AVENTINE RENEWABLE ENERGY HOLDINGS INC
Form 10-K
March 05, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

for the fiscal year ended December 31, 2006

OR

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

for the transition period from to .

Commission file number 001-32922

AVENTINE RENEWABLE ENERGY HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

Delaware	**05-0569368**
(State of Incorporation or organization)	(IRS Employer Identification No.)
1300 South 2nd Street **Pekin, Illinois**	**61554**
(Address of principal executive offices)	(Zip Code)

(309) 347-9200

(Registrant s Telephone Number, including Area Code)

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

Title of each class	**Name of exchange on which registered:**
Common Stock, $0.001 par value	New York Stock Exchange

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

Indicate by check mark whether the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES o NO x

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 o NO x

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 x NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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 o

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

Large accelerated filer o Accelerated filer o Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

YES o NO x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2006 was approximately $1,007,987,731 based upon the closing price of the Common Stock reported for such date on the New York Stock Exchange. For purposes of this disclosure, shares of Common Stock held by executive officers, directors and beneficial owners of more than 5% of the Common Stock of the registrant have been excluded because such persons may be deemed to be affiliates.

Indicate the number of shares outstanding of each class of Common Stock, as of the latest practicable date:

Class	**Outstanding as of February 26, 2007**
Common Stock, $0.001 par value	41,782,276 Shares

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the annual meeting of stockholders to be held on May 9, 2007 are incorporated by reference into Part III.

FORM 10-K

YEAR ENDED DECEMBER 31, 2006

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PART I

Item 1. Business

General

Aventine Renewable Energy Holdings, Inc. (the Company, Aventine, we, our, or us) is a leading producer and marketer of ethanol in the Un States (U.S.), based on both the number of gallons produced and the number of gallons sold. Through our own production facilities, marketing alliances with other ethanol producers and our purchase/resale operations, we marketed and distributed 695.8 million gallons of ethanol in 2006 and 529.8 million gallons of ethanol in 2005. For the years ended December 31, 2006 and 2005, we sold approximately 12.9% and 13.5%, respectively, of the total volume of ethanol sold in the U.S. We market and distribute ethanol to many of the leading energy companies in the U.S., including Royal Dutch Shell and its affiliates, Marathon Petroleum, BP, ConocoPhillips, Valero Marketing and Supply Company, Exxon/Mobil and Texaco/Chevron. We have comprehensive national distribution capabilities through our leased railcar fleet and terminal network structure at critical points on the nation s transportation grid where our ethanol is blended with our customers gasoline. In addition to producing ethanol, our facilities also produce several co-products, such as distillers grain, corn gluten feed, corn germ and brewers yeast, which generate incremental revenue and help offset a significant portion of our corn costs.

We were acquired by the Morgan Stanley Capital Partners (MSCP) funds from a subsidiary of The Williams Companies, Inc. on May 30, 2003. The acquisition was accounted for as a purchase business combination in accordance with Statement of Financial Accounting Standards No. 141 (SFAS 141), *Business Combinations*.

Effective July 5, 2006, we completed an initial public offering of our common stock, $0.001 par value, pursuant to a Registration Statement on Form S-1, as amended (Reg. No. 333-132860), that was declared effective on June 28, 2006. We registered 9,058,450 shares of our common stock, all of which were sold in the offering at a gross per share price of $43.00 for an aggregate offering price of $389,513,350. Of the 9,058,450 shares sold, the Company sold 6,410,256 shares for an aggregate offering price of $275,641,008 and existing shareholders and management sold 2,648,194 shares for an aggregate offering price of $113,872,342.

We are a Delaware corporation organized in 2003, and are the successor to businesses engaged in the production and marketing of ethanol since 1981.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports are available on our website, at no charge, at www.aventinerei.com, as soon as reasonably practicable after electronic filing or furnishing such information to the U.S. Securities and Exchange Commission (SEC). Also available on our website, or in print upon written request at no charge, are our corporate governance guidelines, the charters of our audit, compensation and nominating and corporate governance committees, and a copy of our code of business conduct and ethics that applies to our directors, officers and employees, including our chief executive officer, principal financial officer, principal accounting officer, controller or other persons performing similar functions. Information on our website should not be considered to be part of this annual report on Form 10-K.

Industry Overview

Ethanol is marketed across the U.S. as a gasoline blend component that serves as a clean air additive, an octane enhancer and a renewable fuel resource. It is blended with gasoline (i) as an oxygenate to help meet fuel emission standards, (ii) to improve gasoline performance by increasing octane levels and (iii) to extend fuel supplies. A small but growing amount of ethanol is also used as E85, a renewable fuels-driven blend comprised of up to 85% ethanol.

Generally, ethanol is sold through contracts which are typically six months in duration. Ethanol is generally priced using one of three methodologies: a negotiated fixed price, a price based upon the spot market price of ethanol at the time of shipment plus or minus a fixed amount, or a price based upon the price of wholesale gasoline plus a fixed amount.

The principal factors historically affecting the price of ethanol are:

- *The price of gasoline*. Because ethanol is sold in both discretionary markets as well as in markets where reformulated gasoline (RFG) is required in order to meet federal and state fuel emission standards, and is used as both an additive to, and as a substitute for, gasoline, the price of ethanol over the long term has been highly correlated to the price of gasoline, which closely follows the price of oil;

- *Federal ethanol tax incentives*. The Volumetric Ethanol Excise Tax Credit (VEETC) enables refiners and blenders to pay a premium for ethanol relative to the price of gasoline. As a result, over the long term, ethanol has generally been priced at the cost of wholesale gasoline plus the value of the VEETC; and

- *Ethanol industry fundamentals (i.e. capacity and demand)*. The ethanol industry has experienced explosive growth in recent years, both in terms of supply capacity and demand. In periods when supply has exceeded demand, the price of ethanol has tended to fall below the cost of wholesale gasoline plus the value of the VEETC. In periods when demand outpaced supply, the price of ethanol tended to be at or above the cost of wholesale gasoline plus the value of the VEETC. See Item 1A Risk Factors We operate in a highly competitive industry with low barriers to entry. In addition, if the expected increase in ethanol demand does not occur, of if the demand for ethanol otherwise decreases, there may be excess capacity in our industry.

According to recent industry reports, approximately 95% of domestic ethanol has been produced from corn fermentation and, as such, is primarily produced in the Midwestern corn-growing states. The principal factor affecting the cost to produce ethanol is the price of corn.

The U.S. fuel ethanol industry has experienced rapid growth, increasing from 1.3 billion gallons of production in 1997 to 4.8 billion gallons produced in 2006, with year-end production capacity of 5.4 billion gallons annually. Ethanol blends now account for approximately 40% of the U.S. gasoline supply. Increases in ethanol demand have been driven by recent trends as more fully described below:

- *Emission reduction*. Ethanol is an oxygenate which, when blended with gasoline, reduces vehicle emissions. Ethanol s high oxygen content burns more completely, emitting fewer pollutants into the air. Ethanol demand increased substantially after 1990 when federal law began requiring the use of oxygenates (such as ethanol or methyl tertiary butyl ether (MTBE)) in RFG in cities with unhealthy levels of air pollution on a seasonal or year round basis. Although the federal oxygenate requirement was eliminated in May 2006, oxygenated gasoline continues to be used in order to help meet separate federal and state fuel emission standards. Historically, refiners chose MTBE over ethanol as the main oxygenate in RFG in cities outside of the Midwest because MTBE could be blended at the refinery and shipped through existing pipelines. Twenty-five states have now banned, or significantly limited the use of MBTE, including California and New York. The refining industry has all but abandoned the use of MTBE, making ethanol the primary clean air oxygenate currently used. See Item 1 Business Legislative Drivers and Government Regulation State legislation banning or significantly limiting the use of MTBE.

- *Energy Independence.* The U.S. s dependence on foreign oil has increased every year. The EIA states that out of the 19.7 million barrels of petroleum consumed by the U.S. in 2002, 62% was imported. This dependency is estimated to rise to 70% by 2025. Political instability and attacks on oil infrastructure in the major oil producing nations periodically disrupt the flow of oil and have added a risk premium to world oil prices. At the same time, demand for oil has increased as developing nations such as China and India continue to industrialize. As a result, world oil prices topped $70/barrel several times in 2005 and 2006 and averaged above $60/barrel in 2006. Ethanol is a domestic, renewable source of energy, and thus could increase the availability of domestic fuel supplies and reduces the U.S. dependence on foreign oil. In 2004, the RFA calculated that ethanol usage reduced the U.S. trade deficit by $5.1 billion by eliminating the need to import 143.3 million barrels of oil.

- *Octane enhancer*. Ethanol, with an octane rating of 113, is used to increase the octane value of gasoline with which it is blended, thereby improving engine performance. It is used as an octane enhancer both for producing regular grade gasoline from lower octane blending stocks (including both reformulated gasoline blendstock for oxygenate blending (RBOB) and conventional gasoline blendstock for oxygenate blending (CBOB)), and for upgrading regular gasoline to premium grades.

- *Fuel stock extender*. According to the EIA, while domestic petroleum refinery output has increased by approximately 27% from 1980 to 2005, domestic gasoline product supplied has increased 39% over the same period. By blending ethanol with gasoline, refiners are able to expand the volume of the gasoline they are able to sell.

- *Growth in E85 usage*. E85 is a blended motor fuel containing 85% ethanol and 15% gasoline currently sold at approximately 1,200 stations across the United States. E85 can be used in approximately 5 million Flexible Fuel Vehicles presently on the road. Although E85 currently represents less than 1% of the ethanol market (and less than 0.5% of the ethanol we produce), automakers such as Ford Motor Company and General Motors have recently announced initiatives to double flexible fuel vehicle production. Additionally, several states, such as New York, Pennsylvania, Michigan and Missouri, have launched "Ethanol Corridor" initiatives which call for availability of E85 fuel at every service station along a major interstate.

The positive emissions and engine performance attributes of ethanol have, in part, led to a number of legislative proposals intended to increase the usage of ethanol and renewable fuels generally. Several of these proposals are highlighted below.

- The VEETC, which was recently extended until 2010, allows those who blend ethanol with gasoline to take a $0.51 excise tax credit for each gallon of ethanol they use, or $0.051 per gallon of gasoline sold at a blend rate of 10%. The proposed Renewable Fuels and Energy Independence Act of 2007, as currently drafted, would permanently extend this blender tax credit. In addition, a tariff of $0.54 per gallon is generally levied on certain imported ethanol, which Congress has recently extended until January 1, 2009.

- The Energy Policy Act of 2005 included a nationwide renewable fuels standard (RFS) as a replacement for the federal oxygenate requirement. The RFS establishes minimum nationwide levels of renewable fuels, such as ethanol. The RFS increases from 4.0 billion gallons of RFS required usage in 2006 to 7.5 billion gallons by 2012. Several states, such as Minnesota, Montana and Hawaii have enacted their own renewable fuel standards, which in some instances exceed federally-mandated targets.

- Most recently, President Bush announced, in his 2007 State of the Union address, support for reducing gasoline usage by 20% from current levels by 2017, and proposing an increase in the federally-mandated usage of renewable fuels, which includes corn ethanol, to 35 billion gallons per year by 2017. We believe that continued legislative support for renewable fuels, combined with the positive performance and environmental characteristics of ethanol, will support increases in ethanol demand in the future.

Ethanol Production Processes

The production of ethanol from corn can be accomplished through one of two distinct processes: wet milling and dry milling. Although the number of dry mill facilities significantly exceeds the number of wet mill facilities, their size is typically smaller. The principal difference between the two processes is the initial treatment of the grain and the resulting co-products. The increased production of higher margin co-products in the wet mill process results in a lower ethanol yield. A typical wet mill yields approximately 2.6 gallons of ethanol per bushel of corn, while a typical dry mill yields approximately 2.8 gallons of ethanol per bushel of corn.

Wet Milling

In the wet mill process, the corn is soaked or steeped in water and sulfurous acid for 24 to 48 hours to separate the grain into its many parts. After steeping, the corn slurry is processed to separate the various components of the corn kernel, including the corn germ, which is then sold for processing into corn oil. The starch and any remaining water from the slurry can then be fermented and distilled into ethanol. The ethanol is then blended with about 5% denaturant, such as gasoline, to render it undrinkable and thus not subject to the alcohol beverage tax.

The remaining parts of the grain in the wet mill process are processed into a number of different forms of protein used to feed livestock. The multiple co-products from a wet mill facility generate a higher level of cost recovery from corn than the principal co-product from the dry mill process. In addition, a wet mill, if properly equipped, can produce a higher value brewers yeast in order to lower its net corn cost. For the years ended December 31, 2006, 2005 and 2004, we recovered 51.1%, 61.5% and 51.4%, respectively, of our total corn costs related to our wet mill process through our sale of co-products and bio-products.

Dry Milling

In a dry mill process, the entire corn kernel is first ground into a flour, which is referred to in the industry as meal , and is processed without first separating the various component parts of the grain. The meal is processed with enzymes, ammonia and water, and then placed in a high-temperature cooker to reduce bacteria levels ahead of fermentation. It is then transferred to fermenters where yeast is added and the conversion of sugar to ethanol begins. The fermentation process generally takes between 40 and 50 hours. After fermentation, the resulting liquid is transferred to distillation columns where the ethanol is evaporated from the remaining stillage for fuel uses. As with the wet milling process, the ethanol is then blended with approximately 5% denaturant, such as gasoline, to render the ethanol undrinkable and thus not subject to the alcohol beverage tax.

With the starch elements of the corn kernel consumed in the above described process, the principal co-product produced by the dry mill process is dried distillers grains with solubles (DDGS). DDGS is sold as a protein used in animal feed and recovers a portion of the total cost of the corn, although less than the co-products resulting from the wet mill process described above. For the years ended December 31, 2006, 2005 and 2004, we recovered 27.7%, 36.7% and 33.9%, respectively, of our corn costs related to our dry mill process through the sale of DDGS and other co-products.

The following graphic depicts the corn to ethanol conversion process:

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Business Overview

We derive our revenue from the sale of ethanol and the sale of co-products (corn gluten feed and meal, corn germ, condensed corn distillers with solubles (CCDS), carbon dioxide, DDGS and wet distillers grains with solubles (WDGS)) and bio-products (brewers yeast) which are produced as by-products during the production of ethanol at our plants. We source ethanol we sell from the following sources:

- Ethanol we manufacture at our own plants, which we refer to as equity production;
- Ethanol we purchase from marketing alliance partners, which we refer to as marketing alliance production, and
- Ethanol we purchase on the spot market, which we refer to as purchase/resale.

We market and sell ethanol without regard to whether we produced it, are reselling it, or are marketing it for our marketing alliance partners. Through our own production facilities, marketing alliances with other ethanol producers and our purchase/resale operations, we marketed and distributed 695.8 million, 529.8 million, and 505.3 million gallons of ethanol for the years 2006, 2005 and 2004, respectively.

Equity Production

We own and operate one of the few low cost, coal-fired, corn wet mill plants in the U.S. in Pekin, Illinois, which we refer to as the Illinois wet mill facility, and hold a 78.4% interest in a natural gas-fired corn dry mill plant in Aurora, Nebraska, which we refer to as the Nebraska facility. The remaining 21.6% of the Nebraska facility is owned by Nebraska Energy Cooperative, an agricultural cooperative comprised of over 200 corn producers. We consolidate all of the assets, liabilities, revenue, expenses and cash flows of the Nebraska facility in our financial statements and the interest therein of the Nebraska Energy Cooperative is reflected as minority interest.

At December 31, 2006, our facilities have a combined total nameplate ethanol production capacity of 150 million gallons annually with corn processing capacity of approximately 56.4 million bushels per year. We expanded our Pekin, Illinois facility by adding a new natural gas-fired dry mill, which we refer to as our Illinois dry mill facility , which was completed in early 2007. This expansion increased our total annual production capacity by approximately 57 million gallons, or 38%, to approximately 207 million gallons. Our plants typically operate at or near nameplate capacity except for scheduled outages that typically average approximately one week each year. We may also occasionally experience unplanned outages at our facilities which may negatively impact equity production and related revenue.

For the years ended December 31, 2006, 2005 and 2004, we produced 133.0 million, 138.1 million and 139.4 million gallons of ethanol, respectively, from our own facilities. Our equity production operations generate the substantial majority of our operating income.

Marketing Alliance Production

We also source ethanol from marketing alliance partners. Our marketing alliance partners are third-party producers (including producers in which we may have a minority interest, each of which is less than 8%), which sell their ethanol production to us on an exclusive basis. Ethanol produced by our marketing alliance partners enables us to meet major ethanol consumer needs by providing us with a nationwide market presence and leveraging our marketing expertise and our distribution systems. Our marketing alliance contracts require us to purchase all of the production from these facilities and sell it at contract or prevailing market prices. We are entitled to commissions on the sale of marketing alliance gallons in accordance with the terms of the marketing alliance contracts. Commission rates typically are

1% or less of the netback price. The netback price is the selling price of ethanol less a cost recovery component. The cost recovery component represents reimbursement to us for certain costs, including freight, storage, inventory carrying cost and indirect marketing costs. The purchase price we pay our marketing alliance partners is based on an average price at which we sell ethanol less the cost recovery component and commission. Revenue from marketing alliance gallons sold include the gross revenue from such sales and not merely the commissions earned because we (i) take title to the inventory, (ii) are the primary obligor in the sales arrangement with the customer, and (iii) assume all the credit risk. Since we are obligated to purchase all of the production of our marketing alliance partners, and since they typically operate at or near capacity, the volume of ethanol we purchase from our marketing alliance partners is driven by the capacity of their plants. See Item 1 Business Marketing Alliances .

For the years ended December 31, 2006, 2005 and 2004, we purchased 493.0 million, 340.6 million and 297.2 million gallons of ethanol, respectively, from our marketing alliance partners. Contribution to our operating income from the sale of marketing alliance gallons is relatively small.

Two of our alliance partners (VeraSun Fort Dodge, LLC and VeraSun Aurora Corporation with annual ethanol production of 230 million gallons) have elected not to renew their marketing alliance agreement with us upon termination on March 31, 2007. Granite Falls Energy, LLC, which produces 52 million gallons of ethanol annually, has notified us in writing that they will not renew their marketing alliance agreement with us upon termination on November 30, 2007. However, Granite Falls has asked us to submit a new proposal for marketing services. As of December 31, 2006, we have signed additional marketing alliance contracts with both existing and new alliance partners that have either announced new ethanol production facilities or have facilities currently under construction which are expected to produce an additional 860 million gallons of ethanol per year when completed. Accordingly, we expect revenue and marketing alliance production to significantly decrease in the second quarter and third quarters of 2007 and to recover as our additional marketing partners come online.

Purchase/Resale

We also purchase ethanol from unaffiliated producers and marketers. These transactions are driven by our ability to purchase ethanol and then, through our distribution network and customer relationships, to sell the ethanol. The margin for purchase/resale transactions can be volatile and we can occasionally lose money on this type of transaction.

For the years ended December 31, 2006, 2005 and 2004, we purchased for resale 68.2 million, 68.8 million and 62.9 million gallons of ethanol, respectively, from unaffiliated producers and marketers. The contribution to our operating income from purchase/resale transactions has historically been limited.

By-Products

We generate additional revenue through the sale of by-products (both co-products and bio-products) that result from the ethanol production process. These by-products include brewers yeast, corn gluten feed and meal, corn germ, CCDS, carbon dioxide, DDGS and WDGS. The volume of by-products we produce varies with the level of our equity production. Scheduled maintenance, along with other non-scheduled operational difficulties, may affect the volume of by-products produced. We may also shift the mix of these by-products to increase our revenue. By-product revenue is driven by both the quantity of by-product produced and from the market price received for our by-products, which have historically tracked the price of corn.

For the years ended December 31, 2006, 2005 and 2004, we generated approximately $54.7 million, $60.3 million and $65.7 million, respectively, of revenue from the sale of co-products and bio-products, allowing us to offset approximately 44.7%, 55.9%, and 47.0% of our corn costs, respectively, in each of these years.

Due to recent and planned industry increases in U.S. dry mill ethanol production, the production of co-products from dry mills in the U.S. has increased dramatically, and this trend may continue. This may cause co-product prices to fall in the U.S., unless demand increases or other market sources are found. To date, demand for DDGS, (the principal co-product produced by dry mills) in the U.S. has increased roughly in proportion to supply. We believe this is because U.S. farmers use DDGS as a feedstock, and DDGS are slightly less expensive than corn, for which it is a substitute. However, if prices for DDGS in the U.S. fall, it may have an adverse effect on our business, which might be material.

Product Segments

We operate in one reportable segment, the manufacture and marketing of fuel-grade ethanol.

Products

Ethanol

Our principal product is fuel-grade ethanol, an alcohol which is derived in the U.S. principally from corn. Ethanol is sold primarily for blending with gasoline as an octane enhancer and as an oxygenate additive for the purpose of meeting fuel emission standards. The demand for ethanol is principally driven by the overall demand for gasoline. For the years ended December 31, 2006, 2005 and 2004, ethanol sales represented 95.4%, 92.4% and 91.8%, respectively, of our total revenue.

Co-Products

Our Illinois wet mill facility produces co-products such as corn gluten feed, corn gluten meal, CCDS (both wet and dry) and corn germ. In addition, the fermentation process yields carbon dioxide. These co-products are sold for various consumer uses into large commodity markets. Corn gluten feed, corn gluten meal and CCDS are used as animal feed ingredients, corn germ is sold for the extraction of corn oil, and carbon dioxide is sold for food-grade use such as beverage carbonation and dry ice. Our dry mill facility in Aurora, Nebraska produces co-products such as DDGS, WDGS and carbon dioxide. Distillers products are marketed as high protein animal feed and carbon dioxide is sold for food-grade use. For the years ended December 31, 2006, 2005 and 2004, co-products represented 2.9%, 5.3% and 6.7%, respectively, of our total revenue.

Bio-Products

Our Illinois wet mill facility also produces bio-products, Kosher and Chametz free brewers yeast, which is processed into a growing variety of products for use in animal and human food and fermentation applications. For the years ended December 31, 2006, 2005 and 2004, bio-products represented 0.6%, 1.1% and 1.0%, respectively, of our total revenue.

Competition

As of December 2006, there are 94 producers operating 111 ethanol plants in the U.S. The top ten producers accounted for approximately 44.4%, 46.3% and 51.9% of total industry capacity for the years 2006, 2005 and 2004, respectively. The remaining producers consist primarily of farmer cooperatives.

The world s ethanol producers have historically competed primarily on a regional basis. Imports into the U.S. have generally been limited by an import tariff of $0.54 per gallon (other than from Caribbean basin countries which are exempt from this tariff up to specified limits). In 2006, in response to higher ethanol prices and increased demand (due in part to the elimination of MTBE as an oxygenate), a significant amount of ethanol was imported into the U.S. from Brazil, thereby negatively affecting ethanol prices during the second half of the year.

Certain of our competitors have significantly larger market shares than we have, and tend to be price leaders in the industry. If any of these competitors were to significantly reduce their prices, our business, operating results and financial condition could be adversely affected.

We could also be adversely affected if new products or technologies emerge that reduce or eliminate the need for ethanol. Our ethanol production is corn based, and competes with ethanol made from alternative materials, such as sugar, wheat and sorghum. Cellulosic sources of materials may also become a substitute feedstock for ethanol production, or other products may be devised which eliminate the need for ethanol entirely. Continued increases in the price of corn, or sustained high corn prices, could decrease the relative attractiveness of corn-based ethanol where alternatives exist, thereby adversely affecting our business, operating results or financial condition.

Business and Growth Strategy

We are pursuing the following business strategies:

Add Production Capacity to Meet Expected Demand for Ethanol

We are continually exploring opportunities to increase our equity production capacity through the development of new production facilities or acquisitions. In addition to the 57 million gallon dry mill expansion of our Pekin, Illinois facility which was completed in early 2007, we are exploring expanding capacity at three sites:

- a 113 million gallon dry mill in Pekin, Illinois
- a 226 million gallon dry mill adjacent to our Nebraska facility (to be constructed in two phases of 113 million gallons each) and
- a 226 million gallon dry mill in Mount Vernon, Indiana (to be constructed in two phases of 113 million gallons each)

We intend to substantially complete 226 million gallons of capacity expansions in 2008. While we originally intended to complete an additional 339 million gallons of capacity expansions in 2009, based on current construction costs and market conditions, we may elect to delay some or all of the 339 million gallons of capacity scheduled for 2009. The timing of the remaining expansions will be based upon, among other factors, market conditions and the availability of financing on attractive terms. We are still in the process of determining which combination of these potential expansions we will complete in 2008. Our decision will be based upon, among other factors, the availability of permits and the results of our negotiations of engineering, procurement and construction (EPC) contracts. We anticipate this first stage of expansion will be substantially completed by the end of 2008. We are currently negotiating EPC contracts for development of these first stage expansions with a construction firm, Kiewit Energy Company, and technology provider, Delta-T. Our timetable is subject to numerous factors beyond our control. In particular, we have not yet received any environmental or other permits with respect to these expansions (although construction and certain other permit applications have been filed). Accordingly, cannot give assurance that these expansion projects will be completed on a timely basis or at all or that we will realize the benefits we anticipate. In addition, while we expect to raise additional debt to fund these first stage facility additions, we cannot be sure that we will be able to obtain additional financing for these transactions on attractive terms or at all.

Expand Marketing Alliances

We signed our first marketing alliance agreement in 2001 and as of December 31, 2006 have increased the program to 12 alliance contracts with operating third-party plants. As of December 31, 2006, these 12 alliance partners have operations whose current production capacities total approximately 517 million gallons of ethanol annually.

Capitalize on Current and Changing Regulation

Through expansion of marketing alliances and continued investment in increasing production capacity, we believe we are well positioned to take advantage of the current and changing regulatory environment in our industry. For example, the Energy Policy Act of 2005 created the RFS which is expected to increase demand for ethanol and other renewable fuels. Moreover, President George Bush, in his January 2007 State of the Union speech, called for substantial increases in subsidized ethanol production. The President s proposal has been met with strong support by organizations such as the National Corn Growers Association.

Research into Cellulosic Ethanol

Cellulosic plant biomass represents an untapped potential feedstock for the generation of fuel ethanol from renewable resources. In 2001, we teamed with Purdue University and the U.S. Department of Agriculture s (USDA) National Center for Agriculture Utilization Research in Peoria, Illinois to develop an efficient and economical pretreatment process for corn fiber and corn stover (the stalks and husks left over after harvest). We spent approximately $0.2 million on cellulosic research in 2006, and $0.1 million in 2005 and 2004. We maintain our commitment to continue our research of the potential benefits associated with cellulosic ethanol.

Entry into new and diversified markets.

We are continually expanding our number of terminals in new markets in the United States and negotiating additional sales agreements. We persistently strive to optimize our multiple modes of transportation and sources of production. In addition, as numerous countries in Europe, Asia and South America have increased the mandated use of renewable fuels, we believe that there are export opportunities for our ethanol and by-products.

Sales and Marketing

We employ direct sales personnel to pursue sales opportunities. In addition, customer service representatives are available to respond to customer questions and to undertake or resolve any required customer service issues. Our sales structure forms an integral, critical link in communicating with our customers. The sales function is coordinated through key senior executives responsible for our sales and marketing efforts.

