts receivable balance, as defined, at each month end of not less than $10.0 million beginning August 31, 2008, maintain 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 at each quarter end beginning September 30, 2008, and a debt service ratio, as defined, of not less than 1.5 to 1 for each quarterly period beginning June 30, 2009. 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. However, if we default on the Credit Agreement, all of the obligations under the Credit Agreement will become due and payable and all funds received in our lock-box held by PCB will be applied to the balance due on 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 guidance in Emerging Issues Tax Force Issue No. 95-22 *Balance Sheet Classification of Borrowings Outstanding under Revolving Credit Agreements That Include both a Subjective Acceleration Clause and a Lock-Box Arrangement* (EITF No. 95-22), 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 and $2.5 million we have deposited with PCB in a payment reserve account will be applied to the balance due on the Credit Agreement. We were in compliance with the covenants as of December 31, 2008.

One of our bank covenants is a requirement to maintain accounts receivable balances from certain subsidiaries above $10.0 million at each month-end during the term. 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. In this event, we would seek a waiver from the bank. We were in compliance with this covenant as of January 31, 2009.

Risk Management Activities

Historically, a significant portion of our natural gas fuel sales are 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."

Risk Management Practices Before February 2007

Historically, when we entered into a contract to sell natural gas fuel to a customer at a fixed price or a variable price subject to a cap, we generally sought to manage our exposure to natural gas price increases for some or all of the expected contract volumes in the natural gas futures market. We did this by purchasing futures contracts that were designed to cover the difference between the commodity portion of the price at which we were committed to sell natural gas and the price we had to pay for gas at delivery, thereby fixing the cost of natural gas we were paying. We generally purchased futures covering all or a portion of our anticipated volumes in future periods.

From time to time, if we believed natural gas prices would decline in the future, we often elected to terminate futures contracts associated with fixed price or price cap customer contracts by selling the futures contracts and recognizing a gain upon such sales. When we did so, we lost future economic protections provided by the futures contracts.

From 2003 through 2005, we sold futures contracts covering estimated sales volumes over future periods and realized a net gain of approximately $44.8 million upon the sale of these contracts. In 2006, we disposed of certain futures contracts covering estimated sales volumes over future periods and realized a net loss of $78.7 million. These futures contracts were transferred to and assumed by Boone Pickens in December 2006. See note 13 to our consolidated financial statements and the discussion below.

Our derivative activities that do not qualify for hedge accounting are reflected in the line item derivative (gains) losses in our consolidated statements of operations. Two components make up this line item: (1) realized (gains) losses, and (2) unrealized (gains) losses. Realized (gains) losses represent the actual (gains) losses we realize when we sell or settle a futures contract during a period. Unrealized (gains) losses represent the (gain) or loss we record at the end of each period when we mark to market our open futures contracts at the end of each period. For realized (gains) losses on contracts sold or settled during a period, there is typically a corresponding unrealized loss (gain) on the contracts since the contracts are no longer outstanding at the end of the period and are therefore marked to zero.

We have a derivative committee of our board of directors and have historically conducted our futures contract activity under the advice of BP Capital L.P. (BP Capital), an entity of which Boone Pickens, our largest stockholder and a director, is the principal. Through March 31, 2007, we paid BP Capital a monthly fee of $10,000 and a commission equal to 20% of our realized gains, net of realized losses, during a calendar year relating to the purchase and sale of natural gas futures contracts. BP Capital remits realized net gains to us, less its applicable commissions, on a monthly basis. We paid fees to BP Capital of $2.4 million in 2006, and $120,000 in 2007 and in 2008. In March 2007, we amended our agreement with BP Capital to remove the 20% commission on our realized gains and losses during a calendar year.

We historically have purchased our natural gas futures contracts from Sempra Energy Trading Corp. The futures are based on the Henry Hub natural gas price set on the New York Mercantile Exchange. One futures contract for CNG covers approximately 80,000 gasoline gallon equivalents of CNG, and one futures contract for LNG covers approximately 120,000 gallons of LNG.

August 2006 Purchase of Futures Contracts and December 2006 Assumption by Boone Pickens

On August 2, 2006, we purchased the following futures contracts and made related deposits of $9.5 million:

Futures settlement year	Volume covered by futures (gasoline gallon equivalents)
2008	161,300,000
2009	201,625,000
2010	201,625,000
2011	201,625,000

In December 2006, Mr. Pickens assumed all of these futures contracts, together with any and all associated liabilities and obligations, in exchange for (1) the issuance to Mr. Pickens of a five-year warrant to purchase up to 15,000,000 shares of our common stock at a purchase price of $10.00 per share (which warrant was valued at $80.9 million), and (2) the assignment to Mr. Pickens of any refunds of margin deposits related to the assumed futures contracts that were made using money borrowed under the line of credit. See note 13 to our consolidated financial statements. At the time of assumption, these futures contracts had lost $78.7 million in value. The difference between the value of the warrant and the value of the losses on the futures contracts ($2.2 million) was recorded in our statement of operations as a loss on extinguishment of derivative liability. This warrant will be dilutive to net income per share if the fair market value of our common stock exceeds $10 per share in the future.

Adoption of Revised Natural Gas Hedging Policy in February 2007

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 offer 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 and is incorporated by reference herein. 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. 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 significantly 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 contract. The amount of this price component will vary based on the anticipated volume to be covered under the fixed-price sales contract.

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.

Note Receivable Reserve

At December 31, 2008, we have reserved $1.4 million against a $3.6 million loan to a natural gas vehicle conversion company. When assessing the collectability of the note, we assess the company's projected future cash flows, their backlog of business, and the value of our collateral, among other factors. We recorded $1.2 million of the reserve in 2007, and $0.2 million of the reserve in 2008. If the company's future cash projections do not materialize as planned, or they require and we agree to loan them additional money, we could incur additional losses on this loan in the future.

Revenue Recognition

We recognize revenue on our gas sales and for our O&M services in accordance with SEC Staff Accounting Bulletin No. 104, *Revenue Recognition*, which requires 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 the guidance set forth in EITF No. 00-21, 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 2006, 2007 and 2008, we did not have objective evidence for our multi-deliverable contracts. 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 SFAS No. 13, *Accounting for Leases*. 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 in AICPA Statement of Position 81-1, *Accounting for Performance of Construction Type and Certain Production Type Contracts*.

Derivative Activities

We account for our derivative instruments, specifically our futures contracts, in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. SFAS No. 133 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. Our derivatives did not qualify for hedge accounting under SFAS No. 133 for the years ended December 31, 2005 and 2006, and we did not have any derivative activities in 2007. As such, changes in the fair value of the derivatives were recorded directly to our consolidated statements of operations in 2005 and 2006. 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. During 2008, we had two contracts that did qualify for hedge accounting and certain other contracts that did not qualify for hedge accounting.

We record gains or losses realized on our derivative instruments that do not qualify for hedge accounting under SFAS No. 133 during the period in the line item derivative (gains) losses in our consolidated statements of operations. We also mark-to-market our open positions that do not qualify for hedge accounting under SFAS No. 133 at the end of each reporting period with the resulting gain or loss recorded to derivative (gains) losses in our consolidated statements of operations. At December 31, 2008, all of our futures contracts qualified for hedge accounting.

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

Our contracts to sell CNG and LNG at a fixed price or a variable price subject to a cap are, for accounting purposes, firm commitments. Under U.S. generally accepted accounting principles, or GAAP, we record the actual results of delivering the fuel under the contract as the sale of the natural gas occurs. When we enter into these fixed price or price cap contracts with our 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 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 develops after we enter into the sales contract. If we do not have a derivative contract to hedge the natural gas, and if at the time we sell natural gas under the contract the prevailing index price for natural gas exceeds the commodity portion of our contracted sale price, we incur a loss. Prior to December 31, 2007, we entered into several contracts to sell LNG or CNG to customers at a fixed price or an index-based price that is subject to a fixed price cap and subsequently sold the underlying futures contract prior to the expiration of the customer's sales contract. During these contracts, the price of natural gas generally increased from the price of natural gas when we set the CNG and LNG price.

The following table summarizes important information regarding our fixed price and price cap supply contracts where we do not have an underlying futures contract and we are required to sell fuel to our customers as of December 31, 2008:

	Estimated volumes[(a)]	Average price[(b)]	Contracts Duration
CNG fixed price contracts	1,150,067	$1.18	through 12/13
LNG fixed price contracts	1,061,667	$0.60	through 07/09
CNG price cap contracts	1,560,375	$0.81	through 12/09
LNG price cap contracts	525,000	$0.62	through 03/09

This table does not include two 2.1 million LNG gallon per year renewal options beginning April 1, 2009 that one of our customers possesses related to an LNG price cap contract. The contract contains a price cap of $7.50 per MMbtu on the SoCal Border Index.

(a) Estimated volumes are in gasoline gallon equivalents for CNG contracts and are in LNG gallons for LNG contracts and represent the volumes we anticipate delivering over the remaining duration of the contracts.

(b) Average prices are in gasoline gallon equivalents for CNG contracts and are in LNG gallons for LNG contracts. The average prices represent the natural gas commodity component in the customer's contract.

The price of natural gas has generally increased since we entered into these contracts and fixed or capped the price of CNG or LNG that we sell to the customers. If these contracts had a notional amount as defined under GAAP, then the contracts would be considered derivatives and we would record a loss based on estimated future volumes and the estimated excess of current market prices for natural gas above the cost of the natural gas commodity component of our customer's fixed price or price cap. However, because the contracts have no minimum purchase requirements, they are not considered derivatives and any estimated future losses under these contracts cannot be accrued in our financial statements under GAAP and we recognize the actual results of performing under the contract as the fuel is delivered. If we applied a derivative valuation methodology to these contracts using estimated volumes along with other assumptions, including forward pricing curves and discount rates, we estimate our pre-tax net income would have been higher by the following ranges for the periods indicated:

Year Ended			
December 31, 2006	$ 14,267,259	to	$ 17,437,761
December 31, 2007	$ 4,122,914	to	$ 5,039,117
December 31, 2008	$ 348,540	to	$ 425,994

These amounts are based on estimates involving a high degree of judgment and actual results may vary materially from these estimates. These amounts have not been recorded in our statements of operations as they are non-GAAP.

At December 31, 2008, we estimate we will incur between $70,000 and $85,000 to cover the increased price of natural gas above the inherent price of natural gas embedded in our customer's fixed price and price cap contracts over the duration of the contracts. These estimates were based on natural gas futures prices on December 31, 2008, and these estimates may change based on future natural gas prices and may be significantly higher or lower.

Our volumes under these contracts, in gasoline gallon equivalents, expire as follows:

2009	2,831,296
2010	230,000
2011	230,000
2012	230,000
2013	230,000

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

Effective January 1, 2006, we account for stock options granted using Statement of Financial Accounting Standards No. 123(R) (SFAS No. 123(R)), *Share-Based Payment*, which has replaced SFAS No. 123 and APB 25. Under SFAS No. 123(R), companies are no longer able to account for share-based compensation transactions using the intrinsic method in accordance with APB 25, but are required to account for such transactions using a fair-value method and recognize 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. We adopted the provisions of SFAS No. 123(R) using the prospective transition method. Under the prospective transition method, only new awards, or awards that have been modified, repurchased or cancelled after January 1, 2006 are accounted for using the fair value method.

