HALLADOR ENERGY CO
Form 10-K
March 04, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K

[x] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: December 31, 2010 OR

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 0-14731

"COAL KEEPS YOUR LIGHTS ON"

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HALLADOR ENERGY COMPANY
(www.halladorenergy.com)

COLORADO	84-1014610
(State of incorporation)	(IRS Employer Identification No.)
1660 Lincoln Street, Suite 2700, Denver, Colorado	80264-2701
(Address of principal executive offices)	(Zip Code)
Issuer's telephone number: 303.839.5504	Fax: 303.832.3013

Securities registered pursuant to Section 12(b) of the Exchange Act: NONE

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $.01 par value

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

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

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 and 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 þ 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 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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o No o

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

o Large accelerated filer	o Accelerated filer
o Non-accelerated filer (do not check if a small reporting company)	þ Smaller reporting company

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

The aggregate market value of the common stock held by non-affiliates on June 30, 2010 was about $68 million based on the closing price reported that date by the NASDAQ of $8.95 per share.

As of March 3, 2011 we had 28,064,000 shares outstanding.

Portions of our information statement to be filed with the SEC in connection with our annual stockholders' meeting to be held on May 25, 2011 are incorporated by reference into Part III of this Form 10-K.

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PART 1

ITEM 1. BUSINESS.

General Development of Business

In December 2009 we changed our name from Hallador Petroleum Company to Hallador Energy Company. We are a Colorado corporation and were organized by our predecessor in 1949. About 85% of our stock is held by officers, directors and their affiliates. Our stock is thinly traded on the NASDAQ Capital Market listing under the symbol HNRG.

The largest portion of our business is devoted to underground coal mining in the state of Indiana through Sunrise Coal LLC (a wholly-owned subsidiary) serving the electric power generation industry. We also own a 45% equity interest in Savoy Energy, L.P., a private oil and gas company with operations in Michigan. In late December 2010 we invested $2.4 million for a 50% interest in Sunrise Energy, LLC which then purchased existing gas reserves and gathering equipment from an unrelated 3rd party with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for coal-bed methane gas reserves on or near our underground coal reserves. From the closing date through year end, such operations were not material. We account for our investments in Savoy and Sunrise Energy using the equity method. Through our Denver operations we also lease oil and gas mineral rights with the intent to sell the prospects to third parties and retain an overriding royalty interest (ORRI) or carried interest. Occasionally, we participate in the drilling of oil and gas wells. See Item 7- MD&A on page 20 for a discussion of Savoy, our lease play in North Dakota and our ORRI in Wyoming.

Our largest contributor to revenue and earnings is the Carlisle underground coal mine located in western Indiana. The Carlisle mine was in the development stage through January 31, 2007. Coal shipments began February 5, 2007.

Active Reserve (assigned) - Carlisle

Our coal reserves at December 31, 2010 assigned to the Carlisle mine were 46.7 million tons compared to beginning of year reserves of 47.3 million tons. Primarily through the execution of new leases, our reserve additions of 2.4 million tons replaced 80% of our 2010 production of approximately 3 million tons.

In addition to the Allerton reserve discussed below, we are currently evaluating multiple mining projects which could add to our coal reserves by the end of 2012. These projects are near the Carlisle mine and if they come to fruition we expect to utilize our existing wash plant and load-out facility.

New Reserve (unassigned) - Allerton

We have leased roughly 19,000 acres in Vermillion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 26.2 million tons of recoverable coal reserves; 10.7 million which are proven and 15.5 million which are probable. A considerable amount of our 19,000 acres of leases has yet to receive any exploratory drilling, thus we anticipate our controlled reserves to grow as we continue drilling in 2011. We will start the permitting process this spring and anticipate receiving a mining permit in early 2013. Unassigned reserves represent coal reserves that would require new mineshafts, mining equipment and plant facilities before operations could begin on the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital expenditures before production can begin.

Our Coal Contracts

Over the past three years we sold over 95% of our coal to three investment-grade customers. We have close relationships with these customers: Duke Energy Corporation (NYSE:DUK), Hoosier Energy, an electric cooperative, and Indianapolis Power & Light Company, a wholly-owned subsidiary of The AES Corporation (NYSE:AES). We have added Jacksonville Electric Authority (JEA) as a customer in 2011. The addition of JEA is noteworthy as this is the first time we have sold coal to a customer as far as Jacksonville, Florida. We believe this sale is the continuation of the trend of Illinois Basin (ILB) coal leaving traditional markets and moving to the southeast.

Only about 37% of our 2014 expected coal production is contracted for and we have no contracts extending past 2014. Of our 47 million tons of coal reserves assigned to the Carlisle mine, only 10.1 million tons are under contract; in other words about 80% of our reserves are uncommitted.

The table below illustrates the status of our current coal contracts:

Year	Contracted Tons	Average Price
2011	3,200,000	$41.40
2012	2,900,000	42.15
2013*	2,900,000	38.90-44.15
2014*	1,100,000	45.20-57.45

*For 2013 and 2014 we have a contract for 900,000 tons each year with one of our customers and we have agreed to reopen the contracted price during 2013. Each side has agreed to negotiate in good faith; however, if we can’t reach an agreed upon price, then our customer has the right to call the tons at the higher contracted price or if they don’t call the tons then we have the right to put the tons to them at the lower contracted price. For purposes of the table we used the range of the two prices averaged with our existing contracts with other customers.

If our future cash mining costs remain in our historical range of $24-25/ton over these three years (2011-2013) we expect to generate ample amounts of cash flow.

We have two sister wash plants engineered to work together with an annual capacity of 3.5-3.9 million clean tons at current recoveries. We have the capability of expanding underground production to meet this capacity. If prices are favorable we will expand underground production.

Our long term view of the supply/demand dynamics in the domestic steam coal markets remains positive. Coal stockpiles declined during the fourth quarter 2010 and the U.S. economy appears to have stabilized and is showing signs of growth, raising expectations for higher electricity consumption in the future and pointing to increased coal demand. Furthermore, tight global metallurgical coal markets helped to pull additional supply out of the steam coal market and growing seaborne thermal demand should help increase U.S. coal exports in 2011; further reducing supply available to domestic power plants. As discussed further under "Competitive Pressures" on page 8, natural gas has increased its share as a fuel in electrical generation in recent years.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. Our approach is to selectively renew, blend and extend existing contracts, or enter into new, coal supply contracts when we can do so at prices we believe are favorable.

Typically, customers enter into coal supply agreements to secure reliable sources of coal at predictable prices while we seek stable sources of revenue to support the investments required to open, expand and maintain or improve productivity at the mines needed to supply these contracts. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers.

Quality and volumes for the coal are stipulated in coal supply agreements and in some limited instances buyers have the option to vary annual or monthly volumes if necessary. Variations to the quality and volumes of coal may lead to adjustments in the contract price. Our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content (British Thermal Units-Btu), moisture, sulfur and ash content.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, steel-related (including roof control) products, belting products, lubricants, electricity, fuel and tires. Although we have many long, well-established relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers other than for purchases of certain underground mining equipment and electricity. The supplier base providing mining materials has been relatively consistent in recent years, although there has been some consolidation. Purchases of certain underground mining equipment are concentrated with one principle supplier; however, supplier competition continues to develop.

Carlisle Mine

The Carlisle mine is located in the ILB and has about 46.7 million tons of high-sulfur bituminous coal reserves. Our quality specifications for salable product are: < 16% moisture; > 11,200 Btu; < 10% ash; and < 6.5 LB SO_2. Compared to other ILB mines, our reserves have lower chlorine (<0.10%) than the average ILB of 0.22%. The relatively low chlorine content makes it highly attractive to buyers given their desire to limit the corrosive effects in their power plants.

The ILB boasts several long-term trends that are expected to benefit coal producers in the region. Historically, ILB coal demand has outpaced supply for several years. This supply/demand dynamic is driven by an increase in scrubber retrofits, new coal-fired capacity coming on line and coal depletion in the Eastern Basins. The local Indiana supply/demand market dynamics, coupled with new pockets of demand from nearby domestic markets, should provide a strong long-term demand foundation for our coal. Over 95% of the electricity generated in Indiana comes from coal-fired plants. Only West Virginia is higher. The majority of Indiana coal is consumed in Indiana.