Marketing Alliances

We believe we have one of the largest marketing alliance networks in the ethanol industry, which allows for increased sales and enhances our position as a leading player in the ethanol industry. In exchange for allowing us to market their ethanol exclusively, marketing alliance partners gain the benefit of our customer relationships and extensive distribution network. Under our marketing alliance contracts, we agree to purchase all fuel-grade ethanol produced by our marketing alliance partners. The purchase price we pay our marketing alliance partners is based on an average price at which we sell ethanol less a cost recovery component and commission. The cost recovery component represents reimbursement to us for certain costs, including freight, storage, inventory carrying cost and indirect marketing costs. In addition, our marketing alliance partners pay us a commission which is generally 1% or less of the netback price. The netback price is the selling price of ethanol less the cost recovery component. Our marketing alliance contracts typically have two year terms and renew automatically for additional one year terms unless either party elects to terminate in advance. During the years ended December 31, 2006, 2005 and 2004, we purchased 493.0 million, 340.6 million and 297.2 million gallons, respectively, of ethanol produced by our marketing alliance partners.

We signed our first marketing alliance agreement in 2001 and as of December 31, 2006 have increased the program to 12 alliance contracts with operating third-party plants. As of December 31, 2006, these 12 alliance partners have operations whose current production capacities total approximately 517 million gallons of ethanol annually. In addition, as of December 31, 2006, we have signed additional marketing alliance contracts with both existing and new alliance partners that have either announced new ethanol production facilities or have facilities currently under construction which are expected to produce an additional 860 million gallons of ethanol per year when completed.

The following table presents our marketing alliances as of December 31, 2006:

Marketing Alliances

Name	Location	Annual Capacity (millions of gallons)	Status
Functioning Marketing Alliances			
Verasun Aurora Corporation (formerly Verasun Energy) (2)	Aurora, SD	120	Functioning
Verasun Fort Dodge LLC (2)	Fort Dodge, IA	110	Functioning
Glacial Lakes Energy	Watertown, SD	50	Functioning
Granite Falls Energy, LLC * (3)	Granite Falls, MN	52	Functioning
Adkins Energy	Lena, IL	40	Functioning
Ace Ethanol, LLC *	Stanley, WI	41	Functioning
Advanced BioEnergy, LLC * (1)	Huron, SD	30	Functioning
Advanced BioEnergy, LLC * (1)	Aberdeen, SD	9	Functioning
Quad County Corn Processors	Galva, IA	27	Functioning
Agri Energy, LLC	LuVerne, MN	21	Functioning
Reeve Agri-Energy	Garden City, KS	12	Functioning
Xethanol Biofuels	Blairstown, IA	5	Functioning
		517	
Marketing Alliances Under Construction/Under Development			
Panda Energy	Hereford, TX	100	Under construction
Holt County Ethanol	Holt County, NE	100	Under development
Indiana Bio-Energy, LLC *	Bluffton, IN	101	Under construction
Phelps County Ethanol	Holdridge, NE	100	Under development
E Energy Adams	Adams, NE	50	Under construction
Redfield Energy, LLC	Redfield, SD	50	Under construction
Xethanol Biofuels	Blairstown, IA	35	Under development
E3 Biofuels	Meade, NE	24	Under construction
Midwest Ethanol	Blencoe, IA	100	Under development
Midwest Ethanol	Elm Creek, NE	100	Under development
Midwest Ethanol	Araphoe, NE	100	Under development
		860	
Total Marketing Alliances		1,377	

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* Denotes marketing alliance partners in which we have made equity investments.

(1) We previously had a 2% investment in Heartland Grain Fuels (Heartland), which was acquired by Advanced BioEnergy, LLC in 2006. Our 2% investment in Heartland was converted to a 1% investment in Advanced BioEnergy, LLC upon the purchase of Heartland by Advanced BioEnergy, LLC.

(2) VeraSun Fort Dodge, LLC and VeraSun Aurora Corporation (formerly VeraSun Energy Corporation), which represent 230 million gallons of capacity, have notified us in writing that they will not renew their marketing alliance agreement with us upon termination on March 31, 2007.

(3) Granite Falls Energy, LLC, which produces 52 million gallons of ethanol annually, has notified us in writing that they will not renew their marketing alliance agreement with us upon termination on November 30, 2007. However, Granite Falls has asked us to submit a new proposal for marketing services.

The Company has made investments in four marketing alliance partners (each of which is less than 8% of total ownership at December 31, 2006). Investments made by the Company after May 31, 2003 are recorded at cost. Investments made by the predecessor Company in one ethanol plant prior to May 31, 2003 was written down to zero as part of the purchase price allocation upon the acquisition of the Company by MSCP. In conjunction with our investment in Ace Ethanol, LLC and Indiana BioEnergy, LLC, we are entitled to a seat on each of these companies Board of Directors for as long as we maintain an ownership interest.

Our marketing alliance contracts require us to purchase all of the production from these facilities and sell it at contract or prevailing market prices. The price at which we sell ethanol for our marketing alliance partners is the same price at which we sell our own production. The purchase price we pay our marketing alliance partners for their ethanol is based on an average price at which we sell ethanol, less the cost recovery component and commission. See Item 1 Business Distribution Strategy.

Our marketing alliances are a major component of our growth strategy. Through these alliances, we believe we are able to increase sales and market share by using our existing marketing expertise and distribution systems without necessarily incurring the cost of constructing new ethanol production capacity. As the scale of the marketing alliances increase, we expect to increase our level of efficiency and customer service.

The marketing alliances are also beneficial to us on an industry-wide basis. By performing the marketing function for a myriad of individual plants, we are able to better supply a sizable and consistent volume of ethanol to meet customer demand overall.

Distribution Strategy

Our extensive logistics system is a key component to our customer service commitment. With our current 52 leased terminal locations, and our owned and alliance partner production facilities in the Midwest, and on the Gulf Coast and East Coast, we believe our ethanol delivery system provides us with a significant competitive advantage. Our current network of 52 terminals creates an extensive distribution system that facilitates and enhances our ability to market ethanol. We and our marketing alliance partners deliver ethanol to these terminals for onward distribution to the customers. At these terminals, our ethanol is blended with gasoline as it is loaded onto the customers trucks. A large number of terminals enhances our marketing alliance strategy and purchase/resale operations through improved access to participating ethanol plants and improved distribution and storage capabilities.

Under terminal contracts, we generally lease space on both a fixed and throughput volume basis. Contracts are medium to long term in nature and are generally renewable subject to certain terms and conditions. The costs associated with leasing these terminals are factored into the purchase price we pay our marketing alliance partners for the ethanol that we purchase from them and, therefore, a portion of these leasing costs are effectively paid by our marketing alliance partners. See Item 1 Business Marketing Alliances.

Legislative Drivers and Governmental Regulation

The U.S. ethanol industry is highly dependent upon state and federal legislation, in particular:

- The federal ethanol tax incentive program;
- The use of fuel oxygenates;
- The RFS of the Energy Policy Act of 2005;
- State legislation banning or significantly limiting the use of MTBE, a competing oxygenate;
- Federal tariff on imported ethanol;
- State mandates; and
- Federal farm legislation.

The federal ethanol tax incentive program

First passed in 1979, the VEETC program allows gasoline distributors who blend ethanol with gasoline to receive a federal excise tax credit for each gallon of ethanol they blend. The federal Transportation Efficiency Act of the 21st Century, or TEA-21, extended the ethanol tax credit first passed in 1979 through 2007. The American Jobs Creation Act of 2004 extended the subsidy again to 2010 by allowing distributors to take a $0.51 excise tax credit for each gallon of ethanol they blend. We cannot give assurance that the tax incentives will be renewed in 2010 or, if renewed, on what terms they will be renewed. See Item 1A Risk Factors The U.S. ethanol industry is highly dependent upon a myriad of federal and state legislation and regulation, and any changes in such legislation or regulation could materially adversely affect our results of operations and financial condition The elimination or significant reduction in the federal ethanol tax incentive could have a material adverse effect on our results of operations.

Use of fuel oxygenates

Ethanol is used by the refining industry as a fuel oxygenate, which when blended with gasoline, allows engines to burn fuel more completely and reduce emissions from motor vehicles. The use of ethanol as an oxygenate had been driven by regulatory factors, specifically two programs in the federal Clean Air Act Amendments of 1990, that required the use of oxygenated gasoline in areas with unhealthy levels of air pollution.

- The winter Oxyfuel Program required oxygenated gasoline during winter months in cities that had high levels of carbon monoxide, but were not required to use RFG year round. According to the EPA, ethanol was the primary oxygenate used in this program.

- The RFG program required RFG year-round in cities with the worst smog, such as Los Angeles and Chicago. RFG is oxygenated gasoline that is specially blended to burn cleaner, and thus, result in fewer air pollutants than conventional gasoline. Historically, refiners chose MTBE over ethanol as the main oxygenate in RFG in cities outside of the Midwest because MTBE could be blended at the refinery and shipped through existing pipelines. In addition, its volatility was also lower, making it easier to meet emission standards. As discussed below, as a result of state legislation and environmental concerns, refiners switched to using ethanol instead of MTBE.

Although the federal oxygenate requirements for RFG included in the Clean Air Act were completely eliminated on May 5, 2006 by the Energy Policy Act of 2005, refiners continue to use oxygenated gasoline in order to meet continued federal and state fuel emission standards.

The Renewable Fuels Standard

Adopted on August 8, 2005 as part of the Energy Policy Act of 2005, the RFS establishes minimum nationwide levels of renewable fuels (ethanol, biodiesel or any other liquid fuel produced from biomass or biogas) to be included in gasoline, increasing from 4.0 billion gallons of RFS mandated usage in 2006 to 7.5 billion gallons by 2012. The RFA expects that ethanol should account for the largest share of renewable fuels produced and consumed under the RFS.

State legislation banning or significantly limiting the use of MTBE

Due to their availability and cost, ethanol and MTBE had been the two primary additives that were used to meet the federal Clean Air Act s oxygenate requirements. Because MTBE could be blended with gasoline at the refinery and transported via pipeline (and was produced from petroleum derivatives), it was initially the preferred oxygenate ingredient used in most RFG by the petroleum industry. In contrast, ethanol s affinity for water makes it more difficult to transport ethanol blended gasoline through existing petroleum pipelines since the presence of water in the pipelines (which often results from the previous transport of diesel fuel) could result in the ethanol separating from the gasoline during transport. Therefore, ethanol has historically been transported at higher expense via truck, rail or barge to a terminal for blending with gasoline and then transported via truck to the customer. In recent years, public concern about MTBE contamination of water supplies grew as a result of leaks from underground storage tanks and pipes. MTBE contamination raised several issues. First, some researchers and regulatory agencies expressed concern that MTBE may be a human carcinogen. MTBE opponents also contended that since MTBE was more soluble in water than other gasoline constituents, it was capable of traveling farther in groundwater and was more likely to contaminate public and private water wells, which, at a minimum, allegedly resulted in bad tasting, and therefore undrinkable, water. Lastly, MTBE opponents claimed that due to MTBE s solubility, it is difficult to remediate, and therefore, MTBE clean-ups may be more costly and time-consuming than clean-ups associated with other types of gasoline constituents. Twenty-five states have now banned, or significantly limited, the use of MTBE, including California and New York. Since most of the states that consumed significant amounts of oxygenated gasoline have already banned or limited the use of MTBE, the potential for additional significant growth in ethanol consumption as a result of the prohibition or significant limitation on the use of MTBE is limited.

Federal tariff on imported ethanol

In 1980, Congress imposed a tariff on foreign produced ethanol to make it more expensive than domestic supplies derived from corn. This tariff was designed to protect the benefits of the federal tax subsidies for U.S. farmers. The tariff was originally $0.60 per gallon in addition to a 3.0% *ad valorem* duty. The tariff was subsequently lowered to $0.54 per gallon and was not adjusted completely in sync with the change in the VEETC. On December 20, 2006, the $0.54 per gallon tariff on foreign produced ethanol was extended until January 1, 2009.

Ethanol imports from 24 countries in Central America and the Caribbean Islands are exempt from this tariff under the Caribbean Basin Initiative (CBI) in order to spur economic development in that region. Under the terms of the CBI, member nations may export ethanol into the U.S. up to a total limit of 7% of U.S. production per year (with additional exemptions from ethanol produced from feedstock in the Caribbean region over the 7% limit). In 2006, there were also significant imports of ethanol from non-CBI countries. Although these imports were subject to the tariff, significant increases in the price of

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ethanol in 2006 made the importation of ethanol from non-CBI countries profitable, in spite of the tariff. See Item 1A Risk Factors The U.S. ethanol industry is highly dependent upon a myriad of federal and state legislation and regulation, and any changes in such legislation or regulation could materially adversely affect our results of operations and financial condition Certain countries can import ethanol into the U.S. duty free, which may undermine the ethanol industry in the U.S.

Customers

We focus on providing exceptional customer service and, as a result, have had relatively little customer turnover. The substantial majority of our customer base has purchased ethanol from us for over five years (including our predecessor companies). In 2006, 2005, and 2004, our 10 largest customers accounted for approximately 75%, 77%, and 78%, respectively, of our consolidated net revenue. Two of our customers, BP and Exxon/Mobil, accounted for approximately 18% and 12%, respectively, of our consolidated 2006 revenue.

Pricing and Backlog

Generally, ethanol delivered to customers is priced in accordance with one of the following methods: (i) a negotiated fixed contract price per gallon, (ii) a price per gallon based on an average spot value of ethanol at the time of shipment plus or minus a fixed amount, or (iii) a price per gallon based on the market value of wholesale unleaded gasoline plus a fixed amount. The Company believes its pricing strategies, in conjunction with the rapid turnover of its inventory, provide a natural hedge against changes in the market price of ethanol.

As of December 31, 2006, we had contracts for delivery of ethanol totaling 291.6 million gallons for delivery throughout 2007. These commitments were for 94.6 million gallons at a fixed price of $1.97, 68.6 million gallons at a positive spread to wholesale gasoline of $0.41 (based upon the NYMEX, Chicago and NY harbor indices), and 128.4 million gallons at spot prices (using various Platt, OPIS and AXXIS indices). Although these contracts are for delivery throughout 2007, they are heavily weighted towards the first and second quarters of 2007.

Raw Materials and Suppliers

Our principal raw material is #2 yellow corn. In 2006, 2005 and 2004, we purchased approximately 51.0 million, 51.9 million and 52.0 million bushels of corn, respectively. We contract for our corn requirements through a variety of sources, including farmers, grain elevators, and cooperatives. Due to our plants being located in or near the Midwestern portion of the U.S., we believe that we have ample access to various corn markets and suppliers. Although corn can be obtained from multiple sources, and while historically we have not suffered any significant limitations on our ability to procure corn, any delay or disruption in our suppliers ability to provide us with the necessary corn requirements may significantly affect our business operations and have a negative effect on our operating results or financial condition. At any given time, we may have up to 1.0 million bushels (or a 5 to 7 day supply) of corn stored on-site at our production facilities.

The key elements of our corn procurement strategies are the assurance of a stable supply and the avoidance, where possible, of exposures to corn price fluctuations. Corn prices fluctuate daily, typically using the Chicago Board of Trade (CBOT) price as a benchmark. Corn is delivered to our facilities via truck through local distribution networks and by rail.

Research and Development

Our research and development efforts are primarily conducted from our corporate office in Pekin, Illinois and are done in conjunction with the efforts of outside entities. These efforts consist of research into cellulosic ethanol (cellulosic plant biomass representing an untapped potential feedstock for the generation of fuel ethanol from renewable resources). We have partnered with Purdue University and the USDA s National Center for Agriculture Utilization Research in Peoria, Illinois to develop and scale up an efficient and economical pretreatment process for corn fiber and corn stover (the stalks and husks left over after harvest). We currently have two patents pending with Purdue University for the conversion of corn fiber to ethanol. We are committed to continuing research into the potential benefits associated with cellulosic ethanol.

Research and development expense was approximately $0.2 million in 2006, and $0.1 million in 2005 and 2004.

Patents and Trademarks

We own a number of trademarks and patents within the U.S. While we believe that our patents and trademarks provide a competitive advantage and have value, we do not consider the success of our business, as a whole, to be dependent on these patents, patent rights or trademarks.

Environmental and Regulatory Matters

We are subject to various stringent federal, state and local environmental laws, regulations and permit conditions (and interpretations thereof), including those relating to the discharge of materials into the air, water and ground, the generation, storage, handling, use, transportation and disposal of hazardous materials, and the health and safety of our employees. These laws, regulations and permits can often require expensive pollution control equipment or operational changes to limit actual or potential impacts to the environment. A violation of these laws, regulations or permit conditions can result in substantial fines, natural resource damages, criminal sanctions, permit revocations and/or facility shutdowns. We cannot assure you that we have been, are or will be at all times in complete compliance with these laws, regulations or permits or that we have had or currently have all permits required for our operations. From time to time, we have not been in full compliance with the wastewater and air discharge permits for our Illinois and Nebraska facilities. In the past, we have been subject to legal actions brought by environmental, regulatory authorities, advocacy groups and other parties for actual or alleged violations of environmental laws and regulations and certain of our environmental permits.

In addition, our air emissions are subject to the federal Clean Air Act, the federal Clean Air Act Amendments of 1990 and similar state laws which generally require us to obtain and maintain air emission permits for our ongoing operations as well as for any expansion of existing facilities or any new facilities. Obtaining and maintaining those permits requires us to incur costs, and any future more stringent standards may result in increased costs and may limit or interfere with our operating flexibility. A failure to obtain or maintain appropriate permits could delay any expansion or development of new facilities or delay or interfere with our operations. In addition, the permits ultimately issued may impose conditions which are more costly to implement than we had anticipated. These costs and potential delays could have a material adverse affect on our financial condition and results of operations. Because other ethanol manufacturers in the U.S. are and will continue to be subject to similar laws and restrictions, we do not currently believe that our costs to comply with current or future environmental laws and regulations will adversely affect our competitive position. However, because ethanol is produced and traded internationally, these costs could adversely affect us in our efforts to compete with foreign producers not subject to such stringent requirements.

Federal and state environmental authorities have been investigating alleged excess volatile organic compound, or VOC, emissions and other air emissions from many U.S. ethanol plants, including our Illinois and Nebraska facilities. In April 2005, we entered into a consent decree with state authorities settling their investigation of our Nebraska facility, which required us to, among other things, secure a new air emissions permit, install additional air pollution control equipment and pay a $40 thousand fine. The fine was paid in May 2005 and the permit issued in October 2005. The installation of the new equipment was completed in October 2006. We incurred approximately $4 million in costs relating to various pollution control equipment and to otherwise meet the requirements of the consent decree. The matter relating to our Illinois wet mill facility is still pending. We could be required to install additional air pollution control equipment, or take other measures to control air pollutant emissions at that facility. If authorities require us to install controls, we would anticipate that costs would be higher than those we incurred at our Nebraska facility due to the larger size of the Illinois wet mill facility. In addition, if the authorities determine our emissions were in violation of applicable law, we would likely be required to pay fines that could be material.

We have made, and expect to continue making, significant capital expenditures on an ongoing basis to comply with increasingly stringent environmental laws, regulations and permits. We have included in our capital budget for 2007 and 2008 approximately $10.8 million and $4.5 million, respectively, for projects relating to environmental, health and safety matters, including for the installation of air pollution control equipment and for wastewater discharge improvements at our Illinois wet mill facility. The majority of the 2007 environmental capital budget relates to compliance with the EPA s final National Emissions Standard for Hazardous Air Pollutants, or NESHAP, under the federal Clean Air Act for industrial, commercial and institutional boilers and process heaters. This NESHAP will require us to implement maximum achievable control technology at our Illinois wet mill facility to reduce hazardous air pollutant emissions from certain of our boilers and process heaters by September 13, 2007. Based on engineering conducted to date and currently available information, we have budgeted $7.4 million to comply with this NESHAP in 2007. Due to various reasons, including equipment delivery delays, however, we may not be able to meet the September 2007 deadline. We are continuing to discuss a deadline extension with the state authorities. If an extension is not granted, and we do not meet the September 2007 deadline, fines and penalties could be imposed on us, which could be substantial. See Item 7 Management s Discussion and Analysis of Financial Conditions and Results of Operations Liquidity and Capital Resources Uses of Liquidity Capital Expenditures, and Item 7 Management s Discussion and Analysis of Financial Conditions and Results of Operations Environmental Matters.

We are also subject to potential liability for the investigation and cleanup of environmental contamination at each of the properties that we own or operate and at off-site locations where we arranged for the disposal of hazardous wastes. For instance, soil and groundwater contamination has been identified in the past at our Illinois campus. If any of these sites are subject to investigation and/or remediation requirements, we may be responsible under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) or other environmental laws for all or part of the costs of such investigation and/or remediation, and for damages to natural resources. We may also be subject to related claims by private parties alleging property damage or personal injury due to exposure to hazardous or other materials at or from such properties. While costs to address contamination or related third party claims could be significant, based upon currently available information, we are not aware of any material contamination or third party claims, and we have not accrued any amounts for environmental matters as of December 31, 2006.

Recently, Underwriters Laboratories, or UL, an independent, not-for-profit product-safety testing and certification organization, withdrew approval of E-85 dispensers at gasoline stations until consistent and appropriate safety requirements for E-85 dispensers and components can be established. Although no instances of E-85 dispenser corrosion have been reported, UL indicated that a prudent course is to conduct corrosion testing before reinstating approval. We do not market branded E-85 and total E-85 sales are less than one half of one percent of our total ethanol sales. In the event that E-85 sales are restricted due to UL s review, the ethanol used to produce E-85 can easily be diverted back to the supply of regular denatured fuel ethanol at minimal cost.

See Item 1A Risk Factors We may be adversely affected by environmental, health and safety laws, regulations and liabilities.

Employees

At December 31, 2006, we had a total of 321 full-time equivalent employees. Approximately 52% of our employees (comprised of the hourly employees at our Illinois facilities) are represented by a union. The unionized employees are covered by a collective bargaining agreement between our subsidiary, Aventine Renewable Energy, Inc. and the United Steelworkers International Union, Local 7-662, that expires in June 2009. As a whole, we believe our relations with our employees are good.

Item 1A. Risk Factors

We operate in a highly competitive industry with low barriers to entry. In addition, if the expected increase in ethanol demand does not occur, or if the demand for ethanol otherwise decreases, there may be excess capacity in our industry.

In the U.S., we compete with other corn processors and refiners, including Archer-Daniels-Midland Company, VeraSun Energy Corporation, Hawkeye Holdings, Inc., Pacific Ethanol, U.S. BioEnergy Corporation, Cargill, Inc. and A.E. Staley Manufacturing Company, a subsidiary of Tate & Lyle, PLC. Some of our competitors are divisions of larger enterprises and have greater financial resources than we do. Although many of our competitors are larger than we are, we also have smaller competitors. Farm cooperatives comprised of groups of individual farmers have been able to compete successfully. As of December 2006, the top ten domestic producers accounted for approximately 45% of all production capacity.

We also face increasing competition from international suppliers. Although there is a tariff on foreign produced ethanol that is slightly larger than the federal ethanol tax incentive, ethanol imports equivalent to up to 7% of total domestic production from certain countries were exempted from this tariff under the CBI (The Caribbean Basin Initiative) to spur economic development in Central America and the Caribbean.

Moreover, domestic capacity has increased steadily from 1.3 billion gallons per year in 1997 to 5.4 billion gallons per year at the end of 2006. In addition, there is a significant amount of capacity being added to our industry. According to the RFA, approximately 6.0 billion gallons per year of production capacity was under construction as of December 2006. This capacity is being added to address anticipated increases in demand. Demand for ethanol may not increase as quickly as expected or to a level that exceeds supply, or may not increase at all. If the ethanol industry has excess capacity and such excess capacity results in a fall in prices, it will have an adverse impact on our results of operations, cash flows and financial condition. Excess capacity may result from the increases in capacity coupled with insufficient demand. Demand could be impaired due to a number of factors, including regulatory developments and reduced U.S. gasoline consumption. Reduced gasoline consumption could occur as a result of increased gasoline or oil prices. For example, price increases could cause businesses and consumers to reduce driving or acquire vehicles with more favorable gasoline mileage. There is some evidence that this has occurred in the recent past as U.S. gasoline prices have increased. Demand for ethanol can also fall if gasoline prices decrease because ethanol is used as a potential substitute for gasoline.

During 2002, our results of operations were significantly negatively impacted because of the excess capacity which came online in anticipation of the MTBE ban in California which became effective later than expected. Our top customers are oil companies which make significant profits from the sale of gasoline. As such they may oppose mandated blending of gasoline with ethanol and any increase in such mandated blending. Our competitors include plants owned by farmers who earn their livelihood through the sale of corn, and hence may not be as focused on obtaining optimal value for their produced ethanol as we are.

Our business is dependent upon the availability and price of corn. Significant disruptions in the supply of corn will materially affect our operating results. In addition, since we generally cannot pass on increases in corn prices to our customers, continued periods of historically high corn prices will also materially adversely affect our operating results.

The principal raw material we use to produce ethanol and ethanol by-products is corn. In 2006, we purchased approximately 51.0 million bushels of corn at a cost of $122.4 million, which comprised about 57.2% of our total cost of production. In 2006, our average corn cost ranged from a low of $2.05 per bushel in January 2006 to a high of $3.14 per bushel in December 2006. Beginning in September 2006, corn prices began rising significantly, and this trend continues. The vast increase in U.S. ethanol capacity under construction could outpace increases in corn production, which may increase corn prices and significantly impact our profitability.

As a result, changes in the price of corn have had an impact on our business. In general, higher corn prices produce lower profit margins and, therefore, represent unfavorable market conditions. This is especially true when market conditions do not allow us to pass along increased corn costs to our customers. At certain levels, corn prices may make ethanol uneconomical to use in markets and volumes above the requirements set forth in the renewable fuels standard or for which ethanol is used as an oxygenate in order to meet federal and state fuel emission standards.

The price of corn is influenced by general economic, market and regulatory factors. These factors include weather conditions, farmer planting decisions, government policies and subsidies with respect to agriculture and international trade and global demand and supply. The significance and relative impact of these factors on the price of corn is difficult to predict. Factors such as severe weather or crop disease could have an adverse impact on our business because we may be unable to pass on higher corn costs to our customers. Any event that tends to negatively impact the supply of corn will tend to increase prices and potentially harm our business. The increasing ethanol capacity could boost demand for corn and result in increased prices for corn. We expect the price of corn to continue to remain at levels that would be considered as historically high.

In an attempt to partially offset the effects of fluctuations in corn costs on operating income, we take hedging positions in the corn futures markets. However, these hedging transactions also involve risk to our business. See Item 1A Risk Factors We may engage in hedging or derivative transactions which involve risks that can harm our business.

The spread between ethanol and corn prices can vary significantly and our profitability from gallons produced at our facilities is dependent on this spread.

Gross profit on gallons produced at our facilities, which accounts for the substantial majority of our operating income, is principally dependent on the spread between ethanol and corn prices. The spread between ethanol and corn prices in 2006 was at historically high levels, driven in large part by high oil prices and shortages of ethanol. The spread between ethanol and corn prices has fallen significantly since the summer of 2006. Any reduction in the spread between ethanol and corn prices, whether as a result of an increase in corn prices or a reduction in ethanol prices, would adversely affect our financial performance. If the spread decreases below a certain level, we will likely experience losses.