As of December 31, 2005, there were no unvested stock options. Therefore, the impact of SFAS No. 123(R) has been reflected in the consolidated statements of operations for share-based awards granted in 2006, 2007 and 2008.

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 Statement of Financial Accounting Standards No. 142 (SFAS No. 142), *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, as determined in accordance with SFAS No. 142, to the book value. 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, 2008 was $20.8 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, 2006, 2007 and 2008, and there was no impairment indicated.

Recently Issued Accounting Pronouncements

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

Results of Operations

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

Revenue. Revenue increased by $11.8 million to $129.5 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 $20.8 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 new City of Phoenix LNG supply contract that began July 1, 2008. 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 a 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 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.

Minority interest in net income. During the year ended December 31, 2008, we recorded $0.1 million for the minority interest in the net income of DCE. The minority 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.

Fiscal Year Ended December 31, 2007 Compared to Fiscal Year Ended December 31, 2006

Revenue. Revenue increased by $26.2 million to $117.7 million in the year ended December 31, 2007, from $91.5 million in the year ended December 31, 2006. A portion of this increase was the result of an increase in the number of CNG and LNG gallons delivered from 68.4 million gasoline gallon equivalents to 75.3 million gasoline gallon equivalents, together with an increase in our average price per gallon between periods. Our effective price per gallon was $1.27 in the year ended December 31, 2007, which represents a $0.01 per gallon increase from $1.26 in the year ended December 31, 2006. One of our new transit customers (Long Island Bus, NY) and one of our new airport customers (Los Angeles International Airport shuttle busses) together accounted for 5.6 million gasoline gallons equivalents of the increase. The remaining increase in gasoline gallon equivalents delivered was due to the addition of other smaller new customers and growth from our existing customers. We recorded $13.2 million of additional revenue related to fuel tax credits in 2007 compared to 2006. The credits first became available in October 2006. We also experienced an increase between periods of $3.2 million in station construction revenue.

Cost of sales. Cost of sales increased by $11.7 million to $85.7 million in the year ended December 31, 2007, from $74.0 million in the year ended December 31, 2006. This increase was primarily the result of an increase in costs related to delivering more CNG and LNG between periods. Also contributing to the increase in cost of sales between periods was a $3.2 million increase in costs related to construction activities during the year ended December 31, 2007. In addition, our cost of sales increased between periods as our effective cost per gallon rose to $1.08 in 2007, which represents a $0.02 per gallon increase over 2006.

Derivative losses. We incurred derivative losses of $79.0 million in the year ended December 31, 2006, primarily related to mark-to-market losses recorded on certain futures contracts related to future periods. 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 $15.0 million to $35.9 million in the year ended December 31, 2007, from $20.9 million in the year ended December 31, 2006. The increase was primarily related to recording an aggregate of $7.4 million of stock option expense in the second, third and fourth quarters of 2007 associated with the stock options we granted to our employees in May 2007, September 2007 and December 2007. There was also an increase of $2.7 million in salaries and benefits between periods primarily related to the increased compensation due to our executive officers and the hiring of additional employees. Our employee headcount increased from 97 at December 31, 2006 to 121 at December 31, 2007. In addition, our travel and entertainment expenses increased $0.6 million between periods, primarily due to increased travel related to our sales team. Our marketing expenses increased $1.3 million between periods, primarily due to certain advertising we conducted related to our refuse market segment and in the Ports of Los Angeles and Long Beach. Our bad debt expense increased $1.1 million between periods as we provided a reserve against loans made to a vehicle manufacturer and two of our vehicle financing customers during 2007. Our professional service fees increased $1.1 million between periods primarily for legal, audit and consulting services related to our status as a public company. Our business insurance costs also increased $0.8 million between periods, primarily due to premium increases in our directors and officers insurance between periods.

Depreciation and amortization. Depreciation and amortization increased by $1.3 million to $7.1 million in the year ended December 31, 2007, from $5.8 million in the year ended December 31, 2006. This increase was primarily related to the result of additional depreciation expense in 2007 related to increased property and equipment balances between periods, primarily related to our expanded station network and fleet of LNG tanker trailers.

Interest income, net. Interest income, net, increased by $2.8 million from $0.7 million in the year ended December 31, 2006, to $3.5 million for the year ended December 31, 2007. This increase was primarily the result of a decrease in interest expense in 2007 due to the conversion of $4 million of convertible notes in April 2007, which eliminated the interest expense on these notes. In addition, interest income in 2007 increased in comparison to 2006 due to higher average cash balances on hand in 2007 associated with the proceeds received from our initial public offering in May 2007.

Other expense, net. Other expense, net, was $192,000 in the year ended December 31, 2007, as compared to $255,000 in the year ended December 31, 2006. In 2006, costs related to station closures were higher due to the closing of six CNG stations in Canada.

Seasonality and Inflation

To some extent, we experience seasonality in our results of operations. Natural gas vehicle fuel 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 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.

Liquidity and Capital Resources

Historically, our principal sources of liquidity have consisted of cash provided by operations and financing activities, cash and cash equivalents, the issuance of common stock, sometimes in association with the exercise of certain warrants that were callable at our option, and in 2006 a revolving line of credit with Boone Pickens, our majority stockholder. 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 PlainsCapital Bank pursuant to which we borrowed $18.0 million under a term loan and an additional $4.8 million (as of December 31, 2008) 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 (See note 9 to the accompanying consolidated financial statements for a discussion of the transaction) and we raised net proceeds of approximately $32.5 million after deducting offering costs.

In addition to funding operations, our principal uses of cash have been, and are expected to be, the construction of new fueling stations, the construction of our new LNG liquefaction plant in California, the purchase of new LNG tanker trailers, 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, our support for Proposition 10 and for working capital for our expansion. We may also seek to acquire companies or assets in the natural gas fueling infrastructure, services and production industries. We financed our operations in 2008 primarily through cash on hand.

At December 31, 2008, we had total cash and cash equivalents of $36.3 million compared to $67.9 million at December 31, 2007. We did not have any short-term investments at December 31, 2008 as we sold them all in 2008. We had $12.5 million of short-term investments at December 31, 2007.

Cash used in operating activities was $2.1 million for the year ended December 31, 2008, compared to cash provided by operating activities of $7.1 million for the year ended December 31, 2007. This decrease in operating cash flow was primarily related to an increase in our net loss between periods, which included $18.6 million of expenditures to support Proposition 10 in 2008. We also made $1.1 million of deposits on our futures contracts in 2008. Offsetting these decreases was a $23.8 million increase between periods related to returns of LNG truck deposits. 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 $92.3 million for the year ended December 31, 2008, compared to $50.6 million for the year ended December 31, 2007. Our purchases of property and equipment were $78.0 million during 2008. Included in purchases of property and equipment in 2008 was $49.1 million of construction costs related to our LNG liquefaction plant in California. In 2007, we purchased $12.5 million of short-term investments with our initial public offering proceeds from May 2007. In 2008, all of our short-term investments were sold or matured resulting in net cash proceeds of $12.5 million. In August 2008, we purchased a 70% interest in DCE and our total cash outlay for the acquisition including transaction costs was approximately $19.3 million, net of cash acquired. We also made an investment during 2008 of $4.6 million in the Vehicle Production Group, LLC, a company developing a CNG taxi and a paratransit vehicle, and transferred $2.5 million of our cash balance to a restricted account in accordance with our August 2008 credit agreement with PlainsCapital Bank.

Cash provided by financing activities for the year ended December 31, 2008 was $62.7 million, compared to cash provided by financing activities of $110.5 million for the year ended December 31,

2007. In May 2007, we completed our initial public offering, which raised $110.2 million during 2007. In August 2008, we borrowed $22.8 million to fund the acquisition of our interest in DCE, and to pay other amounts related to the transaction. In September 2008, we issued and sold 319,488 shares of our common stock for an aggregate purchase price of approximately $5.0 million to Boone Pickens. In addition, in November 2008, we issued and sold to third-party investors 4,419,192 units of common stock and warrants (consisting of an aggregate of 4,419,492 shares of common stock, Series I Warrants to purchase up to an aggregate of 3,314,394 shares of common stock, and Series II Warrants to purchase up to an aggregate of 1,136,364 shares of common stock) and we raised net proceeds of approximately $32.5 million after deducting offering costs. In December 2008, we executed capital leases for equipment at two fueling station locations and raised $2.4 million. We had paid for the equipment throughout 2008 before executing the capital leases.

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, and our capital expenditure requirements, which consist primarily of station construction, LNG plant construction and maintenance costs, and the purchase of LNG tanker trailers and equipment.

Capital Expenditures

Our current business plan calls for approximately $31.6 million in capital expenditures in 2009, primarily related to construction of new fueling stations. In addition, we anticipate that during 2009 we will provide approximately $2.0 million for financing natural gas vehicle purchases by our customers and up to $6.2 million in financing that we may be required to provide to the Vehicle Production Group LLC, a company that is developing CNG paratransit vehicles and taxis. Through March 13, 2009, we have provided our joint-venture subsidiary DCE with approximately $4.4 million in financing under our loan agreement with DCE and we anticipate that we will provide up to approximately $2.9 million in additional loan financing to DCE during the remainder of 2009 for additional capital expenditures and expenses. Financing provided to DCE is not included in our 2009 capital expenditure business plan and we anticipate that we will fund all additional financing we provide to DCE through our $12.0 million Facility B loan with PlainsCapital Bank, which has approximately $4.1 million in remaining available credit as of March 13, 2009. We intend to fund our principal liquidity requirements, other than our loan to DCE, through cash and cash equivalents and cash provided by operations; however, we may pursue station construction opportunities that are not currently under contract or in our 2009 capital expenditure plan or seek to acquire or invest in companies or assets in the natural gas fueling infrastructure, services and production industries. We may also decide to invest in expanding our California LNG plant or other LNG production assets. We will need to raise additional capital as necessary to fund any such acquisitions, strategic transactions, increases in station construction activity, expansion of our California LNG plant or other unanticipated capital expenditures. If we do need to raise additional capital, the timing and necessity of any future capital raise will depend primarily on our rate of new station construction and the decision on when we need to expand our California LNG plant. 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 and invest in strategic transactions or acquisitions and reduce our ability to invest in our business and generate increased revenues.