Outside of the local market, demand for ILB coal has been on the rise and is expected to continue for the foreseeable future. ILB coal is well positioned to supply other domestic markets, as Eastern U.S. coal providers with depleting reserves continue to seek higher prices in international markets.

Transportation Advantage

The Carlisle mine has a double 100 rail car loop facility and a four-hour certified batch load out facility connected to the CSX railroad. The Indiana Rail Road (INRD) also has limited running rights on the CSX to our mine. Dual rail access gives us a freight advantage to our Indiana customers. Long term, the CSX anticipates our coal being shipped to southeast markets via their railroad.

We sell our coal FOB the mine. Substantially all of our coal is transported by rail. Our mine is accessible by truck and is within 90 miles of nine coal-fired plants that have been retrofitted to burn our high-sulfur coal.

Coal Preparation

Coal extracted from Carlisle contains impurities such as rock and sulfur. We utilize a wash plant located at the mine to remove impurities from the coal and to insure our product meets contract specifications. Our wash plant allows us to treat the coal we extract from Carlisle to ensure a consistent quality.

Illinois Basin (ILB)

The coal industry underwent a significant transformation in the early 1990s, as greater environmental accountability was established in the electric utility industry. Through the U.S. Clean Air Act, acceptable baseline levels were established for the release of sulfur dioxide in power plant emissions. In order to comply with the new law, most utilities switched fuel consumption to low-sulfur coal, thereby stripping the ILB of over 50 million tons of annual coal demand. This strategy continued until mid 2000 when a shortage of low-sulfur coal drove up prices. This price increase combined with the assurance from the U.S. government that the utility industry would be able to recoup their costs to install scrubbers caused utilities to begin investing in scrubbers on a large scale. With scrubbers, the ILB has reopened as a significant fuel source for utilities and has enabled them to burn lower cost, high sulfur coal.

The ILB consists of coal mining operations covering more than 50,000 square miles in Illinois, Indiana and western Kentucky. The ILB is centrally located between four of the largest regions that consume coal as fuel for electricity generation (East North Central, West South Central, West North Central and East South Central). These regions consumed about 63% of coal used in electric generation in 2008. The region also has access to sufficient rail and water transportation routes that service coal-fired power plants in these regions as well as other significant coal consuming regions of the South Atlantic and Middle Atlantic.

U. S. Coal Industry

The U.S. has over 200 billion tons of recoverable coal reserves, representing about 94% of the domestic fossil fuel energy, according to the U.S. Geological Survey (USGS). This is about 27% of the world's total proven reserves. The energy potential of American coal exceeds that of all the oil in the Middle East. The EIA (Energy Information Administration) estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for 200 years. The U.S. is also the second largest coal producer in the world, exceeded only by China. Annual coal production in the U.S. has increased from 434 million tons in 1960 to about 1.2 billion tons in 2009, based on information provided by the EIA. Coal is the fastest growing fuel in the world. The majority of coal consumed in the United States is used to generate electricity, with the balance used by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Metallurgical coal is predominately consumed in the production of metallurgical coke used in steelmaking blast furnaces. In 2009, coal-fired power plants produced approximately 45.0% of all electric power generation, more than natural gas and nuclear, the two next largest domestic fuel sources, combined. Steam coal used by utilities and independent power producers to generate electricity, accounted for 92.0% of total coal consumption in 2009.

In 2009, total coal consumption in the United States decreased by approximately 11.0% from 2008 levels, reflecting the effects of the economic recession. The drop in coal consumption was driven primarily by the reduction in electric power demand and the steep decline in natural gas prices that encouraged coal to natural gas switching among electric utilities. The decreased electric power demand was particularly apparent in the industrial sector where demand fell by an estimated 10.4% in 2009. Unusually cool summer temperatures in some areas of the country where coal is the predominant source of electric power generation also resulted in lower coal consumption.

Over the long term, the EIA forecasts in its 2010 reference case that total coal consumption will grow by 14.0% through 2015 and 32.0% through 2035, primarily due to gradual increases in coal-fired electric power generation and the introduction of coal-to-liquids plants.

The major coal production basins in the U.S. include Central Appalachia (App), Northern App, Illinois Basin, Powder River Basin and the Western Bituminous region. The Central App Basin includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. The Northern App Basin includes Maryland, Ohio, Pennsylvania and northern West Virginia. The Illinois Basin includes Illinois, Indiana and western Kentucky. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. The Western Bituminous Basin includes western Colorado, eastern Utah and southern Wyoming.

Coal type varies by basin. Heat value and sulfur content are important quality characteristics and determine the end use for each coal type.

Coal in the U.S. is mined through surface and underground mining methods. According to the National Mining Association (NMA), of the coal produced during 2009, 70% came from surface mines and 30% from underground mines.

The primary underground mining techniques are longwall mining and continuous (room-and-pillar) mining. The geological conditions dictate which technique to use. The Carlisle mine uses the continuous technique.

In continuous mining, rooms are cut into the coal bed leaving a series of pillars, or columns of coal, to help support the mine roof and control the flow of air. Continuous mining equipment cuts the coal from the mining face. Generally, openings are driven 20’ wide and the pillars are rectangular in shape measuring 40’x 40’. As mining advances, a grid-like pattern of entries and pillars is formed. Roof bolts are used to secure the roof of the mine. Battery cars move the coal to the conveyor belt for transport to the surface. The pillars can constitute up to 50% of the total coal in a seam.

Competitive Pressures

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. We compete against large producers and hundreds of small producers in the United States. The five largest producers are estimated by the 2009 NMA Survey to have produced approximately 53% (based on tonnage produced) of the total United States production in 2009. The U.S. Department of Energy reported 1,375 active coal mines in the United States in 2009, the latest year for which government statistics are available. Peabody Energy Corporation (NYSE:BTU) and Foresight Energy, a private company controlled by Chris Cline are probably the two largest operators in the ILB. While we sold about three million tons from our Carlisle mine, Peabody sold about 30 million tons from 13 mines (surface and underground) in the ILB during 2010. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power or wind;
- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of fuel supply.

Continued demand for our coal and the prices that we receive are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing coal and alternative fuel supplies.

Coal is the primary fuel source (about 45%) for electrical generation in the U.S. Despite capacity growth for other fuel sources of electricity, coal is still expected to provide the largest share of energy for U.S. electricity generation.

Natural Gas

One of the trends that cause us concern is the burning of natural gas to generate electricity in the U.S. Affordability plays a significant role in coal’s position as the most used fuel source in energy generation. In the U.S., coal has historically had a relatively lower delivered cost per million Btu (MMBtu) compared to other energy sources. During August 2009, the delivered cost of coal to electrical plants was $2.22 per MMBtu, considerably lower than the delivered cost for natural gas of $4.09 per MMBtu.

Although coal has been and remains the major fuel for electricity generation in the U.S., natural gas has increased its share as a fuel in electrical generation in recent years. High natural gas prices in 2003 and 2004 made it economical for power generators to retrofit existing coal-burning units with scrubbers and low nitrogen oxide burner technology or switch to lower-sulfur coals in order to reduce emissions. Recently, however, natural gas substitution in electricity generation has increased. Natural gas spot prices declined sharply from about $13 per MMBtu in the summer of 2008 to current prices in the $3.80 -$4 per MMBtu range prompting some utilities to substitute natural gas for coal as fuel in electricity generation.

Gas producers have been arguing for some time that new sources of fuel, especially shale gas, have made it both plentiful and reliable. Furthermore, carbon dioxide emission from burning natural gas compared to coal is about 50% less. But residential and industrial consumers, from homeowners to power utilities, have been reluctant to increase their dependence on natural gas because of concerns about price volatility. This appears to be changing, due to a combination of factors. Huge new discoveries in the U.S. and Canada have greatly increased supplies, lowering prices. Big infrastructure build-outs in recent years have made it easier to move gas around to where it is needed, helping ease regional price spikes. ExxonMobil Corp.'s decision to buy one of the largest U.S. gas producers, XTO Energy, is the latest sign that deep-pocketed oil and gas corporate giants see U.S. natural gas, especially gas found in shale rock, as a giant resource. Gas producers hope the Exxon deal will help them convince federal officials and power executives that prices are entering a period of relative calm.

There are some that believe natural gas will overtake coal as the most economic way to produce electricity in the U.S. In the event the government places a price tag on carbon emissions, natural gas would gain another advantage over coal since electricity from coal produces more carbon. Some natural gas producers believe that there is certainly the potential for natural gas producers and utilities to develop a new relationship that has not been possible historically.