Fluctuations in the demand for gasoline may reduce demand for ethanol.

Ethanol is marketed as both an oxygenate to reduce vehicle emissions from gasoline and as an octane enhancer to improve the octane rating of gasoline with which it is blended. As a result, ethanol demand is influenced by the supply of and demand for gasoline. Therefore, the price of ethanol tends to rise and fall with gasoline prices. If gasoline demand decreases, our results of operations and financial condition may be materially adversely affected.

The U.S. ethanol industry is highly dependent upon a myriad of federal and state legislation and regulation, and any changes in such legislation or regulation could materially adversely affect our results of operations and financial condition.

The elimination or significant reduction in the federal ethanol tax incentive could have a material adverse effect on our results of operations.

The production of ethanol is made significantly more competitive by federal tax incentives. The federal excise tax incentive program, which is scheduled to expire on December 31, 2010, allows gasoline distributors and refiners who blend ethanol with gasoline to receive a federal excise tax credit for each blended gallon they sell regardless of the blend rate. If the fuel is blended with ethanol, the blender may claim a $0.51 per gallon tax credit for each gallon of ethanol used in the mixture. We cannot provide any assurance, however, that the federal ethanol tax incentives will be renewed in 2010 or if renewed, on what terms they will be renewed. The elimination of, or a significant reduction in, the federal ethanol tax incentive could have a material adverse effect on our results of operations.

Waivers of the RFS minimum levels of renewable fuels included in gasoline could have a material adverse affect on our results of operations.

Under the Energy Policy Act of 2005, the Department of Energy, in consultation with the Secretary of Agriculture and the Secretary of Energy, may waive the RFS mandate with respect to one or more states if the administrator determines that implementing the requirements would severely harm the economy or the environment of a state, a region or the U.S., or that there is inadequate supply to meet the requirement. Any waiver of the RFS with respect to one or more states would adversely offset demand for ethanol and could have a material adverse effect on our results of operations and financial condition.

While the Energy Policy Act of 2005 imposes a RFS, it does not mandate the use of ethanol.

The RFS included in the Energy Policy Act of 2005 requires blenders and refiners to use renewable fuels (which includes ethanol), in amounts prescribed in the Act. While the RFA expects that ethanol should account for the largest share of renewable fuels produced and consumed under the RFS, the RFS is not limited to ethanol and also includes biodiesel and any other liquid fuel produced from biomass or biogas. Currently, there is not significant industrial capacity to produce these alternatives. However, we believe there are proto-type plants in operation and there could be plans to build additional plants.

Although the RFS requires the use of prescribed amounts of renewable fuels, the EPA has not finalized the rules which will enforce this requirement. We expect those rules to include credit trading by our customers. It is possible that the practical application of these rules will not result in as much demand for ethanol as anticipated.

While the Energy Policy Act of 2005 eliminated the oxygenate requirement contained in the Clean Air Act, it did not eliminate fuel emission standards that refiners must meet. Oxygenates, particularly ethanol, continue to be used by refiners to meet federal and state fuel emission requirements. However, we cannot provide any assurance that the elimination of the oxygenate requirement for reformulated gasoline in the RFG program included in the Clean Air Act will not result in a decline in ethanol consumption, which in turn could have a material adverse effect on our results of operations and financial condition.

Certain countries can import ethanol into the U.S. duty free, which may undermine the ethanol industry in the U.S.

Imported ethanol is generally subject to a $0.54 per gallon tariff and a 2.5% *ad valorem* tax that was designed to offset the $0.51 per gallon ethanol subsidy currently available under the federal excise tax incentive program for refineries and blenders that mix ethanol with their gasoline. On December 20, 2006, the tariff on foreign produced ethanol was extended until January 1, 2009. At a certain price level, imported ethanol may become profitable for sale in the U.S. despite the tariff. This occurred in the second half of 2006, due to a spike in the ethanol prices and insufficient supply. As a result, there may effectively be a ceiling on U.S. ethanol prices. This, combined with uncertainties surrounding U.S. producers ability to meet domestic demand, resulted in significant imports of ethanol, especially from Brazil. Furthermore, East Coast facilities are better suited to bringing in product by water rather than rail (the preferred path for ethanol from the Midwest). The combination made it more economic for some buyers to import ethanol with the full import duty than to bring supplies from the Midwest. Given the increase in ethanol demand from the elimination of MTBE and expected transportation bottlenecks delivering material from the Midwest, imports of ethanol could rise.

There is a special exemption from the tariff for ethanol imported from 24 countries in Central America and the Caribbean islands which is limited to a total of 7% of U.S. production per year (with additional exemptions for ethanol produced from feedstock in the Caribbean region over the 7% limit). In addition, the NAFTA (The North America Free Trade Agreement which was signed into law January 1, 1994) countries, Canada and Mexico, are exempt from duty. See Item 1 Business Legislative Drivers and Government Regulation The federal ethanol tax incentive program. Imports from the exempted countries have increased in recent years and are expected to increase further as a result of new plants under development.

We may be adversely affected by environmental, health and safety laws, regulations and liabilities.

We are subject to various stringent federal, state and local environmental laws and regulations, including those relating to the discharge of materials into the air, water and ground, the generation, storage, handling, use, transportation and disposal of hazardous materials, and the health and safety of our employees. In addition, some of these laws and regulations require our facilities to operate under permits that are subject to renewal or modification. These laws, regulations and permits can often require expensive pollution control equipment or operational changes to limit actual or potential impacts to the environment. A violation of these laws and regulations or permit conditions can result in substantial fines, natural resource damages, criminal sanctions, permit revocations and/or facility shutdowns. We cannot assure you that we have been, are or will be at all times in complete compliance with these laws, regulations or permits or that we have had or currently have all permits required to operate our business. Environmental laws and regulations (and interpretations thereof) change over time, and any such changes, more vigorous enforcement policies or the discovery of currently unknown conditions may require substantial additional environmental expenditures and may have a material adverse effect on our results of operations or financial condition. In addition, continued government and public emphasis on environmental issues can be expected to result in increased future investments for environmental controls at our ongoing operations. In the past, we have been subject to legal actions brought by environmental, regulatory authorities, advocacy groups and other parties for actual or alleged violations of environmental laws and regulations and certain of our environmental permits. We cannot assure you that we will not be subject to legal actions brought by such parties in the future for actual or alleged violations.

Federal and state environmental authorities have been investigating alleged excess VOC emissions and other air emissions from U.S. ethanol plants, including our Illinois wet mill and Nebraska facilities. In April 2005, we entered into a consent decree with state authorities, settling their investigation with respect to our Nebraska facility, which consent decree required us to secure a new air emissions permit, install additional air pollution control equipment at a cost of approximately $4 million and pay a $40 thousand fine. The matter relating to our Illinois wet mill facility is still pending, and we could be required to install additional air pollution control equipment or take other measures to control air pollutant emissions at this facility. If authorities require us to install controls, costs would likely be higher than those expended at our Nebraska facility due to the larger size of the Illinois wet mill facility. In addition, we may be required to pay fines that could be material if the authorities determine our emissions were in violation of applicable law. We cannot assure you that the resolution of this or any other environmental matters affecting us will not have a material adverse effect on our results of operations or financial condition.

We have made, and expect to continue making, significant capital expenditures on an ongoing basis to comply with increasingly stringent environmental laws, regulations and permits. We have included in our capital budget for 2007 and 2008 approximately $10.8 million and $4.5 million, respectively, for projects relating to environmental, health and safety matters, including for the installation of air pollution control equipment and for wastewater discharge improvements at our Illinois wet mill facility. The majority of the 2007 environmental capital budget relates to compliance with the EPA s final National Emissions Standard for Hazardous Air Pollutants, or NESHAP, under the federal Clean Air Act for industrial, commercial and institutional boilers and process heaters. This NESHAP will require us to implement maximum achievable control technology at our Illinois wet mill facility to reduce hazardous air pollutant emissions from certain of our boilers and process heaters by September 13, 2007. Based on engineering conducted to date and currently available information, we have budgeted $7.4 million to comply with this NESHAP in 2007. Due to various reasons, including equipment delivery delays, however, we may not be able to meet the September 2007 deadline. We are continuing to discuss a deadline extension with the state authorities. If an extension is not granted, and we do not meet the September 2007 deadline, fines and penalties could be imposed on us, which could be substantial. See Item 7 Management s Discussion and Analysis of Financial Conditions and Results of Operations Liquidity and Capital Resources Uses of Liquidity Capital Expenditures, and Item 7 Management s Discussion and Analysis of Financial Conditions and Results of Operations Environmental Matters.

We are also subject to potential liability for the investigation and cleanup of environmental contamination at each of the properties that we own or operate and at off-site locations where we arranged for the disposal of hazardous wastes, including contamination caused by prior owners or operators of all such locations, abutters or other persons. If hazardous or other materials have been or are disposed of or released at sites that undergo investigation and/or remediation, we may be responsible under CERCLA or other environmental laws for all or part of the costs of such investigation and/or remediation, and for damages to natural resources. We have not accrued any amounts for environmental contamination matters as of December 31, 2006. The ultimate costs of any liabilities that may be identified or the discovery of additional contaminants could adversely impact our results of operation or financial condition. We may also be subject to related claims by private parties alleging property damage and personal injury due to exposure to hazardous or other materials at or from such properties. Some of these matters may require us to expend significant amounts for investigation and/or cleanup or other costs.

In addition, the hazards and risks associated with producing and transporting our products (such as fires, natural disasters, explosions, abnormal pressures and spills) may result in personal injury claims or damage to property, natural resources and third parties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. Our coverage includes, but is not limited to, physical damage to assets, employer s liability, comprehensive general liability, automobile liability and workers compensation. We do not carry environmental insurance. We believe that our insurance is adequate for our industry, but losses could occur for uninsurable, or uninsured, risks or in amounts in excess of existing insurance coverage. The occurrence of events which result in significant personal injury or damage to our property, natural resources or third parties that are not covered by insurance could have a material adverse impact on our results of operations and financial condition.

We currently generate revenue from the sale of carbon dioxide which is a co-product of the ethanol production process at each of our Illinois and Nebraska facilities. If new laws or regulations are passed relating to the production, disposal or emissions of carbon dioxide, we may not be able to continue generating revenue from carbon dioxide sales. Furthermore, we may also be required to incur significant costs to comply with any new laws or regulations relating to carbon dioxide.

For more information about our environmental compliance and actual and potential environmental liabilities, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Uses of Liquidity Capital Expenditures, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental Matters, and Item 1 Business Environmental Matters.

We may engage in hedging or derivative transactions which involve risks that can harm our business.

In an attempt to minimize the effects of the volatility of the price of corn, natural gas, electricity and ethanol (commodities) and interest rates on operating income, we may take hedging positions in the commodities and enter into interest rates futures, options, swaps and caps. Hedging arrangements also expose us to the risk of financial loss in situations where the other party to the hedging contract defaults on its contract or there is a change in the expected differential between the underlying price in the hedging agreement and the actual price of the commodities. Although we attempt to link our hedging activities to sales plans and pricing activities, occasionally such hedging activities can themselves result in losses. There can be no assurance that such losses will not occur. Alternatively, we may choose not to engage in hedging transactions in the future. As a result, our results of operations may be adversely affected during periods in which corn and/or natural gas prices increase.

We are substantially dependent on our three facilities and our alliance partner facilities and any operational disruption could result in a reduction of our sales volumes and could cause us to incur substantial expenditures.

The substantial majority of our net income is derived from the sale of ethanol and the related bio-products and co-products that we produce at our Illinois facilities and our Nebraska facility. Our operations may be subject to significant interruption if either of the Illinois facilities or Nebraska facility experiences a major accident or is damaged by severe weather or other natural disaster. In addition, our operations may be subject to labor disruptions and unscheduled downtime, or other hazards inherent in our industry. Some of those hazards may cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension or termination of operations and the imposition of civil or criminal penalties. As protection against these hazards, we maintain property, business interruption and casualty insurance which we believe is in accordance with customary industry practices, but we cannot provide any assurance that this insurance will be adequate to fully cover the potential hazards described above or that we will be able to renew this insurance on commercially reasonable terms or at all.

Any disruptions at our alliance partners facilities could have a material adverse effect on our results of operations and financial condition. We agree through our alliance partner agreements to purchase all fuel grade ethanol produced by our alliance partners and title to the product transfers to us when product is loaded. Any disruptions at the alliance partners facilities could affect our ability to meet our customers demands. As a result of a disruption at an alliance facility, we may have to purchase ethanol from the spot market.

The market for natural gas is subject to market conditions that create uncertainty in the price and availability of the natural gas that we utilize in our production process.

We rely upon third parties for our supply of natural gas which is consumed in the production of ethanol. The prices for and availability of natural gas are subject to volatile market conditions. These market conditions often are affected by factors beyond our control such as weather conditions (including hurricanes), overall economic conditions and foreign and domestic governmental regulation and relations. Significant disruptions in the supply of natural gas could temporarily impair our ability to produce ethanol for our customers. Further, increases in natural gas prices or changes in our natural gas costs relative to natural gas costs paid by competitors may adversely affect our results of operations and financial condition. The price fluctuation in natural gas prices over the seven year period from 1999 through December 31, 2006, based on the New York Mercantile Exchange, or Nymex, daily futures data, has ranged from a low of $1.63 per MMBtu in 1999 to a high of $15.38 per MMBtu in December 2005. We currently use approximately 4.1 million MMBtu s of natural gas annually, depending upon business conditions, in the manufacture of our products. Our usage of natural gas will increase with the planned expansion of our production facilities.

In an attempt to minimize the effects of fluctuations in natural gas costs on operating income, we may take hedging positions in the natural gas futures markets; however, these hedging transactions also involve risk to our operations. Since natural gas prices are volatile should we not take hedging positions, as occurs from time to time, our results could be adversely affected by an increase in natural gas prices. See We may engage in hedging or derivative transactions which involve risks that can harm our business.

Our fixed price contracts for ethanol may be at a price level lower than the prevailing price.

At any given time, our contract prices for ethanol may be at a price level different from the current prevailing price, and such a difference could materially adversely affect our results of operations and financial condition. These contracts typically provide for delivery from one month to one year later. As of December 31, 2006 we had contracted to sell 94.6 million gallons of ethanol at an average fixed price of $1.97. We have also contracted to sell 68.6 million gallons of ethanol at an average positive spread of $0.41 per gallon to the wholesale value of gasoline at the time of delivery and 128.4 million gallons of ethanol at the spot price at the time of delivery. These contracts provide for delivery throughout 2007, but they are heavily weighted towards the first and second quarters of 2007.

Changes in ethanol prices can affect the value of our inventory which may significantly affect our profitability.

Our distribution system allows us to carry an inventory of ethanol to better serve our customers and to take advantage of opportunities in the marketplace. Our inventory is valued based upon a weighted average price we pay for ethanol that we purchase from our marketing alliance partners and our purchase/resale transactions, along with our own cost to produce ethanol. We occasionally increase our inventory, in order to profit when we believe market prices will rise. Changes, either upward or downward, in our purchased cost of ethanol or our own production costs, will cause the inventory value to fluctuate from period to period, perhaps significantly. These changes in value flow through our statement of operations as the inventory is sold and can significantly increase or decrease our profitability.

We depend on rail, truck and barge transportation for delivery of corn to us and the distribution of ethanol to our customers.

We depend on rail, truck and barge to deliver corn to us and to distribute ethanol to the 52 terminals currently in our network. Disruption to the timely supply of these transportation services or increases in the cost of these services for any reason, including the availability or cost of fuel, regulations affecting the industry, or labor stoppages in the transportation industry, could have an adverse effect on our ability to supply corn to our production or to distribute ethanol to our terminals, and could have a material adverse effect on our financial performance.

Under certain conditions, we are contractually obligated to complete capacity expansions in Mount Vernon, Indiana and Aurora, Nebraska. If the conditions to our obligations to complete these plants are satisfied and we fail to complete them, we will be subject to material penalties.

We are contractually obligated, subject to certain conditions, including obtaining necessary permits, to develop both a 113 million gallon dry mill adjacent to our Nebraska facility (using commercially reasonable best efforts to obtain a permit for 226 million gallon capacity) and a 226 million gallon dry mill in Mount Vernon, Indiana. If we do not meet certain specified milestones we will be subject to penalties. The contract to complete the 226 million gallon dry mill expansion adjacent to our Nebraska facility provides for liquidated damages not exceeding $5 million if specified milestones are not met or we do not construct a facility with a capacity of at least 110 million gallons. If such penalties are not paid, the counterparty to the contract has the right to repurchase the property at cost (subject to adjustment for any expenses, which we have paid with respect to infrastructure construction). In certain cases, the counterparty can agree to an extension and limited cure rights for payments. The contract for completion of the 226 million gallon dry mill in Mount Vernon, Indiana provides that, if we do not meet certain milestones, subject to specified extension rights and cure periods, we will be in default under our lease with the Indiana Port Commission and the State of Indiana may complete construction of the plant at our expense if we fail to do so and does not provide for liquidated damages as an alternative. In addition, we would also be subject to certain other penalties provided for in the lease. Notwithstanding the above, if, despite our diligent efforts, we are unable to obtain permits for the Mt. Vernon facility by a certain date, we can negotiate a waiver of the compliance date and establish a new date for compliance. If we do not reach an agreement, either the Mt. Vernon lessor or we can terminate the Mt. Vernon lease. Accordingly, we cannot estimate the amount of damages we could be liable for.

We, and some of our major customers, have unionized employees and could be adversely affected by labor disputes.

Some of our employees and some employees of our major customers are unionized. At December 31, 2006, approximately 52% of our employees were unionized. Our unionized employees are hourly workers located at our Illinois campus. The unionized employees are covered by a collective bargaining agreement between our subsidiary, Aventine Renewable Energy, Inc. and the United Steelworkers International Union, Local 7-662, that expires in June 2009. Any labor dispute by any of our employees, or our customers employees, could again have a significant negative effect on our financial results and operations.

We depend on our marketing alliance contracts for a majority of the gallons we sell and significant synergies.

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We source a significant amount of the ethanol that we sell from our marketing alliance partners. Although their contribution to our operating income is limited, these marketing alliance contracts contribute significantly to our market presence and enable us to meet major ethanol consumer needs and leverage our marketing expertise and distribution systems. Our marketing alliance contracts typically have a two year term and automatically renew for additional one year terms unless either party elects to terminate in advance. We cannot give assurance that we will be able to renew these contracts or enter into similar contracts with other ethanol producers. In fact, two of our alliance partners (VeraSun Fort Dodge, LLC and VeraSun Aurora Corporation formerly VeraSun Energy Corporation) which represent 230 million gallons of capacity, have notified us in writing that they will not renew their marketing alliances with us upon termination on March 31, 2007. In addition, a third marketing alliance partner, Granite Falls Energy, LLC, which produces approximately 52 million gallons of ethanol annually, has also notified us that they will not renew their marketing alliance contract upon termination on November 30, 2007. However, Granite Falls has asked us to submit a new proposal for marketing services. Although we believe that the loss of this capacity will be eventually offset by the addition of capacity already announced or under construction and by increased volume of purchase/resale activity, we cannot give any assurance that this additional capacity will be constructed on time or at all.

We are controlled by principal stockholders whose interests may differ from your interests and who will be able to exert significant influence over corporate decisions of the Company.

Through their ownership of Aventine Holdings LLC, the MSCP funds beneficially own approximately 28.3% of our outstanding common stock. In July 2004, Morgan Stanley Investment Management Inc. entered into definitive agreements under which Metalmark Subadvisor LLC, an affiliate of Metalmark, an independent private equity firm established by former principals of Morgan Stanley Capital Partners, manages the existing MSCP funds on a sub-advisory basis. Two of our directors, Messrs. Abramson and Hoffman, currently are employees of Metalmark. Our amended and restated certificate of incorporation provides that directors may not be removed from office by the stockholders except for cause and only by the affirmative vote of the holders of not less than 85% of the voting power of the issued and outstanding shares of our capital stock entitled to vote generally at an election of directors.

As a result, Metalmark may be deemed to control our management and policies. Metalmark may have an interest in pursuing transactions that, in their judgment, enhance the value of the MSCP funds equity investment in our Company, even though those transactions may involve risks to you as a stockholder. In addition, circumstances could arise under which the interests of Metalmark could be in conflict with the interests of our other stockholders. For example, Metalmark has and may in the future make significant investments in other companies, some of which may be competitors. Metalmark is not obligated to advise us of any investment or business opportunities of which they are aware, and they are not restricted or prohibited from competing with us.

Our less than 100% ownership of Nebraska Energy, LLC (NELLC) and the supermajority provisions contained in the operating agreement that governs NELLC may restrict our ability to govern and manage our business.

We own 78.4% of NELLC which owns our Nebraska facility. The other 21.6% is owned by Nebraska Energy Cooperative, an agricultural cooperative comprised of over 200 corn producers. NELLC is governed by an operating agreement which, among other things, requires a vote of holders of at least 80% of the outstanding member interests before NELLC may undertake certain actions, including, but not limited to the following:

• loans or advances to or investments in any other person, other than in the ordinary course of business;

• acquisitions of capital assets or other capital expenditures during any taxable year in excess of certain specified thresholds;

• the sale, lease or disposition of the property having a fair market value in excess of certain specified thresholds;

• borrowings (including under capitalized leases, but excluding trade payables in the ordinary course of business) or the grant or creation of any security interest or other lien on any of NELLC s property;

• the guarantee or assumption of any liability or obligation of any person, except in the ordinary course of business;

• except as provided in the operating agreement, the acquisition of any member s interests in NELLC by redemption or otherwise;

• the engagement of any member or affiliate of any member to provide any services or perform any functions to or for NELLC (such as renting office space, providing accounting services, providing self-insurance or allocations of any member overhead to NELLC); and

• any transaction not in the ordinary course of business or affairs or in the usual way of business and affairs NELLC.

The operating agreement also contains provisions which require NELLC to obtain the approval of holders of at least 80% of the membership interests in order to distribute an amount in excess of 60% of its annual taxable income (as defined in the operating agreement).

These provisions may limit our ability to quickly and adequately respond to changes in the business environment and may restrict our ability to manage the NELLC facility in a manner that benefits our Company as a whole. For example, we may not be able to access additional financing unless we can obtain the guarantee of NELLC or a pledge of its assets, and the other members of NELLC may not approve such a guarantee or pledge. These provisions limit our ability to transfer cash from the NELLC to meet our obligations.

The relationship between the sales price of our co-products and the price we pay for corn can fluctuate significantly which may affect our results of operations and profitability.

We sell co-products and bio-products that are remnants of the ethanol production process in order to reduce our costs and increase profitability. Historically, sales prices for these co-products have tracked along with the price of corn. Recently, due to the significant and rapid rise of corn prices, the value of these co-products and bio-products has lagged behind increases in corn prices. As a result, we may generate less revenue from the sale of these co-products and bio-products relative to the price of corn. In addition, several of our co-products compete with similar products made from other plant feedstock. The cost of these other feedstocks may not have risen as corn prices have risen. Consequently, the price we may receive for these products may not rise as corn prices rise, thereby lowering our cost recovery percentage relative to corn.

Due to recent and planned industry increases in U.S. dry mill ethanol production, the production of DDGS in the U.S. has increased dramatically, and this trend may continue. This may cause DDGS prices to fall in the U.S., unless demand increases or other market sources are found. To date, demand for DDGS in the U.S. has increased roughly in proportion to supply. We believe this is because U.S. farmers use DDGS as a feedstock, and DDGS are slightly less expensive than corn, for which it is a substitute. However, if prices for DDGS in the U.S. fall, it may have an adverse effect on our business, which might be material.

Our results of operations may be adversely affected by technological advances.

The development and implementation of new technologies may result in a significant reduction in the costs of ethanol production. We cannot predict when new technologies may become available, the rate of acceptance of new technologies by our competitors or the costs associated with such new technologies. In addition, advances in the development of alternatives to ethanol, or corn ethanol in particular, could significantly reduce demand for or eliminate the need for ethanol, or corn ethanol in particular, as a fuel oxygenate or octane enhancer.

Any advances in technology which require significant capital expenditures for us to remain competitive or which otherwise reduce demand for ethanol will have a material adverse effect on our results of operations and financial condition.

The requirements of complying with the Exchange Act and the Sarbanes-Oxley Act may strain our resources and distract management.

We are subject to the reporting requirements of the Exchange Act, and the Sarbanes-Oxley Act, including Section 404. These requirements may place a strain on our systems and resources. The Exchange Act requires that we file annual, quarterly and current reports with respect to our business and financial condition. The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures, corporate governance standards and internal controls over financial reporting. Pursuant to Section 404 of the Sarbanes-Oxley Act, our management will be required to deliver a report that assesses the effectiveness of our internal control over financial reporting. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight will be required as we may need to devote additional time and personnel to legal, financial and accounting activities to ensure our ongoing compliance with public company reporting requirements. We are currently working towards completing our Sarbanes-Oxley and Exchange Act obligations. We may not be able to complete the documentation and management assessment required by Section 404 of the Sarbanes-Oxley Act by the date it becomes applicable to us. Our first attestation will be for the year ended December 31, 2007. In addition, the effort to prepare for these obligations may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, we may need to hire additional accounting and financial staff with appropriate public company experience and technical accounting knowledge, and might not be able to do so in a timely fashion.

The loss of any of our major customers could adversely affect our revenue and financial health.

In 2006 and 2005, our 10 largest customers accounted for approximately 75% and 77%, respectively, of gallons sold. If we were to lose any of our relationships with these customers, our revenue, and results of operations and financial condition might suffer.

Risks associated with the operation of our production facilities may have a material adverse effect on our business.

Our revenue is dependent on the continued operation of our various production facilities. The operation of production plants involves many risks including:

- the breakdown, failure or substandard performance of equipment or processes, as occurred in the second and third quarters of 2006;
- inclement weather and natural disasters, as occurred in the fourth quarter of 2006;
- the need to comply with directives of, and maintain all necessary permits from, governmental agencies;

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- raw material supply disruptions;
- labor force shortages, work stoppages, or other labor difficulties; and
- transportation disruptions.

The occurrence of material operational problems, including but not limited to the above events, may have an adverse effect on the productivity and profitability of a particular facility, or to us as a whole.

For example, during the second and third quarters of 2006, we experienced operational issues at our Nebraska facility. These operational issues reduced the amount of ethanol and co-products produced by this facility during that time period. In addition, we also experienced weather-related disruptions of our operations during the fourth quarter of 2006 at both the Illinois wet mill facility and the Nebraska facility, which reduced production and increased maintenance costs.

If we are unable to attract and retain key personnel, our ability to operate effectively may be impaired.

Our ability to operate our business and implement strategies depends, in part, on the efforts of our executive officers and other key employees. Our management philosophy of cost-control means that we operate with a limited number of corporate personnel, and our commitment to a less centralized organization also places greater emphasis on the strength of local management. Our future success will depend on, among other factors, our ability to attract and retain other qualified personnel, particularly executive management. The loss of the services of any of our key employees or the failure to attract or retain other qualified personnel, domestically or abroad, could have a material adverse effect on our business or business prospects.

If our internal computer network and applications suffer disruptions or fail to operate as designed, our operations will be disrupted and our business may be harmed.