Our credit agreement with PlainsCapital Bank requires that we comply with certain covenants, as detailed in footnote 8 of our financial statements. One of the covenants requires that we maintain accounts receivable balances from certain subsidiaries above $10.0 million at each month-end during the term. To the extent natural gas prices continue to fall, which would result in decreased revenues, or our volumes sold decline, we could violate this covenant in the future. In this event, we would seek a waiver from the bank, which the bank is not obligated to grant. If the bank does not grant the waiver, all of the obligations under the credit agreement will become immediately due and payable and $2.5 million of our funds held by PlainsCapital Bank would be applied to the balance due on the PlainsCapital Bank loans. We also would be unable to use the PlainsCapital line of credit to fund our loan to DCE if this were to occur. We were in compliance with all of the covenants as of January 31, 2009.

Contractual Obligations

The following represents the scheduled maturities of our contractual obligations as of December 31, 2008:

	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)]	$30,624,058	$ 3,608,866	$ 6,538,240	$19,882,602	$ 594,350
Operating lease commitments[(b)]	16,288,001	1,865,597	3,501,055	3,222,281	7,699,068
"Take or pay" LNG purchase contracts[(c)]	5,113,500	2,121,000	2,992,500	0	0
Construction contracts[(d)]	6,571,735	6,571,735	0	0	0
Other long-term contract liabilities[(e)]	2,247,209	2,247,209	0	0	0
Total	$60,844,503	$16,414,407	$13,031,795	$23,104,883	$8,293,418

(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 not reflected in the table above because the obligation is contingent on the completion of construction of the LNG plant, which is anticipated to occur in the second quarter of 2009.

(d) Consists of our obligations to fund various fueling station construction projects, net of amounts funded through December 31, 2008, and excluding contractual commitments related to station sales contracts.

(e) Consists of our obligations to fund certain vehicles under binding purchase agreements and our commitments under binding purchase agreements and contracts we have entered into to acquire certain equipment and services related to the construction of our LNG plant in California.

Off-Balance Sheet Arrangements

At December 31, 2008, we had the following off-balance sheet arrangements that had, or are reasonably likely to have, a material affect on our financial condition.

- outstanding surety bonds for construction contracts and general corporate purposes totaling $10.1 million,

- two take-or-pay contracts for the purchase of LNG,
- operating leases where we are the lessee,
- capital leases where we are the lessor and owner of the equipment, and
- firm commitments to sell CNG and LNG at fixed prices or index-plus prices subject to a price cap.

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 contracts with two vendors to purchase LNG that require us to purchase minimum volumes from the vendors. One of the contracts expires in March 2009 and the other contract expires in June 2011. The minimum commitments under these two contracts are 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 not included in the table above as it is contingent on the LNG plant being constructed. We anticipate construction of the plant will be completed in the second quarter of 2009.

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 are building an LNG liquefaction plant. The lease is for an initial term of 30 years, beginning on the date that the plant commences operations, and requires annual base rent 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 for certain other services that the landlord will provide. Commercial operations began December 1, 2008, and the 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. The leases generally qualify as sales-type leases for accounting purposes, which result in our customers, the lessees, reflecting the property and equipment on their balance sheets.

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 58% of our cost of sales for 2007 and 60% of our cost of sales for 2008. Prices for natural gas over the eight-year period from December 31, 1999 through December 31, 2008, based on the NYMEX daily futures data, has ranged from a low of $1.65 per Mcf to a high of $19.38 per Mcf. At December 31, 2008, the NYMEX index price of natural gas was $6.90 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 SFAS 133. Under this standard, the accounting for changes in the fair value of a derivative depends upon whether it has been designated 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 SFAS 133 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 supply 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 changing market conditions. The net effect of the realized and unrealized gains and losses related to these derivative instruments for the year ended December 31, 2006 was a $79.0 million decrease to pre-tax income. 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 SFAS 133, 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 futures contracts we hold as of December 31, 2008 to hedge the fixed-price component of two LNG 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, 2008 ($6.90 per Mcf), we could expect a corresponding fluctuation in the value of the contracts of approximately $0.1 million.

We have also prepared a sensitivity analysis to estimate our exposure to market risk with respect to our fixed price and price cap sales contracts as of December 31, 2008 where we do not have an underlying futures contract. Market risk is estimated as the potential loss resulting from a hypothetical 10.0% adverse change in the fair market value of natural gas prices. The results of this analysis, which assumes natural gas prices are in excess of our customer's price cap arrangements, and may differ from actual results, are as follows:

	Hypothetical adverse change in price	Change in annual pre-tax income
		(in millions)
Fixed price contracts	10.0%	$(0.2)
Price cap contracts	10.0%	$(0.2)

This table does not include two 2.1 million LNG gallon per year renewal options beginning April 1, 2009, that one of our customers possesses related to an LNG price cap contract. Had the contract been included, assuming both renewal options were exercised, the resulting amount for the price cap contracts would be $(0.4) 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, 2008. The information for each quarter is unaudited and the Company has prepared it 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, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Revenue:				
Product revenues	$27,204,073	$29,647,585	$ 28,102,850	$ 28,723,622
Service revenues	962,971	1,016,012	1,107,314	951,806
Total revenues	28,167,044	30,663,597	29,210,164	29,675,428
Operating expenses:				
Cost of sales:				
Product cost of sales	21,122,483	22,247,493	19,989,466	21,231,755
Service cost of sales	198,676	279,069	263,278	328,109
Selling, general and administrative	6,299,878	10,440,718	9,528,605	9,664,493
Depreciation and amortization	1,576,057	1,700,164	1,814,176	2,017,545
Total operating expenses	29,197,094	34,667,444	31,595,525	33,241,902
Operating income (loss)	(1,030,050)	(4,003,847)	(2,385,361)	(3,566,474)
Interest income (expense), net	292,212	546,750	1,414,120	1,252,515
Other income (expense), net	(123,372)	(55,805)	(50,000)	36,830
Income (loss) before income taxes	(861,210)	(3,512,902)	(1,021,241)	(2,277,129)
Income tax (expense) benefit	(8,969)	(50,000)	(523,729)	(639,182)
Net income (loss)	$ (870,179)	$ (3,562,902)	$ (1,544,970)	$ (2,916,311)
Basic earnings (loss) per share	$ (0.03)	$ (0.09)	$ (0.03)	$ (0.07)
Fully diluted earnings (loss) per share	$ (0.03)	$ (0.09)	$ (0.03)	$ (0.07)

	For the Quarter Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Revenue:				
Product revenues	$28,960,706	$33,514,614	$ 33,390,485	$ 27,900,990
Service revenues	986,651	1,087,367	1,883,202	1,748,518
Total revenues	29,947,357	34,601,981	35,273,687	29,649,508
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	—	(5,706,981)	6,047,727	270,429
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 income (loss)	(6,117,458)	(2,628,220)	(10,593,534)	(22,606,241)
Interest income (expense), net	839,216	265,347	78,399	447,474
Other income (expense), net	38,356	1,622	(28,801)	(180,336)
Equity in gains (losses) of equity method investee	(145,046)	4,724	19,881	(67,745)
Income (loss) before income taxes	(5,384,932)	(2,356,527)	(10,524,055)	(22,406,848)
Income tax (expense) benefit	(43,767)	(56,203)	(99,171)	(90,000)
Minority interest in net income	—	—	(13,920)	118,749
Net income (loss)	$(5,428,699)	$(2,412,730)	$(10,637,146)	$(22,378,099)
Basic earnings (loss) per share	$ (0.12)	$ (0.05)	$ (0.24)	$ (0.47)
Fully diluted earnings (loss) per share	$ (0.12)	$ (0.05)	$ (0.24)	$ (0.47)

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, 2007 and 2008, and the related consolidated statements of operations, stockholders' equity and comprehensive (loss) income, and cash flows for each of the years in the three-year period ended December 31, 2008. 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, 2008, 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 audit 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 consolidated 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 audit 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, 2007 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, 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, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2007, the Company changed its method of accounting for uncertain tax positions as required by Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*.

/s/ KPMG LLP

Los Angeles, California
March 13, 2009

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Balance Sheets

	December 31, 2007	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 67,937,602	$ 36,284,431
Restricted cash	—	2,500,000
Short-term investments	12,479,684	—
Accounts receivable, net of allowance for doubtful accounts of $501,751 and $657,734 as of December 31, 2007 and 2008, respectively	11,026,890	10,530,638
Other receivables	23,153,904	12,995,507
Inventory, net	2,403,890	3,110,731
Deposits on LNG trucks	15,515,927	6,197,746
Prepaid expenses and other current assets	3,633,318	3,542,387
Total current assets	136,151,215	75,161,440
Land, property and equipment, net	88,676,318	160,593,665
Capital lease receivables	763,500	364,500
Notes receivable and other long term assets	2,126,007	7,176,755
Investments in other entities	385,806	4,879,604
Goodwill	20,797,878	20,797,878
Intangible assets, net of accumulated amortization	124,220	21,400,558
	$249,024,944	$ 290,374,400
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$ 63,520	$ 2,232,875
Accounts payable	10,547,451	14,276,591
Accrued liabilities	5,381,541	6,647,454
Deferred revenue	677,826	1,060,582
Total current liabilities	16,670,338	24,217,502
Long-term debt and capital lease obligations, less current portion	161,377	22,850,927
Other long-term liabilities	1,260,755	2,297,446
Total liabilities	18,092,470	49,365,875
Commitments and contingencies		
Minority interest in subsidiary	—	3,625,922
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 44,274,375 shares and 50,238,212 shares at December 31, 2007 and 2008, respectively	4,428	5,024
Additional paid-in capital	297,866,745	346,466,999
Accumulated deficit	(69,086,583)	(109,943,257)
Accumulated other comprehensive income	2,147,884	853,837
Total stockholders' equity	230,932,474	237,382,603
	$249,024,944	$ 290,374,400

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries
Consolidated Statements of Operations

	Years Ended December 31,		
	2006	2007	2008
Revenue:			
Product revenues	$ 88,240,252	$113,678,130	$123,766,795
Service revenues	3,307,064	4,038,103	5,705,738
Total revenue	91,547,316	117,716,233	129,472,533
Operating expenses:			
Cost of sales:			
Product cost of sales	73,390,329	84,591,197	97,014,917
Service cost of sales	657,572	1,069,132	1,752,668
Derivative losses	78,994,947	—	611,175
Loss on extinguishment of derivative liability	2,142,095	—	—
Selling, general and administrative	20,860,181	35,933,694	62,415,554
Depreciation and amortization	5,765,001	7,107,942	9,623,672
Total operating expenses	181,810,125	128,701,965	171,417,986
Operating loss	(90,262,809)	(10,985,732)	(41,945,453)
Interest income, net	746,339	3,505,597	1,630,436
Other expense, net	(255,479)	(192,347)	(169,159)
Equity in losses of equity method investee	—	—	(188,186)
Loss before income taxes	(89,771,949)	(7,672,482)	(40,672,362)
Income tax (expense) benefit	12,271,208	(1,221,880)	(289,141)
Minority interest in net income	—	—	104,829
Net loss	$(77,500,741)	$ (8,894,362)	$(40,856,674)
Loss per share:			
Basic	$ (2.45)	$ (0.22)	$ (0.90)
Diluted	$ (2.45)	$ (0.22)	$ (0.90)
Weighted average common shares outstanding:			
Basic	31,676,399	40,258,440	45,367,991
Diluted	31,676,399	40,258,440	45,367,991

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	Total Stockholders' Equity	Total Comprehensive Income (Loss)
	Shares	Amount					
Balance, December 31, 2005	25,558,114	$2,556	$ 74,755,049	$ 17,308,520	$1,423,743	$ 93,489,868	
Issuance of common stock upon exercise of warrants	7,094,594	709	20,999,288	—	—	20,999,997	
Issuance of common stock upon exercise of options	359,500	36	994,676	—	—	994,712	
Conversion of debt	1,179,953	118	4,022,522	—	—	4,022,640	
Assumption of derivative contract obligations by shareholder and issuance of warrant	—	—	80,854,694	—	—	80,854,694	
Stock-based compensation	—	—	52,632	—	—	52,632	
Foreign currency translation adjustment	—	—	—	—	2,055	2,055	$ 2,055
Net loss	—	—	—	(77,500,741)	—	(77,500,741)	(77,500,741)
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)	—	—	—	
Stock-based compensation	—	—	10,735,861	—	—	10,735,861	
Net loss	—	—	—	(40,856,674)	—	(40,856,674)	(40,856,674)
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	$(109,943,257)	$ 853,837	$237,382,603	$(42,150,721)

See accompanying notes to consolidated financial statements.