Employees

Our coal operations currently employ 332 people. We use a consulting geologist when evaluating new coal mine projects. We also use a consultant to sell our coal, find new buyers and help in contract negotiations. The mine currently operates two production shifts and one maintenance shift while coal is produced 270 days of the year. The Carlisle mine is non-union.

Safety and Environmental Regulations

Our operations, like operations of other coal companies, are subject to regulation, primarily by federal and state authorities, on matters such as: air quality standards; reclamation and restoration activities involving our mining properties; mine permits and other licensing requirements; water pollution; employee health and safety; management of materials generated by mining operations; storage of petroleum products; protection of wetlands and endangered plant and wildlife protection. Many of these regulations require registration, permitting, compliance, monitoring and self-reporting and may impose civil and criminal penalties for non-compliance.

Additionally, the electric generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our coal over time. The possibility exists that new legislation or regulations may be adopted or that the enforcement of existing laws could become more stringent, causing coal to become a less attractive fuel source and reducing the percentage of electricity generated from coal. Future legislation or regulation or more stringent enforcement of existing laws may have a significant impact on our mining operations or our customers' ability to use coal.

While it is not possible to accurately quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds or post letters of credit from our banks to guarantee performance or payment of certain long-term obligations, including mine closure and reclamation costs.

Reclamation

The Carlisle mine began commercial production in February 2007 and is operating in compliance with all local, state, and federal regulations. We have no old mine properties to reclaim, other than the Howesville mine, which was operated for only eight months before it was closed in June 2006 due to safety concerns. During 2007, we finished Phase I of the reclamation of the Howesville mine. To reach final reclamation we must raise commercial crops for a period of five years.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. The authorization, permitting and implementation requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations. Regulations also provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a shareholder with a 10% or greater interest in the entity is affiliated with another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, we submit the necessary permit applications several months or even years before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain, and the application review processes are taking longer to complete and becoming increasingly subject to challenge.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. Compliance with these laws has increased the cost of coal mining for domestic coal producers.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since Congress adopted the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed comprehensive safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, the state in which we operate also has programs for mine safety and health regulation and enforcement. In reaction to several mine accidents in recent years, federal and state legislatures and regulatory authorities have increased scrutiny of mine safety matters and passed more stringent laws governing mining. For example, in 2006, Congress enacted the Mine Improvement and New Emergency Response Act of 2006 (MINER Act). The MINER Act imposes additional obligations on coal operators including, among other things, the following:

- development of new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel;
- establishment of additional requirements for mine rescue teams;
- notification of federal authorities in the event of certain events;
- increased penalties for violations of the applicable federal laws and regulations; and
- requirement that standards be implemented regarding the manner in which closed areas of underground mines are sealed.

Additionally, on October 14, 2010, the Mine Safety and Health Administration (MSHA) published a proposed rule to reduce the permissible concentration of respirable dust in underground coal mines from the current standard of two milligrams per cubic meter of air to one milligram per cubic meter. MSHA had also proposed new safety standards for proximity protection for miners that will require certain underground mining equipment to be equipped with devices that will shut the equipment down if a person is too close to the equipment to avoid injuries where individuals are caught between equipment and blocks of unmined coal. As currently written, both of these proposed rules could add substantial costs to mining coal.

Clean Air Act and Related Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, and gas processing operations primarily through permitting and/or emissions control requirements. For example, regulations relating to fugitive dust and coal combustion emissions could restrict our ability to develop new mines or require us to modify our operations. National Ambient Air Quality Standards (NAAQS) for particulate matter resulted in some areas of the country being classified as non-attainment for fine particulate matter. Because thermal dryers located at coal preparation plants burn coal and emit particulate matter, our mining operations are likely to be directly affected where the NAAQS are implemented by the states.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal-fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas (GHG), is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales. For example, the federal Clean Air Act places limits on sulfur dioxide, nitrogen dioxide, and mercury emissions from electric power plants.

In October 1998, the EPA finalized a rule requiring a number of eastern U.S. states to make substantial reductions in nitrogen oxide emissions by June 1, 2004 (the NOX SIP call). Further sulfur dioxide and nitrogen oxide emission reductions were adopted by regulations called the Clean Air Interstate Rules (CAIR), which were promulgated by the EPA in 2005. In July and December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR regulations to the EPA but did not vacate the regulations. The regulations were not vacated because many states were already implementing them and some coal-fired electric generating facilities were being equipped with scrubbers in order to comply with the CAIR requirements. In August 2010, the EPA published in the Federal Register the proposed Clean Air Transport Rule (the Transport Rule). The Transport Rule is intended to replace CAIR. The Transport Rule will allow minimal or no interstate trading. This will likely make compliance more expensive. The EPA’s schedule is to finalize the Transport Rule by July 2011. The first phase of the Transport Rule emission reductions will go into effect in 2012.

The installation of additional control measures to achieve regulatory emission reductions makes it more costly to operate coal-fired power plants and could make coal a less attractive fuel. In order to meet the proposed new limits for sulfur dioxide emissions from electric power plants, many coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. More strict emission limits mean few coals can be burned without the installation of supplemental environmental control technology in the form of scrubbers. Many of our customers are in the process of installing scrubbers in response to the CAIR emissions requirements. We estimate that by 2012, more than half of the installed, coal-fired power plant capacity east of the Mississippi will be scrubbed. The increase in scrubbed capacity allows customers to consider purchasing more of our higher sulfur coals.

In 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) which imposed caps on mercury emissions from coal-fired electric generating units. The first phase of the emission caps would have taken effect in 2010. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR. EPA is developing emission limits for mercury for coal-fired electric-generating facilities under Section 112 of the Clean Air Act, which requires the EPA to impose maximum achievable control technology (MACT) limits. The EPA intends to issue proposed MACT regulations for mercury in March 2011 and to issue final MACT regulations in November 2011. Various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric-generating units. Regulation of mercury emissions from coal-fired electric-generating units could impact the market for coal.

A regional haze program initiated by the EPA to protect and to improve visibility at and around national parks, national wilderness areas and international parks may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

Also, numerous proposals have been made at the international, national, regional and state levels that are intended to limit or capture emissions of GHG, such as carbon dioxide and methane, and several states have adopted measures intended to reduce GHG loading in the atmosphere. The burning of fossil fuels produce carbon dioxide. If comprehensive legislation focusing on GHG emissions is enacted by the United States or individual states, it may adversely affect the use of and demand for fossil fuels, particularly coal, as an energy source for electricity generation. In 2007, the U.S. Supreme Court held in Massachusetts v. Environmental Protection Agency (EPA), that the EPA had authority to regulate GHGs under the Clean Air Act and a number of states have filed lawsuits seeking to force the EPA to adopt GHG regulations. In December 2009, the EPA made a determination that GHGs cause or contribute to air pollution and may reasonably be anticipated to endanger public health or welfare, which findings are prerequisites to the EPA regulating GHGs under the Clean Air Act. Although, efforts to enact GHG legislation have failed, the EPA is proceeding with GHG regulations. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires reporting of emissions from coal mines and gas wells and associated facilities for 2011 emissions. In December 2010, the EPA announced a proposed schedule for establishing GHG emission limits for fossil fuel fired electric-generating facilities (proposed regulations by July 2011 and final regulations by May 2012.) Such regulations could significantly increase the cost of generation of electricity at coal-fired facilities and could make competing forms of electricity generation more competitive.

Other

We have no significant patents, trademarks, licenses, franchises or concessions.

Other than the 332 Sunrise Coal employees in Indiana, our CEO, CFO, controller, geologist, land person and two part time administrative staff work in the Denver office.

Our Denver office is located at 1660 Lincoln Street, Suite 2700, Denver, Colorado 80264, phone 303.839.5504, fax 303.832.3013 and Sunrise Coal's corporate office is located at 1183 Canvasback Drive, Terre Haute, Indiana 47802, phone 812.299.2800, fax 812.299.2810. Terre Haute is approximately 70 miles west of Indianapolis, Indiana. Our website is www.halladorenergy.com and Sunrise Coal’s is www.sunrisecoal.com.

ITEM 1A. RISK FACTORS.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Smaller reporting companies are not required to provide the information required by this item; however, there were none.

ITEM 2. PROPERTIES.