We rely on network infrastructure and enterprise applications, and internal technology systems for our operational, marketing support and sales, and product development activities. The hardware and software systems related to such activities are subject to damage from earthquakes, floods, lightning, tornadoes, fire, power loss, telecommunication failures and other similar events. They are also subject to acts such as computer viruses, physical or electronic vandalism or other similar disruptions that could cause system interruptions and loss of critical data, and could prevent us from fulfilling our customers orders. We have developed disaster recovery plans and backup systems to reduce the potentially adverse effects of such events, but there are no assurances such plans and systems would be sufficient. Any event that causes failures or interruption in our hardware or software systems could result in disruption of our business operations, have a negative impact on our operating results, and damage our reputation.

We and our subsidiaries are able to incur substantial debt. This could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries are able to incur substantial indebtedness in the future. Our planned capacity increases require us to incur substantial additional indebtedness. If new debt is added, the related risks that we and our subsidiaries now face could intensify.

Any acquisitions or developments we complete could dilute your ownership interest in us or have a material adverse affect on our financial condition and operating results.

The integration of any acquisition or facility development into our business may result in unforeseen operating difficulties and may require significant financial and managerial resources that would otherwise be available for the ongoing development or expansion of our existing operations.

Future acquisitions or facility developments may involve the issuance of our equity securities as payment or in connection with financing the business or assets acquired. Consummating these transactions could also result in the incurrence of additional debt and related interest expense, as well as unforeseen liabilities, all of which could have a material adverse effect on our financial condition and operating results.

In addition, other marketing alliances exist and additional alliances may be formed which would compete to market production, including production of our current marketing alliance partners. These competing alliances could persuade our current partners not to renew their agreements or could cause the terms of future contracts to be less favorable to us. If we lose marketing partners to competing marketing alliances or are unable to add new producers to our alliance, our results of operations may be adversely affected.

Our stock price may be volatile.

The market price of our common stock could be subject to significant fluctuations. Among the factors that could affect our stock price are:

- quarterly variations in our operating results;
- changes in revenue or earnings estimates or publication of research reports by analysts;
- failure to meet analysts   or our own revenue or earnings estimates;
- speculation in the press or investment community;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- the impact of the risks discussed herein and our ability to react effectively to those risks;
- limited trading volume of our common stock;
- a change in technology that may add to production costs;
- actions by institutional stockholders;
- general market conditions; and
- domestic and international economic factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Limited trading volume of our common stock may contribute to its price volatility.

Our common stock is traded on the New York Stock Exchange. For the period of June 29, 2006 to December 31, 2006 (the time period that our common stock was traded on the NYSE), the average daily trading volume of our common stock as reported by Bloomberg L.P. was approximately 670,000 shares. It is uncertain whether a more active trading market in our common stock will develop. If analysts were to discontinue coverage of our common stock, our trading volume may be further reduced. As a result, relatively small trades could potentially have a significant impact on the market price of our common stock, which could increase the volatility and depress the price of our stock.

Future sales of our common stock may cause the price of our common stock to decline or impair our ability to raise capital in the equity markets.

In the future, we may sell additional shares of our common stock in public or private offerings, and we may also issue additional shares of common stock to finance future acquisitions. Shares of our common stock are also available for future sales pursuant to stock options and/or restricted stock that we have granted to certain employees and directors, and in the future we may grant additional stock options and/or restricted stock to our employees and directors. Sales of substantial amounts of common stock, or

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the perception that such sales could occur, may adversely affect prevailing market prices for shares of our common stock and could impair our ability to raise capital through future offerings.

Provisions in our charter documents, Delaware law and in other agreements may delay or prevent an acquisition of Aventine, which could decrease the value of our common stock.

Provisions in our amended certificate of incorporation and bylaws, Delaware corporate law and our stockholder rights plan may make it more difficult and expensive for a third party to pursue a tender offer, change in control or takeover attempt without the consent of our board of directors. These provisions include a classified board of directors, removal of directors only for cause, and the inability of stockholders to act by written consent or to call special meetings. Although we believe these provisions provide for an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our board of directors, these provisions apply even if the offer may be considered beneficial by some stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We have current capacity to produce 207 million gallons of ethanol per year. Our corporate headquarters are located in Pekin, Illinois. Listed below are our production facilities and land acquired for planned expansions/future developments:

Current Production Facilities:

Location	Owned/ Leased	Property Size (acres)	Nameplate Capacity (in millions of gallons)	Mill Type	Year Opened	Number of Production Related Employees at Dec. 31, 2006	Description
Pekin, IL	**Owned**	**83**	**100**	**Wet**	**1981**	**218**	**Produces fuel-grade ethanol, as well as co-products and bio-products consisting of corn gluten feed, corn gluten meal, condensed corn distillers with solubles (both wet and dry), corn germ, carbon dioxide and Kosher and Chametz free brewers yeast. The Pekin facility also houses our corporate staff.**
Pekin, IL	**Owned**	**11**	**57**	**Dry**	**2007**	**17**	**Produces fuel-grade ethanol, as well as co-products consisting of dried distillers grains, wet distillers grains and carbon dioxide.**
Aurora, NE	**Owned**	**30**	**50**	**Dry**	**1995**	**41**	**Produces fuel-grade ethanol, as well as co-products consisting of dried distillers grains, wet distillers grains and carbon dioxide.**

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Land for Future Expansion:

Location	Owned/Leased	Property Size (acres)	Description
Aurora, NE	**Owned**	**86**	**The Company purchased this property for the development and operation of a 226 million gallon ethanol facility.**
Pekin, IL	Owned	26	The Company has owned this property since 2003 and plans to develop and operate a 113 million gallon ethanol facility at this location.
Mount Vernon, IN	Leased (1)	116	The Company leases this property from the State of Indiana with the obligation of developing and operating a 226 million gallon ethanol facility.

(1) The Mount Vernon lease has an initial expiration date of October 31, 2026, with six five-year extension options.

We believe that our existing facilities are adequate for our current and reasonably anticipated future needs, except in respect to our planned increases in production.

Item 3. Legal Proceedings

Our facilities and operations are subject to extensive environmental laws and regulations, and we are currently involved in various proceedings relating to environmental matters as described under Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental Matters and incorporated herein by reference. We are not involved in any legal proceedings that we believe could have a material adverse effect upon our business, operating results or financial condition.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2006.

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PART II

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

Effective July 5, 2006, we completed an initial public offering of our common stock, $0.001 par value, pursuant to our Registration Statement on Form S-1, as amended (Reg. No. 333-132860), that was declared effective on June 28, 2006. We registered 9,058,450 shares of our common stock at a maximum offering price of $389,513,350, all of which were sold in the offering at a gross per share price of $43.00. The Company sold 6,410,256 shares for an aggregate offering price of $275,641,008 and existing shareholders and management sold 2,648,194 shares for an aggregate offering price of $113,872,342.

Discounts and commissions to underwriters totaled $19,475,668 (or $2.15 per share sold) of which $13,840,000 was for the Company s account. Other net expenses incurred for the account of the Company in connection with the offering were $917,966 resulting in total expenses for the Company of $14,757,966. Net proceeds to the Company were $260,883,042. None of the underwriting discounts and commissions or offering expenses was incurred or paid to associates of our directors or to persons holding 10% or more of our common stock or to our affiliates.

We used $168.9 million (including premiums) to fund the repurchase of all $160.0 million aggregate principal amount of our senior secured floating rate notes in two separate transactions on July 13, 2006 and on December 29, 2006**.** The remainder of the proceeds will be used to fund capital expenditures, to repurchase our common stock, and for general corporate purposes.

On September 18, 2006, the Company granted Consolidated Grain and Barge Co. (CGB) an option to purchase up to 412,780 shares of its common stock at an exercise price of $24.226 per share (the CGB Option) in connection with a definitive agreement relating to our Mount Vernon, Indiana site entered into with CGB on the same date. The CGB Option expired unexercised on September 20, 2006.

Our Common Stock is traded on the New York Stock Exchange under the symbol AVR. As of February 28, 2007, there were 41,782,276 shares of Common Stock outstanding, held by 7 holders of record based on the records of our transfer agent.

The following table sets forth, for the periods indicated, the range of high and low reported sale prices for our Common Stock on the New York Stock Exchange from the date our shares began trading on the New York Stock Exchange on June 29, 2006 forward:

Period	**2006 High**	**Low**	**2005 High**	**Low**
First Quarter	n/a	n/a	n/a	n/a
Second Quarter	$ 38.37	$ 39.05	n/a	n/a
Third Quarter	$ 40.28	$ 19.45	n/a	n/a
Fourth Quarter	$ 25.58	$ 19.51	n/a	n/a

We did not declare or pay cash dividends on our Common Stock during the years ended December 31, 2006 or 2005. In 2004, we paid dividends totaling $142 million to our stockholders. We do not currently plan to pay cash dividends on our Common Stock. Any future determination to pay cash dividends will depend on our results of operations, financial condition, contractual restrictions and other factors deemed relevant by the Board of Directors. We intend to retain earnings to support the growth of our business. In addition, the agreement governing our secured revolving credit facility generally prohibits the payment of cash dividends on our Common Stock.

The following table presents information with respect to repurchases of Common Stock made by the Company during the quarter ended December 31, 2006. All of the repurchased shares were purchased on the open market under a share repurchase plan approved by the Board of Directors.

Period	Total Number of Shares Purchased	Average Price Paid Per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value that May Yet Be Purchased Under the Plans or Programs
10/01/05 10/31/06	-	$	-	
11/01/06 11/30/06	50,000	23.04	50,000	48,848,000
12/01/06 12/31/06				
Total	50,000	$ 23.04	50,000	$ 48,848,000

(1) Average price paid per share reflects the average share price paid for Aventine Common Stock on the business day the shares were repurchased on the open market.

Item 6. Selected Financial Data

The historical consolidated financial data presented below should be read in conjunction with the information set forth under Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, and our Consolidated Financial Statements beginning on page F-1.

The balance sheet data presented below as of December 31, 2006 and 2005 and the statement of operations data presented below for each of the years in the three-year period ended December 31, 2006, are derived from our audited Consolidated Financial Statements beginning on page F-1. The other balance sheet data and statement of operations data for the seven months ended December 31, 2003, and for the five months ended May 30, 2003 presented below, is derived from our previously audited Consolidated Financial Statements included in our S-1 registration statement, which is not presented herein. The selected predecessor historical consolidated financial data for the year ended December 31, 2002 is unaudited.

Statement of Operations Data:	**Year Ended December 31, 2006**	**2005**	**2004**	**Period from May 31 to December 31, 2003**	**Period from January 1 to May 30, 2003 Predecessor Historical (1)**	**(Unaudited) Year Ended December 31, 2002 Predecessor Historical (1)**
(in thousands, except per share amounts)						
Net sales	**$ 1,592,420**	$ 935,468	$ 858,876	$ 404,389	$ 271,379	$ 458,570
Cost of goods sold	**1,460,806**	848,053	793,070	375,042	270,242	445,789
Gross profit	**131,614**	87,415	65,806	29,347	1,137	12,781
Selling, general and administrative expenses	**28,328**	22,500	16,236	6,986	6,278	13,086
Other expense (income)	**(3,389)**	(989)	(3,196)	(161)	210	3,176
Provision for asset impairment (3)						195,784
Operating income (loss)	**106,675**	65,904	52,766	22,522	(5,351)	(199,265)
Other income (expense):						
Interest expense	**(9,348)**	(16,510)	(2,035)	(419)	(4,226)	(7,250)
Interest income	**4,771**	2,218	19	4	3	
Loss on early extinguishment of debt	**(14,598)**					
Other non-operating income (expense)	**3,654**	1,781	(924)	(2,560)	1,024	(1,340)
Minority interest	**(4,568)**	(2,404)	(2,148)	(1,025)	378	6,070
Income (loss) before income taxes	**86,586**	50,989	47,678	18,522	(8,172)	(201,785)
Income tax expense (benefit)	**31,685**	18,807	18,433	7,473	(3,269)	(1,498)
Net income (loss)	**$ 54,901**	$ 32,182	$ 29,245	$ 11,049	$ (4,903)	$ (200,287)

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	Year Ended December 31 2006	2005	2004	Period from May 31 to December 31, 2003	Period from January 1 to May 30, 2003	(Unaudited) Year Ended December 31, 2002
Income (loss) per common share-basic (5)	**$ 1.43**	$ 0.93	$ 0.84	$ 0.32	($0.14)	($5.78)
Basic weighted-average common shares	**38,411**	34,686	34,684	34,643	34,643	34,643
Income (loss) per common share-diluted (5)	**$ 1.39**	$ 0.89	$ 0.82	$ 0.32	($0.14)	($5.78)
Diluted weighted-average common and common equivalent shares	**39,639**	36,052	35,768	34,643	34,643	34,643
Other Data:						
(In thousands, except per bushel and per gallon amounts)						
Gallons sold	**695,784**	529,836	505,251	271,344	n/a	n/a
EBITDA (4)	**$ 109,475**	$ 67,555	$ 51,281	$ 19,718	n/a	n/a
Capital expenditures	**$ 76,499**	$ 20,672	$ 4,653	$ 2,952	n/a	n/a
Average price per gallon of ethanol sold	**$ 2.18**	$ 1.63	$ 1.55	$ 1.21	n/a	n/a
Average price of corn per bushel	**$ 2.41**	$ 2.08	$ 2.68	$ 2.42	n/a	n/a
Balance Sheet Data:						
(in thousands, at period end)						
Total assets (7)	**$ 408,136**	$ 221,977	$ 163,598	$ 106,449	$ 89,805	$ 98,251
Total debt (2)(6)	**-**	$ 161,514	$ 172,791	$ 3,922	$ 152,759	$ 162,169
Stockholders equity (deficit)	**$ 304,163**	$ (20,654)	$ (56,581)	$ (53,785)	n/a	n/a

(1) The financial statements for the year ended 2002 and for the period from January 1, 2003 to May 30, 2003 were prepared using the historical basis of accounting applied by the subsidiary of The Williams Companies, Inc. which owned and operated our business prior to May 30, 2003. These financial statements are designated as Predecessor because they are not comparable to our operating and cash flow results subsequent to our acquisition by the MSCP funds.

(2) Total debt includes amounts outstanding under our revolving credit agreement and senior secured notes outstanding.

(3) Provision for asset impairment was the result of writing down the fixed assets of Williams Bio-Energy LLC on the financial statements of The Williams Companies, Inc.

(4) EBITDA is defined as earnings before interest expense, interest income, income tax expense, depreciation, and loss on the early extinguishment of debt. EBITDA is not a measure of financial performance under accounting principles generally accepted in the United States and should not be considered an alternative to net earnings or any other measure of performance under accounting principles generally accepted in the U.S. or to cash flows from operating, investing or financing activities as an indicator of cash flows or as a measure of liquidity. EBITDA has its limitations as an analytical tool, and you should not consider it in isolation or as a substitute for analysis of our results as reported under generally accepted accounting principles. Some of the limitations of EBITDA are:

- EBITDA does not reflect our cash used for capital expenditures;
- although depreciation and amortization are non-cash charges, the assets being depreciated or amortized often will have to be replaced and EBITDA does not reflect the cash requirements for such replacements;
- EBITDA does not reflect changes in, or cash requirements for, our working capital requirements;

- EBITDA does not reflect the cash necessary to make payments of interest or principal on our indebtedness; and
- EBITDA includes non recurring payments to us which are reflected in other income.

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The following table reconciles our EBITDA to net income for each period presented:

(In thousands)	For the Years Ended December 31, 2006	2005	2004	Period from May 31 to December 31, 2003
Net income	$ 54,901	$ 32,182	$ 29,245	$ 11,049
Depreciation	3,714	2,274	1,587	781
Interest expense	9,348	16,510	2,035	419
Loss on early extinguishment of debt	14,598	-	-	-
Interest income	(4,771)	(2,218)	(19)	(4)
Income tax expense	31,685	18,807	18,433	7,473
Earnings before interest, taxes, depreciation and amortization	$ 109,475	$ 67,555	$ 51,281	$ 19,718

We have included EBITDA primarily as a performance measure because management uses it as a key measure of our performance and ability to generate cash necessary to meet our future requirements for debt service, capital expenditures, working capital and taxes.

(5) Pro forma net income (loss) per common share of our predecessor is based upon the weighted-average number of shares of common stock outstanding at the inception of the Company.

(6) In the periods prior to May 31, 2003, our predecessor s business was financed by its parent company. Therefore, the only debt incurred by our predecessor was intercompany debt, which we have disclosed in this schedule as Total debt for periods prior to May 31, 2003.

(7) In the periods prior to May 31, 2003, our predecessor s Total assets disclosed excludes intercompany receivables.

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

The following discussion of our consolidated operating results and financial condition for the three years ended December 31, 2006 should be read in conjunction with the Consolidated Financial Statements, and related notes beginning on page F-1.

Overview

We are a leading producer and marketer of ethanol based on both the number of gallons produced and sold. Through our own production facilities, marketing alliances with other ethanol producers and our purchase/resale operations, we market and distribute ethanol to many of the leading energy companies in the U.S. We have a comprehensive national distribution network utilizing a leased railcar fleet and a terminal network at critical points on the nation s transportation grid where our ethanol is blended with our customers gasoline. In addition to producing ethanol, our facilities also produce several by-products including: corn gluten feed and meal, corn germ, condensed corn distillers solubles, dried distillers grain with solubles, wet distillers grain with solubles, carbon dioxide and brewers yeast.

We were acquired by the Morgan Stanley Capital Partners funds (MSCP) from a subsidiary of The Williams Companies, Inc. on May 30, 2003. The acquisition was accounted for as a purchase business combination in accordance with Statements of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141).

Effective July 5, 2006, we completed an initial public offering of 9,058,450 shares of our common stock, $0.001 par value, at a gross per share price of $43.00 (the initial public offering). The Company sold 6,410,256 shares and received approximately $260.9 million in proceeds, net of discounts and commissions, from this initial public offering. Existing shareholders and management sold 2,648,194 shares of common stock during the initial public offering, which includes 268,707 shares issued from the exercise of outstanding options. Immediately following our initial public offering, we had 41,831,651 shares of common stock outstanding.

In anticipation of our initial public offering, on June 6, 2006, our Board gave contingent approval of the acceleration of vesting of 71,488 options held by officers and employees to be effective immediately prior to the consummation of the initial public offering. The Board approved the acceleration of the vesting in order to permit certain members of management the ability to sell stock in our initial public offering. These options had a weighted-average exercise price of $4.35 per share. As a result of the accelerated vesting, we recorded a pre-tax charge to earnings of $0.6 million in 2006.

Because we market and sell ethanol without regard to whether we produced it, are reselling it, or are marketing it for our marketing alliance partners, our general ledger system does not track or report ethanol revenue by source or the gallons of ethanol we sell by source. Our general ledger does track the number of gallons produced, the number of gallons purchased and the total number of gallons sold. We arrive at the change in inventory by subtracting the gallons produced and the gallons purchased from the total gallons sold. The difference is the amount of gallons taken from or put into inventory. We reconcile the calculated ethanol gallons in inventory to actual on a monthly basis through a physical inventory audit.

Our plants typically operate at or near nameplate capacity except for scheduled outages that typically average approximately one week each year. We may also occasionally experience unplanned outages at our facilities which may negatively impact equity production and related revenue. For example, equity production declined in 2006 as a result of maintenance performed at both production facilities in the second quarter, and from production issues surrounding our Nebraska facility in the second and third quarters of 2006.

We also generate revenue by selling ethanol that we purchase from our marketing alliance partners. See Item 1 Business Marketing Alliances. We signed our first marketing alliance agreement in 2001 and as of December 31, 2006 have increased the program to 12 alliance contracts with third-party plants that have the capacity to produce 517 million gallons of ethanol per year. As of December 31, 2006, we have signed additional marketing alliance contracts with both existing and new alliance partners that have either announced new ethanol production facilities or have facilities currently under construction which are expected to produce an additional 860 million gallons of ethanol per year when completed.

Two of our alliance partners with the capacity to produce 230 million gallons per year (VeraSun Fort Dodge, LLC and VeraSun Aurora Corporation, formerly VeraSun Energy Corporation) represented by the parent company VeraSun Energy Corporation have notified the Company in writing that they have elected not to permit automatic renewal of their marketing alliance agreement with the Company on March 31, 2007. In addition, a third marketing alliance partner, Granite Falls Energy, LLC, which produces approximately 52 million gallons of ethanol annually, has also notified us that they will not renew their marketing alliance contract upon termination on November 30, 2007. Although we believe that the loss of this capacity will be eventually offset by the addition of 860 million gallons of capacity announced or under construction as of December 31, 2006 by new alliance partners and by increased volume of purchase and resale activity, we cannot assure you that this additional capacity will be constructed on time or at all.

We also resell ethanol that we purchase from unrelated producers and marketers.

We generate additional revenue through the sale of by-products (both bio-products and co-products) that result from our ethanol production process. These by products include brewers yeast, corn gluten feed and meal, corn germ, CCDS, carbon dioxide, DDGS and WDGS. The volume of by-products we produce varies with the level of our equity production. Scheduled maintenance, along with other non-scheduled operational issues, may affect the volume of by-products produced. We may also shift the mix of these by-products, to optimize our revenue, by altering the production process. By-product revenue is driven by both the quantity of by-products produced and from the market price received for our by-products, which have historically tracked the price of corn.

We are continually exploring opportunities to increase our equity production capacity through acquisitions or through the development of new production facilities. In addition to the 57 million gallon dry mill expansion of our Pekin, Illinois facility which was completed in early 2007, we are exploring expanding capacity at three sites:

- a 113 million gallon dry mill in Pekin, Illinois
- a 226 million gallon dry mill adjacent to our Nebraska facility (to be constructed in two phases of 113 million gallons each) and
- a 226 million gallon dry mill in Mount Vernon, Indiana (to be constructed in two phases of 113 million gallons each)

We intend to substantially complete 226 million gallons of capacity expansions in 2008. While we originally intended to complete an additional 339 million gallons of capacity expansions in 2009, based on current construction costs and market conditions we may elect to delay some or all of the 339 million gallons of capacity scheduled for 2009. The timing of the remaining expansions will be based upon, among other factors, market conditions and the availability of financing on attractive terms. We are still in the process of determining which combination of these potential expansions we will complete in 2008. Our decision will be based upon, among other factors, the availability of permits and the results of our negotiations of EPC contracts. We anticipate this first stage of expansion will be substantially completed by the end of 2008. We are currently negotiating EPC contracts for development of these first stage expansions with a construction firm, Kiewit Energy Company, and technology provider, Delta-T. Our timetable is subject to numerous factors beyond our control. In particular, we have not yet received any environmental or other permits with respect to these expansions (although construction and certain other permit applications have been filed). Accordingly, cannot give assurance that these expansion projects will be completed on a timely basis or at all or that we will realize the benefits we anticipate. In addition, while we expect to raise additional debt to fund these first stage facility additions, we cannot be sure that we will be able to obtain additional financing for these transactions on attractive terms or at all.

Executive Summary

We generated net income of $54.9 million, or $1.39 per diluted share, in 2006. This is a 70.6% increase in earnings and a 56.2% increase in earnings per share over 2005. 2006 results include the effects of a non-recurring loss from the early extinguishment of debt totaling $14.6 million related to the repurchase of our senior secured floating rate notes and our amended secured revolving credit. These non-recurring charges reduced diluted earnings per share in 2006 by $0.24 per share. Revenue for 2006 was $1.6 billion, an increase of $0.7 billion, or 70.2%, over 2005 revenue of $0.9 billion. The increase in revenue is mainly the result of pricing gains caused by the significant year over year rise in the price per gallon of ethanol and an increase in the number of gallons sold. The average sales price per gallon of ethanol in 2006 was $2.18 per gallon, up from $1.63 per gallon in 2005.

The increase in the average price of ethanol year over year was primarily due to demand for ethanol exceeding supply for most of 2006, including demand caused by the elimination of MTBE as an oxygenate, by demand resulting from the renewable fuels standard required by the Energy Policy Act of 2005 and by the high price of gasoline during the first half of 2006.

Gallons of ethanol sold in 2006 increased 31.3% to 695.8 million gallons, as compared to 529.8 million gallons in 2005. The increase in gallons sold is primarily due to increased demand as a result of the elimination of MTBE as a gasoline additive, and the high price of oil. Increased purchases from our marketing alliance partners allowed us to meet this increased demand. Purchases from non-affiliated producers decreased year over year in response to the significant increase in demand caused by the switchover from MTBE to ethanol in the first half of 2006. Because of shortages of ethanol that existed, there was less ethanol available to purchase in the spot market and, hence, less opportunity in the purchase/resale market. Equity production declined in 2006 versus 2005, due to maintenance shutdowns taken by both production facilities in the second quarter of 2006, and by the production issues surrounding our Nebraska facility in the second and third quarters of 2006.

Gross profit totaled $131.6 million in 2006, an increase of $44.2 million, or 50.6%, from 2005. The increase in gross profit was the result of a combination of factors, including higher average commodity spreads (the difference between the selling price per gallon of ethanol less net corn costs for gallons produced at our plants). Significant increases in the price of corn beginning late in the third quarter had a significant negative impact on commodity spreads and our gross margin during the fourth quarter. Corn prices increased on average by approximately $0.60 per bushel during the fourth quarter of 2006. Gross profit was also negatively affected throughout 2006 from increased costs, including increased maintenance costs, lower margins obtained on gallons sourced from our purchase/resale business, increasing corn prices and increases in freight and other production expenses. Our gross corn cost for 2006 was $2.41 per bushel, as compared to $2.08 per bushel in 2005.

Non-Recurring Charges

As a result of the repurchase of our senior secured floating rate notes, the Company recorded a pre-tax charge in 2006 of $14.6 million comprised of (i) $8.9 million for the tender and consent premiums and related fees and expenses, (ii) $4.9 million for the write-off of unamortized debt issuance costs, and (iii) $0.8 million for the write-off of unamortized deferred debt costs related to our amended secured revolving credit agreement.

Non-recurring charges reduced diluted earnings per share by $0.24 per share in 2006.

General

The following general factors should be considered in analyzing our results of operations:

Variability of Gross Profit

Our gross profit has fluctuated and may continue to fluctuate substantially from period to period. Gross profit from ethanol sales is mainly affected by changes in selling prices for ethanol, the cost to us of purchasing ethanol from marketing alliance partners and unaffiliated producers, and from the cost of corn. The rise and fall of ethanol and corn prices affects the levels of our costs of goods, gross profit and inventory values, even in the absence of any increases or decreases in business activity. Selling prices for ethanol are affected principally by the price of oil and gasoline and other market factors. All of these factors are beyond our control.

Our most volatile manufacturing costs are natural gas and corn. See Item 1A Risk Factors Our business is dependent upon the availability and price of corn. Significant disruptions in the supply of corn will materially affect our operating results. In addition, since we generally cannot pass on increases in corn prices to our customers, continued periods of historically high corn prices will also materially adversely affect our operating results, and The market for natural gas is subject to market conditions

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that create uncertainty in the price and availability of the natural gas that we utilize in our manufacturing process. Since both natural gas and ethanol are energy-related products, there has been significant, although not perfect, correlation between their market prices. As a result, at times when natural gas prices had increased, thereby increasing our costs, ethanol prices have typically increased, thereby increasing our revenues and offsetting some of the impact on our results of operations.