Clean Energy Fuels Corp. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2006	2007	2008
Cash flows from operating activities:			
Net loss	$(77,500,741)	$ (8,894,362)	$(40,856,674)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation and amortization	5,765,001	7,107,942	9,623,672
Provision for doubtful accounts and notes	230,486	1,309,428	528,885
Unrealized loss on futures contracts	8,956,599	—	—
Loss on extinguishment of derivative liability	2,142,095	—	—
Loss on disposal of assets	362,653	237,783	170,781
Deferred income taxes	(7,020,994)	—	—
Non-cash derivative contract loss	78,712,599	—	—
Stock option expense	52,632	7,370,874	10,735,861
Common stock issued in exchange for services	—	—	30,000
Minority interest in net income	—	—	(104,829)
Changes in operating assets and liabilities, net of assets and liabilities acquired:			
Accounts and other receivables	(35,273,741)	13,313,304	11,224,221
Inventory	(610,781)	154,799	(706,841)
Capital lease receivables	649,000	649,000	399,000
Margin deposits on futures contracts	196,600	—	(1,114,227)
Deposits on LNG trucks	(975,620)	(14,540,307)	9,318,181
Prepaid expenses and other assets	(2,354,700)	(1,942,715)	(3,800,121)
Accounts payable	(3,433,773)	1,556,817	445,361
Income taxes payable	(6,761,739)	—	—
Accrued expenses and other	253,001	778,543	2,030,827
Net cash provided by (used in) operating activities	(36,611,423)	7,101,106	(2,075,903)
Cash flows from investing activities:			
Purchases of property and equipment	(12,414,066)	(38,082,456)	(78,031,747)
Proceeds from sale of property and equipment	—	—	386,502
Purchase 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)
Acquisition, net of cash acquired	—	—	(19,274,948)
Investments in other entities	—	—	(4,616,283)
Restricted cash deposits	—	—	(2,500,000)
Net cash used in investing activities	(12,414,066)	(50,562,140)	(92,271,162)
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	21,994,709	110,518,690	5,350,610
Proceeds from long-term debt	—	—	22,828,425
Proceeds from capital leases	—	—	2,410,423
Repayment of capital lease obligations and long-term debt	(795,220)	(57,499)	(379,943)
Net cash provided by financing activities	21,199,489	110,461,191	62,693,894
Net increase (decrease) in cash	(27,826,000)	67,000,157	(31,653,171)
Cash, beginning of year	28,763,445	937,445	67,937,602
Cash, end of year	$ 937,445	$ 67,937,602	$ 36,284,431
Supplemental disclosure of cash flow information:			
Income taxes paid	$ 6,318,954	$ 1,214,464	$ 149,219
Interest paid	$ 1,414,908	$ 27,038	$ 449,187
Non-cash financing activities:			
Margin deposits directly advanced by majority stockholder to broker under line of credit	$ 69,500,000	$ —	$ —
Extinguishment of line of credit in exchange for rights to margin deposits	$(69,500,000)	$ —	$ —

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 or supplies approximately 175 fueling locations in California, Texas, Colorado, Maryland, New York, New Mexico, Nevada, Washington, Massachusetts, Georgia, Wyoming, Arizona, Ohio and Alabama 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 landfill gas in Dallas, Texas.

(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.

(d) Recently Issued Accounting Pronouncements

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 141(R), *Business Combinations* (SFAS 141(R)). SFAS 141(R) provides new accounting guidance and disclosure requirements for business combinations. SFAS 141(R) is effective for business combinations which occur in the first fiscal year beginning on or after December 15, 2008. The adoption of SFAS 141(R) did not have a material impact on the Company's financial statements.

(1) Summary of Significant Accounting Policies (Continued)

In December 2007, the FASB issued Statement of Financial Accounting Standard No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* (SFAS 160). SFAS 160 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 non-controlling 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 will be accounted for through earnings. SFAS 160 is effective the first fiscal year beginning on or after December 31, 2008. The adoption will impact the classification of minority interest on the Company's income statement and balance sheet, but the Company does not anticipate that the adoption of this statement will have a material impact on its consolidated financial position or results of operations when it becomes effective.

In March 2008, the FASB issued Statement of Financial Accounting Standards No. 161, *"Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133"* (SFAS 161). SFAS 161 amends and expands the disclosure requirements of FASB Statement No. 133 (SFAS 133), requiring 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 under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect the Company's financial position, results of operations, and cash flows. SFAS 161 is effective prospectively, with comparative disclosures of earlier periods encouraged upon initial adoption. SFAS 161 is effective for financial statements issued for fiscal years beginning after November 15, 2008 and interim periods within those fiscal years. The Company does not anticipate that the adoption of this statement will have a material impact on its consolidated financial statements.

In April 2008, the FASB issued FASB Staff Position No. FAS 142-3, *Determination of the Useful Life of Intangible Assets* (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, *Goodwill and Other Intangible Asset.* More specifically, FSP FAS 142-3 removes the requirement under paragraph 11 of SFAS 142 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. FSP FAS 142-3 also requires expanded disclosure related to the determination of intangible asset useful lives. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 31, 2008, and interim periods within those fiscal years. Early adoption is not permitted. The Company does not anticipate that the adoption of this statement will have a material impact on its consolidated financial statements.

In June 2008, the Emerging Issues Task Force (EITF) reached a consensus in EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity's Own Stock* (EITF No. 07-5). The Task Force 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. As discussed in note 9, the Company issued Series I warrants on October 28, 2008 that are linked to an entity's own equity shares; however, the investor has

(1) Summary of Significant Accounting Policies (Continued)

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 will account for the Series I warrants as a derivative under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133). The consensus is effective for fiscal years beginning after December 15, 2008, and will be initially applied by recording a cumulative-effect adjustment to opening retained earnings at the date of adoption.

(e) Recently Adopted Accounting Changes

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), which prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position 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. Clean Energy adopted FIN 48 on January 1, 2007. The adoption of FIN 48 did not have a material impact on its financial statements.

On January 1, 2008, the Company adopted the applicable provisions of SFAS No. 157, *Fair Value Measurements* (SFAS 157), 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 SFAS 157 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's adoption of SFAS 157 was limited to financial assets and liabilities.

During the year ended December 31, 2008, the Company's financial instruments have consisted of short-term investments and natural gas futures contracts. The Company uses quoted market prices to measure fair value of its short-term investments. The Company uses quoted forward price curves, discounted to reflect the time value of money, to value its natural gas futures contracts. At December 31, 2008, the Company did not have any short-term investments and its futures contracts are recorded in accrued liabilities in the accompanying consolidated balance sheet at December 31, 2008.

SFAS 157 includes a fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The fair value hierarchy is based on inputs to valuation techniques that are used to measure fair value that are either observable or unobservable. Observable inputs reflect assumptions market participants would use in pricing an asset or liability based on market data obtained from independent sources while unobservable inputs reflect a reporting entity's pricing based upon their own market assumptions. SFAS 157 establishes a three-tiered fair value hierarchy which prioritizes the inputs used in measuring fair value as follows:

- *Level 1.* Observable inputs such as quoted prices in active markets;
- *Level 2.* Inputs, other than quoted prices, that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active; and
- *Level 3.* Unobservable inputs in which there is little or no market data, which require the reporting entity to develop its own assumptions.

(1) Summary of Significant Accounting Policies (Continued)

The following table reflects the fair value as defined by SFAS 157, of the Company's natural gas futures contracts at December 31, 2008:

	Balance at December 31, 2008	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 obligation . .	$654,483	$—	$654,483	$—

In June 2006, the FASB ratified its consensus on EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement* (EITF 06-3). The scope of EITF 06-3 includes any tax assessed by a governmental authority that is imposed concurrent with or subsequent to a revenue-producing transaction between a seller and a customer and excludes taxes that are assessed on gross receipts or that are an inventoriable cost. For taxes within the scope of this issue that are significant in amount, the consensus requires the following disclosures: (i) the accounting policy elected for these taxes and (ii) the amount of the taxes reflected gross in the income statement on an interim and annual basis for all periods presented. The consensus was effective for the Company on January 1, 2007. The Company has presented sales taxes and excise taxes on sales to its customers on a net basis in its financial statements both prior to and subsequent to the adoption of EITF 06-3.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). SFAS 159 permits entities to choose to measure certain financial instruments and other eligible items at fair value when the items are not otherwise currently required to be measured at fair value. Under SFAS 159, the decision to measure items at fair value is made at specified election dates on an irrevocable instrument-by-instrument basis. Entities electing the fair value option would be required to recognize changes in fair value in earnings and to expense upfront costs and fees associated with the item for which the fair value option is elected. Entities electing the fair value option are required to distinguish, on the face of the statement of financial position, the fair value of assets and liabilities for which the fair value option has been elected and similar assets and liabilities measured using another measurement attribute. The adoption of SFAS 159 did not have a material impact on the Company's financial statements.

(f) Foreign Currency Translation

The Company follows the principles of Statement of Financial Accounting Standards No. 52, *Foreign Currency Translation,* using 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 $26,540, $10,286 and $8,766 in 2006, 2007 and 2008, respectively. The functional currency for the Company's subsidiary in Canada is the Canadian dollar.

(1) Summary of Significant Accounting Policies (Continued)

The accompanying consolidated balance sheets include total assets of the Canadian subsidiary of $5,851,602 and $2,529,011 expressed in U.S. dollars, as of December 31, 2007 and 2008, respectively. Sales made by the Canadian subsidiary totaled $2,550,066, $1,360,593 and $1,020,040 in U.S. dollars for the years ended December 31, 2006, 2007 and 2008, respectively.

(g) 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.