The Carlisle mine, located near the town of Carlisle in Sullivan County, Indiana, is an underground mine which became operational in January 2007. The coal is accessed with a slope to a depth of 340'. The coal is mined in the Indiana Coal V seam which is highly volatile bituminous coal.

Our current mine plan indicates 14,200 acres of mineable coal with an approximate 4' to 7' thickness in the project area. Of the 14,200 acres, 11,800 are currently under lease to Sunrise. The Indiana V seam has been extensively mined by underground and surface methods in the general area and is the most economically significant coal in Indiana.

Findings are based on generally accepted engineering principles and professional experience in the mining industry. All judgments are based on the facts that are available at this time.

Assigned Coal Reserve Estimates- Carlisle Mine

We estimate that, as of December 31, 2010, the Carlisle Mine had total recoverable reserves of approximately 46.7 million tons consisting of both proven (36.5 million) and probable (10.2 million) reserves. “Reserves” are defined by the SEC Industry Guide 7 (Guide 7) as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. “Recoverable” reserves mean coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. “Proven (measured) reserves” are defined by Guide 7 as reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. “Probable reserves” are defined by Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Unassigned New Coal Reserves - Allerton

We have leased about 19,000 acres in Vermillion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 26.2 million tons of recoverable coal reserves; 10.7 million which are proven and 15.5 million which are probable. A considerable amount of our 19,000 acres of leases has yet to receive any exploratory drilling, thus we anticipate our controlled reserves to grow as we continue drilling in 2011. We will start the permitting process this spring and anticipate receiving a mining permit in early 2013. Unassigned reserves represent coal reserves that would require new mineshafts, mining equipment and plant facilities before operations could begin on the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital expenditures before production can begin.

Our reserve estimates were prepared by Samuel Elder, one of our mining engineers. Mr. Elder is a licensed Professional Engineer in the State of Indiana and has over 25 years experience estimating coal reserves.

The reserve estimates for all leased acres was made utilizing Carlson Mining 2009 (software developed by Carlson Software). To convert volumes of coal to an in-place tonnage, a weight of 80 pounds/cubic foot was used for both reserve areas. To convert Carlisle reserve to product tonnage, a 55% mine recovery and an average of 81% washed recovery (coal only recovery, no out-of- seam dilution included) were used.

Example: In-place tonnage x 55% x 81% = product tonnage.

To convert Allerton reserve to product tonnage, a 45% mine recovery and an average of 74% washed recovery (coal only recovery, no out-of- seam dilution included) were used.

Example: In-place tonnage x 45% x 74% = product tonnage.

Standards set forth by the USGS were used to place areas of the mine reserves into the Proven (measured) and Probable (indicated) categories. Under these standards, coal within 1,320' of a data point is considered to be proven, and coal within 1,320' to 3,960' is placed in the Probable category. All reserves are stated as a final salable product.

ADDITIONAL DISCLOSURES FOR THE CARLISLE MINE

1. The Carlisle mine currently has road frontage on State Highway 58, and is adjacent to the CSX railroad. The Carlisle mine has a double 100 car loop facility. Substantially all of our coal is shipped by rail.

2. Currently only the Indiana V seam is planned to be mined, and all of the controlled tonnage is leased to Sunrise. Most leases have unlimited terms once mining has begun, and yearly payments or earned royalties are kept current. Mineable coal thickness used is greater than four feet. The current Carlisle mine plan is broken into four areas– North Main – South Main – West Main – 2 South Main. Approximately 84% of the total mine plan is currently under lease ("controlled"). It is believed that all additional property that would be required to access all lease areas can be obtained but, if some properties cannot be leased, some modification of the current mine plan would be required. All coal should be mined within the terms of the leases. Leasing programs are continuing by our staff.

3. The Carlisle mine has a dual-use slope for the main coal conveyor and the moving of supplies and personnel without a hoist. There are two 8' diameter shafts at the base of the slope for mine ventilation. Two additional air shafts (8' and 10.5' diameter) were completed about three miles north of the original air shaft in 2009 to facilitate the mine expansion. The slope (15% grade) is 18' wide with concrete and steel arch construction. A 16' hoist is currently under construction approximately four miles north of the main slope for the movement of materials and personnel into the north main and north main addition. The hoist is scheduled to be completed in the spring of 2011. All underground mining equipment is powered with electricity and underground compliant diesel.

4. A new slurry impoundment estimated to handle slurry disposal for all the controlled reserves is currently under construction and completion is scheduled by the end of 2011.

5. Current production capabilities are projected to be in the range of 3 to 3.3 million tons per year giving the mine a reserve life of about 15 years. The mine plan is basic room-and-pillar using a synchronized continuous miner section with no retreat mining. Plans are for pillars to be centered on a 60'x80' pattern with 18' entries for our mains, and pillars on 60'x60' centers with 20' entries in the rooms.

6. The Carlisle mine has been in production since February 2007. The North Main, Sub Main #1, and the South Main have been developed with four units currently in production.

7. Quality specifications for salable product are: less than 16% moisture; greater than 11,200 Btu; less than 10% ash; and less than 6.5 LB SO2.

8. The Carlisle mine has two wash plants capable of 950 tons/hour of raw feed.

Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal engineers. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;
- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates.

ITEM 3. LEGAL PROCEEDINGS. None

ITEM 4. (Removed and Reserved).

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock is traded on the NASDAQ Capital Market under the symbol HNRG. Prior to May 27, 2010 we were traded on the OTC Bulletin Board under the symbol HPCO.OB. The following table sets forth the high and low closing sales price for the periods indicated:

	High	Low
2011		
(January 1 through March 3, 2011)	$ 11.50	$ 9.79
2010		
Fourth quarter	12.64	10.47
Third quarter	12.10	7.36
Second quarter	13.00	8.25
First quarter	9.80	7.50
2009		
Fourth quarter	8.90	6.00
Third quarter	6.75	5.00
Second quarter	6.50	3.74
First quarter	3.75	2.95

On May 27, 2010 we declared our first cash dividend of $0.10 per common share of which there were 27,782,028 outstanding. The cash dividend was paid July 16, 2010 to shareholders of record at the close of business July 9, 2010. Furthermore, our board approved that the $0.10 dividend would also apply to the 1,150,000 outstanding restricted stock units and to the 434,167 outstanding stock options on that date. The total cash payment for all the outstanding securities was $2.9 million. This spring we will evaluate our cash position and capital requirements and decide if we will again pay a cash dividend. Our loan agreement does not restrict our ability to pay dividends.

At March 3, 2011, we had 344 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 300 street name holders. On March 3, 2011 our stock closed at $10.34.

Equity Compensation Plan Information

On January 7, 2011 we allowed four Denver employees (non officers) an opportunity to relinquish 100% of their vested options (234,167) for 181,261 shares of our common stock. The exchange ratio was based on the intrinsic value of their options. These shares were issued under our Stock Bonus Plan which was created in December 2009. Under such plan employees are allowed to relinquish shares to pay for their income taxes; accordingly, 41,645 shares were relinquished. These transactions were and will be treated as a charge to equity.

Currently we have 200,000 outstanding stock options to our CEO with an exercise price of $2.30. The options are fully vested and expire in April 2015.

At December 31, 2010 we had 953,000 Restricted Stock Units (RSUs) outstanding and about 830,000 available for future issuance. Our RSU and stock option plans were approved by our BODs and collectively they and their affiliates control about 85% of our stock.

ITEM 6. SELECTED FINANCIAL DATA.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Overview

The largest portion of our business is devoted to underground coal mining in the state of Indiana through Sunrise Coal LLC (a wholly-owned subsidiary) serving the electric power generation industry. We also own a 45% equity interest in Savoy Energy, L.P., a private oil and gas company with operations in Michigan. In late December 2010 we invested $2.4 million for a 50% interest in Sunrise Energy, LLC which then purchased existing gas reserves and gathering equipment from an unrelated 3rd party with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for coal-bed methane gas reserves on or near our underground coal reserves. From the closing date through year end, such operations were not material. We account for our investments in Savoy and Sunrise Energy using the equity method. Through our Denver operations we also lease oil and gas mineral rights with the intent to sell the prospects to third parties and retain an overriding royalty interest (ORRI) or carried interest. Occasionally, we participate in the drilling of oil and gas wells. Further below is a more in-depth discussion of Savoy.