Impact of Product Mix

Ethanol we sell is obtained from three sources: ethanol we produce, ethanol purchased from marketing alliance partners and ethanol from purchases we may make under our purchase/resale program. While our marketing alliance and purchase/resale businesses are important to our overall strategies, the great majority of our gross profit comes from our own equity production. Our overall profitability from period to period is affected by the mix of sales within these categories.

Conversion Costs

Conversion costs per gallon are an important metric in determining our profitability. Conversion costs represent the cost of converting the corn into ethanol, and include production salaries, wages and stock compensation costs, fringe benefits, utilities (including coal and natural gas), maintenance, denaturant, insurance, materials and supplies and other miscellaneous production costs. It does not include depreciation and amortization expense. We began discussing conversion costs as a separate item in our Management s Discussion and Analysis of Financial Condition and Results of Operations in 2006.

Summary of Critical Accounting Policies

We base this discussion and analysis of results of operations, cash flow and financial condition on our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the U.S.

Share-based Compensation Expense

Effective January 1, 2006, we adopted, on a modified prospective transition method, SFAS 123(R), which requires measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on fair values. We previously accounted for share-based compensation expense using SFAS 123, using the minimum value method. Our financial statements for the year ended December 31, 2006 reflect the impact of adopting SFAS 123(R). In accordance with the modified prospective transition method, our financial statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS 123(R). Share-based compensation expense recognized is based on the value of the portion of share-based payment awards that is ultimately expected to vest. Share-based compensation expense recognized in our Consolidated Statements of Operations for the year ended December 31, 2006 included compensation expense for unvested share-based payment awards granted prior to December 31, 2005, based on the grant date fair value estimated in accordance with the minimum value method as outlined in SFAS 123, and compensation expense for the share-based payment awards granted subsequent to December 31, 2005 based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In conjunction with the adoption of SFAS 123(R), we elected to attribute the value of share-based compensation to expense over the periods of requisite service using the straight line method.

Upon adoption of SFAS 123(R), we elected to value our share-based payment awards granted beginning in fiscal year 2006 using the Black-Scholes model, which was previously used to calculate stock-based compensation expense using the minimum value method as outlined in SFAS 123. The determination of fair value of share-based payment awards on the date of grant using the Black-Scholes model is affected by our stock price as well as the input of other subjective assumptions. The Black-Scholes model requires a number of assumptions, of which the most significant are expected stock price volatility, the expected pre-vesting forfeiture rate and the expected option term (the amount of time from the grant date until the options are exercised or expire). Expected volatility is normally calculated based upon actual historical stock price movements over the expected option term. Since we have no history of stock price volatility as a public company at the time of the grants, we calculated volatility by considering, among other things, the expected volatilities of public companies engaged in similar industries. Pre-vesting forfeitures are estimated using a 3% forfeiture rate. The expected option term is calculated using the simplified method permitted by SAB 107. Our options have characteristics significantly different from those of traded options, and changes in the assumptions can materially affect the fair value estimates.

Inventory

Inventories are stated at the lower of cost or market. Cost is determined using a weighted-average first-in-first-out (FIFO) method for gallons produced at our plants, gallons purchased from our marketing alliance partners and other gallons purchased for resale. In assessing the ultimate realization of inventories, we perform a periodic analysis of market price and compare that to our weighted-average FIFO cost to ensure that our inventories are properly stated at the lower of cost or market.

Derivatives and Hedging Activities

Our operations and cash flows are subject to fluctuations due to changes in commodity prices. We use derivative financial instruments from time-to-time to manage commodity prices. Derivatives used are primarily commodity futures contracts, swaps and option contracts.

We apply the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by Statement of Financial Accounting Standards No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and by Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (hereinafter collectively referred to as SFAS 133), for our derivatives. These derivative contracts are not designated as hedges and, therefore, are marked to market each period, with corresponding gains and losses recorded in other non-operating income (loss). The fair value of these derivative assets is recognized in other current assets or liabilities in the Consolidated Balance Sheets, net of any cash received from the relevant brokers.

Income Taxes

For financial reporting purposes, we determine our current and deferred tax liabilities in accordance with the liability method of accounting for income taxes as specified in Statement of Financial Accounting Standards No. 109 (SFAS 109), *Accounting for Income Taxes*. Under SFAS 109, deferred tax liabilities and assets are recorded for the expected future tax consequences of events that have been recognized in our financial statements or tax returns. Property, plant and equipment, marketing alliance investments, goodwill, stock-based compensation, prepaid pension, postretirement benefit obligations, and certain other accrued liabilities are the primary sources of these temporary differences.

Deferred tax assets include the excess tax basis in assets over the corresponding book basis as a result of the purchase of such assets from The Williams Companies, Inc. on May 30, 2003. We established a valuation allowance against certain deferred tax assets related to the tax basis in fixed assets, goodwill, bad debt and employee benefits. We determined, after weighing all available evidence, that a portion of the deferred tax assets would not be realized due to limitations imposed by Internal Revenue Code Section 382. Because of the ownership change on May 30, 2003, Section 382 imposes an annual limitation on the amount of pre-transaction losses that can offset post-transaction income for the five-year period following the transaction. Deductions related to depreciation, goodwill amortization, bad debt write-offs, and accrued vacation are considered losses under Section 382, subject to the limitation. Based upon our analysis of the Section 382 limitations, we established an initial valuation allowance at the acquisition date, as we concluded that a portion of our deferred tax assets would not be realized.

We have implemented tax planning strategies which have allowed us to take tax return filing positions to deduct certain depreciation and amortization deductions that would otherwise have been subject to Section 382 limitations. As we have realized the benefit of certain deferred tax assets on our income tax returns, we have reduced the associated valuation allowance. However, we have considered such tax planning strategies in our analysis of the need for our remaining valuation allowance and tax contingency reserves. We believe our valuation allowance and contingency reserves are appropriate in the circumstances.

Pension and Postretirement Benefit Costs

Net pension and postretirement costs were $0.5 million, $0.6 million and $0.4 million, respectively, for the years ended December 31, 2006, 2005 and 2004. Total estimated pension and postretirement expense in 2007 is expected to be approximately $0.4 million. These expenses are primarily included in cost of goods sold, and in selling, general and administrative expenses. In 2006 and 2005, we made contributions to our defined benefit pension plan of $2.0 million and $0.3 million, respectively. We did not make any contributions to our defined benefit plan in 2004. In 2007, we expect to make contributions totaling $0.5 million to our defined benefit plan.

Our pension and postretirement benefit costs are developed from actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected long-term rates of return on plan assets. Material changes in our pension and postretirement benefit costs may occur in the future due to changes in these assumptions, changes in the number of plan participants, changes in the level of benefits provided, changes to the level of contributions to these plans and other factors.

We determine our actuarial assumptions for our pension and post retirement plans, after consultation with our actuaries, on December 31 of each year to calculate liability information as of that date and pension and postretirement expense for the following year. The discount rate assumption is determined based on a spot yield curve that includes bonds that are rated Corporate AA or higher with maturities that match expected benefit payments under the plan.

The expected long-term rate of return on plan assets reflects projected returns for the investment mix that have been determined to meet the plan s investment objectives. The expected long-term rate of return on plan assets is selected by taking into account the expected weighted averages of the investments of the assets, the fact that the plan assets are actively managed to mitigate downside risks, the historical performance of the market in general and the historical performance of the retirement plan assets over the past ten years.

Recent Accounting Pronouncements

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 prescribes a comprehensive model for how a company should recognize, measure, present, and disclose in its financial statements uncertain tax positions that the company has taken or expects to take on a tax return. The interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the effect that the adoption of FIN 48 will have, if any, on its consolidated results of

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operations, financial position and related disclosures, but does not expect it to have a material impact on the financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157 (SFAS 157), *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is currently evaluating the effect that the adoption of SFAS 157 will have, if any, on its consolidated results of operations, financial position and related disclosures, but does not expect it to have a material impact on the financial statements.

Results of Operations

Year Ended December 31, 2006, Compared with Year Ended December 31, 2005

Total gallons shipped in 2006 were 695.8 million gallons, versus 529.8 million gallons shipped in 2005, an increase of 166.0 million gallons or 31.3%. The increase/(decrease) in gallons by source was as follows:

For the Year Ended December 31,

(In thousands, except for percentages)	**2006**	**2005**	**Increase/ (Decrease)**	**% Increase/ (Decrease)**
Equity production	**132,957**	138,119	(5,162)	(3.7)%
Marketing alliance purchases	**492,973**	340,589	152,384	44.7 %
Purchase/resale	**68,234**	68,791	(557)	(0.8)%
Decrease/(increase) in inventory	**1,620**	(17,663)	19,283	N.M.*
Total	**695,784**	529,836	165,948	31.3 %

* N.M. not meaningful

Net sales in 2006 increased 70.2% from 2005. Net sales were $1.6 billion in 2006 versus $0.9 billion in 2005. Overall, the increase in net sales was the result of the increase in the average sales price of ethanol and an increase in gallons sold. The average gross selling price of ethanol in 2006 was $2.18 per gallon, up from the $1.63 received in 2005. The increase in ethanol prices is mostly the result of increased ethanol demand caused by the phase-out of MTBE as an oxygenate and from an increase in the RFS, as well as from increases in discretionary blending. Increased demand caused the price of ethanol to increase in the first half of 2006. Ethanol prices in the second quarter reached new highs, and began to fall significantly during the third quarter as a result of Brazilian imports. Ethanol prices regained strength in the fourth quarter as the Brazilian imports were consumed into the marketplace and demand again exceeded supply.

Co-product sales for 2006 totaled $54.7 million, which was slightly lower than the $60.4 million in 2005. Co-product sales in 2006 was affected by lower average realized prices, and decreased co-product production due to maintenance. Co-product shipments decreased in 2006 to 927.2 thousand tons, from 946.7 thousand tons in 2005 due to production issues.

Cost of goods sold consists of the cost to produce ethanol at our own facilities, the cost of purchasing ethanol from our marketing alliance partners and from unaffiliated producers and marketers, freight and logistics costs and the cost of motor fuel taxes which have been billed to customers. Cost of goods sold for the year ended December 31, 2006 was $1.5 billion, compared to $0.9 billion for the year ended December 31, 2005, an increase of $0.6 billion or 72.2%. This increase is the result of higher costs for purchased ethanol and from increased production costs.

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Purchased ethanol in 2006 totaled $1.1 billion, versus $0.6 billion in 2005. The increase in purchased ethanol results from an increase in both the number of gallons of ethanol purchased, along with increases in the cost per gallon of ethanol. In 2006, we purchased 561.2 million gallons of ethanol at an average cost of $2.04 per gallon as compared to 409.4 million gallons of ethanol at an average cost of $1.52 in 2005.

Production costs include corn costs, conversion costs and depreciation and amortization. Corn costs in 2006 totaled $122.4 million or $2.41 per bushel, versus $108.0 million, or $2.08 per bushel in 2005. The increase in corn costs is principally the result of a perceived increased demand by the marketplace as a result of expected new ethanol production facilities being built. Conversion costs for the year increased to $87.2 million, or $0.66 per gallon, from $77.1 million, or $0.56 per gallon for 2005. The increase is mostly the result of higher costs due to the maintenance required at our Illinois wet mill facility and our Nebraska facility in the second quarter of 2006, along with production issues incurred at our Nebraska facility in the second and third quarters of 2006, and from the results of severe weather which disrupted production at both the Illinois wet mill and the Nebraska facilities in early December 2006. Conversion costs were also affected in 2006 by stock-based compensation expense, higher enzyme and denaturant costs, and from one-time start-up costs related to the new Illinois dry mill.

Depreciation in 2006 totaled $3.7 million, versus $2.3 million in 2005. Motor fuel taxes were $13.6 million in 2006 versus $6.3 million in 2005. The cost of motor fuel taxes are recovered through billings to customers.

Freight/logistics costs in 2006 increased to $101.7 million, or approximately $0.15 per gallon, from $58.0 million, or $0.11 per gallon in 2005. The increase in freight/logistics cost is the result of higher transportation expenses, fuel surcharges and from the expansion of our distribution system footprint.

Selling, general and administrative expenses (SG&A) expenses were $28.3 million in 2006, compared to $22.5 million in 2005. SG&A expenses increased as a result of expensing stock-based compensation in accordance with SFAS 123R and increased costs related to being a public company. Stock-based compensation expense in 2006 totaled $6.5 million, versus $1.9 million in 2005.

Other operating income of $3.4 million includes a $1.3 million one-time special cash dividend from Heartland Grain Fuels, a marketing alliance partner in which we hold an ownership interest, prior to their being acquired by Advanced BioEnergy, LLC. The remainder represents dividends received from our cost method investments in marketing alliance partners, and in payments received from various governmental agencies for ethanol production.

Interest income in 2006 was $4.7 million, versus $2.2 million in 2005. The increase in interest income is the result of a combination of a higher level of investable funds due to cash received from our initial public offering and better operating results, along with increased short-term investment rates due to increases in interest rates in general.

Interest expense in 2006 was $9.3 million, as compared to $16.5 million in 2005. Interest expense declined in 2006 principally as a result of the repurchase of our outstanding bonds, along with interest capitalized as a result of the construction of our Pekin dry mill facility and lower usage of our secured revolving credit facility. Interest expense in 2006 was also affected by the impact of year over year increases in variable interest rates.

The minority interest for the year ended December 31, 2006 was a $4.6 million charge to income compared to $2.4 million charge to income for the year ended December 31, 2005. This increase reflects the higher operating results of our Nebraska subsidiary in the year ended December 31, 2006.

Other non-operating income for 2006 includes $3.7 million of mark to market gains on corn futures contracts, versus mark to market gains of $1.8 million in 2005. Other non-operating income consists of realized or unrealized gains or losses on commodity derivative instruments and mark to market adjustments on an interest rate cap agreement.

Loss on early extinguishment of debt totaled $14.6 million in 2006. The loss is related to the repurchase of all $160 million aggregate principal amount of our floating rate senior secured notes (including premiums), and from the write-off of deferred financing fees related to our amended and restated secured revolving credit facility.

Tax expense for 2006 was $31.7 million, or approximately 36.6%, versus $18.8 million, or 36.9%, in 2005. Our effective tax rate was affected by a lower estimated state tax rate in 2006 which more accurately reflected state income tax rates being incurred.

Year Ended December 31, 2005, Compared with Year Ended December 31, 2004

Total gallons shipped in 2005 were 529.8 million, versus 505.3 million gallons in 2004, an increase of 24.5 million gallons or 4.9%. The increase/decrease in gallons by source is as follows:

For the Year Ended December 31, *(In thousands, except for percentages)*	**2005**	**2004**	**Increase/ (Decrease)**	**% Increase/ (Decrease)**
Equity production	138,119	139,400	(1,281)	(0.9)%
Marketing alliance purchases	340,589	297,200	43,389	14.6 %
Purchase/resale	68,791	62,900	5,891	9.4 %
Decreases/(increases) in inventory	(17,663)	5,800	(23,463)	N.M*
Total	529,836	505,300	24,536	4.9 %

* N.M. not meaningful

Net sales for the year ended December 31, 2005 were $935.5 million, compared to $858.9 million for the year ended December 31, 2004, an increase of $76.6 million or 8.9%. The increase in net sales was a combination of an increase in the average gross ethanol price to $1.63 per gallon in 2005, from $1.55 per gallon in 2004, and from an increase in ethanol demand. Ethanol prices increased largely as a result of the tightening of gasoline supplies and higher prices.

The price of ethanol varied throughout 2005, with lower prices occurring in the second quarter due to a temporary oversupply situation, escalating in the third quarter as a result of tight gasoline supplies brought on by the disruption of the oil supply caused by hurricanes in the U.S. Gulf Coast, and then returning to more normal levels in the fourth quarter. The lower ethanol price in the second quarter of 2005 negatively influenced the pricing on fixed price contracts for the October 2005 through March 2006 delivery period which constituted approximately 55% of contracted volume for the period. Sharp increases in prices in the third quarter 2005 and declines in the fourth quarter 2005 resulted in higher margins in the third quarter 2005 and lower margins in the fourth quarter 2005.

Co-product sales for the year ended December 31, 2005 was $60.4 million, as compared to $65.7 million for the year ended December 31, 2004. In 2005, we sold 946.7 thousand tons of co-products compared to 867.3 thousand tons of co-products in 2004. This decrease in co-product sales reflects the overall reduction in the cost of corn.

Cost of goods sold for the year ended December 31, 2005 was $848.1 million, compared to $793.1 million for the year ended December 31, 2004, an increase of $55.0 million or 6.9%. This increase was mainly the result of higher purchased ethanol prices and higher natural gas costs offset by lower corn costs. Our average corn cost was $2.08 per bushel for the year ended December 31, 2005 compared to $2.68 per bushel for the year ended December 31, 2004. The decrease in corn costs reflects the oversupply of corn from the strong 2004 U.S. harvest. Increased energy costs reflected the higher cost of natural gas, which was up approximately $2.4 million, or 20.2% when compared to the same period of 2004.

Our gross margin increased from 7.7% for the year ended December 31, 2004 to 9.3% for the year ended December 31, 2005. This increase was largely a result of higher ethanol prices and the resulting favorable spread between ethanol prices and corn costs offset by substantially higher marketing alliance revenue, which generally have a lower margin in comparison to our ethanol production revenue.

SG&A expenses for the year ended December 31, 2005 were $22.5 million compared to $16.2 million for the year ended December 31, 2004, an increase of $6.3 million or 38.9%. Our selling, general and administrative expenses were higher in the year ended December 31, 2005 compared to the same period of 2004 due primarily to additional staffing, payment of the final installment of a special management bonus in the fourth quarter of $3.3 million, and recording non-cash expense for stock-based compensation of $1.9 million in 2005 compared to $0.1 million in 2004 respectively. In addition, other higher costs were associated with fees related to our annual audit, enhancement of our ORACLE information system, costs associated with preparing for implementation of internal control requirements related to the Sarbanes-Oxley Act, and various factors related to increased marketing and sales activities, and a logistical study.

Other operating income for the year ended December 31, 2005 was $1.0 million compared to $3.2 million for the year ended December 31, 2004. Other income decreased in the year ended December 31, 2005 mainly due to a reduction of $1.9 million in receipts from the USDA under the CCC BioEnergy Program. The USDA credits are based upon production from the prior year of 2004. Under the CCC BioEnergy Program, the USDA makes cash payments to companies that increase their purchases of corn, other specified commodities, fats, oils and greases derived from an agricultural product or any animal by product to expand production of ethanol, biodiesel or other biofuels of fuel grade ethanol. See Item 1 Business Legislative Drivers Federal Farm Legislation.

Interest income in 2005 was $2.2 million, versus $19 thousand in 2004. The increase in interest income is the result of a higher level of investable funds due to cash received from the debt offering of our $160 million senior secured floating rate notes in December 2004.

Interest expense for the year ended December 31, 2005 was $16.5 million compared to $2.0 million for the year ended December 31, 2004, a difference of $14.5 million. This increase was mainly the result of the issuance of the $160 million aggregate principal amount of senior secured notes in December 2004. In addition, as of December 31, 2005, $1.5 million was outstanding under the revolving credit facility.

The minority interest for the year ended December 31, 2005 was a $2.4 million charge to income compared to $2.1 million charge to income for the year ended December 31, 2004. This increase reflects the higher operating results of our Nebraska subsidiary in the year ended December 31, 2005.

Other non-operating income increased in the year ended December 31, 2005 by approximately $2.7 million. Other non-operating income was $1.8 million for the year ended December 31, 2005 compared to a $0.9 million loss for the year ended December 31, 2004 as a result of marking our derivative instruments to market as required by SFAS 133. Other non-operating income consists of realized or unrealized gains or losses on commodity derivative instruments and mark to market adjustments on an interest rate cap agreement.

Income taxes for the year ended December 31, 2005 were $18.8 million compared to $18.4 million for the year ended December 31, 2004. This increase was mainly the result of the increase in taxable income in the year ended December 31, 2005 in comparison to the year ended December 31, 2004 which reflects our overall higher operating income in the 2005 period. Our effective tax rate decreased to 36.9% in 2005 from 38.7% in 2004 due to the tax benefit from the domestic manufacturing deduction as a result of the Jobs Creation Act of 2004.

Trends and Factors that May Affect Future Operating Results

Ethanol Supports

We receive significant benefits from federal and state statutes, regulations and programs and the trend at the governmental level appears to be to continue to try to provide economic support to the ethanol industry. Notwithstanding the above, changes to federal and state statutes, regulations or programs could have an adverse effect on our business. Recent federal legislation, however, has benefited the ethanol industry. In 2005, the Energy Policy Act was passed which contained a new support program, the RFS, which requires fuel refiners to use a certain minimum amount of renewable fuels (including ethanol) which will rise to 7.5 billion gallons by 2012. Ethanol benefits from an excise tax credit of $0.51 per ethanol gallon. This excise tax credit provides incentives for blenders and refiners to blend ethanol with gasoline.

Supply and Demand

Ethanol demand in the U.S. in 2006 exceeded production. U.S production of 4.8 billion gallons in 2006 was slightly less than 2006 consumption of 5.4 billion gallons. The shortfall in 2006 was filled by imports from other countries, principally Brazil. At the end of 2006, U.S. production capacity was 5.4 billion gallons annually. According to the RFA, another 6.0 billion gallons of production capacity was under construction at year-end.

It is expected that annual ethanol production capacity in the U.S. will total in excess of 7.5 billion gallons annually by the end of 2007, which is the amount of the RFS required in 2012. This additional capacity may cause supply to exceed demand. If additional demand for ethanol is not created, through either additions to discretionary blending (through increased penetration rates in areas that blend ethanol today or through the establishment of new markets where little to no ethanol is blended today), or through additional governmental mandates at either the federal or state level, the excess supply may cause ethanol prices to decrease, perhaps substantially.

Commodity Prices

Our primary grain feedstock is corn. The cost of corn is dependent upon factors that are generally unrelated to those affecting the selling price of ethanol. Corn prices generally vary with international and regional grain supplies, and can be significantly affected by weather, planting and carryout projections, government programs, exports, and other international and regional market conditions. Due to the significant expansion of the ethanol industry, corn futures have increased substantially as a result of this new perceived demand. This trend is likely to continue and could have a material impact on our results of operation and financial condition. In addition, factors such as USDA estimates of acres planted, export demand and other domestic usage also have significant effects on the corn market. Weather-related impacts upon the corn market and prices are expected to be mitigated by new more reliant hybrid varieties of corn. Other factors such as acres planted and weather could also start to have more of an impact and lead to potentially volatile and higher corn prices.

Natural Gas Prices

Natural gas is an important input in our ethanol and co-product production process. We use natural gas to dry distillers grains for storage and transportation over longer distances. This allows us to market distillers grains to broader livestock markets in the U.S.. Although natural gas prices trended lower during the second half of 2006, and prices fluctuated in a narrower price band during this time, natural gas prices could again increase significantly as a result of actual or perceived shortages in supply. Our current natural gas usage is approximately 342,000 MMBtus per month.

Expansion

We are currently considering the expansion of capacity at three sites representing an aggregate of 565 million gallons of capacity. We have not yet negotiated EPC contracts for any of these expansions or obtained financing therefor. The timing of such expansions, the terms of the EPC contracts and the terms of the financing therefor may all have a material affect on our results of operations. In addition, because we have decided to stage our expansion plans, we may have to pay penalties or damages under certain contracts related to such capacity expansions. For a discussion of these potential penalties and damages see Liquidity and Capital Resources Overview and Outlook below.

Liquidity and Capital Resources

The following table set forth selected information concerning our financial condition:

(In thousands)	**December 31, 2006**	**December 31, 2005**
Cash and cash equivalents	$ 29,791	$ 3,750
Short-term investments	$ 98,925	
Working capital	$ 203,247	$ 49,878
Total debt		$ 161,514
Current ratio	3.44	1.83

Overview and Outlook

We completed our initial public offering at the beginning of the third quarter of 2006. This transaction resulted in the issuance of 6,410,256 new shares, and raised approximately $260.9 million, net of discounts and commissions to underwriters and IPO-related expenses, in new equity for the Company. Consequently, our liquidity and capital position have improved significantly during 2006. This, together with cash generated from operations during 2006, has significantly increased our working capital position.

In June 2006, we commenced a cash tender offer (Tender Offer) for all $160 million aggregate principal amount of our outstanding senior secured floating rate notes due 2011 (Notes). Approximately 97% of the outstanding aggregate amount of Notes was tendered. In July 2006, we paid $163.7 million (including premiums) from the funds received in our initial public offering to fund the repurchase of $155.0 million aggregate principal amount of Notes redeemed in the Tender Offer. On December 29, 2006, we redeemed the remaining $5 million of the Notes. We paid an additional $5.2 million, including premiums, to redeem the Notes.

As a result of the completion of the Tender Offer, cash that was classified as restricted and earmarked for the Pekin, Illinois plant expansion was no longer subject to the restrictions previously imposed by the indenture under which the Notes were issued.

On October 26, 2006, Aventine s Board of Directors approved a share buyback program of up to $50 million. Under the repurchase program, the Company may buy back shares from time to time on the open market. The program has no minimum share repurchase amounts, and there is no fixed time period under which any share repurchases must take place. This share repurchase program is not expected to impact the Company s previously announced expansion plans.

With our current cash balances, amounts available under our secured revolving credit facility and anticipated cash flow from operations, we believe that we will be able to satisfy existing anticipated working capital needs, debt service obligations, non-expansion related capital expenditures and other anticipated cash requirements for 2007.

We will need raise additional capital through a combination of either debt or equity financing to fund our planned capacity expansions. The amount of capital expenditures necessary to build our proposed 113 million gallon dry mill expansion in Pekin, Illinois, our proposed 226 million gallon dry mill adjacent to our Nebraska facility and our proposed 226 million gallon dry mill in Mt Vernon, Indiana, is currently estimated to be between $1.90 and $2.00 per denatured gallon of capacity, or a total of approximately $1.1 billion. We are contractually obligated, subject to certain conditions, including obtaining necessary permits, to develop both a 113 million gallon dry mill adjacent to our Nebraska facility (using commercially reasonable best efforts to obtain a permit for 226 million gallon capacity) and a 226 million gallon dry mill in Mount Vernon, Indiana. If we do not meet certain specified milestones we will be subject to penalties. The contract to complete the 226 million gallon dry mill expansion adjacent to our Nebraska facility provides for liquidated damages not exceeding $5 million if specified milestones are not met or we do not construct a facility with a capacity of at least 110 million gallons. If such penalties are not paid, the counterparty to the contract has the right to repurchase the property at cost (subject to adjustment for any expenses, which we have paid with respect to infrastructure construction). In certain cases, the counterparty can agree to an extension and limited cure rights for payments. The contract for completion of the 226 million gallon dry mill in Mount Vernon, Indiana provides that, if we do not meet certain milestones, subject to specified extension rights and cure periods, we will be in default under our lease with the Indiana Port Commission and the State of Indiana may complete construction of the plant at our expense if we fail to do so and does not provide for liquidated damages as an alternative. In addition, we would also be subject to certain other penalties provided for in the lease. Notwithstanding the above, if, despite our diligent efforts, we are unable to obtain permits for the Mt. Vernon facility by a certain date, we can negotiate a waiver of the compliance date and establish a new date for compliance. If we do not reach an agreement, either the Mt. Vernon lessor or we can terminate the Mt. Vernon lease. Accordingly, we cannot estimate the amount of damages we could be liable for.