(h) 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.

(i) Inventories

Parts inventories, which consist of spare parts for service of fueling locations, are stated at the lower of cost or market on a first-in, first-out basis. 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.

(j) 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, 2006, 2007 and 2008.

Advertising costs are expensed as incurred. Advertising costs amounted to approximately $560,000, $1,316,000 and $985,000 for the years ended December 31, 2006, 2007 and 2008, respectively. During 2008, the Company also spent $18.6 million in support of Proposition 10 on the California ballot in November 2008.

(k) 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 20-30 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 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

(1) Summary of Significant Accounting Policies (Continued)

proceeds received were approximately $775,000, $300,000 and $384,000 for the years ended December 31, 2006, 2007 and 2008, respectively.

(l) 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.

(m) 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 the provisions of SFAS No. 142, *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, which could occur during the current economic contraction, 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 to their estimated residual values, and reviewed for impairment in accordance with SFAS No. 144, *Accounting for Impairment or Disposal of Long-Lived Assets*. Amortization expense for intangible assets was $35,491, $35,491 and $534,979 for the years ended December 31, 2006, 2007 and 2008, respectively. Estimated amortization expense for the five years succeeding the year ended December 31, 2008 is approximately $1.3 million in each year. Accumulated amortization at December 31, 2007 and 2008 was $729,446 and $1,264,425, respectively.

(n) 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 $164,441 and $411,060 is included in other long-term liabilities, with the remaining current portion included in accrued liabilities, at December 31, 2007 and 2008, respectively:

	2007	2008
Beginning balance	$170,012	$224,455
Liabilities incurred	53,584	267,524
Liabilities settled	(6,185)	(13,349)
Accretion expense	7,044	10,055
Ending balance	$224,455	$488,685

(o) Stock-Based Compensation

Effective January 1, 2006, the Company adopted FASB Statement No. 123(R), *Share-Based Payment* (SFAS No. 123(R)). This statement replaced SFAS No. 123 and superseded APB No. 25. SFAS No. 123(R) and requires that all stock-based compensation be recognized as an expense in the financial statements and that such cost be measured at the fair value of the award. SFAS No. 123(R) was adopted using the modified prospective method of application, which requires the Company to recognize compensation expense on a prospective basis. Therefore, prior years' financial statements have not been restated. For stock-based awards granted after January 1, 2006, the Company recognizes compensation expense based on estimated grant-date fair value using the Black-Scholes option-pricing model.

(p) Revenue Recognition

Revenue from the sale of natural gas and from operations and maintenance agreements is recognized in accordance with SEC Staff Accounting Bulletin No. 104, *Revenue Recognition*, which is 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 the guidance set forth in EITF No. 00-21, 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 SFAS No. 13, *Accounting for Leases*. 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.

(1) Summary of Significant Accounting Policies (Continued)

The Company has evaluated the relative fair values of the deliverables for the one station that it sold during 2006, three stations that it sold in 2007, and the two stations it sold in 2008, 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. Additionally, the Company sold one station during 2007 and two stations in 2008 that was not part of a multi-deliverable contract and recognized the associated revenue and costs during the period.

Revenue on construction contracts has been recognized using the completed contract method in accordance with AICPA Statement of Position 81-1, *Accounting for Performance of Construction Type and Certain Production Type Contracts.*

(q) 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.

(r) 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 2006, 2007 and 2008 were $3.8 million, $17.0 million, and $20.8 million, respectively.

(s) 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.

(t) Derivative Financial Instruments and Long Term Sales Commitments

The Company, in an effort to manage its natural gas commodity price risk exposures, 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 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. SFAS No. 133 requires the recognition of all derivatives as either assets or liabilities in the

(1) Summary of Significant Accounting Policies (Continued)

consolidated balance sheet and the measurement of those instruments at fair value. The Company's derivative instruments did not qualify for hedge accounting under SFAS No. 133 for the years ended December 31, 2005 and 2006. As such, changes in the fair value of the derivatives were recorded directly to the consolidated statements of operations. The Company did not have any derivative instruments during the year ended December 31, 2007. During 2008, the Company had certain contracts that did qualify for hedge accounting and certain contracts that did not qualify.

The Company enters into contracts with various customers, primarily municipalities, to sell LNG or CNG at fixed prices or at prices subject to a price cap. The contracts generally range from two to five years. The most significant cost component of LNG and CNG is the price of natural gas. Historically, the Company has entered into these contracts with its customers and then sold the underlying futures contract prior to the expiration of the customer's sales 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 customers do not agree to purchase a minimum amount of volume or guarantee their volume of purchases. Rather, 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 guidance in SFAS No. 133.

The Company's agreements to 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 a difference between the fixed price of the natural gas included in the customer's contract and the corresponding index price of natural gas typically develops after the Company enters into the contract. During 2003 to 2007, the Company entered into several contracts to sell LNG or CNG to customers at a fixed price or an index-based price that is subject to a fixed price cap and subsequently sold the underlying futures contract prior to the expiration of the customer's sales contract. During these times, the price of natural gas generally increased. From an accounting perspective, during the periods of rising natural gas prices (when the Company conducted the majority of its hedging activities), the Company's futures contracts were generally 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 for the increased market price of natural gas above the cost of natural gas included in the Company's sales price to its customers under these contracts. As a result, 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) (see note 18).

(1) Summary of Significant Accounting Policies (Continued)

(u) 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) LNG Plant Purchase

On November 28, 2005, the Company purchased an LNG liquefaction plant, which it renamed the Pickens Plant, including the inventory located in the storage tank at the plant, five LNG trailers, and certain station equipment for approximately $14,800,000. The Company accounted for the acquisition as an asset purchase in which the Company allocated the entire purchase price to the assets acquired based on their respective fair values.

(3) Acquisition

On August 15, 2008, Clean Energy and Cambrian Energy McCommas Bluff LLC ("Cambrian") formed a joint venture to acquire all of the outstanding membership interests of Dallas Clean Energy, LLC ("DCE") which owns a facility that collects, processes and sells landfill gas at the McCommas Bluff landfill located in Dallas, Texas. This acquisition enables Clean Energy 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. Of the purchase price, $1.0 million was deposited into a third-party escrow as security for indemnification claims. The amount remaining in the escrow will be released to the sellers on August 15, 2009, except for amounts subject to pending indemnification claims, if any.

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 to finance its acquisition of its membership interests in DCE. The Company also obtained a $12.0 million line of credit from PlainsCapital Bank 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 PlainsCapital Bank loan. As of December 31, 2008, the Company had borrowed $4.8 million under the line of credit (see note 8).

The Company accounted for the acquisition in accordance with SFAS No. 141, *Business Combinations.* The Company has completed a preliminary allocation of the purchase price. Such allocation and amounts may change as management finalizes its analyses. The assets acquired and liabilities assumed were recorded at their estimated fair values at the acquisition date. The following

(3) Acquisition (Continued)

table summarizes the preliminary allocation of the aggregate purchase price to the fair value of the assets acquired and liabilities assumed, net of Cambrian's minority 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)
Minority interest	(3,730,751)
Total purchase price	$19,550,624

Management preliminarily allocated approximately $21.8 million to the identifiable intangible asset related to the fair value of DCE's landfill lease with the City of Dallas that was acquired with the acquisition. 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. The pro-forma effect of the acquisition is not material to the Company's results of operations for the years ended December 31, 2007 and 2008.

(4) Other Receivables

Other receivables at December 31, 2007 and 2008 consisted of the following:

	2007	2008
Loans to customers to finance vehicle purchases	$ 1,393,549	$ 1,983,414
Advances to vehicle manufacturers	4,871,373	4,510,386
Fuel tax credits	14,920,145	5,511,908
Other	1,968,837	989,799
	$23,153,904	$12,995,507

(5) Land, Property and Equipment

Land, property and equipment at December 31, 2007 and 2008 are summarized as follows:

	2007	2008
Land	$ 472,616	$ 472,616
LNG liquefaction plants	12,898,178	88,366,069
Station equipment	48,318,709	57,994,315
LNG trailers	11,698,145	11,863,681
Other equipment	6,937,083	11,533,656
Construction in progress	32,297,191	22,439,115
	112,621,922	192,669,452
Less accumulated depreciation	(23,945,604)	(32,075,787)
	$ 88,676,318	$160,593,665

(6) Investment in Other Entities

In 2008, the Company invested approximately $4.6 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 million in VPG from August 2008 through March 2010. $7.5 million is a firm commitment by the Company, and $2.5 million is contingent on VPG not being able to raise money on more-favorable terms than the funding from the original investor group. In addition, 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.

On August 27, 2008, a subsidiary of the Company converted outstanding commercial loans previously made to Bachman NGV, Inc. (BAF), a natural gas vehicle conversion company, into a secured convertible promissory note (the Note) that is convertible into equity interests in BAF. The Note is convertible at the Company's option after August 27, 2009 and may be converted earlier upon an acquisition of BAF. As of December 31, 2008, the $3.6 million outstanding under the Note would convert into approximately 47% of the outstanding equity interests of BAF if fully converted. The Company may, at the Company's discretion, advance up to $2.4 million in additional funds to BAF under the Note. The Note bears interest at 5% per annum and is due August 30, 2010.

(7) Accrued Liabilities

Accrued liabilities at December 31, 2007 and 2008 consisted of the following:

	2007	2008
Salaries and wages	$1,495,196	$ 568,760
Accrued gas purchases	1,837,005	777,086
Obligation under derivative liabilities	—	654,483
Accrued professional fees	454,961	1,230,958
Accrued employee benefits	317,798	434,788
Other	1,276,581	2,981,379
	$5,381,541	$6,647,454

(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 PlainsCapital Bank. 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 PlainsCapital Bank to finance capital improvements of the DCE processing facility and to pay certain costs and expenses related to the acquisition and the PlainsCapital Bank loans (the "Facility B Loan"). As of December 31, 2008, the Company had borrowed $4.8 million under the Facility B Loan. The Company may request funds up to $12.0 million under the Facility B Loan through August 14, 2009. Interest accrues daily on the Facility A and B Loans at the greater of the prime rate of interest for the United States plus 0.50% per annum or 5.50% per annum. The Company paid a facility fee of $300,000 in connection with the Credit Agreement. As of December 31, 2008, the unamortized balance of the facility fee was $277,500. Amortization of the facility fee is recorded as additional interest expense in the consolidated statements of operations.

The Facility A Loan is due in level payments of principal and interest based on a 14 year amortization period. Payments of principal and interest are due on the 15th of each month until August 15, 2013, at which time the remaining amount of the unpaid principal and interest on the Facility A Loan is due and payable.

Interest on the unpaid principal balance of the Facility B Loans is due and payable quarterly commencing on September 30, 2008. The principal amount of the Facility B Loans 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 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 Loans is due and payable.