Through a series of independent transactions which began in 2006 and ended in September 2009, we own 100% of Sunrise Coal, LLC (Sunrise). At the end of 2006 and 2007 we owned 60% of Sunrise; at the end of 2008 we owned 80%; and at the end of 2009 we owned 100%.

Our largest contributor to revenue and earnings is the Carlisle underground coal mine located in western Indiana. The Carlisle mine was in the development stage through January 31, 2007. Coal shipments began February 5, 2007.

Our long term view of the supply/demand dynamics in the domestic steam coal markets remains positive. Coal stockpiles declined during the fourth quarter 2010 and the U.S. economy appears to have stabilized and is showing signs of growth, raising expectations for higher electricity consumption in the future and pointing to increased coal demand. Furthermore, tight global metallurgical coal markets helped to pull additional supply out of the steam coal market and growing seaborne thermal demand should help increase U.S. coal exports in 2011; further reducing supply available to domestic power plants. As discussed further under “Competitive Pressures” on page 8, natural gas has increased its share as a fuel in electrical generation in recent years.

We have entered into significant equity transactions with the Yorktown Energy group of partnerships (Yorktown) and other entities that invest with them. Yorktown, our largest shareholder, owns about 55% of our common stock and is represented on our board.

Our consolidated financial statements should be read in conjunction with this discussion.

Prospective Information

See page 3 of this report for a table that illustrates the status of our current coal contracts.

Liquidity and Capital Resources

Our EBITDA during 2010 enabled us to reduce our bank debt by $10 million while investing $34.7 million in the Carlisle mine. For 2011 we are scheduled to reduce our bank debt by another $10 million and we anticipate our capital expenditures for the Carlisle mine falling to $15 million.

For 2010 we generated $45.5 million in cash from operations and expect the next two years to be about the same or slightly higher. We do not anticipate any liquidity issues in the foreseeable future. Eventually, when we develop a new reserve, we intend to incur additional debt and restructure our existing credit facility.

We have no material off-balance sheet arrangements.

On May 27, 2010 we declared our first cash dividend of $0.10 per common share of which there were 27,782,028 outstanding. The cash dividend was paid July 16, 2010 to shareholders of record at the close of business July 9, 2010. Furthermore, our board approved that the $0.10 dividend would also apply to the 1,150,000 outstanding restricted stock units and to the 434,167 outstanding stock options on that date. The total cash payment for all the outstanding securities was about $2.9 million. This spring we will evaluate our cash position and capital requirements and decide if we will again pay a cash dividend.

In late August 2010 we decided to drop the property insurance on $76 million (historical cost) of our underground mining equipment. We feel comfortable with this decision as such equipment is allocated among four mining units spread out over eight miles.

MSHA Reimbursements

Under our coal contracts with two of our customers we are allowed to pass on certain costs incurred by us resulting from changes in costs to comply with government mandates issued by MSHA. In late December 2010, we submitted a report which was reviewed by an outside consulting firm engaged by our customers. In January 2011 the customers agreed to reimburse us about $1.9 million of such costs incurred by us during 2008 and 2009. During those years we were not able to accurately estimate what the ultimate outcome of these reimbursable costs would be so we did not record them until we were certain of the amounts. Such amounts will be recorded during the first quarter of 2011. Until we meet with our customers we are not able to estimate what such reimbursements for 2010 and 2011 will be but should have an idea sometime this summer for the 2010 costs.

Oil and Gas Properties

ORRI

We have an ORRI of about 2% on 22,500 acres and a 4% ORRI on 2,500 acres in Laramie County, Wyoming. During 2010, SM Energy Company (formerly St. Mary Land) (NYSE:SM) drilled a discovery well (the Atlas 1-19) on this acreage. This is a Niobrara oil shale play in the northern D-J Basin. There are 40 additional 640-acre horizontal well locations available for development of this prospect. To date, SM has announced five additional drilling locations for this prospect for 2011. We are currently receiving $6,000 per month from this royalty; $72,000 annualized.

North Dakota Lease Play (Patriots Prospect)

We have invested close to $1 million in a lease play located in Slope, Hettinger and Stark counties of North Dakota which has resulted in the purchase of about 7,500 net acres of oil and gas leases in this area which we named the Patriots Prospect. During the spring of 2011 we plan to sell our position and retain some sort of ORRI or carried interest. The prospect is being marketed as a Bakken/Three Forks shale play. We estimate the targeted depth to be 9,500 feet with an estimated cost of $6 million to drill and complete a horizontal well. As mentioned before, our goal is to sell the leases, not to exploit them. Our leases have terms of about five years.

Results of Operations

For 2010 we sold 3,050,000 tons at an average price of $42.31/ton. For 2009, we sold 2,651,000 tons at an average price of $44.30/ton. Our average price for 2011, based on our contracts, is expected to be about $41.30/ton.

The 2010 “other loss” of $772,000 was attributable primarily to our participating in the drilling of a dry hole in Michigan on a gas prospect developed by Savoy. Our share of the dry hole was about $1 million.

Cost of coal sales averaged $24.04/ton in 2010 compared to $24.69 in 2009. Our mining employees totaled 332 at December 31, 2010 compared to 309 at December 31, 2009. We expect our cost of sales to average $24-25/ton for 2011.

The increase in DD&A was due to the significant increase in our coal production and the additions to plant and equipment to support the higher sales volume.

The increase in SG&A is attributable to the amortization of our RSUs. Total RSU expense in 2010 was $2.2 million compared to $353,000 in 2009. Included in cost of coal sales for 2010 was $514,000 for RSU amortization compared to nil for 2009. Based on the number of RSUs we have outstanding at December 31, 2010, our stock based compensation amortization expense for the next three years will be about $2.1 million for 2011; $2 million for 2012 and $1.6 million for 2013. Our SG&A expense for 2010 is representative of our future SG&A expense with some slight increases. Other than 10,000 RSUs granted in January 2011 and 20,000 to be granted in the spring, we do not expect any more grants during 2011.

Included in 2010 interest expense was a credit of $712,000 relating to our interest rate swaps; such amount for 2009 was a credit of $886,000. In addition, we capitalized $293,000 in interest expense for 2009. Because our mine expansion was completed in the summer of 2009, we are no longer capitalizing interest.

Our effective tax rate for 2010 was about 39% and we expect such rate to be in the 38-40% range for the foreseeable future.

45% Ownership in Savoy

Savoy operates almost exclusively in Michigan. They have an interest in the Trenton-Black River Play in Southern Michigan. They hold 250,000 gross acres (about 125,000 net) in Hillsdale and Lenawee counties. During 2010 Savoy drilled 11 wells (gross) in this play of which two were dry and nine were successful. During 2011 Savoy plans on drilling 8-10 additional wells in the play. Drilling locations in this play are identified based on the evaluation of extensive 3-D seismic shoots. Savoy operates their own wells and their working interest averages between 40 and 50% and their net revenue interest averages between 34 and 42%. Savoy’s net daily oil production currently averages about 655 barrels of oil and 423 thousand cubic feet (Mcf) of gas.

Savoy’s proved reserves at December 31, 2010 were 774,000 barrels of oil and 787,000 Mcf of gas using prices as dictated by the SEC. The SEC prices are based on the average first-of-month prices for the year which was $74 for oil and $4.40 for gas. The price Savoy receives for its oil is about $5 less per barrel than West Texas intermediate (WTI) spot prices due to a Michigan differential. The pre-tax (Savoy is a partnership) present value of their future cash flows discounted at 10% (PV10) was about $34 million. Investors should note that the above numbers are to the 100%; our ownership in Savoy is 45% so our share of the PV10 using SEC prices would $15.3 million. The table below reflects the PV 10 value using more current prices.

At December 31, 2010 a few of the wells in the report were classified in the proved non-producing and proved undeveloped category; as of February 11, 2011 all of the wells in the reserve report would be classified as proved producing. About 95% of the PV10 value is attributable to oil.

The reserve report was prepared by Timothy Lovseth, our full-time geologist who has 30 years of experience in the oil and gas industry. Mr. Lovseth has no ownership in Savoy.

For 2010 Savoy had net income of about $2.2 million almost all of which related to a non-recurring gain on sale of some of their unproved acreage. Without the gain 2010 would have been a breakeven year. Our share of such income was about $1 million. Savoy’s fourth quarter 2010 oil production was about 57,000 barrels compared to 13,000 barrels for 2009; over a 4X increase. Oil and liquids make up about 94% of their oil and gas revenue.