Sources of Liquidity

Our principal sources of liquidity are cash, short-term investments, cash provided by operations, and cash available under our secured revolving credit facility.

Cash and short-term investments. During 2006, cash and short-term investments increased by $125.0 million. Cash and short-term investments as of December 31, 2006 and 2005 were $128.7 million and $3.7 million, respectively. The increase in cash is principally the result of cash received in our initial public offering and from the removal of all restrictions surrounding cash previously classified as restricted, and by cash generated from operations.

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Restricted cash. Restricted cash at December 31, 2005 was $60.4 million. Restricted cash had previously been set aside to be used solely for the expansion of our Pekin, IL facility. The restrictions in place relative to these funds in accordance with the bond indenture for our Notes ceased to be applicable after completion of the Tender Offer on July 13, 2006. As a result, all cash previously classified as restricted is now classified as unrestricted.

Cash provided by operations. Net cash provided by operating activities in 2006 was $55.8 million, as compared to cash provided by operating activities of $26.7 million for 2005. The increase in net cash provided by operating activities in 2006 versus 2005 is primarily the result of increased operating performance as a result of the widening of the commodity spread due to the increase in ethanol prices. Cash provided by operations was negatively affected in 2006 by the effects of increasing ethanol prices, which increased both accounts receivable and inventory. This increase in accounts receivable and inventory more than offset a corresponding increase in accounts payable.

Cash available under our credit facility. During 2006, we amended and reduced our revolving credit facility to $30.0 million from $60.0 million. The previous facility contained restrictive covenants along with a higher fee structure. The amended facility also removed restrictive covenants relative to our growth plans.

We had no borrowings outstanding under our amended secured revolving credit facility at December 31, 2006 and $4.0 million of standby letters of credit outstanding, leaving approximately $26.0 million in additional borrowing availability under our amended secured revolving credit facility as of that date.

Uses of Liquidity

Our principal uses of liquidity are capital expenditures, payments related to previously outstanding debt and our credit facility, and the repurchase of shares of our common stock.

Capital expenditures. Capital expenditures for the expansion of our Illinois dry mill facility totaled $58.7 million in 2006 and $6.8 million in 2005. We expect in 2007 to incur additional expenditures for the Illinois dry mill expansion of approximately $3.4 million. In addition, we also spent $5.9 million on the proposed expansion projects in Pekin, Illinois, Aurora, Nebraska, and Mount Vernon, Indiana. Subject to receiving applicable permits, negotiating final EPC contracts, and obtaining adequate financing, we expect to spend approximately $250 million on expansion projects in 2007, and significant additional amounts thereafter.

In 2006, other capital expenditures (excluding expenditures made for capacity expansions) totaled $11.9 million versus $6.6 million in 2005. Other capital expenditures include asset replacement, environmental and safety compliance, and cost reduction and productivity improvement items. Our capital spending plan for 2007, excluding any expenditures for facility additions or expansion, is forecasted to be between $20 million and $22 million. We currently expect capital spending for 2008 to include $4.5 million for air emissions control technology at our Illinois wet mill facility.

Payments related to our outstanding debt and credit facility. In 2006, we made interest payments on our debt and our credit facility totaling $11.2 million, versus payments of $15.0 million in 2005. In addition, we also paid $168.9 million (including premiums) in 2006 to repurchase all $160 million aggregate principal amount of our senior secured floating rate notes. The decrease in interest payments from 2005 to 2006 results primarily from the repurchase of outstanding senior secured floating rate notes and a reduction in the amount outstanding under our secured revolving credit facility, offset somewhat by increases in variable interest rates.

Repurchase of shares of common stock. In 2006, we repurchased 50,000 shares of our common stock at an average price of $23.04, spending a total of approximately $1.2 million. These shares were repurchased under a share repurchase program approved by our Board of Directors. The share repurchase program allows the repurchase of up to $50 million of our outstanding common stock, although there are no minimum share purchase requirements. There is approximately $48.8 million available to be repurchased under this program.

Off-Balance Sheet Arrangements

We have not entered into any off-balance sheet arrangements that either have, or are reasonably likely to have, a material adverse current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contractual Obligations and Commercial Commitments

The following table provides a summary of our contractual obligations and commercial commitments as of December 31, 2006. Other non-current liabilities included in our Consolidated Balance Sheet that may not be fully disclosed below include accrued pension and post retirement costs. Refer to Notes 11 and 12 of the Notes to the Consolidated Financial Statements.

	Payments due or expiring by period				
(In thousands)	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Contractual obligations:					
Operating leases railcars	$ 169,303	$ 10,604	$ 34,025	$ 38,042	$ 86,632
Operating leases terminal leases	20,583	7,206	7,404	2,702	3,271
Operating leases other	10,545	2,641	980	947	5,977
Commitments for capital expenditures	4,383	4,383			
Estimated payments for defined benefit pension plan	500	500			
IT services	4,501	676	1,039	796	1,990
Purchased ethanol (1)	10,450,276	980,182	2,128,270	2,097,664	5,244,160
Corn	40,248	38,708	1,540		
Coal	43,248	13,892	29,356		
Natural gas	9,018	9,018			
Electricity	3,270	3,270			
Other purchase obligations	315	315			
Total contractual obligations	$ 10,756,190	$ 1,071,395	$ 2,202,614	$ 2,140,151	$ 5,342,030

(1) The dollar value of our commitments under these contracts is estimated based on the volume commitment under the contracts, purchased ethanol contracts not being renewed upon termination and an estimated ethanol purchase price of $1.93. Under these contracts, we are generally obligated to purchase a set volume of ethanol at a purchase price that is based upon an average price at which we sell ethanol less a pre-negotiated margin. As a result, our exposure to market risk under these contracts as a result of fluctuations in ethanol prices is limited. The estimated ethanol price used in this disclosure should not be relied upon as a forecast of ethanol prices in future periods.

Secured Revolving Credit Facility

Our liquidity facility consists of a secured revolving credit facility with JP MorganChase Bank of up to $30 million. The facility expires on September 14, 2007, and is secured by substantially all of the Company s assets, with the exception of our interest in NELLC.

We had no borrowings outstanding under our secured revolving credit facility at December 31, 2006, and approximately $4.0 million of standby letters of credit outstanding, leaving approximately $26.0 million in additional borrowing availability under our secured revolving credit facility as of that date.

Environmental Matters

We are subject to extensive federal, state and local environmental laws, regulations and permit conditions (and interpretations thereof), including those relating to the discharge of materials into the air, water and ground, the generation, storage, handling, use, transportation and disposal of hazardous materials, and the health and safety of our employees. These laws, regulations, and permits require us to incur significant capital and other costs, including costs to obtain and maintain expensive pollution control equipment. They may also require us to make operational changes to limit actual or potential impacts to the environment. A violation of these laws, regulations or permit conditions can result in substantial fines, natural resource damages, criminal sanctions, permit revocations and/or facility shutdowns. In addition, environmental laws and regulations (and interpretations thereof) change over time, and any such changes, more vigorous enforcement policies or the discovery of currently unknown conditions may require substantial additional environmental expenditures.

We are also subject to potential liability for the investigation and cleanup of environmental contamination at each of the properties that we own or operate and at off-site locations where we arranged for the disposal of hazardous wastes. For instance, soil and groundwater contamination has been identified in the past at our Illinois campus. If any of these sites are subject to investigation and/or remediation requirements, we may be responsible under CERCLA or other environmental laws for all or part of the costs of such investigation and/or remediation, and for damages to natural resources. We may also be subject to related claims by private parties alleging property damage or personal injury due to exposure to hazardous or other materials at or from such properties. We have not accrued any amounts for environmental matters as of December 31, 2006. The ultimate costs of any liabilities that may be identified or the discovery of additional contaminants could adversely impact our results of operation or financial condition.

In addition, the hazards and risks associated with producing and transporting our products (such as fires, natural disasters, explosions, abnormal pressures and spills) may result in spills or releases of hazardous substances, and may result in claims from governmental authorities or third parties relating to actual or alleged personal injury, property damage, or damages to natural resources. We maintain insurance coverage against some, but not all, potential losses caused by our operations. Our coverage includes, but is not limited to, physical damage to assets, employer s liability, comprehensive general liability, automobile liability and workers compensation. We do not carry environmental insurance. We believe that our insurance is adequate for our industry, but losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of events which result in significant personal injury or damage to our property, natural resources or third parties that is not covered by insurance could have a material adverse impact on our results of operations and financial condition.

Our air emissions are subject to the federal Clean Air Act, the federal Clean Air Act Amendments of 1990 and similar state laws which generally require us to obtain and maintain air emission permits for our ongoing operations as well as for any expansion of existing facilities or any new facilities. Obtaining and maintaining those permits requires us to incur costs, and any future more stringent standards may result in increased costs and may limit or interfere with our operating flexibility. In addition, the permits ultimately issued may impose conditions which are more costly to implement than we had anticipated. These costs could have a material adverse affect on our financial condition and results of operations. Because other ethanol manufacturers in the U.S. are and will continue to be subject to similar laws and restrictions, we do not currently believe that our costs to comply with current or future environmental laws and regulations will adversely affect our competitive position. However, because ethanol is produced and traded internationally, these costs could adversely affect us in our efforts to compete with foreign producers not subject to such stringent requirements.

Federal and state environmental authorities have been investigating alleged excess VOC emissions and other air emissions from many U.S. ethanol plants, including our Illinois and Nebraska facilities. The matter relating to our Illinois wet mill facility is still pending, and we could be required to install additional air pollution control equipment or take other measures to control air pollutant emissions at that facility. If authorities require us to install controls, we would anticipate that costs would be higher than the costs we incurred for this matter at our Nebraska facility due to the larger size of the Illinois wet mill facility. In addition, if the authorities determine our emissions were in violation of applicable law, we would likely be required to pay fines that could be material.

We have made, and expect to continue making, significant capital expenditures on an ongoing basis to comply with increasingly stringent environmental laws, regulations and permits. We have included in our capital budget for 2007 and 2008 approximately $10.8 million and $4.5 million, respectively, for projects relating to environmental, health and safety matters, including for the installation of air pollution control equipment and for wastewater discharge improvements at our Illinois wet mill facility. The majority of the 2007 environmental capital budget relates to compliance with the EPA s final National Emissions Standard for Hazardous Air Pollutants, or NESHAP, under the federal Clean Air Act for industrial, commercial and institutional boilers and process heaters. This NESHAP will require us to implement maximum achievable control technology at our Illinois wet mill facility to reduce hazardous air pollutant emissions from certain of our boilers and process heaters by September 13, 2007. Based on engineering conducted to date and currently available information, we have budgeted $7.4 million to comply with this NESHAP in 2007. Due to various reasons, including equipment delivery delays, however, we may not be able to meet the September 2007 deadline. We are continuing to discuss a deadline extension with the state authorities. If an extension is not granted, and we do not meet the September 2007 deadline, fines and penalties could be imposed on us, which could be substantial.

We currently generate revenue from the sale of carbon dioxide, which is a co-product of the ethanol production process at each of our Illinois and Nebraska facilities. New laws or regulations relating to the production, disposal or emissions of carbon dioxide may require us to incur significant additional costs and may also adversely affect our ability to continue generating revenue from carbon dioxide sales.

Market Risks

We are exposed to various market risks, including changes in commodity prices and interest rates. Market risk is the potential loss arising from adverse changes in market rates and prices. In the ordinary course of business, we enter into various types of transactions involving financial instruments to manage and reduce the impact of changes in commodity prices and interest rates.

Commodity Price Risks

We are subject to market risk with respect to the price and availability of corn, the principal raw material we use to produce ethanol and ethanol by products. In general, rising corn prices result in lower profit margins and, therefore, represent unfavorable market conditions. This is especially true when market conditions do not allow us to pass along increased corn costs to our customers. The availability and price of corn is subject to wide fluctuations due to unpredictable factors such as weather conditions, farmer planting decisions, governmental policies with respect to agriculture and international trade, and global demand and supply. Our weighted-average gross corn costs for the years ended December 31, 2006 and 2005 was $2.41 and $2.08 per bushel, respectively.

We have firm-price purchase commitments with some of our corn suppliers under which we agree to buy corn at a price set in advance of the actual delivery of that corn to us. Under these arrangements, we assume the risk of a price decrease in the market price of corn between the time this price is fixed and the time the corn is delivered. In order to reduce our market exposure to price decreases, at the time we enter into a firm-price purchase commitment, we also often enter into commodity futures contracts to sell a like amount of corn at the then-current price for delivery to the counterparty at a later date. We account for these transactions under SFAS 133. These futures contracts are not designated as hedges and, therefore, are marked to market each period, with corresponding gains and losses recorded in other non-operating income. The fair value of these derivative contracts are recognized in other current liabilities in the Consolidated Balance Sheet, net of any cash paid to brokers. Information on this type of derivative transaction is as follows:

(In millions)	**Year Ended December 31, 2006**	**2005**
Gain/(loss) included in earnings	**$ 0.1**	$ 1.5

(In millions)	**December 31, 2006**	**2005**
Net bushels sold	**8.0**	1.2
Aggregate notional value of derivatives outstanding	**$ 28.0**	$ 2.6
Period through which derivative positions currently exist	**December 2009**	July 2007
Loss on fair value of derivatives	**$ 3.1**	$ 0.0
The change in fair value due to the effect of a 10% adverse change in commodity prices to current fair value	**$ (3.2)**	$ (0.3)

We have also entered into commodity futures contracts in connection with the purchase of corn to reduce our risk of future price increases. We account for these transactions under SFAS 133. These futures contracts are not designated as hedges and, therefore, are marked to market each period, with corresponding gains and losses recorded in other non-operating income. The fair value of these derivative contracts are recognized in other current assets in the Consolidated Balance Sheet, net of any cash received from the brokers. Information on this type of derivative transaction is as follows:

(In millions)	**Year Ended December 31, 2006**	**2005**
Gain included in earnings	**$ 2.8**	$

(In millions)	**December 31, 2006**	**2005**
Net bushels bought	**2.0**	
Aggregate notional value of derivatives outstanding	**$ 5.1**	$
Period through which derivative positions currently exist	**March 2007**	
Gain on fair value of derivatives	**$ 2.8**	$
The change in fair value due to the effect of a 10% adverse change in commodity prices to current fair value	**$ (0.8)**	$

We may also subject to market risk with respect to our supply of natural gas which is consumed during the production of ethanol and its co-products and has historically been subject to volatile market conditions. Natural gas prices and availability are affected by weather conditions, overall economic conditions and foreign and domestic governmental regulation. The price fluctuation in natural gas prices over the six year period from 1999 through December 2006, based on the New York Mercantile Exchange daily futures data, has ranged from a low of $1.63 per MMBtu in 1999 to a high of $15.82 per

MMBtu in 2003. Natural gas costs comprised 13.8% and 18.4%, respectively, of our total production costs for the years ended December 31, 2006 and 2005.

We did not have any exchange traded futures contracts for the purchase or sale of natural gas as of December 31, 2006. Based upon our annual average estimated natural gas usage and the December 31, 2006 year end price of natural gas of $6.30 per MMBtu, a 10% increase in natural gas prices would negatively affect our results of operations by approximately $2.6 million.

Material Limitations

The disclosures with respect to the above noted risks do not take into account the underlying commitments or anticipated transactions. If the underlying items were included in the analysis, the gains or losses on the futures contracts may be offset. Actual results will be determined by a number of factors that are not generally under our control and could vary significantly from those results disclosed.

We are exposed to credit losses in the event of nonperformance by counterparties on the above instruments, as well as credit or performance risk with respect to our hedged commitments. Although nonperformance is possible, we do not anticipate nonperformance by any of these parties.

Subsequent Event

We have a signed commitment letter and are currently in the process of seeking to obtain a secured revolving credit facility to fund a portion of our expansion plans and other liquidity needs. We cannot assure you that we will be successful in obtaining any such facility or, if we are successful, what the terms thereof will be.

Impact of Recently Issued Accounting Standards

See Note 2, Summary of Critical Accounting Policies - Recent Accounting Pronouncements, of the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item is contained in Item 7 - Management s Discussion and Analysis of Financial Condition and Results of Operations and is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

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

An evaluation was conducted under the supervision and with the participation of the Company s management, including our Chief Executive Officer (CEO), Ronald H. Miller, and our Chief Financial Officer (CFO), Ajay Sabherwal, of the effectiveness of the design and operation of the Company s disclosure controls and procedures as of December 31, 2006. Based upon that evaluation, the CEO and CFO concluded that the Company s disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the report that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Section 404 Compliance

We maintain a system of internal control over financial reporting that is designed to provide reasonable assurance that our books and records accurately reflect our transactions and that our established policies and procedures are followed. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

As a result of the SEC s deferral of the deadline for newly public companies compliance with the internal control requirements of Section 404 of the Sarbanes-Oxley Act of 2002, we are not yet required to include a report by management or an auditor s attestation report on internal control over financial reporting in our annual report. We will be required to be fully compliant in fiscal year 2008 with respect to the management report and the independent registered public accounting firm attestation report as of December 31, 2007. We intend to comply by the required deadline.

Inherent Limitation of the Effectiveness of Internal Control

A control system, no matter how well conceived and operated, can only provide reasonable, not absolute, assurance that the objectives of the internal control system are met. Because of the inherent limitations of any internal control system, no evaluation of controls can provide absolute assurance that all control issues, if any, within a company have been detected.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information required by this item with respect to our directors, audit committee, and our audit committee financial experts is incorporated by reference from the information under the caption Election of Directors contained in our definitive proxy statement for the 2007 Annual Meeting of Stockholders. The required information concerning our executive officers is incorporated by reference from the information under the caption Executive Officers of the Registrant contained in our definitive proxy statement for the 2007 Annual Meeting of Stockholders. The required information concerning our adoption of a code of ethics that applies to our chief executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions and the availability of this code of ethics upon written request is contained in Part I Item 1 Business Available Information of this report.

The required information concerning compliance with Section 16(a) of the Exchange Act is incorporated by reference from the information under the caption Section 16(a) Beneficial Ownership Reporting Compliance contained in our definitive proxy statement for the 2007 Annual Meeting of Stockholders.

Item 11. Executive Compensation

The information required by this item is incorporated by reference from the information under the captions Executive Compensation and Company Stock Price Performance in our definitive proxy statement for the 2007 Annual Meeting of Stockholders.

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

The information required by this item is incorporated by reference from the information under the caption Security Ownership of Certain Beneficial Owners and Management and Executive Compensation - Equity Compensation Plan Information in our definitive proxy statement for the 2007 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions

The information required by this item is incorporated by reference from the information contained under the caption Executive Compensation - Certain Relationships and Related Transactions in our definitive proxy statement for the 2007 Annual Meeting of Stockholders.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference from the information under the caption Ratification of Appointment of Independent Auditors - Principal Accounting Firm Fees and Ratification of Appointment of Independent Auditors Audit Committee s Pre-Approval Policies and Procedures contained in our definitive proxy statement for the 2007 Annual Meeting of Stockholders.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Index to exhibits, financial statements and schedules.

(1) The following consolidated financial statements and reports are included beginning on page F-1 hereof:

Consolidated Statements of Operations For the years ended December 31, 2006, 2005, and 2004.

Consolidated Balance Sheets December 31, 2006 and 2005.

Consolidated Statements of Stockholders Equity (Deficit) For the years ended December 31, 2006, 2005, and 2004.

Consolidated Statements of Cash Flows For the years ended December 31, 2006, 2005, and 2004.

Notes to Consolidated Financial Statements.

Report of Independent Registered Public Accounting Firm.

(2) The following consolidated financial statement schedule of the Company is included on page S-1 hereof:

SCHEDULE II Valuation and Qualifying Accounts

All other financial statements and schedules not listed have been omitted since the required information is included in the consolidated financial statements or the notes thereto, or is not applicable or required.

(3) Exhibits required by Item 601 of Regulation S-K:

EXHIBIT INDEX

Exhibit Number	Description
3.1(1)	Amended and Restated Certificate of Incorporation of Aventine Renewable Energy Holdings, Inc.
3.2 (1)	Amended and Restated Bylaws of Aventine Renewable Energy Holdings, Inc.
4.1(1)	Registration Rights Agreement dated as of December 12. 2005 among Aventine Renewable Energy Holdings, Inc., the Investor Holders and the Management Holders named therein
4.2(1)	Registration Rights Agreement dated as of December 23, 2005 by and between Aventine Renewable Energy Holdings, Inc. and Friedman, Billings, Ramsey & Co., Inc.
10.1	Lease Agreement, dated as of October 31, 2006 by and between the Indiana Port Commission and Aventine Renewable Energy Mt Vernon, LLC
10.2	Amended and Restated Credit Agreement among JPMorgan Chase Bank as Administrative Agent and Issuing Bank, Aventine Renewable Energy, Inc., Aventine Renewable Energy LLC, and the lenders from time to time party thereto dated as of September 15, 2006

Exhibit Number	Description
10.3	Amended and Restated Guarantee and Security Agreement dated as of September 15, 2006 among JPMorgan Chase Bank, N.A. as Administrative Agent, Aventine Renewable Energy. Inc. and Aventine Renewable Energy, LLC
10.4(1)	Rights Agreement dated as of December 19, 2005 between Aventine Renewable Energy Holdings. Inc. and American Stock Transfer & Trust Company, as Rights Agent
10.5(1*)	Aventine Renewable Energy Holdings. Inc. 2003 Stock Incentive Plan (2003 Plan)
10.6(5)	Design-Builder Agreement between Fagen, Inc. and Aventine Renewable Energy Holdings, Inc. dated as of September 9, 2005
10.7(5)	Ethanol Marketing Agreement, dated October 14, 2002, between Aventine Renewable Energy, Inc. (f/k/a Williams Ethanol Services, Inc.) and VeraSun Aurora Corporation (f/k/a VeraSun Energy Corporation), as amended on December 8, 2003 and February 22, 2005
10.8(5)	Ethanol Marketing Agreement, dated February 22, 2005, between Aventine Renewable Energy, Inc. and VeraSun Fort Dodge, LLC
10.9(3*)	Non-Employee Director Compensation Schedule
10.10(3*)	Form of Non-Employee Director Restricted Stock Award Agreement under the Aventine Renewable Energy Holdings, Inc. 2003 Stock Incentive Plan
10.11(3*)	Form of Stock Option Award Agreement under the Aventine Renewable Energy Holdings, Inc. 2003 Stock Incentive Plan
10.12(3*)	Stock Option Award Agreement for Ajay Sabherwal dated November 14, 2005
10.13(3*)	Amendment to Stock Option Award Agreement for Ajay Sabherwal dated December 30, 2005
10.14(6*)	Form of Performance Stock Unit Award Agreement under 2003 Plan
10.15(6*)	Form of Restricted Stock Award Agreement under 2003 Plan
10.16(6*)	Form of Non-Employee Director Restricted Stock Unit Award under 2003 Plan
21.1	List of subsidiaries
23.1	Consent of Ernst & Young, LLP
31.1	Certificate of Chief Executive Officer of Aventine Renewable Energy Holdings, Inc. pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
31.2	Certificate of Chief Financial Officer of Aventine Renewable Energy Holdings, Inc. pursuant to Rule 13(a)-14(a) under the Securities Exchange Act of 1934
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(1) Filed with the registration statement on Form S-1 (333-132860) on March 30, 2006.

(2) Filed with the registration statement on Form S-1 (333-132881) on March 31, 2006.

(3) Filed with the amended registration statement on Form S-1/A (333-132860) on June 13, 2006.

(4) Filed with the amended registration statement on Form S-1/A (333-132881) on July 24, 2006.

(5) Application was made to the Securities and Exchange Commission to seek confidential treatment of certain provisions. Omitted material for which confidential treatment was requested and granted has been filed separately with the Securities and Exchange Commission.

(6) Incorporated by reference to the Company s current report on Form 8-K filed on February 27, 2007.

* 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, in the City of Pekin, State of Illinois, on the 5th day of March 2007.

AVENTINE RENEWABLE ENERGY HOLDINGS, INC.

By:	/s/William J. Brennan
Name:	William J. Brennan
Title:	Principal Accounting Officer

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

Signature	Title	Date
By: /s/ Ronald H. Miller Ronald H. Miller	President and Chief Executive Officer and Director (Principal Executive Officer)	March 5, 2007
By: /s/ Ajay Sabherwal Ajay Sabherwal	Chief Financial Officer (Principal Financial Officer)	March 5, 2007
By: /s/ William J. Brennan William J. Brennan	Chief Compliance and Accounting Officer (Principal Accounting Officer)	March 5, 2007
By: /s/ Bobby Latham Bobby Latham	Non-Executive Chairman of the Board and Director	March 5, 2007
By: /s/ Leigh J. Abramson Leigh J. Abramson	Director	March 5, 2007
By: /s/ Richard A. Derbes Richard A. Derbes	Director	March 5, 2007
By: /s/ Farokh S. Hakimi Farokh S. Hakimi	Director	March 5, 2007
By: /s/ Michael C. Hoffman Michael C. Hoffman	Director	March 5, 2007
By: /s/ Wayne D. Kuhn Wayne D. Kuhn	Director	March 5, 2007

Aventine Renewable Energy Holdings, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year ended December 31, 2006	2005	2004
(In thousands except per share amounts)			
Net sales	**$ 1,592,420**	$ 935,468	$ 858,876
Cost of goods sold	**1,460,806**	848,053	793,070
Gross profit	**131,614**	87,415	65,806
Selling, general and administrative expenses	**28,328**	22,500	16,236
Other income	**(3,389)**	(989)	(3,196)
Operating income	**106,675**	65,904	52,766
Other income (expense):			
Interest expense	**(9,348)**	(16,510)	(2,035)
Interest income	**4,771**	2,218	19
Loss on early extinguishment of debt	**(14,598)**		
Other non-operating income (expense)	**3,654**	1,781	(924)
Minority interest	**(4,568)**	(2,404)	(2,148)
Income before income taxes	**86,586**	50,989	47,678
Income tax expense	**31,685**	18,807	18,433
Net income	**$ 54,901**	$ 32,182	$ 29,245
Income per common share basic	**$ 1.43**	$ 0.93	$ 0.84
Basic weighted-average number of shares	**38,411**	34,686	34,684
Income per common share diluted	**$ 1.39**	$ 0.89	$ 0.82
Diluted weighted-average number of common and common equivalent shares	**39,639**	36,052	35,768

The accompanying notes are an integral part of the consolidated financial statements.