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 minimum liquidity of not less than $6.0 million at each quarter end beginning December 31, 2008, maintain an accounts receivable balance, as defined, at each month end of not less than $10.0 million beginning August 31, 2008, maintain 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 at each quarter end beginning September 30, 2008, and a debt service ratio, as defined, of not less than

(8) Long-term Debt (Continued)

1.5 to 1 for each quarterly period beginning June 30, 2009. 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 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 Facility A and B Loans. One of the events of default is the occurrence of a "material adverse change," which is a subjective acceleration clause. Based on the guidance in Emerging Issues Tax Force Issue No. 95-22 *Balance Sheet Classification of Borrowings Outstanding under Revolving Credit Agreements That Include both a Subjective Acceleration Clause and a Lock-Box Arrangement* (EITF No. 95-22), 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. The Company is in compliance with the covenants as of December 31, 2008.

One of the Company's bank covenants is a requirement to maintain accounts receivable balances from certain subsidiaries above $10.0 million at each month-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. In this event, the Company would seek a waiver from the bank. The Company was in compliance with this covenant as of January 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 inventory balances and 45 of the Company's LNG tanker trailers. 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 Facility A and B Loans. Such amount is included as restricted cash in the Company's consolidated balance sheet at December 31, 2008.

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. Upon closing of the acquisition of DCE, the Company funded approximately $714,000 under the agreement. The funds were obtained as part of the initial $4.2 million funded under the Facility B Loan with PlainsCapital Bank to the Company. Interest on the unpaid balance accrues at a rate of 12% per annum and is payable quarterly beginning 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 PlainsCapital Bank. 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.

(8) Long-term Debt (Continued)

Principal payments under long-term debt during the years ending December 31, are as follows:

	Facility A Loan	Facility B Loan	Total
2009	$ 873,556	$ 960,716	$ 1,834,272
2010	931,269	768,572	1,699,841
2011	984,548	614,858	1,599,406
2012	1,038,525	491,886	1,530,411
2013	13,880,527	1,967,546	15,848,073
Total	$17,708,425	$4,803,578	$22,512,003

(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, 2008, 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, 2006, 2007 or 2008.

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 September 24, 2008, the Company entered into a subscription agreement with Boone Pickens Interests, Ltd. pursuant to which the Company issued and sold a total of 319,488 shares of its common stock at a purchase price of $15.65 per share, the closing price of its common stock on the Nasdaq Global Market, for an aggregate purchase price of approximately $5.0 million. Boone Pickens Interests, Ltd. is a limited partnership, the limited partner interest in which is owned collectively by certain trusts. Boone Pickens, a director of the Company and the Company's largest stockholder, is the settlor of such trusts.

(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

(9) Stockholders' Equity (Continued)

"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 are 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 $13.50 per share. On the first 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. 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 second 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 first or 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 Warrant and the Series II Warrant. The Company allocated $19.1 million, $9.8 million and $3.6 million to the common stock, the Series I Warrant and the Series II Warrant, respectively. The Series I Warrant is an equity classified instrument as of and for the year ended December 31, 2008. However, effective January 1, 2009, based on the guidance in EITF No. 07-5, which becomes effective for the Company on January 1, 2009, the Company will treat this as a derivative under SFAS No. 133 and mark-to-market the change in the value of the derivative liability through the statement of operations. The Company expects to record 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.

(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.

(9) Stockholders' Equity (Continued)

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, 2008, the Company had 8,390,500 shares reserved for issuance in total under the 2006 Plan. At December 31, 2008, the Company had 11,405 shares available for grant in total under the 2006 Plan.

Option activity for 2006, 2007, and 2008 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, 2005	2,737,750	2.96		
Options exercised	(359,500)	2.77		
Options granted	25,000	3.86		
Options forfeited	(1,000)	2.96		
Balance, December 31, 2006	2,402,250	2.97		
Options granted	4,266,500	12.85		
Options exercised	(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	7.9	$8,143
Exercisable, December 31, 2008	4,515,370	7.75	6.7	$6,903

(9) Stockholders' Equity (Continued)

A summary of the Company's non-vested stock options as of December 31, 2008 and the changes during the year ended December 31, 2008 are presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested options at December 31, 2007	3,304,167	$7.29
Granted	1,921,512	4.89
Vested	(1,363,916)	7.15
Forfeited	(142,666)	7.65
Non-vested options at December 31, 2008	3,719,097	6.09

As of December 31, 2008, there was $22.7 million of total unrecognized compensation cost related to non-vested shares. That cost is expected to be recognized over a weighted average period of two years. The total fair value of shares vested during the year ended December 31, 2008 was $9.7 million.

All options granted in 2006, 2007 and 2008 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 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 under the provisions of SFAS No. 123(R) 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 2006, 2007 and 2008 was $482,076, $981,886 and $576,293, 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, 2008:

Dividend yield	0.00%
Expected volatility	64.14%
Risk-free interest rate	2.19%
Expected life in years	6.00

The weighted average grant date fair value of options granted using these assumptions was $4.89 for the year ended December 31, 2008. 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

(9) Stockholders' Equity (Continued)

Company recorded approximately $10,736,000 of expense during the year ended December 31, 2008 under the provisions of SFAS No. 123(R). The Company did not record any tax benefit during the year ended December 31, 2008 related to its stock option expense.

On January 2, 2009, the Company issued 975,413 options valued at $3.98 per option.

(e) Equity Option Agreements and Warrants

On April 8, 2005, the Company entered into equity option agreements with two stockholders under which the stockholders, at the Company's option (expiring February 28, 2007), became obligated to purchase up to an aggregate of 11,824,324 shares of the Company's common stock at an exercise price of $2.96 per share. On each of May 31, 2005 and November 29, 2005, the Company exercised its option and required the stockholders to purchase an aggregate of 2,364,865 shares for proceeds of approximately $7 million. On January 31, 2006, the Company exercised its option and required the stockholders to purchase the remaining 7,094,594 shares outstanding under the equity option agreements for proceeds of approximately $21 million.

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. See note 13.

As of December 31, 2008, the Series I Warrant discussed in note 9 (c) is also outstanding.

(f) Conversion of Promissory Notes

Boone Pickens Convertible Promissory Note

On June 12, 2001, the Company signed a secured convertible promissory note payable to Boone Pickens (the Note) in the original principal amount of $3,200,000. Interest accrued at 8% per annum and was payable quarterly in arrears on the first business day of each calendar quarter. The principal amount and any accrued interest was convertible into the number of shares determined by dividing the convertible amount by the conversion price then in effect. The conversion price was $3.41 per share. On April 28, 2006, this note was converted into 944,255 shares of the Company's common stock.

Pickens Grandchildren's Trust Convertible Promissory Note

On June 12, 2001, the Company signed a secured convertible promissory note payable to the Pickens Grandchildren's Trust (the Trust Note) in the original principal amount of $800,000. Interest accrued at 8% per annum and was payable quarterly in arrears on the first business day of each calendar quarter. The principal amount and any accrued interest was convertible into the number of shares determined by dividing the convertible amount by the conversion price then in effect. The conversion price was $3.41 per share. On April 21, 2006, this note was converted into 235,698 shares of the Company's common stock. The converted shares were simultaneously sold to Boone Pickens.

(10) Income Taxes

The components of income (loss) before income taxes for the years ended December 31, 2006, 2007, and 2008 are as follows:

	2006	2007	2008
U.S.	$(89,370,978)	$(6,717,982)	$(39,391,399)
Foreign	(400,971)	(954,500)	(1,176,134)
	$(89,771,949)	$(7,672,482)	$(40,567,533)

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

	2006	2007	2008
Current:			
State	$ (109,284)	$ 536,970	$ 261,511
Federal	(5,140,930)	684,910	27,630
Total current	(5,250,214)	1,221,880	289,141
Deferred:			
State	(6,338,146)	(380,091)	(1,242,348)
Federal	(21,818,295)	(2,026,323)	(5,931,561)
Foreign	(102,941)	(284,869)	(375,498)
Change in valuation allowance	21,238,388	2,691,283	7,549,407
Total deferred	(7,020,994)	—	—
Total	$(12,271,208)	$ 1,221,880	$ 289,141

Income tax expense (benefit) for the years ended December 31, 2006, 2007 and 2008 differs from the “expected” amount computed using the federal income tax rate of 34% as a result of the following:

	2006	2007	2008
Computed expected tax expense (benefit)	$(30,522,462)	$(2,608,644)	$(13,792,961)
State and local taxes, net of federal benefit	(4,359,324)	354,400	147,994
Nondeductible expenses	1,339,770	1,186,137	8,419,392
Other	32,420	(491,290)	(779,400)
Change in valuation allowance	21,238,388	2,781,277	6,294,116
Total tax expense (benefit)	$(12,271,208)	$ 1,221,880	$ 289,141

(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, 2007 and 2008 are as follows:

	2007	2008
Deferred tax assets:		
Accrued expenses	$ 907,688	$ 975,440
Sales-type leases	508,014	520,525
Alternative minimum tax and general business credits	1,980,646	2,150,524
Derivative loss	13,588,013	13,783,447
Stock option expense	1,883,231	4,635,342
Other	—	450,845
Net operating loss carryforwards	12,745,504	20,380,290
Total deferred tax assets	31,613,096	42,896,413
Less valuation allowance	(24,019,665)	(31,457,905)
Net deferred tax assets	7,593,431	11,438,508
Deferred tax liabilities:		
Depreciation and amortization—domestic	(7,174,476)	(11,438,508)
Depreciation and amortization—foreign	(418,955)	—
Total deferred tax liabilities	(7,593,431)	(11,438,508)
Net deferred tax assets (liabilities)	$ —	$ —

At December 31, 2008, the Company had federal and state net operating loss carryforwards of approximately $48.1 million and $51.3 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 $4.7 million at December 31, 2008, which will expire beginning in 2009. 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 2006, 2007 and 2008, the Company provided a valuation allowance of $21,238,388, $24,019,665 and $31,457,905, 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, 2006, 2007 and 2008 was $(21,238,388), $(2,781,277) and $(7,549,407), respectively, after adjustments between current and deferred taxes.

On January 1, 2007, the Company adopted the provisions of FIN 48, which clarifies the accounting for uncertain positions. FIN 48 requires that the Company recognizes the impact of a tax position in its

(10) Income Taxes (Continued)

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 FIN 48 was immaterial to the Company's consolidated financial statements. The total amount of unrecognized tax benefits as of January 1, 2007, December 31, 2007 and 2008 were $50,000, $369,000 and $369,000, 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, 2007 and 2008:

Unrecognized tax benefit—January 1, 2007	$ 50,000
Gross increases—tax positions in prior years	319,000
Unrecognized tax benefit—December 31, 2007	369,000
Gross increases—tax positions in prior years	—
Unrecognized tax benefit—December 31, 2008	$369,000

FIN 48 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, 2007 and 2008, the Company accrued $60,000 and $20,000 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 2003 through 2007 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 2004.

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. 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, 2008, it is possible that the Company's liability for uncertain tax positions will be reduced by as much as $319,000 during the year ended December 31, 2009 as a result of the settlement of tax positions with various tax authorities.