For 2009 Savoy had a net loss of about $3.6 million, our share being about $1.6 million. The key metric we want to convey to our investors is that for the past two years (2008 and 2009) we recorded an equity loss from Savoy; for 2010 we recorded income and expect such trend to continue.

The table below illustrates the growth in Savoy over the last two years (financial statement data in thousands):

	2010	2009
Revenue:		
Oil	$11,138	$2,544
Gas	760	894
NGLs (natural gas liquids)	227	76
Contract drilling	1,735	3,934
Gain on sale of unproved properties	2,225	
Other	587	284
Total revenue	16,672	7,732
Costs and expenses:		
LOE (lease operating expenses)	2,543	1,411
Contract drilling costs	1,445	2,579
DD&A (depreciation, depletion & amortization)	3,147	2,119
Geological and geophysical costs	2,632	1,021
Dry hole costs	808	986
Impairment of unproved properties	2,543	1,838
Other exploration costs	204	207
G&A (general & administrative)	1,116	1,220
Total expenses	14,438	11,381
Net income (loss)	$2,234	$(3,649)

The information below is not in thousands:

	2010	2009
Oil production in barrels	149,000	43,000
4th quarter oil production in barrels	57,000	13,000
Gas production in Mcf	173,000	175,000
Average oil prices/barrel for the year	$75	$59
Average gas prices/Mcf for the year	$4.38	$5.11
Oil reserves (Bbls)	774,000	517,000
Gas reserves (Mcf) (1)	787,000	3,317,000
PV 10 using SEC dictated average prices (oil @ $74)	$34 million	$14 million
PV 10 using oil prices of $80 and LOE held constant (prices even higher due to the Libya uprising)	$38 million	
PV 10 using one year NYMEX oil prices of $88 (prices even higher as mentioned above)	$42 million	

(1) Gas reserves declined due to downward revisions in the proved undeveloped category.

Critical Accounting Estimates and Significant Accounting Policies

We believe that the estimates of our coal reserves and our deferred tax assets and liability accounts are our only critical accounting estimates. Since the Carlisle mine has only been in production since February 2007 we do not have a long history to rely on. The reserve estimates are used in the DD&A calculation, in our impairment test and in our internal cash flow projections. If these estimates turn out to be materially under or over-stated; our DD&A expense and impairment test may be affected. Furthermore, if our coal reserves are materially overstated our liquidity and stock price could be adversely affected.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. None of our corporate tax returns have been examined in the last ten years. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. Therefore, no reserves for uncertain income tax positions have been recorded.

Our significant accounting policies are set forth in Note 1 to the Financial Statements.

New Accounting Pronouncements

None of the recent FASB pronouncements will have any material effect on us.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Smaller reporting companies are not required to provide the information required by this item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Smaller reporting companies are not required to provide supplementary data

REPORT OF INDEPENDENT REGISTERED
PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Hallador Energy Company
Denver, Colorado

We have audited the accompanying consolidated balance sheet of Hallador Energy Company and Subsidiaries as of December 31, 2009 and 2010, and the related consolidated statements of operations, cash flows and stockholders' equity for each of the years in the two year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with 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 consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit 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 consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hallador Energy Company and Subsidiaries, as of December 31, 2009 and 2010, and the results of their operations and their cash flows for each of the years in the two year period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

/s/ Ehrhardt Keefe Steiner & Hottman PC

March 3, 2011
Denver, Colorado

Consolidated Balance Sheet

As of December 31,
(in thousands, except per share data)

ASSETS				
Current assets:		2010		2009
Cash and cash equivalents	$	10,277	$	15,226
Certificates of deposit		1,291		3,458
Prepaid Federal income taxes		3,853		1,511
Accounts receivable		5,450		5,411
Coal inventory		2,100		2,165
Parts and supply inventory		2,411		2,253
Other		850		245
Total current assets		26,232		30,269
Coal properties, at cost:				
Land, buildings and equipment		114,476		95,270
Mine development		59,351		47,479
		173,827		142,749
Less - accumulated DD&A		(28,435)		(16,958)
		145,392		125,791
Investment in Savoy		7,717		6,259
Other assets (Note 8)		7,323		2,771
	$	186,664	$	165,090
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Current portion of bank debt	$	10,000	$	10,000
Accounts payable and accrued liabilities		8,809		9,950
State income tax payable				464
Interest rate swaps, at estimated fair value		692		
Other				179
Total current liabilities		19,501		20,593
Long-term liabilities:				
Bank debt, net of current portion		17,500		27,500
Interest rate swaps, at estimated fair value				1,404
Deferred income taxes		17,435		1,699
Asset retirement obligations		1,150		922
Other		4,345		4,345
Total long-term liabilities		40,430		35,870
Total liabilities		59,931		56,463
Commitments and Contingencies				
Stockholders' equity:				
Preferred stock, $.10 par value, 10,000 shares authorized; none issued				
Common stock, $.01 par value, 100,000 shares authorized;				
27,924 and 27,782 outstanding, repectively		279		277
Additional paid-in capital		84,073		85,245
Retained earnings		42,381		23,105
Total equity		126,733		108,627

	$	186,664	$	165,090

See accompanying notes.

Consolidated Statement of Operations
For the years ended December 31,
(in thousands, except per share data)

	2010	2009
Revenue:		
Coal sales	$ 129,003	$ 117,445
Equity income (loss) - Savoy	1,005	(1,652)
Other income (loss) (Note 8)	(772)	541
	129,236	116,334
Costs and expenses:		
Cost of coal sales	73,307	65,442
DD&A	11,818	8,837
SG&A	5,556	4,038
Interest (1)	1,926	2,040
	92,607	80,357
Income before income taxes	36,629	35,977
Less income taxes:		
Current	885	728
Deferred	13,369	13,044
	14,254	13,772
Net income	22,375	22,205
Less net income attributable to the noncontrolling interest		(2,020)
Net income attributable to Hallador	$ 22,375	$ 20,185
Net income per share attributable to Hallador:		
Basic	$ .81	$ .84
Diluted	$ .78	$ .83
Weighted average shares outstanding:		
Basic	27,790	24,017
Diluted	28,571	24,441

(1) Included in interest expense for 2010 and 2009 is a credit of $712 and $886, respectively, for the change in the estimated fair value of our interest rate swaps. We also capitalized nil and $ 293 in interest charges for 2010 and 2009, respectively.

See accompanying notes.

Consolidated Statement of Cash Flows

For the years ended December 31,
(in thousands)

	2010	2009
Operating activities:		
Net income	$ 22,375	$ 22,205
Deferred income taxes	13,369	13,044
Equity (income) loss – Savoy	(1,005)	1,652
DD&A	11,818	8,837
Change in fair value of interest rate swaps	(712)	(886)
Stock-based compensation	2,194	534
Other		379
Taxes paid on vesting of RSUs	(746)	
Change in current assets and liabilities:		
Accounts receivable	(163)	900
Coal inventory	66	(1,389)
Income tax accounts	(2,807)	(141)
Accounts payable and accrued liabilities	1,415	795
Other	(259)	(710)
Cash provided by operating activities	45,545	45,220
Investing activities:		
Capital expenditures for coal properties	(34,714)	(43,491)
Capital expenditures for oil and gas properties	(915)	(713)
Investment in Sunrise Energy Joint Venture	(2,375)	
Investment in Savoy	(453)	
Change in CDs	2,167	(2,458)
Other	(752)	
Cash used in investing activities	(37,042)	(46,662)
Financing activities:		
Proceeds from bank debt		4,000
Payments of bank debt	(10,000)	(6,500)
Proceeds from stock sales		24,900
Acquisition of remaining 20% interest in Sunrise		(25,805)
Cash distributions to noncontrolling interests	(163)	(909)
Cash dividends	(2,937)	
Stock option buy-out	(679)	
Tax benefit from stock-based compensation	327	
Other		(31)
Cash used in financing activities	(13,452)	(4,345)
Decrease in cash and cash equivalents	(4,949)	(5,787)
Cash and cash equivalents, beginning of year	15,226	21,013
Cash and cash equivalents, end of year	$ 10,277	$ 15,226
Cash paid for interest (net of amount capitalized -nil and $293)	$ 2,255	$ 3,307
Cash paid for income taxes	$ 4,400	$ 850
Changes in accounts payable for coal properties	$ (2,088)	$ (1,810)
Non cash portion of Sunrise buyout		$ 6,800

See accompanying notes.