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Aventine Renewable Energy Holdings, Inc. and Subsidiaries

Consolidated Balance Sheets

	December 31, 2006	2005
(In thousands except share and per share amounts)		
Assets		
Current assets:		
Cash and equivalents	**$ 29,791**	$ 3,750
Short-term investments	**98,925**	
Accounts receivable, net of allowance for doubtful accounts of $25 in 2006 and 2005	**79,729**	46,625
Inventories	**67,051**	54,651
Income taxes receivable	**6,446**	2,628
Prepaid expenses and other	**4,549**	2,519
Total current assets	**286,491**	110,173
Property, plant and equipment	**115,645**	42,856
Restricted cash for plant expansion		60,362
Investment in marketing alliance partners	**6,000**	1,000
Other assets		7,586
Total assets	**$ 408,136**	$ 221,977
Liabilities and Stockholders Equity (Deficit)		
Current liabilities:		
Accounts payable	**$ 77,442**	$ 51,528
Accrued liabilities	**3,679**	4,104
Credit agreement borrowings		1,514
Other current liabilities	**2,123**	3,149
Total current liabilities	**83,244**	60,295
Senior secured floating rate notes		160,000
Deferred taxes	**6,104**	6,703
Minority interest	**10,221**	8,675
Other long-term liabilities	**4,404**	6,958
Total liabilities	**103,973**	242,631
Stockholders equity (deficit):		
Common stock, par value $0.001 per share; 185,000,000 shares authorized, 41,782,276 and 35,145,253 shares outstanding as of December 31, 2006 and 2005, respectively, net of 21,229,025 and 21,179,025 shares held in treasury as of December 31, 2006 and 2005	**42**	35
Preferred stock, 50,000,000 shares authorized, no shares issued or outstanding		
Additional paid-in capital	**274,307**	4,191
Retained earnings (deficit)	**30,888**	(24,013)
Accumulated other comprehensive loss, net	**(1,074)**	(867)
Total stockholders equity (deficit)	**304,163**	(20,654)
Total liabilities and stockholders equity (deficit)	**$ 408,136**	$ 221,977

The accompanying notes are an integral part of the consolidated financial statements.

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Aventine Renewable Energy Holdings, Inc. and Subsidiaries

Consolidated Statements of Stockholders Equity (Deficit)

(In thousands except number of shares)	**Treasury Shares**	**Common Stock Shares**	**Amount**	**Additional Paid-In Capital**	**Retained Earnings**	**Accumulated Other Compre-hensive (Loss)**	**Total Stock-holders Equity**
Balance at January 1, 2004		34,643,253	$	$ 43,010	$ 11,049	$ (274)	$ 53,785
Capital contribution				2,343			2,343
Issuance of common stock		41,000		50			50
Distribution to stockholders				(45,511)	(96,489)		(142,000)
Stock-based compensation				108			108
Comprehensive income:							
Net income					29,245		29,245
Minimum pension liability, net of tax of $76						(112)	(112)
Total comprehensive income							29,133
Balance at December 31, 2004		34,684,253			(56,195)	(386)	(56,581)
Reclassification of additional paid-in capital to par value of common stock			35	(35)			
Proceeds from common stock offering		21,179,025	21	256,033			256,054
Repurchase of common stock for the treasury	21,179,025	(21,179,025)	(21)	(256,033)			(256,054)
Tax benefit of stock option exercises				2,122			2,122
Stock option exercises		461,000		173			173
Stock-based compensation				1,931			1,931
Comprehensive income:							
Net income					32,182		32,182
Minimum pension liability, net of tax of $320						(481)	(481)
Total comprehensive income							31,701
Balance at December 31, 2005	21,179,025	35,145,253	35	4,191	(24,013)	(867)	(20,654)
Issuance of common stock		**6,410,256**	**7**	**260,883**			**260,890**
Tax benefit of stock option exercises				**3,687**			**3,687**
Stock option exercises		**268,707**		**220**			**220**
Repurchase of common stock for the treasury	**50,000**	**(50,000)**		**(1,152)**			**(1,152)**
Stock-based compensation				**6,426**			**6,426**
Issuance of restricted stock awards and amortization of unearned compensation		**8,060**		**52**			**52**
Comprehensive income:							
Net income					**54,901**		**54,901**
Total comprehensive income							**54,901**
Adjustment to initially apply SFAS 158, net of tax of $109						**(207)**	**(207)**
Balance at December 31, 2006	**21,229,025**	**41,782,276**	**$ 42**	**$ 274,307**	**$ 30,888**	**$ (1,074)**	**$ 304,163**

The accompanying notes are an integral part of these consolidated financial statements.

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Aventine Renewable Energy Holdings, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

(In thousands)	Year ended December 31, 2006	2005	2004
Operating Activities			
Net income	**$ 54,901**	$ 32,182	$ 29,245
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**4,628**	3,623	2,135
Loss on early extinguishment of debt	**14,598**		
Deferred income taxes	**(1,177)**	2,589	4,836
Gain on disposal of fixed assets	**(110)**	(3)	
Minority interest	**4,568**	2,404	2,148
Stock-based compensation expense	**6,478**	1,931	108
Mark to market of derivative contracts	**839**	(898)	(857)
Changes in operating assets and liabilities:			
Accounts receivable, net	**(33,104)**	(16,580)	11,484
Inventories	**(12,400)**	(29,813)	5,494
Proceeds from marketing commission buydown		3,000	
Prepaid expenses and other	**(5,315)**	1,137	(693)
Accounts payable	**25,914**	26,716	(4,498)
Accrued liabilities, including pension and postretirement benefits	**(4,058)**	417	171
Net cash provided by operating activities	**55,762**	26,705	49,573
Investing Activities			
Additions to property, plant and equipment, net	**(76,499)**	(20,672)	(4,653)
Investment in short-term investments	**(98,925)**		
Investment in marketing alliance partners	**(5,000)**		(500)
Increase in restricted cash for plant expansion	**(1,257)**	(1,971)	(62,500)
Release of restricted cash related to repayment of senior notes	**29,762**		
Use of restricted cash for plant expansion	**31,857**	4,109	
Proceeds from the sale of fixed asset	**131**		
Net cash used for investing activities	**(119,931)**	(18,534)	(67,653)
Financing Activities			
Distributions to stockholders			(142,000)
Proceeds from issuance of senior secured floating rate notes			160,000
Financing fees and expenses paid			(6,841)
Capital contribution from Aventine Renewable Energy Holdings, LLC			2,343
Net borrowings from (repayments of) revolving credit facilities	**(1,514)**	(11,277)	8,869
Repayment of senior secured floating rate notes and related premium	**(168,899)**		
Distribution to minority shareholders	**(3,022)**	(2,590)	(2,470)
Net proceeds from issuance of common stock, net	**260,890**	256,054	
Repurchase of common stock	**(1,152)**	(256,054)	
Tax benefit of stock option exercises	**3,687**	2,122	
Proceeds from stock option exercises	**220**	173	
Net cash provided by (used for) financing activities	**90,210**	(11,572)	19,901
Net increase (decrease) in cash and equivalents	**26,041**	(3,401)	1,821
Cash and equivalents at beginning of year	**3,750**	7,151	5,330
Cash and equivalents at end of year	**$ 29,791**	$ 3,750	$ 7,151
Supplemental disclosure of cash flow:			
Interest paid	**$ 11,162**	$ 15,046	$ 846
Income taxes paid	**$ 33,161**	$ 16,913	$ 13,660

The accompanying notes are an integral part of the consolidated financial statements.

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Aventine Renewable Energy Holdings, Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Nature of Operations

Aventine Renewable Energy Holdings, Inc. and Subsidiaries (the Company, Aventine, we, our, or us) is a leading producer and marketer of ethanol both in terms of gallons produced and gallons sold. Through our own production facilities, marketing alliances with other ethanol producers and our purchase/resale operations, we market and distribute ethanol to many of the leading energy companies in the U.S. We have a comprehensive national distribution network utilizing a leased railcar fleet and a terminal network at critical points on the nation s transportation grid where our ethanol is blended with our customers gasoline. In addition to producing ethanol, our facilities also produce several co-products including: corn gluten feed and meal, corn germ, condensed corn distillers solubles, dried distillers grain with solubles, wet distillers grain with solubles, carbon dioxide and brewers yeast.

We were acquired by the Morgan Stanley Capital Partners (MSCP) funds from a subsidiary of The Williams Companies, Inc. on May 30, 2003. The acquisition was accounted for as a purchase business combination in accordance with Statement of Financial Accounting Standards No. 141 (SFAS 141), *Business Combinations*.

On December 17, 2004, we completed an offering of $160 million of senior secured floating rate notes. The net proceeds from the offering, along with an additional $15.5 million borrowed on our secured revolving credit facility, were used to fund $62.5 million into an escrow account for a plant expansion at the Pekin facility and to pay a $107 million distribution to shareholders. The distribution, together with a $35 million distribution paid to shareholders on April 13, 2004, resulted in the retained deficit on the accompanying consolidated balance sheet.

On December 23, 2005, the Company completed an equity offering (the 144a equity offering) of 21,179,025 shares of common stock pursuant to Rule 144a of the Securities Act. All of the net proceeds of the 144a equity offering were used to repurchase an equal number of shares from existing shareholders. The repurchase of shares is reflected as a treasury stock transaction in the accompanying consolidated financial statements. The shares sold were subject to a registration rights agreement where the Company agreed, at its expense, to use reasonable efforts to file a shelf registration statement registering for resale the shares sold in the offering. In connection with the offering, the Company authorized a 805.47131 for 1 stock split. All share data presented has been adjusted to reflect the stock split.

Effective July 5, 2006, we completed an initial public offering of 9,058,450 shares of our common stock, $0.001 par value, at a gross per share price of $43.00 (the initial public offering). The Company sold 6,410,256 shares and received approximately $260.9 million in proceeds, net of discounts and commissions, from this initial public offering. Existing shareholders and management also sold 2,648,194 shares of common stock during the initial public offering, which includes 268,707 shares issued from the exercise of outstanding options. Immediately following our initial public offering, we had 41,831,651 shares of common stock issued and outstanding.

In anticipation of our initial public offering, on June 6, 2006, our Board gave contingent approval of the acceleration of vesting of 71,488 options held by officers and employees to be effective immediately prior to the consummation of the initial public offering. The Board approved the acceleration of the vesting in order to permit certain members of management the ability to sell stock in our initial public offering. These options had a weighted-average exercise price of $4.35 per share. As a result of the accelerated vesting, we recorded a pre-tax charge to earnings of $0.6 million for the year-ended December 31, 2006.

2. Summary of Critical Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Aventine and its subsidiaries. All significant intercompany transactions and accounts have been eliminated in consolidation.

Aventine owns 78.4% of Nebraska Energy, LLC. The remaining 21.6% of Nebraska Energy, LLC is owned by Nebraska Energy Cooperative. The Company has included in its consolidated financial statements all of the revenues and expenses of Nebraska Energy, LLC in its financial statements and the interest therein of the Nebraska Energy Cooperative is reflected as minority interest.

Uses of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires 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 financial statements, as well as amounts of revenue and expenses during the reporting periods. Actual results could differ from those estimates.

Industry Segments

We operate in one reportable segment, the manufacture and marketing of fuel-grade ethanol.

Revenue Recognition Policy

Revenue is generally recognized when title to products transfer to an unaffiliated customer. This generally occurs after the product has been offloaded at the customers site, the sales price is fixed and determinable, and collection is reasonably assured. Sales are made under normal terms and usually do not require collateral. The Company also markets ethanol for its marketing alliance partners and from unaffiliated producers. Sales revenue on non-Aventine produced gallons are recorded on a gross basis (and not simply the commission amount) in the accompanying statements of operations, because the Company takes title to and is the primary obligor in the sales arrangement with customers.

Shipping and handling and motor fuel tax costs invoiced to the customer are included in sales, and the related expenses are included in cost of goods sold.

Cash Equivalents

We consider all highly liquid short-term investments purchased with a maturity of three months or less to be cash equivalents. Cash equivalents are carried at cost, which approximates fair value.

Short-Term Investments

We have invested certain cash proceeds received from the initial public offering in tax-free municipal auction rate certificates which generally have contractual maturities of greater than 20 years. We consider these certificates as available for sale. These certificates are widely traded in the public markets and may be sold as needed. The interest rates on these certificates reprice every 35 days to the then current market rate. Generally, the carrying value of these securities approximates fair value, and there is no gain or loss expected from changes in fair value.

Accounts Receivable and Concentration of Credit Risk

Accounts receivable are recorded on a gross basis, with no discounting, less an allowance for doubtful accounts. An allowance for doubtful accounts is not recognized at the time the revenue which generated the accounts receivable is recognized. Management estimates the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers, and the amount and age of past due accounts.

The Company sells ethanol to most of the major integrated oil companies and a significant number of large, independent refiners and petroleum wholesalers. Our trade receivables result primarily from our ethanol marketing operations. As a general policy, collateral is not required for receivables, but customers financial condition and creditworthiness are evaluated regularly. Credit risk concentration related to our accounts receivable results from our top 10 customers generating 75% of our sales revenue. Our two largest customers, BP and Exxon/Mobil, accounted for approximately 18% and 12%, respectively, of our consolidated 2006 revenue.

Inventories

Inventories are stated at the lower of cost or market. Cost is determined using a weighted average first-in-first-out (FIFO) method for gallons produced at our plants, gallons purchased from our marketing alliance partners and other gallons purchased for resale. Inventory costs include expenditures incurred in bringing inventory to its existing condition and location. In assessing the ultimate realization of inventories, we perform a periodic analysis of market price and compare that to our weighted-average FIFO to ensure that our inventories are properly stated at the lower of cost or market.

Property, Plant and Equipment

Newly acquired land, buildings and equipment are carried at cost less accumulated depreciation. Depreciation is provided over the estimated useful lives of the assets, generally on the straight-line method for financial reporting purposes (furniture and fixtures 3 20 years, machinery and equipment 5 25 years, storage tanks 25 30 years, and buildings and improvements 20 45 years), and on accelerated methods for tax purposes.

In connection with the acquisition of the Company by MSCP, the excess of the fair value of the net current assets over the purchase price was allocated to reduce the carrying values of the non-current assets, including property, plant and equipment.

Impairment of Long-Lived Assets

Long-lived assets are evaluated for impairment under the provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 144 (SFAS 144), *Accounting for the Impairment or Disposal of Long-Lived Assets*. When facts and circumstances indicate that long-lived assets used in operations may be impaired, and the undiscounted cash flows estimated to be generated from those assets are less than their carrying values, an impairment charge is recorded equal to the excess of the carrying value over fair value.

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Investments in Marketing Alliances

The Company has made investments in four marketing alliance partners (each of which is less than 8% of total ownership at December 31, 2006). The total investment made by the Company after May 31, 2003 of $6 million is accounted for using the cost method. Investments made by the predecessor company in one marketing alliance partner prior to May 30, 2003 was written down to zero as part of the purchase price allocation upon the acquisition of the Company by MSCP. In conjunction with our investment in Ace Ethanol, LLC and Indiana BioEnergy, LLC, we are entitled to a seat on each of these companies Board of Directors for as long as we maintain an ownership interest.

Unearned Revenue

In 2005, the Company received $3 million from a marketing alliance partner to amend the marketing agreement with this partner. The Company recorded this amount as deferred revenue and is recognizing the related revenue over the life of the agreement which extends through August 2012. The unrecognized balance at December 31, 2006 is $2.4 million. The portion to be recognized over the next 12 months of $0.4 million is included in other current liabilities. The remainder is included in other liabilities on the consolidated balance sheets.

Employment-Related Benefits

Employment-related benefits associated with pensions and postretirement health care are expensed as actuarially determined. The recognition of expense is impacted by estimates made by management, such as discount rates used to value certain liabilities, investment rates of return on plan assets, increases in future wage amounts and future health care costs. The Company uses third-party specialists to assist management in appropriately measuring the expense and liabilities associated with employment-related benefits.

We determine our actuarial assumptions for the pension and post retirement plans, after consultation with our actuaries, on December 31 of each year to calculate liability information as of that date and pension and postretirement expense for the following year. The discount rate assumption is determined based on a spot yield curve that includes bonds that are rated Corporate AA or higher with maturities that match expected benefit payments under the plan.

The expected long-term rate of return on plan assets reflects projected returns for the investment mix that have been determined to meet the plans investment objectives. The expected long-term rate of return on plan assets is selected by taking into account the expected weighted averages of the investments of the assets, the fact that the plan assets are actively managed to mitigate downside risks, the historical performance of the market in general and the historical performance of the retirement plan assets over the past ten years.

On December 31, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 158 (SFAS 158), *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*. SFAS 158 requires the Company to recognize in its statement of financial position an asset for a defined benefit postretirement plan s overfunded status or a liability for a defined benefit postretirement plan s underfunded status. In addition, the Company must recognize changes in the funded status of a defined benefit postretirement plan in comprehensive income in the year in which the changes occur. The effect of adopting SFAS 158 on the Company s Consolidated Balance Sheet at December 31, 2006 was immaterial.

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Income Taxes

Under Statement of Financial Accounting Standards No. 109 (SFAS 109), *Accounting for Income Taxes*, deferred tax liabilities and assets are recorded for the expected future tax consequences of events that have been recognized in our financial statements or tax returns. Property, plant and equipment, inventories, prepaid pension, postretirement benefit obligations, and certain other accrued liabilities are the primary sources of these temporary differences. Deferred income tax also includes tax credit carryforwards. The Company establishes valuation allowances to reduce deferred tax assets to amounts it believes are realizable and contingency reserves for implemented tax planning strategies. These valuation allowances and contingency reserves are adjusted based upon changing facts and circumstances.

Earnings Per Common Share

Basic earnings per share is computed by dividing net income by the weighted-average number of common shares outstanding. Diluted earnings per share is calculated by including the effect of all dilutive securities, including stock options. To the extent that stock options and unvested restricted stock are anti-dilutive, they are excluded from the calculation of diluted earnings per share.

Derivatives and Hedging Activities

Our operations and cash flows are subject to fluctuations due to changes in commodity prices. We use derivative financial instruments to manage commodity prices. Derivatives used are primarily commodity futures contracts, swaps and option contracts.

We apply the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by Statement of Financial Accounting Standards No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and by Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (hereinafter collectively referred to as SFAS 133), for the Company s derivatives. These futures contracts are not designated as hedges and, therefore, are marked to market each period, with corresponding gains and losses recorded in other non-operating income. The fair value of these derivative instruments is recognized in other current assets or liabilities in the Consolidated Balance Sheet, net of any cash received from the brokers.

Fair Values of Financial Instruments

We use the following methods in estimating fair value disclosures for financial instruments:

<u>Cash and equivalents, short-term investments, accounts receivable and accounts payable</u>: The carrying amount reported in the Consolidated Balance Sheets approximates fair value.

<u>Revolving credit facility and long-term debt</u>: The carrying amount of our borrowings under our revolving credit facilities approximates fair value. The fair value of our senior secured floating rate notes and any derivative financial instruments are based upon quoted market prices.

<u>Commodity derivatives:</u> Commodity derivative instruments held by the Company consist primarily of futures contracts, swaps and option contracts. The fair value of these commodity derivative instruments are determined by reference to quoted market prices.

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The following table summarizes fair value information for our financial instruments:

Assets/(liabilities)	**2006 Carrying value**	**2006 Fair value**	2005 Carrying value	2005 Fair value
(In thousands)				
Cash and cash equivalents	**$ 29,791**	**$ 29,791**	$ 3,750	$ 3,750
Short-term investments	**98,925**	**98,925**		
Commodity margin deposits	**1,503**	**1,503**	90	90
Senior secured floating rate notes			(161,514)	(167,114)
Investment in marketing alliance partners, at cost	**6,000**	**(a)**	1,000	(a)
Interest rate cap			839	839

(a) These investments are in non-publicly traded companies for which it is not practical to estimate fair value.

Environmental Expenditures

Environmental expenditures that pertain to our current operations and relate to future revenue are expensed or capitalized consistent with our capitalization policy. Expenditures that result from the remediation of an existing condition caused by past operations, and that do not contribute to future revenue, are expensed.

Research and Development Costs

Expenditures relating to the development of new products and processes, including significant improvements and refinements to existing products, are expensed as incurred. The amounts charged to expense were approximately $0.2 million in 2006 and $0.1 million in 2005 and 2004.

Reclassifications

Certain prior year amounts have been reclassified to conform with the current year presentation, with no effect on previously reported net income.

Recent Accounting Pronouncements

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 prescribes a comprehensive model for how a company should recognize, measure, present, and disclose in its financial statements uncertain tax positions that the company has taken or expects to take on a tax return. The interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the effect that the adoption of FIN 48 will have, if any, on its consolidated results of operations, financial position and related disclosures, but does not expect it to have a material impact on the financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157 (SFAS 157), *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is currently evaluating the effect that the adoption of SFAS 157 will have, if any, on its consolidated results of operations, financial position and related disclosures, but does not expect it to have a material impact on the financial statements.

3. Related Party Transactions

As of May 30, 2003, the date we were acquired from the William s Companies, Aventine s principal shareholders were the MSCP funds. Morgan Stanley Investment Management, Inc. subsequently entered into definitive agreements under which Metalmark Subadvisor LLC, an affiliate of Metalmark, an independent private equity firm established by former principals of MSCP, manages the MSCP funds on a sub-advisory basis. Monitoring fees paid to the MSCP funds for the year ended December 31, 2004, were $131. No fees were paid in 2005 or 2006.

At the time of the MSCP funds acquisition of the Company, one of the MSCP funds entered into consulting agreements with each of its three directors. Under these agreements, each of these directors agreed to serve as one of the Company s directors and to provide consulting services to the Company, as reasonably requested by such MSCP fund. The agreements had two one-year terms, which would automatically renew, unless either party provides 30 days written notice prior to the end of the term. On April 30, 2004, the MSCP fund assigned its rights and obligations under these consulting agreements to us. The Company was then obligated to pay the directors under these agreements. Except for payments pursuant to the consulting agreements, the directors did not receive any additional compensation for their services as a director. Payments to directors reduced the monitoring fees that would otherwise have been paid to the MSCP funds. Payments of $0.2 million and $0.3 million were made under these agreements in 2004 and 2005, respectively. No payments were made in 2006. The consulting agreements were terminated as of December 31, 2005, and were superseded by a non-employee director compensation program. Two of the Company s directors are currently employees of Metalmark. Our amended and restated certificate of incorporation provides that directors may not be removed from office by the stockholders except for cause and only by an affirmative vote of the holders of not less than 85% of the voting power of the issued and outstanding shares of our capital stock entitled to vote generally at an election of directors.

In conjunction with the $160 million senior secured note offering, we paid an advisory fee of $0.4 million to an affiliate of the MSCP funds. In conjunction with the December 2005 144a equity offering, the MSCP funds agreed to reimburse us for $1.5 million of the expenses incurred as a result of the 144a equity offering. The remaining amount of $0.4 million was paid by the Company and is included in selling, general, and administrative expenses. After giving effect to the 144a equity offering, the MSCP funds owned approximately 39.6% of the Company s outstanding stock. Upon completion of our initial public offering, the MSCP funds owned approximately 28.3% of the Company.

In exchange for providing professional expertise, services, consulting, or advice in accordance with an agreement entered into with one of the MSCP funds prior to the MSCP funds acquisition of the Company, the directors received Class B units in Aventine Holdings LLC (Aventine Holdings, LLC is the investment vehicle in which MSCP holds the Common Stock of the Company). Class B units have no voting rights, participate in distributions only after a specified threshold is met, and are subject to certain additional limitations.

Aventine maintains investments in marketing alliances all of which are less than 8.0% of total ownership. Total purchases from these plants aggregated $228.2 million, and $137.8 million and $127 million, for the years ended December 31, 2006, 2005 and 2004, respectively. These transactions were recorded at market prices and normal commercial terms. As of December 31, 2006, we had recorded in accounts payable approximately $8.8 million owed to the marketing alliance partners where we had an ownership interest. These funds represent amounts owed to these alliance partners for purchased ethanol.

During 2006, we received a $1.3 million one-time special cash dividend from Heartland Grain Fuels, a marketing alliance partner in which we hold an ownership interest, prior to their being acquired by Advanced BioEnergy, LLC.

4. Inventories

Inventories are as follows:

	December 31,	
(In thousands)	**2006**	**2005**
Finished products	**$ 61,775**	$ 50,828
Work-in-process	**1,106**	1,100
Raw materials	**2,070**	1,343
Supplies	**2,100**	1,380
Totals	**$ 67,051**	$ 54,651

5. Prepaid Expenses and Other

Prepaid expenses and other are as follows at December 31:

	2006	**2005**
(In thousands)		
Prepaid insurance	**$ 1,280**	$ 1,408
Fair value of derivative instruments	**1,503**	90
Deferred income taxes current	**1,064**	531
Other prepaid expenses	**702**	490
Totals	**$ 4,549**	$ 2,519

6. Property, Plant and Equipment

Property, plant and equipment at December 31 are as follows:

	2006	**2005**
(In thousands)		
Land and improvements	**$ 1,659**	$ 244
Building and improvements	**1,510**	1,510
Machinery and equipment	**43,242**	25,346
Storage tanks	**2,965**	1,898
Furniture and fixtures	**25**	24
Construction-in-progress	**74,683**	18,563
	124,084	47,585
Less accumulated depreciation	**(8,439)**	(4,729)
Totals	**$ 115,645**	$ 42,856

Depreciation expense in 2006 and 2005 was $3.7 and $2.3 million, respectively.

7. Other Current Liabilities

Other current liabilities are as follows at December 31:

	2006	2005
(In thousands)		
Accrued interest expense	**$**	$ 793
Accrued sales taxes	**821**	473
Accrued income taxes - current		376
Accrued income taxes - deferred	**429**	474
Accrued property taxes	**418**	454
Current portion of unearned commission	**425**	424
Unearned NOX credits sold		131
Other accrued operating expenses	**30**	24
Totals	**$ 2,123**	$ 3,149

8. Secured Revolving Credit Facility

Our liquidity facility consists of a secured revolving credit facility with JP MorganChase Bank of up to $30 million, including a $20 million sub-limit for letters of credit. The facility expires on September 14, 2007, and is secured by substantially all of the Company s assets, with the exception of our interest in Nebraska Energy, LLC.

We had no borrowings outstanding under our secured revolving credit facility at December 31, 2006, and approximately $4.0 million of standby letters of credit outstanding, leaving approximately $26.0 million in additional borrowing availability under our secured revolving credit facility as of that date.

9. Senior Secured Floating Rate Notes

The Company previously had outstanding $160 million of senior secured floating rate notes due 2011. In 2006, we paid $168.9 million (including premiums) from the funds received in our initial public offering to fund the repurchase of $160 million aggregate principal amount of the senior secured floating rate notes.

10. Interest Expense

The following table summarizes interest expense:

	Year Ended December 31,		
	2006	2005	2004
(in thousands)			
Interest expense bonds and other	**$ 10,230**	$ 16,021	$ 719
Interest expense revolving credit facility	**317**	560	1,316
Capitalized interest	**(1,199)**	(71)	
Total interest expense	**$ 9,348**	$ 16,510	$ 2,035

11. Retirement and Pension Plans

We have 401(k) plans covering substantially all of our employees. We provide, at our discretion, a match of employee salaries contributed to the plans. We recorded expense with respect to these plans of $1.3 million in 2006, $1.2 million in 2005, and $1.1 million in 2004.

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Qualified Retirement Plan

We have a defined benefit pension plan (Retirement Plan) that is noncontributory which covers unionized employees at our Pekin, Illinois facility who fulfill minimum age and service requirements. Benefits are based on a prescribed formula based upon the employee s years of service. The Retirement Plan was amended in 2006 to increase the Company s contribution rate for years of service in response to provisions in a new labor agreement between the Company and its unionized employees, which became effective in June 2006.