(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 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.

(11) Commitments and Contingencies (Continued)

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, 2008:

Fiscal year:	
2009	$ 1,865,597
2010	1,805,511
2011	1,695,544
2012	1,612,859
2013	1,609,422
Thereafter	7,699,068
Total future minimum lease payments	$16,288,001

In November 2006, the Company entered into a ground lease for 36 acres in California on which the Company built an LNG liquefaction plant. The lease is for a term of 30 years, beginning on the date that the plant commences 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. The Company must also pay a royalty to the landlord for each gallon of LNG produced at the facility as well as for certain other services that the landlord will provide. The Company began paying rent on December 1, 2008. At December 31, 2008, the Company has remaining contractual commitments related to the plant of $2.2 million.

Rent expense totaled $1,183,061, $1,692,982 and $2,218,690 for the years ended December 31, 2006, 2007 and 2008, respectively.

Take-or-Pay LNG Supply Contracts

At December 31, 2008, the Company has entered into two LNG supply contracts at market prices that contain minimum take or pay provisions over the term of the contracts. The contracts contain fixed amounts the Company must pay for any shortfall below its minimum volume requirements, and

(11) Commitments and Contingencies (Continued)

one of the contracts contains a variable amount that is based on the price of natural gas at the beginning and end of the month where a shortfall occurs. One of the contracts expires in March 2009 and the other contract expires in June 2011. For the years ended December 31, 2006, 2007 and 2008, the Company paid approximately $12,790,928, $10,100,054 and $13,417,473, respectively, under the contracts. At December 31, 2008, the fixed commitments under these contracts totaled approximately $2,121,000, $1,995,000 and $997,500, respectively, for the years ending December 31, 2009, 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 the second quarter of 2009.

(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.

	2006	2007	2008
Revenue:			
United States	$ 88,997,250	$116,355,640	$128,452,493
Canada	2,550,066	1,360,593	1,020,040
Total revenue	$ 91,547,316	$117,716,233	$129,472,533
Operating income (loss):			
United States	$(90,709,364)	$(10,049,214)	$(40,818,926)
Canada	446,555	(936,518)	(1,126,527)
Total operating income (loss)	$(90,262,809)	$(10,985,732)	$(41,945,453)
Long-lived assets:			
United States		$105,502,811	$204,093,876
Canada		4,873,217	3,577,829
Total long-lived assets		$110,376,028	$207,671,705

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

(13) Related Party Transactions

In 2006, 2007 and 2008, 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 majority stockholder and a director of the Company. During 2006, under the agreement, the Company also paid BP Capital approximately $2,253,000 in commissions related to gains on its hedging activities.

(13) Related Party Transactions (Continued)

On August 2, 2006, the Company entered into certain futures contracts related to January 2008 through December 2011 (Positions). During the period August 3, 2006 through December 28, 2006, the Positions decreased in value by $78.7 million. On December 28, 2006, the Company entered into a transaction with Boone Pickens, its majority stockholder, whereby Mr. Pickens assumed the obligations related to the Positions in exchange for a five-year warrant to purchase 15 million shares of the Company's common stock at $10 per share. The derivative obligation of $78.7 million was removed from the Company's balance sheet, and the warrant (valued at $80.9 million) was recorded as an increase of stockholders' equity. The difference between the value of the warrant and the value of the derivative obligation ($2.2 million) was recorded in the Company's consolidated statement of operations for the year ended December 31, 2006 as a loss on extinguishment of derivative liability.

As the Positions decreased in value, the Company was required to make certain additional margin deposits to cover the losses. Mr. Pickens agreed to loan the Company up to $100 million to make such deposits under a revolving line of credit (the Revolver). At December 28, 2006, Mr. Pickens had advanced the Company $69.7 million under the Revolver to make additional margin deposits which he remitted directly to the broker. As part of the transaction, Mr. Pickens received back the deposits he had funded with advances under the Revolver as payment of the outstanding Revolver balance. The Company paid Mr. Pickens $1.2 million of interest expense on advances made under the Revolver during the period. The Revolver was cancelled on December 28, 2006 after the transaction was completed.

In July 2006, the Company entered into an agreement with Inland Kenworth, Inc. (Inland) and Westport Innovations pursuant to which the Company agreed to deposit certain amounts with Inland, as security for a guaranty, to help fund Inland's acquisition from Kenworth Truck Company (Kenworth) of up to 125 diesel tractors, which tractors Westport Innovations will convert to run on LNG. Westport Innovations is a stockholder of the Company and Westport Innovation's chief executive officer was a member of the Company's Board of Directors in 2006 and 2007. In addition, the president and chief executive officer of the Company is also a director of Westport Innovations, and Boone Pickens, a director and the largest stockholder of the Company, is a stockholder of Westport Innovations. At December 31, 2008, approximately $3.2 million of deposits to Inland under this agreement had not been repaid. If any tractor purchased by Inland remains unsold after a period of 365 days, the Company must either purchase the tractor or instruct Inland to sell the tractor. In 2007, the Company also entered into two separate deposit agreements with Westport Innovations to facilitate the production of LNG fuel systems for installation in the diesel tractors referenced above. At December 31, 2008, approximately $3.0 million to Westport Innovations under these agreements has not been repaid. Repayment of these deposits will occur incrementally upon the sale of the converted tractors to third parties, however, to the extent an LNG fuel system incorporated into a tractor is not sold within 24 months of the effective date of the applicable deposit agreement (or such other time period as is agreed by both the Company and Westport Innovations), Westport Innovations is not obligated to repay any of the deposit with respect to such LNG fuel system.

(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, 2006, 2007 and 2008, the Company contributed approximately $217,000, $289,000, and $188,000 of matching contributions to the Savings Plan, respectively.

(15) Supplier Concentrations

During 2006, 2007, and 2008, the Company acquired approximately 47%, 32%, and 29%, respectively, of its natural gas related to its LNG sales from Williams Gas Processing Company pursuant to a floating rate purchase contract that includes minimum purchase commitments. 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, 2008, future payments under these capital leases are as follows:

2009	$ 531,188
2010	571,918
2011	502,626
2012	488,768
2013	488,768
Thereafter	594,350
Total minimum lease payments	3,177,618
Less amount representing interest	(605,819)
Present value of future minimum lease payments	2,571,799
Less current portion	(398,603)
Capital lease obligations, less current portion	$2,173,196

The value of the equipment under capital lease as of December 31, 2008 is $2,943,269, with related accumulated amortization of $516,598.

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 2012.

(16) Capitalized Lease Obligation and Receivables (Continued)

At December 31, 2008, future receipts under these leases are as follows:

2009	$399,000
2010	249,000
2011	99,000
2012	16,500
Total	763,500
Less amount representing interest	(79,464)
	$684,036

(17) Derivative Transactions

The Company, in an effort to manage its natural gas commodity price risk exposures related to certain contracts, uses 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 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended (SFAS 133). SFAS 133 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 2006, the Company's derivative instruments have not qualified for hedge accounting under SFAS 133. The Company did not have any derivative instruments during the year ended December 31, 2007, but had certain futures contracts in place at December 31, 2008 to hedge two supply contracts with two customers that did qualify for hedge accounting. The Company also had other futures contracts during 2008 that did not qualify for hedge accounting. The futures contracts at December 31, 2008 are being accounted for as cash flow hedges under SFAS 133 and are being used to mitigate the Company's exposure to changes in the price of natural gas and not for speculative purposes.

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 statement of operations or in accumulated other comprehensive income in the consolidated balance sheets in accordance with the provisions of SFAS 133. For the year ended December 31, 2008, the Company recorded losses of $0.6 million related to its futures contracts that did not qualify for hedge accounting in its consolidated statement of operations for the year. These futures contracts were related to the portion of an LNG supply contract that the Company bid on but was not awarded. The Company recorded unrealized losses of $0.7 million in accumulated other comprehensive income for the year ended December 31, 2008 for the futures contracts that did qualify for hedge accounting. The liability for these contracts is in accrued liabilities on the Company's consolidated balance sheet at December 31, 2008. The Company's ineffectiveness related to its futures contracts that did qualify for hedge accounting in 2008 was insignificant. The Company recognized losses of $0.5 million during the year ended December 31, 2008 related to futures contracts applicable to its supply contracts that did qualify for hedge accounting. Such amounts are included in cost of sales in the consolidated statement of operations.

(17) Derivative Transactions (Continued)

During 2006, the Company recognized a net loss of $282,348 related to contracts with expiration dates during the period. In 2006, the Company realized a net loss of $78,712,599 related to contracts with expiration dates beyond the current period. See note 13. These realized gains and losses have all been recorded in derivative (gains) losses in the Company's consolidated statements of operations.

The Company is required to make certain deposits on its futures contracts, should any exist. At December 31, 2006 and 2007, the Company did not have any outstanding futures contracts or associated deposits. 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 as of December 31, 2008.

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 majority stockholder and one of its directors. At the advice of BP Capital, the Company historically has liquidated and subsequently re-established its futures positions based on market conditions.

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

Prior to December 31, 2007, the Company entered into certain contracts with various customers, primarily municipalities, to sell LNG or CNG at fixed prices or at prices subject to a price cap. Subsequently, the Company sold the underlying futures contract prior to the expiration of the customer's sales contract. The contracts generally range from two to five years. The most significant cost component of LNG and CNG is the price of natural gas.

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 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 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 guidance in SFAS No. 133.

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 a difference between the fixed price of the natural gas included in the customer's contract and the corresponding index price of natural gas typically develops after the Company enters into the contract. During these time periods, the Company entered into several contracts to sell LNG or CNG to customers at a fixed price or an index-based price that is subject to a fixed price cap. The Company has also generally entered into natural gas futures contracts to offset economically the adverse impact of rising natural gas prices. From an accounting perspective, during periods of rising natural gas prices, the Company's futures contracts 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

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

liability or a corresponding loss has not been recognized in the Company's statements of operations during this historical period of rising natural gas prices for the future commitments under these contracts. As a result, 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).

The following table summarizes important information regarding the Company's fixed price and price cap supply contracts under which it is required to sell fuel to its customers as of December 31, 2008:

	Estimated Volumes[a]	Average Price[b]	Contracts Duration
CNG fixed price contracts	1,150,067	$1.18	through 12/13
LNG fixed price contracts	1,061,667	$0.60	through 07/09
CNG price cap contracts	1,560,375	$0.81	through 12/09
LNG price cap contracts	525,000	$0.62	through 03/09

This table does not include two 2.1 million LNG gallon per year renewal options beginning April 1, 2009 that one of our customers possesses related to an LNG price cap contract. The contract contains a price cap of $7.50 per MMbtu on the SoCal Border Index.

(a) Estimated volumes are in gasoline gallon equivalents for CNG contracts and are in LNG gallons for LNG contracts and represent the volumes the Company anticipates delivering over the remaining duration of the contracts.

(b) Average prices are in gasoline gallon equivalents for CNG contracts and are in LNG gallons for LNG contracts. The average prices represent the natural gas commodity component embedded in the customer's contract.