Consolidated Statement of Stockholders' Equity

(in thousands)

	Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Total
Balance January 1, 2009	22,446	$ 224	$ 69,739	$ 2,920	$ 72,883
Equity offering	4,150	42	24,858		24,900
Stock issued to Sunrise members for their remaining 20% interest valued at par (fair value of $6,800); See Note 4.	1,133	11	(11)		
Cash ($25,805) paid to Sunrise members for their remaining 20% interest, net of deferred income tax assets of $13,045 and $3,703 to close out the noncontrolling interest (treated as an equity transaction) and a $909 cash distribution to the noncontrolling interests			(9,966)		(9,966)
Restricted shares issued	29		161		161
Stock-based compensation			292		292
Bonus shares for employees	24		181		181
Other			(9)		(9)
Net income				20,185	20,185
Balance December 31, 2009	27,782	277	85,245	23,105	108,627
Stock issued to board member for director services	9	1	99		100
Stock- based compensation			2,194		2,194
Stock issued on vesting of RSUs	133	1			1
Taxes paid on vesting of RSUs			(746)		(746)
Tax benefit from stock-based compensation			327		327
Stock option buy out for cash			(679)		(679)
Reduction in deferred tax asset resulting			(2,367)		(2,367)

from Sunrise acquisition (see above)												
Cash distributions to former noncontrolling interests for personal income taxes								(162	)		(162	)
Dividends on common stock								(2,778	)		(2,778	)
Dividends on RSUs and stock options								(159	)		(159	)
Net income								22,375			22,375	
Balance December 31, 2010	27,924	$	279		$	84,073	$	42,381		$	126,733	

See accompanying notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

The consolidated financial statements include the accounts of Hallador Energy Company (the Company) and its wholly-owned subsidiary Sunrise Coal, LLC (Sunrise). All significant intercompany accounts and transactions have been eliminated. We are engaged in the production of steam coal from a shallow underground mine located in western Indiana. We own a 45% equity interest in Savoy Energy L.P., a private oil and gas company which has operations in Michigan and a 50% interest in Sunrise Energy LLC, a private entity engaged in natural gas operations in the same vicinity as our coal mine. We purchased our interest in December 2010. Since closing, operations through the end of the year have not been material.

We have entered into significant equity transactions with Yorktown and other entities that invest with Yorktown. Yorktown currently owns about 55% of our common stock and represents one of the seven seats on our board.

Reclassification

To maintain consistency and comparability, certain amounts in the 2009 financial statements have been reclassified to conform to current year presentation.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs and overhead.

Advance Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced.

Coal Properties

Coal properties are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Expenditures that extend the useful lives or increase the productivity of the assets are capitalized. The cost of maintenance and repairs that do not extend the useful lives or increase the productivity of the assets are expensed as incurred. Other than land and underground mining equipment, coal properties are depreciated using the units-of-production method over the estimated recoverable reserves. Underground mining equipment is depreciated using estimated useful lives ranging from five to twenty years.

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed for recoverability. If this review indicates that the carrying value of the asset will not be recoverable through estimated undiscounted future net cash flows related to the asset over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its estimated fair value.

Mine Development

Costs of developing new coal mines, including asset retirement obligation assets, or significantly expanding the capacity of existing mines, are capitalized and amortized using the units-of-production method over estimated recoverable (proved and probable) reserves.

Asset Retirement Obligations - Reclamation

At the time they are incurred, legal obligations associated with the retirement of long-lived assets are reflected at their estimated fair value, with a corresponding charge to mine development. Obligations are typically incurred when we commence development of underground mines, and include reclamation of support facilities, refuse areas and slurry ponds.

Obligations are reflected at the present value of their discounted cash flows. We reflect accretion of the obligations for the period from the date they are incurred through the date they are extinguished. The asset retirement obligation assets are amortized using the units-of-production method over estimated recoverable (proved and probable) reserves. We are using a 6% discount rate.

Federal and state laws require that mines be reclaimed to their previous condition in accordance with specific standards and approved reclamation plans, as outlined in mining permits. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, and reclamation of refuse areas and slurry ponds.

We assess our ARO at least annually, and reflect revisions for permit changes, as granted by state authorities, for revisions to the estimated reclamation costs, and for revisions to the timing of those costs.

The following table reflects the changes to our ARO:

	2010	2009
Balance beginning of period	$922	$686
Accretion	66	58
Change in cost estimate		178
Additions	162	
Balance end of period	$1,150	$922

Statement of Cash Flows

Cash equivalents include investments with maturities when purchased of three months or less.

Income Taxes

Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on pretax financial income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting and principally relate to differences in the tax basis of assets and liabilities and their reported amounts, using enacted tax rates in effect for the year in which differences are expected to reverse.

Earnings per Share

Basic earnings per share is computed on the basis of the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share is computed on the basis of the weighted average number of shares of common stock plus the effect of dilutive potential common shares outstanding during the period using the treasury stock method. Dilutive potential common shares include outstanding stock options and restricted stock awards.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual amounts could differ from those estimates. The most significant estimates included in the preparation of the financial statements are related to deferred income tax assets and liabilities and coal reserves.

Revenue Recognition

We recognize revenue from coal sales at the time risk of loss passes to the customer at contracted amounts.

Long-term Contracts

We evaluate each of our contracts to determine whether they meet the definition of a derivative and they do not. As of December 31, 2010, we are committed to supply to three customers about 10 million tons of coal during the next four years. These contracts represent about 20% of our recoverable reserves for the Carlisle mine. During 2010 and 2009, three of our customers accounted for 97% or more of our sales: for 2010 one customer accounted for 45%, the second for 36%, and the third for 17%; for 2009 one customer accounted for 62%, the second for 18%, and the third for 17%; We are paid every two to four weeks and do not expect any credit losses.

Stock Based Compensation

Stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as expense over the applicable vesting period of the stock award (generally three to four years) using the straight-line method.

New Accounting Pronouncements

None of the recent FASB pronouncements will have any material effect on us.

Subsequent Events

We have evaluated all subsequent events through the date the financial statements were issued. No material recognized or non-recognizable subsequent events were identified.

(2) Income Taxes (in thousands)

Our income tax is different than the expected amount computed using the applicable federal and state statutory income tax rates. The reasons for and effects of such differences for the years ended December 31 are below:

	2010	2009
Expected amount	$12,820	$11,885
State income taxes, net of federal benefit	1,808	1,784
Other	(374)	103
	$14,254	$13,772

The deferred tax assets and liabilities resulting from temporary differences between book and tax basis are comprised of the following at December 31:

	2010	2009
Long-term deferred tax assets:		
Federal NOL carryforwards	$	$921
AMT credit carryforwards	1,162	1,008
Stock-based compensation	113	605
Investment in Savoy	1,575	2,134
Oil and gas properties	873	
Other		1,014
Net long-term deferred tax assets	3,723	5,682
Long-term deferred tax liabilities:		
Coal properties	(21,158)	(7,381)
Net deferred tax liability	$17,435	$1,699

For accounting purposes the 2009 Sunrise buyout (see Note 4) was treated as an equity transaction among members of a controlled group. For income tax purposes we were able to increase our tax basis in the coal properties and will receive future tax deductions; accordingly, a deferred tax asset of $13 million was recognized with the credit recorded directly to additional paid-in capital. Upon further analysis, in preparing the 2010 tax provision we determined that the tax basis of the incremental assets acquired was less than that originally calculated. As such, in 2010, we reduced our deferred tax assets by $2.37 million with an offset to additional paid-in capital. We have percentage depletion carry forwards of about $2 million which have no expiration date and AMT credit carryforwards of about $1 million.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. None of our corporate tax returns have been examined in the last ten years. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. Therefore, no reserves for uncertain income tax positions have been recorded.

(3) Common Stock, Restricted Stock Units and Stock Options

Common Stock

In September 2009, in a private placement transaction, we sold 4,150,000 shares of our common stock for an aggregate cash purchase price of $24.9 million ($6/share). The proceeds from the sale were used to purchase the remaining 20% membership interests in Sunrise. All but 450,000 shares were sold to our existing shareholders and board members. Yorktown Energy Partners VIII, LP, a private partnership affiliated with board member Bryan Lawrence, purchased 2,950,000 shares and an entity affiliated with board member Sheldon Lubar purchased 750,000 shares.