The average asset allocations for our Retirement Plan at December 31 are as follows:

	2006	2005
Equity securities	**44 %**	47 %
Debt securities	**36**	28
Guaranteed Investment Contracts	**16**	21
Cash and equivalents	**4**	4
Total	**100 %**	100 %

The Company s Pension Committee is responsible for overseeing the investment of pension plan assets. The Pension Committee is responsible for determining and monitoring the appropriate asset allocations and for selecting or replacing investment managers, trustees, and custodians. The pension plan s current investment target allocations are 50% equities, 30% debt and 20% stable funds. The Pension Committee reviews the actual asset allocation in light of these targets periodically and rebalances investments as necessary. The Pension Committee also evaluates the performance of investment managers as compared to the performance of specified benchmarks and peers and monitors the investment managers to ensure adherence to their stated investment style and to the plan s investment guidelines.

On December 31, 2006, the annual measurement date, our Retirement Plan had an accumulated benefit obligation of $8.6 million and the fair value of the plan assets was $8.5 million. In accordance with SFAS 158, we recognized the unfunded status of the plan by recording an accrued pension liability of $0.1 million. The offsetting amount charged to accumulated other comprehensive loss adjusts the total in accumulated other comprehensive loss to $1.6 million pre-tax, which is the amount of the net unrecognized actuarial loss and unrecognized prior service cost.

Items not yet recognized as a component of net periodic pension cost and amounts recognized in the Consolidated Balance Sheets are as follows at December 31:

	2006	2005
(In thousands)		
Funded status	**$ (151)**	$ (1,788)
Amounts recognized in		
Long-term liabilities	**151**	1,788
Deferred taxes	**608**	588
Accumulated other comprehensive loss:		
Unamortized prior service cost	**350**	
Unamortized net actuarial loss	**600**	867

The amount of unamortized prior service costs and unamortized net actuarial losses that will be recognized as a component of net periodic pension cost in 2007 are $42 thousand and $9 thousand, respectively.

Certain assumptions utilized in determining the benefit obligations for the Retirement Plan for the years ended December 31 are as follows:

	2006	2005
Discount rate	**5.75 %**	5.50 %

A summary of the components of net periodic pension cost for the Retirement Plan for the years ended December 31 is as follows:

(In thousands)	**2006**	**2005**	**2004**
Service cost	**$ 285**	$ 277	$ 261
Interest cost	**430**	416	391
Expected return on plan assets	**(512)**	(488)	(487)
Amortization of net actuarial loss	**47**	2	
Net periodic pension cost	**$ 250**	$ 207	$ 165

The amortization of our net actuarial loss in 2006 of $47 thousand is the amortization of total unrecognized losses as of January 1, 2006 that exceeds 10% of our projected benefit obligation, approximately $1.4 million, and is being amortized over the expected average remaining years of service of the plan participants which is 13 years.

Certain assumptions utilized in determining the net periodic benefit cost for the years ended December 31 are as follows:

	2006	**2005**	**2004**
Discount rate	**5.50 %**	6.00 %	6.00 %
Expected long-term rate of return on plan assets	**8.50 %**	8.50 %	8.50 %

The following table sets forth a reconciliation of the projected benefit obligation for the years ended December 31:

(In thousands)	**2006**	**2005**
Benefit obligation at the beginning of the year	**$8,000**	$7,015
Service costs	**285**	277
Interest costs	**430**	416
Actuarial loss/(gain)	**(340)**	604
Benefits paid	**(342)**	(312)
Amendments	**574**	
Benefit obligation at the end of the year	**$8,607**	$8,000

The actuarial gain for the year ended December 31, 2006 results primarily from the increase in the discount rate used in the calculation of the benefit obligation to 5.75% from 5.5%. The actuarial loss for the year ended December 31, 2005 results primarily from the effect of decreasing the discount rate from 2004 to 2005.

The following table sets forth a reconciliation of the plan assets for the years ended December 31:

	2006	2005
(In thousands)		
Fair value of plan assets at the beginning of the year	**$ 6,212**	$ 5,910
Employer contributions	**2,000**	324
Actual return on plan assets	**585**	290
Benefits paid	**(342)**	(312)
Fair value of plan assets at the end of the year	**$ 8,455**	$ 6,212

In 2007, we anticipate making contributions totaling $0.5 million.

The expected future benefits payments for the plan are as follows:

(in thousands)	
2007	$ 405
2008	403
2009	432
2010	450
2011	462
2012 2016	2,673

12. Postretirement Benefit Obligation

We sponsor a health care plan and life insurance plan (Postretirement Plan) that provides postretirement medical benefits and life insurance to certain grandfathered unionized employees. The plan is contributory, with contributions required at the same rate as active employees. Benefit eligibility under the plan reduces at age 65 from a defined benefit to a defined dollar cap based upon years of service.

On December 31, 2006, the annual measurement date, our Postretirement Plan had an accumulated benefit obligation of $2.3 million. The Postretirement Plan is unfunded and has no assets. In accordance with SFAS 158, we recognized the unfunded status of the plan by adjusting the accrued postretirement liability by $0.2 million, to $2.3 million, the unfunded amount. We also adjusted accumulated other comprehensive loss by $0.2 million (pre-tax), bringing the total in accumulated other comprehensive loss to $0.2 million (pre-tax), which is the amount of the net unrecognized actuarial loss.

Items not yet recognized as a component of net periodic pension cost and recognized in the Consolidated Balance Sheets are as follows at December 31:

	2006	2005
(In thousands)		
Funded status	**$ (2,275)**	$ (3,201)
Amounts recognized in:		
Long-term liabilities	**2,275**	1,876
Deferred taxes	**79**	
Accumulated other comprehensive loss:		
Unamortized net actuarial loss	**123**	

There is no expected amortization of the unamortized net actuarial loss in 2007.

Net periodic postretirement benefit cost for the years ended December 31 includes the following components:

(In thousands)	**2006**	2005	2004
Service cost	**$ 153**	$ 188	$ 126
Interest cost	**122**	157	91
Recognized net actuarial gain	**10**	52	6
Net periodic postretirement benefit cost	**$ 285**	$ 397	$ 223

The change in benefit obligation for the years ended December 31 includes the following components:

(In thousands)	**2006**	2005
Benefit obligation at the beginning of the year	**$ 3,201**	$ 1,717
Service cost	**153**	188
Interest cost	**122**	157
Actuarial loss/(gain)	**(1,172)**	1,176
Benefits paid	**(29)**	(37)
Benefit obligation at the end of the year	**$ 2,275**	$ 3,201

The weighted-average discount rate used to determine net periodic postretirement benefit cost was 5.5% at December 31, 2006 and 6.00% at December 31, 2005.

For purposes of determining the cost and obligation for pre-Medicare postretirement medical benefits, a 9.3% annual rate of increase in the per capita cost of covered benefits (i.e., health care trend rate) was assumed for the plan in 2007, grading down to an ultimate rate of 5.00% in 2012. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percent change in the assumed health care cost trend rate would have had the following effects:

(In thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 15	$ (12)
Effect on postretirement benefit obligation	$ 175	$ (146)

13. Environmental Remediation and Contingencies

We are subject to various stringent federal, state and local environmental laws and regulations and permit conditions (and interpretations thereof), including those relating to the discharge of materials into the air, water and ground, the generation, storage, handling, use, transportation and disposal of hazardous materials, and the health and safety of our employees. These laws, regulations and permits require us to incur significant capital and other costs, including costs to obtain and maintain expensive pollution control equipment. They may also require us to make operational changes to limit actual or potential impacts to the environment. A violation of these laws, regulations or permit conditions can result in substantial fines, natural resource damages, criminal sanctions, permit revocations and/or facility shutdowns. We cannot assure you that we have been, are or will be at all times in complete compliance with these laws, regulations or permits or that we have had or currently have all permits required for our operations. In addition, environmental laws and regulations (and interpretations thereof) change over time, and any such changes, more vigorous enforcement policies or the discovery of currently unknown conditions may require substantial additional environmental expenditures.

We are also subject to potential liability for the investigation and cleanup of environmental contamination at each of the properties that we own or operate and at off-site locations where we arranged for the disposal of hazardous wastes. If any of these sites are subject to investigation and/or remediation requirements, we may be responsible under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, or other environmental laws for all or part of the costs of such investigation and/or remediation, and for damages to natural resources. We may also be subject to related claims by private parties alleging property damage or personal injury due to exposure to hazardous or other materials at or from such properties. While costs to address contamination or related third-party claims could be significant, based upon currently available information, we are not aware of any material contamination or third party claims. We have not accrued any amounts for environmental matters as of December 31, 2006.

We are not involved in any legal proceedings that we believe could reasonably have a material adverse effect upon our business, operating results or financial condition.

14. Income Taxes

The provision for income taxes for the years ended December 31 consists of the following:

	2006	2005	2004
(In thousands)			
Current expense	**32,754**	16,218	18,182
Deferred expense/(benefit)	**(1,069)**	2,589	251
Total income tax expense	**31,685**	18,807	18,433

Deferred income taxes included in our Consolidated Balance Sheets reflect the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and the carrying amount for income tax return purposes. Significant components of our deferred tax assets and liabilities are as follows at December 31:

	2006	2005
(In thousands)		
Current deferred tax asset:		
Current liabilities	**$ 1,064**	$ 531
Current deferred tax liability:		
Prepaid assets	**$ 429**	$ 474
Long-term deferred tax liabilities:		
Basis of property, plant and equipment	**$ 447**	$
Production credits	**753**	788
Partnership investment	**1,386**	878
Contingency reserve	**8,899**	6,748
Long-term deferred tax liability	**$ 11,485**	$ 8,414
Long-term deferred tax assets:		
Property, plant and equipment	**$**	$ 149
Investment in marketing alliances	**2,439**	1,488
Benefit obligations	**260**	888
Accumulated other comprehensive income	**687**	578
Goodwill	**2,706**	3,550
Stock-based compensation	**2,826**	761
Long-term deferred tax assets	**8,918**	7,414
Valuation allowance	**(3,537)**	(5,703)
Net long-term deferred tax assets	**5,381**	1,711
Net long-term deferred tax liability	**$ 6,104**	$ 6,703

At December 31, 2006, the Company has recorded a valuation allowance of $3.5 million on its deferred tax assets and a contingency reserve of $8.9 million for tax assets that management believes may not be realized due to potential limitations imposed by Section 382 of the Internal Revenue Code. The deferred tax assets include the excess tax basis in fixed assets over the corresponding book basis and other deductible temporary differences. The Company increased its contingency reserve in 2006 to $8.9 million from $6.7 million in 2005. The valuation allowance is reduced and the contingency reserve is increased as deductions are taken on tax returns which may be subject to potential Section 382 limitations for which the valuation allowance was originally established.

Reconciliation of differences between the statutory U.S. federal income tax rate and our effective tax rate follows for the years ended December 31:

(In thousands)	**2006**	**%**	**2005**	**%**	**2004**	**%**
Income tax provision at federal statutory rate	**$ 30,305**	35.0	$ 17,846	35.0	$ 16,687	35.0
Increase/(decrease) in taxes resulting from:						
State and local taxes, net of federal benefit	**3,314**	3.8	2,209	4.3	2,359	5.0
Other	**(1,934)**	(2.2)	(1,248)	(2.4)	(613)	(1.3)
Income tax expense	**$ 31,685**	36.6	$ 18,807	36.9	$ 18,433	38.7

In December 2004, the FASB issued Staff Position No. FAS 109-1, *Application of SFAS 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities provided by the American Jobs Creation Act of 2004* (FSP 109-1). The Company recognized $0.7 million and $0.3 million in tax benefits related to the qualified domestic production credit for the years ended December 31, 2006 and 2005, respectively.

15. Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss at December 31, are as follows:

	Accumulated Other Comprehensive (Loss)
(In thousands)	
Balance at January 1, 2004	$ (274)
Minimum pension liability adjustment, net of income taxbenefit of $76	(112)
Balance at December 31, 2004	(386)
Minimum pension liability adjustment, net of income tax benefit of $320	(481)
Balance at December 31, 2005	(867)
Adjustment to initially apply SFAS 158, net of tax benefit of $109	(207)
Balance at December 31, 2006	**$ (1,074)**

16. Stockholder Rights Plan

On December 12, 2005, the Board of Directors adopted a stockholder rights plan under which each common shareholder was issued one preferred share purchase right for each share of common stock outstanding prior to the 144a equity offering. In addition, each share of common stock issued in the offering or after the consummation of the offering will be issued with an accompanying preferred share purchase right. Each right will entitle the holder, under certain circumstances, to purchase one one-thousandth of a share of the Company s Series A participating cumulative preferred stock, par value $0.001 per share, at an initial purchase price of $60.00 per one one-thousandth of a share of Series A participating cumulative preferred stock. The Company may exchange the rights at a ratio of one share of common stock for each right at any time after a person or group acquires beneficial ownership of 20% or more of its common stock but before such party acquires beneficial ownership of 50% or more of its common stock. The Company may also redeem the rights at its discretion at a price of $0.001 per right at any time before a person or party has acquired beneficial ownership of 20% or more of its common stock. The rights will expire on November 30, 2015, unless earlier exchanged or redeemed. Each share of Series A participating cumulative preferred stock that is purchased upon exercise of a right entitles the holder to receive an aggregate quarterly dividend payment of $1.00 or 1,000 times the cash and noncash dividends declared per share of common stock, whichever is greater. As of December 31, 2006, there were no Series A participating preferred stock rights that had been exercised.

17. Stock-Based Compensation Plans

As of December 31, 2006, we maintained one stock-based compensation plan, the Aventine Renewable Energy Holdings, Inc. 2003 Stock Incentive Plan (the Plan). Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004) (SFAS 123(R)), *Share-Based Payment* utilizing the modified prospective transition method. SFAS 123(R) requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options and non-vested stock, based on their fair values at the time of grant.

The Plan was adopted by the Board of Directors (the Board) effective May 30, 2003, and was amended on each of September 6, 2005 and on December 12, 2005. The Plan provides for the grant of awards in the form of stock options, restricted shares or units, stock appreciation rights and other equity-based awards to directors, officers, employees and consultants at the discretion of the Board or the Compensation Committee of the Board. The term of awards granted under the plan is determined by the

Board or by the Compensation Committee of the Board, and cannot exceed ten years from the date of grant. The maximum number of shares of common stock that may be issued under the Plan is limited to 5,001,172, provided that no more than 750,000 shares may be granted in the form of stock options or stock appreciation rights to any covered employee (as defined under Section 162(m) of the Internal Revenue Code) in any calendar year. Unless terminated sooner, the Plan will continue in effect until May 29, 2013.

In conjunction with an equity offering and related stock split of 805.47131 to 1 shares completed in December 2005, all then existing option awards were adjusted to reflect the stock split as permitted by the Plan. The modification resulted in an increase in the number of options outstanding in a ratio of 805.47131 to 1. The exercise price of the options was also adjusted downward by this same 805.47131 to 1 ratio. The fair value of the awards immediately after the adjustment did not exceed the fair value of the awards immediately before the adjustment. Therefore, no additional compensation expense was recognized as a result of the modification.

Upon adoption of SFAS 123(R), the Company elected to value its share-based payment awards granted beginning in fiscal year 2006 using the Black-Scholes option-pricing model (Black-Scholes model), which was previously used in determining stock-based compensation cost using the minimum value method as outlined in Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation,* using the modified prospective method as permitted under the provisions of Statement of Accounting Standards No. 148 (SFAS 148), *Accounting for Stock-Based Compensation Transition and Disclosure* (hereinafter called SFAS 123). The Black-Scholes model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. The Black-Scholes model requires the input of certain assumptions. The determination of fair value of share-based payment awards on the date of grant using the Black-Scholes model is affected by our stock price as well as the input of other subjective assumptions. The option-pricing model requires a number of assumptions, of which the most significant are, expected stock price volatility, the expected pre-vesting forfeiture rate and the expected option term (the amount of time from the grant date until the options are exercised or expire). Expected volatility is normally calculated based upon actual historical stock price movements over the expected option term. Since we had no history of stock price volatility as a public company at the time of the grants, we calculated volatility by considering, among other things, the expected volatilities of public companies engaged in similar industries. Pre-vesting forfeitures are estimated using a 3% forfeiture rate. The expected option term is calculated using the simplified method permitted by SAB 107. Our options have characteristics significantly different from those of traded options, and changes in the assumptions can materially affect the fair value estimates.

Pre-tax stock-based compensation expense for the year ended December 31, 2006 was approximately $6.5 million, of which $0.3 million was charged to cost of goods sold and $6.2 million was charged to selling, general and administrative expense. This expense reduced earnings per share by $0.10 per basic and diluted share for the year ended December 31, 2006. The Company recognized a tax benefit on its consolidated statement of income from stock-based compensation expense in the amount of $2.4 million for the 12 month period ended December 31, 2006. The Company recorded pre-tax stock-based compensation expense for the year ended December 31, 2006 as follows:

(in millions)	**Year Ended December 31, 2006**	
Stock-based compensation expense:		
Non-qualified stock options	$	6.4
Restricted stock	$	0.1

Effective January 1, 2004, the Company adopted the fair value provisions of SFAS 123. The minimum value method as permitted by SFAS 123 was utilized in calculating stock-based compensation expense. The Company recorded pre-tax stock-based compensation expense for the years ended December 31, 2005 and 2004 as follows:

(in millions)	**Year Ended December 31, 2005**	**2004**
Stock-based compensation expense:		
Non-qualified stock options	$ 1.9	$ 0.1
Restricted stock		

Prior to the adoption of SFAS 123(R), the Company presented any tax benefits of deductions resulting from the exercise of stock options within operating cash flows in the consolidated statements of cash flows. SFAS 123(R) requires tax benefits resulting from tax deductions in excess of the compensation cost recognized for those options to be classified and reported as both an operating cash outflow and a financing cash inflow upon adoption of SFAS 123(R).

As of December 31, 2006, the Company had not yet recognized compensation expense on the following non-vested awards:

(in millions)	**Non-recognized Compensation**	**Average Remaining Recognition Period (years)**
Non-qualified options	$ 20.1	3.8
Restricted stock	0.2	2.3
Total	$ 20.3	3.8

The Company granted stock options during 2006 and 2005. The determination of the fair value of the stock option awards, using the Black-Scholes model, incorporated the assumptions in the following table for stock options granted during the years ended December 31, 2006 and 2005. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant over the expected term. Expected volatility is calculated by considering, among other things, the expected volatilities of public companies engaged in similar industries. The expected option term is calculated using the simplified method permitted by SAB 107:

	December 31, 2006	**2005**
Expected stock price volatility	58 %	0.01 %
Expected life (in years)	6.5	5
Risk-free interest rate	4.92 %	4.0 %
Expected dividend yield	0 %	0 %
Weighted average fair value	$ 14.52	$ 11.69

The following table summarizes stock options outstanding and changes during the years ended December 31, 2006, 2005 and 2004:

		Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (in thousands)
Options outstanding	January 1, 2004	2,083	$ 1.24		
Granted		371	1.96		
Exercised					
Cancelled or expired		260	1.24		
Options outstanding	December 31, 2004	2,194	$ 0.53		
Granted		1,269	3.80		
Exercised		461	0.23		
Cancelled or expired		83	0.23		
Options outstanding	December 31, 2005	2,919	$ 2.01		
Granted		670	23.70		
Exercised		269	0.82		
Cancelled or expired		55	0.23		
Options outstanding	December 31, 2006	3,265	$ 6.57	8.1	$ 55,472
Options exercisable	December 31, 2006	706	$ 1.39	7.3	$ 15,652

The range of exercise prices of the exercisable options and outstanding options at December 31, 2006 are as follows:

Weighted-Average Exercise Price	Number of Exercisable Options (in thousands)	Number of Outstanding Options (in thousands)	Weighted-Average Remaining Life (years)
$0.23	429	1,094	6.5
$2.36 - $2.92	188	744	8.4
$4.35	89	757	8.8
$22.15 - $22.50		630	9.3
$43.00		40	9.5
Totals	706	3,265	8.1

In 2006, we awarded 8,060 shares of restricted stock under the Plan, with a weighted-average fair value at the date of grant of $27.92 per share. These restricted shares vest 33% per year annually at the anniversary date of the grant. We recorded compensation expense with respect to restricted stock awards of approximately $0.1 million in 2006 which is recognized on a straight-line basis over the three year vesting period of the restricted stock grants.

Restricted stock award activity for the years ended December 31, 2006 is summarized below. There was no restricted stock outstanding nor any restricted stock activity in 2005 or 2004.

	Shares (in thousands)	Weighted - Average Grant Date Fair Value per Award
Unvested Restricted stock awards - January 1, 2006		
Granted	8.1	$ 27.92
Vested		
Cancelled or expired		
Restricted stock awards December 31, 2006	8.1	$ 27.92

In anticipation of our initial public offering, on June 6, 2006, our Board gave contingent approval of the acceleration of vesting of 71,488 options held by officers and employees to be effective immediately prior to the consummation of the initial public offering. The Board approved the acceleration of the vesting in order to permit certain members of management the ability to sell stock in our initial public offering. These options had a weighted-average exercise price of $4.35 per share. As a result of the accelerated vesting, we recorded a pre-tax charge to earnings of $0.6 million in 2006.

18. Commitments

We lease certain assets such as rail cars and terminal facilities from unaffiliated parties under non-cancelable operating leases. Terms of the leases, including renewals, vary by lease. Minimum future rental commitments under our operating leases having non-cancelable lease terms in excess of one year totaled approximately $200.4 million as of December 31, 2006 and are payable as follows:

(in millions)	
2007	$ 20.4
2008	$ 20.3
2009	$ 22.1
2010	$ 21.2
2011	$ 20.5
thereafter	$ 95.9

Rental expense for operating leases was $17.7 million in 2006, $10.8 million in 2005 and $8.7 million in 2004.

At December 31, 2006, we had held back payments totaling $4.4 million towards the construction of our 57 million gallon dry mill facility in Pekin. Other than this holdback which is included in accounts payable at December 31, 2006, we had no other commitments for capital expenditures at December 31, 2006.

We are party to ethanol marketing alliance contracts which require us Aventine to purchase and market all ethanol produced from these alliance ethanol facilities. Under these contracts, the Company is generally obligated to purchase all of the ethanol produced by these facilities at a purchase price that is based upon the price at which it sells the ethanol less a pre-negotiated margin. At December 31, 2006, Aventine had agreements with 12 producing alliance partners. The contracts range from one year to as long as Aventine retains an investment in the alliance facility. In addition, we have entered into new marketing agreements with both existing and new marketing alliance partners for the marketing of additional gallons that are either under construction or planned.

At December 31, 2006, we have committed to purchase approximately 1,138,000 MMBtus of natural gas at a weighted average fixed price of $7.92 during 2007.

At December 31, 2006, we had futures contracts to purchase approximately 735,000 tons of coal at a weighted average fixed price of $58.84 per ton

At December 31, 2006, we also had commitments to purchase approximately 12.3 million bushels of corn through December 2009, at an average price of $3.27 per bushel. These commitments were negotiated in the normal course of business and represent a portion of our corn requirements, which we anticipate will exceed 75 million bushels in 2007.

We have contractual obligations, subject to certain conditions, including obtaining necessary permits, to develop a 113 million gallon plant adjacent to our Nebraska facility (using commercially reasonable best efforts to obtain a permit for 226 million gallon capacity) and a 226 million gallon plant in Mount Vernon, Indiana. Accordingly, if we do not meet certain specified milestones or decide not to pursue the expansions, we would be subject to penalties.

19. Earnings Per Share

The following table sets forth the computation of earnings per share for the years ended December 31:

	2006	2005	2004
(In thousands, except per share amounts)			
Income available to common shares	**$ 54,901**	$ 32,182	$ 29,245
Basic weighted-average common shares	**38,411**	34,686	34,684
Dilutive stock options	**1,228**	1,366	1,084
Diluted weighted-average common and common equivalent shares	**39,639**	36,052	35,768
Earnings per common share basic:	**$ 1.43**	$ 0.93	$ 0.84
Earnings per common share diluted (1):	**$ 1.39**	$ 0.89	$ 0.82

(1) To the extent that stock options are anti-dilutive, they are excluded from the calculation of diluted earnings/(loss) per share in accordance with SFAS 128.

We had additional potential dilutive securities outstanding representing 40,000 common shares for the year ended December 31, 2006 that were not included in the computation of potentially dilutive securities because the options exercise prices were greater than the average market price of the common shares.

20. Quarterly Results of Operations (Unaudited)

The following is a summary of the unaudited quarterly results of operations for the years ended December 31, 2006 and 2005:

2006	**March 31**	**June 30**	**September 30**	**December 31**
(In thousands, except per share amounts)				
Net sales	**$ 313,520**	**$ 442,905**	**$ 407,053**	**$ 428,942**
Gross profit	**30,595**	**50,208**	**27,345**	**23,466**
Net income	**12,187**	**24,654**	**5,287**	**12,773**
Basic earnings per common share:	**$ 0.35**	**$ 0.70**	**$ 0.13**	**$ 0.31**
Diluted earnings per common share:	**$ 0.34**	**$ 0.67**	**$ 0.12**	**$ 0.30**
2005				
(In thousands, except per share amounts)				
Net sales	$ 197,030	$ 190,976	$ 259,203	$ 288,259
Gross profit	18,846	13,905	35,491	19,173
Net income	$ 6,635	$ 3,393	$ 17,660	$ 4,494
Basic earnings per common share:	$ 0.19	$ 0.10	$ 0.51	$ 0.13
Diluted earnings per common share:	$ 0.19	$ 0.09	$ 0.49	$ 0.12

21. Subsequent Event

We have a signed commitment letter and are currently in the process of arranging a secured revolving credit facility to fund a portion of our expansion plans and other liquidity needs. We cannot assure you that we will be successful in obtaining any such facility or, if we are successful, what the terms thereof will be.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Aventine Renewable Energy Holdings, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of Aventine Renewable Energy Holdings, Inc. and Subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity (deficit) and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements 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. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Aventine Renewable Energy Holdings, Inc. and Subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

St. Louis, Missouri

February 26, 2007

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AVENTINE RENEWABLE ENERGY HOLDINGS, INC. AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description *(In thousands)*	**Balance Beginning of Period**	**Charged to Cost and Expenses**	**Charged to Other Accounts**	**Deductions**	**Balance at End of Period**
Year ended December 31, 2006:					
Deducted from assets accounts:					
Deferred tax valuation	**$ 5,703**	**$**	**$**	**$ 2,166**	**$ 3,537**
Year ended December 31, 2005:					
Deducted from assets accounts:					
Deferred tax valuation	$ 7,755	$	$	$ 2,052	$ 5,703
Year ended December 31, 2004:					
Deducted from assets accounts:					
Deferred tax valuation	$ 13,921	$	$	$ 6,166	$ 7,755

EXHIBIT INDEX

Exhibit No.	**Description**
10.1	Lease Agreement, dated as of October 31, 2006 by and between the Indiana Port Commission and Aventine Renewable Energy Mt Vernon, LLC
10.2	Amended and Restated Credit Agreement among JPMorgan Chase Bank as Administrative Agent and Issuing Bank, Aventine Renewable Energy, Inc., Aventine Renewable Energy LLC, and the lenders from time to time party thereto dated as of September 15, 2006
10.3	Amended and Restated Guarantee and Security Agreement dated as of September 15, 2006 among JPMorgan Chase Bank, N.A. as Administrative Agent, Aventine Renewable Energy. Inc. and Aventine Renewable Energy, LLC
21.1	List of Subsidiaries
23.1	Consent of Independent Registered Public Accounting Firm
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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