At December 31, 2008, based on natural gas futures prices as of that date, the Company estimates it will incur between $70,000 and $85,000 to cover the increased price of natural gas above the inherent price of natural gas embedded in its customer's fixed price and price cap contracts over the duration of the contracts. The Company's volumes under these contracts, in gasoline gallon equivalents, expire as follows:

2009	2,831,296
2010	230,000
2011	230,000
2012	230,000
2013	230,000

The price of natural gas has generally increased since the Company entered into these agreements to fix the price or cap the price of LNG or CNG that it sells to these customers. However, this difference has not been reflected in the Company's financial statements as these are executory contracts and are not derivatives under U.S. generally accepted accounting principles.

(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, warrants and convertible promissory notes. The information required to compute basic and diluted earnings per share is as follows:

	2006	2007	2008
Basic:			
Weighted average number of common shares outstanding	31,676,399	40,258,440	45,367,991
Diluted:			
Net income (loss)	$(77,500,741)	$ (8,894,362)	$(40,856,674)
Interest expense related to convertible promissory notes, net of tax	62,933	—	—
Adjusted net income (loss)	$(77,437,808)	$ (8,894,362)	$(40,856,674)
Weighted average number of common shares outstanding	31,676,399	40,258,440	45,367,991
Shares issued upon assumed exercise of stock options	—	—	—
Shares issued upon assumed exercise of warrants	—	—	—
Shares issued upon assumed conversion of convertible promissory notes	—	—	—
Shares used in computing diluted earnings per share	31,676,399	40,258,440	45,367,991

Certain securities were excluded from the diluted earnings per share calculation in 2007 and 2008 as the inclusion of the securities would be anti-dilutive to the calculation. The amounts outstanding as of December 31, 2007 and 2008 for these instruments are as follows:

	2007	2008
Options	6,553,036	8,234,467
Warrants	15,000,000	18,314,394

(20) Fair Value of Financial Instruments

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

	December 31,			
	2007		2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Capital lease receivables	$ 1,412,500	$ 1,402,083	$ 684,036	$ 684,036
Other receivables	21,760,355	21,177,537	11,012,093	10,785,955
Notes receivable	3,068,159	3,068,159	8,081,680	8,063,680
Capital lease obligations	224,897	224,897	2,571,801	2,571,801
Long-term debt	—	—	22,512,003	22,512,003

As of December 31, 2007 and 2008, 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 capital lease receivables, other receivables, notes receivable, capital lease obligations 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.

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, 2008, 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.

There were no 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, 2008. 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. Based on these criteria, our management has concluded that, as of December 31, 2008, our internal control over financial reporting are 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 herein.

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 2009 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2008.

Item 11. Executive Compensation.

The information required by this item is incorporated by reference to the proxy statement for our 2009 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2008.

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 2009 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2008.

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 2009 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2008.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference to the proxy statement for our 2009 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2008.

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, 2007 and 2008

Consolidated Statements of Operations for the Years Ended December 31, 2006, 2007 and 2008

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2006, 2007 and 2008

Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2007 and 2008

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

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

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
2.1	Stock Purchase Agreement dated June 13, 2001, among the registrant, the shareholders of BCG eFuels, Inc. and the shareholders of Pickens Fuel Corp.	Filed as Exhibit 2.1 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
2.2	Membership Interest Purchase Agreement dated December 31, 2002, among the registrant and the individuals holding member interests of Blue Energy & Technologies, LLC	Filed as Exhibit 2.2 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
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	2006 Equity Incentive Plan+	Filed as Exhibit 10.2 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
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
10.5	Letter Agreement dated August 21, 2007, between the registrant and Barclay Corbus+	Filed as Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-33480)	November 13, 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
10.9	Letter Agreement dated April 20, 2005, between the registrant and Warren I. Mitchell+	Filed as Exhibit 10.9 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
10.10	Letter Agreement dated October 15, 2003, between the registrant and Warren I. Mitchell+	Filed as Exhibit 10.10 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	September 6, 2006
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

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
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
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
10.18	LNG Sales Agreement dated May 23, 2003, between the registrant and Williams Gas Processing Company†	Filed as Exhibit 10.18 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.19	Amendment to LNG Sales Agreement, dated March 3, 2005, between the registrant and Williams Gas Processing Company†	Filed as Exhibit 10.19 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
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

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
10.22	$50 Million Revolving Promissory Note dated August 31, 2006 between the registrant and Boone Pickens	Filed as Exhibit 10.22 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.23	Equity Option Agreement dated April 8, 2005 between the registrant and Boone Pickens	Filed as Exhibit 10.23 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.24	Equity Option Agreement dated April 8, 2005 between the registrant and Perseus ENRG Investment, L.L.C.	Filed as Exhibit 10.24 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
10.28	$100 Million Revolving Promissory Note dated November 15, 2006 between the registrant and Boone Pickens	Filed as Exhibit 10.28 to the Registration Statement on Form S-1, as amended (File No. 333-137124)	March 27, 2007
10.29	Letter agreement dated September 11, 2006 between the registrant and Williams Gas Processing Company	Filed as Exhibit 10.29 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
10.37	Agreement Regarding Acquisition, Conversion and Sale of Vehicles dated July 21, 2006 among Clean Energy Finance, LLC, Inland Kenworth, Inc., Westport Fuels Systems Inc. and Westport Innovations Inc.	Filed as Exhibit 10.37 to the Annual Filing on Form 10-K (File No. 001-33480)	March 19, 2008
10.38	First Amendment to Agreement Regarding Acquisition, Conversion and Sale of Vehicles dated July 15, 2007 among Clean Energy Finance, LLC, Inland Kenworth, Inc., Westport Fuels Systems Inc. and Westport Innovations Inc.	Filed as Exhibit 10.38 to the Annual Filing on Form 10-K (File No. 001-33480)	March 19, 2008
10.39	Deposit Agreement No. 1 dated November 30, 2007 between Clean Energy Finance, L.L.C. and Westport Fuel Systems Inc.	Filed as Exhibit 10.39 to the Annual Filing on Form 10-K (File No. 001-33480)	March 19, 2008
10.40	Deposit Agreement No. 2 dated December 13, 2007 between Clean Energy Finance, L.L.C. and Westport Fuel Systems Inc.	Filed as Exhibit 10.40 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

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
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
10.47	First Amendment to Credit Agreement among the registrant Clean Energy and PLAINSCAPITAL Bank.*		
10.48	Second Amendment to Credit Agreement among the registrant Clean Energy and PLAINSCAPITAL Bank.*		
21.1	Subsidiaries*		
23.1	Consent of KPMG LLP*		
24.1	Power of Attorney (incorporated by reference to the signature page of this annual report on Form 10-K)*		
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.*		

Exhibit Number	Description	Incorporated herein by reference to the following filings: Form	Filed on
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 16, 2009

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Andrew J. Littlefair and Richard R. Wheeler, jointly and severally, as his attorney-in-fact, each with the power of substitution, for him in any and all capacities, to sign any amendments to this annual report on Form 10-K and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorneys-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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 16, 2009
/s/ RICHARD R. WHEELER Richard R. Wheeler	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 16, 2009
/s/ WARREN I. MITCHELL Warren I. Mitchell	Chairman of the Board and Director	March 16, 2009
/s/ VINCENT C. TAORMINA Vincent C. Taormina	Director	March 16, 2009
/s/ JOHN S. HERRINGTON John S. Herrington	Director	March 16, 2009
/s/ JAMES C. MILLER III James C. Miller III	Director	March 16, 2009
/s/ BOONE PICKENS Boone Pickens	Director	March 16, 2009
/s/ KENNETH M. SOCHA Kenneth M. Socha	Director	March 16, 2009

Corporate Information

Board of Directors

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

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

Andrew J. Littlefair
Co-Founder,
Clean Energy
June 2001

James C. Miller III
Former Director,
Office of Management and Budget
Governor, U.S. Postal Service
(Former Chairman 2005-2007)
May 2006

T. Boone Pickens
Co-Founder,
Clean Energy
Chairman,
B.P. Capital, L.P.
June 2001

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,
Marketing and Sales

Mitchell W. Pratt
Senior Vice President
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

Annual Meeting

The Annual Meeting of Stockholders will be held at 1:00 p.m., Tuesday, May 12, 2009 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

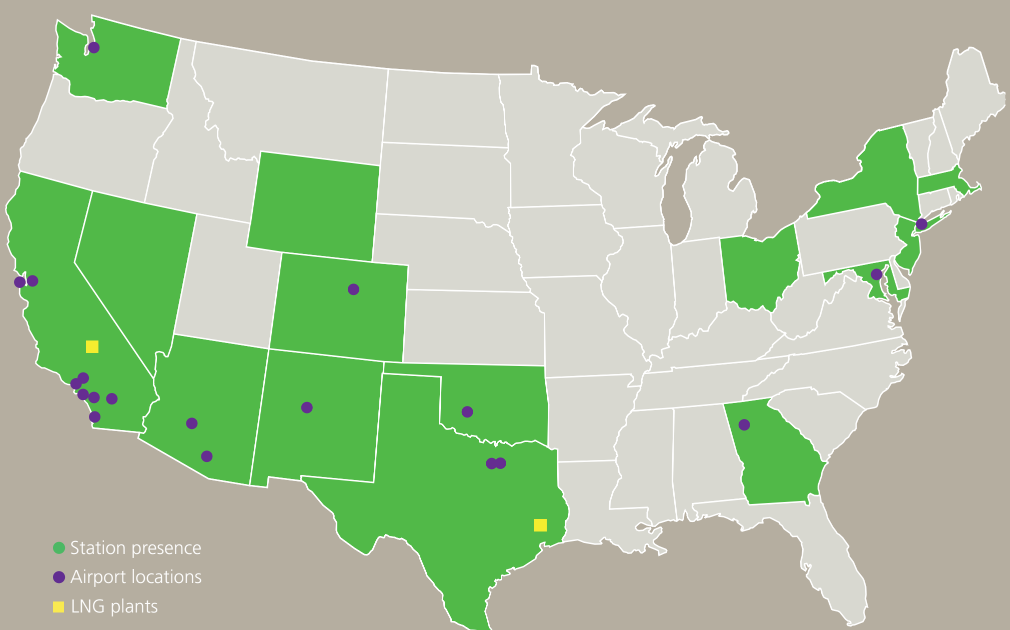
Web Site

www.cleanenergyfuels.com

North America's leader in clean transportation

Clean Energy is the largest provider of natural gas (CNG and LNG) for transportation in North America. It fuels more than 15,000 vehicles at 176 strategic locations across the United States and Canada, including 19 of the nation's airport complexes. Clean Energy also owns and operates two LNG production plants, one in Willis, TX and one in Boron, CA.

In addition to its headquarters in Seal Beach, California, Clean Energy maintains offices in Arizona, Colorado, Massachusetts, Texas, Vancouver, BC and Washington, DC.



Clean Energy
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