Restricted Stock Units

At December 31, 2010 we had 953,000 Restricted Stock Units (RSUs) outstanding and about 838,000 available for future issuance. The outstanding RSUs have a value of about $9.5 million based on our current stock price of about $10. During April 2010 we issued 126,500 RSUs with cliff vesting over three years. On the date of issuance of the RSUs our stock was selling for $8.40. We expect 345,000 RSUs to vest during 2011 under our current vesting schedule. Other than 10,000 RSUs granted in January 2011 and 20,000 to be granted in the spring, we do not expect any more grants during 2011.

During December 2010, 195,000 RSUs vested relating to the December 2009 grant discussed below. On vesting date the shares had a value of about $2.3 million. Under our RSU plan participants are allowed to relinquish shares to pay for their income taxes. During 2010 we only allowed relinquishments based on their minimum statutory withholding rates; accordingly, 61,800 shares were relinquished resulting in about 133,000 shares being issued.

On September 14, 2009 our board authorized the issuance of up to 1,000,000 RSUs to current management. At a meeting of our compensation committee held in December 2009, 330,000 RSUs were granted to Victor Stabio, our CEO; 250,000 were granted to Brent Bilsland our president and 200,000 were granted to W. A. Bishop, our CFO. The RSUs vest equally over four years. The closing price of our stock on the date of grant was $7.90. During 2009 we also issued to other employees 73,000 RSUs with cliff vesting over three years and 22,500 with cliff vesting over five years.

Stock based compensation expense for 2010 and 2009 was $2,194,000 and $353,000, respectively. For 2011 based on existing RSUs outstanding, stock based compensation expense will be about $2.1 million.

Stock Options

In April 2005, we granted 750,000 options at an exercise price of $2.30. No additional grants have been made since then. These options fully vested in April 2008 and expire in April 2015. During 2007, 200,000 options were exercised by our CEO. No options were exercised during the 2009 and 2008. At December 31, 2009 we had outstanding 550,000 fully vested stock options.

On January 7, 2010 we allowed four Denver employees (non officers) a one-time opportunity to relinquish 1/3 of their vested options (115,833) for cash of $679,000; the intrinsic value on such date. This transaction was treated as a charge to equity. On January 7, 2011 we allowed the same four Denver employees (non officers) an opportunity to relinquish 100% of their vested options (234,167) for 181,261 shares of our common stock. The exchange ratio was based on the intrinsic value of their options. These shared were issued under our Stock Bonus Plan which was created in December 2009. Under such plan our employees are allowed to relinquish shares to pay for their income taxes; accordingly, 41,645 shares were relinquished resulting in about 140,000 shares being issued.

Currently we have 200,000 outstanding stock options to our CEO with an exercise price of $2.30. The options are fully vested and expire in April 2015.

Stock Bonus Plan

Our stock bonus plan was authorized by our BODs in late 2009 with 250,000 shares. In early December 2009, we distributed 24,000 shares of our common stock to all of our hourly mine employees as an incentive bonus and recorded a charge of $181,000 based on the stock price that day. As mentioned above under Stock Options, during January 2011, 139,616 shares were issued. Currently, we have about 86,000 shares left in such plan.

(4) 2009 Sunrise Coal Acquisition

On September 16, 2009, we entered into agreements to purchase the remaining 20% membership interest in Sunrise Coal LLC (Sunrise), from the existing members for an aggregate purchase price of about $32.6 million, consisting of about $25.8 million in cash and 1,133,328 in shares of our common stock valued at $6/share ($6.8 million). Brent Bilsland, our new president and board member, received cash of about $3.185 million and 8,333 shares of our stock for his approximate 2% interest and his spouse received cash of about $1.775 million and 208,333 shares of our stock for her interest (slightly less than 2%). His parents also sold their approximate 8% interest in Sunrise under the same terms receiving 383,332 shares and the remainder in cash. In addition, simultaneously Brent Bilsland purchased for cash 200,000 shares (at $6/share) directly from Victor Stabio, our CEO. For accounting purposes the 2009 Sunrise buyout was treated as an equity transaction among members of a controlled group.

(5) Notes Payable

In December 2008, we entered into a new loan agreement with a bank consortium that provides for a $40 million term loan and a $30 million revolving credit facility. At December 31, 2010, we owe $27.5 million on the term loan. We have outstanding letters of credit in the amount of $6 million, which leaves about $24 million available under the revolver. We pay a 2.75% fee on the letters of credit and a .5% commitment fee on the unused funds. Substantially all of Sunrise's assets are pledged under this loan agreement and we are the guarantor. Debt maturities are $10 million during 2011 and $17.5 million during 2012. The loan agreement requires customary covenants, required financial ratios and restrictions on distributions. Closing costs on this loan agreement were about $1.2 million and are being amortized using the effective interest method over its term. The current interest rate is LIBOR- one month (0.27%) plus 2.50% or 2.77%.

In connection with the old loan agreements, we entered into two agreements swapping variable rates for fixed rates. Considering the two swap agreements, fees and amortization of the closing costs, our current interest rate is about 6.6%. One of the swaps expire in December 2011 and the other in July 2012. Accounting rules require us to recognize all derivatives on the balance sheet at estimated fair value. Derivatives that are not hedges must be adjusted to estimated fair value through earnings. We have no derivatives designated as a hedge. The recorded value of our bank debt approximates fair value as it bears interest at a floating rate.

(6) Equity Investment in Savoy

We own a 45% interest in Savoy Energy L.P., a private company engaged in the oil and gas business primarily in the State of Michigan. Savoy uses the successful efforts method of accounting. We account for our interest in Savoy using the equity method of accounting.

Below (in thousands) is a condensed balance sheet at December 31, for both years and a condensed statement of operations for both years.

Condensed Balance Sheet

	2010	2009
Current assets	$11,719	$7,764
PP&E, net	18,026	12,114
	29,745	19,878
Total liabilities	12,620	5,987
Partners' capital	17,125	13,891
	$29,745	$19,878

Condensed Statement of Operations

	2010	2009
Revenue	$14,447	$7,732
Gain on sale of unproved properties	2,225	
Expenses	(14,438)	(11,381)
Net income (loss)	$2,234	$(3,649)

During the fourth quarter of 2010 Savoy recognized a non-recurring gain of $2.2 million on the sale of some of their unproved acreage. If not for the gain, 2010 would have been a breakeven year for them.

Unaudited

Savoy’s proved reserves at December 31, 2010 were 774,000 barrels of oil and 787,000 Mcf of gas using prices as dictated by the SEC. Our 45% share was 348,000 barrels and 354,000 Mcf. The SEC prices are based on the average first-of-month prices for the year which was $74 for oil and $4.40 for gas. The pre-tax (Savoy is a partnership) present value of their future cash flows discounted at 10% (PV10) was about $34 million. About 95% of the PV10 value is attributable to oil. Our 45% of such PV10 amount is about $15 million.

Our 45% equity interest in Savoy's proved reserves at December 31, 2009 were 232,000 barrels of oil and 1,493,000 Mcf of gas. Our 45% equity interest in Savoy's standardized measure of discounted future net cash flows (pre tax since Savoy is an LLP) at December 31, 2009 was about $6.3 million.

(7) Employee Benefits

We have no defined benefit pension plans or any post-retirement benefit plans. We offer our employees a 401(k) Plan, where we match 100% of the first 3% that an employee contributes, a bonus plan based on meeting certain production levels and a discretionary Deferred Bonus Plan for certain key employees. We also offer health benefits to all employees. Our 2010 costs for the 401(k) matching were about $320,000 and our costs for health benefits were about $2.1 million. Our 2009 costs for the 401(k) matching were about $283,000 and our costs for health benefits were about $1.8 million. The 2010 amortized costs for the Deferred Bonus Plan were about $180,000 and the 2009 amortized costs for were about $90,000. The costs for the production bonus plan were $328,000 in 2010 and $324,000 in 2009.

Our mine employees are also covered by workers’ compensation and such costs for 2010 and 2009 were about $1.5 million and $1.9 million, respectively. Workers’ compensation is a no-fault system by which individuals who sustain work related injuries or occupational diseases are compensated. Benefits and coverage are mandated by each state which include disability ratings, medical claims, rehabilitation services, and death and survivor benefits. Our operations are protected from these perils through insurance policies. Our maximum annual exposure is limited to $2 million which is our aggregate deductible. Based on discussions and representations from our insurance carrier we believe that our reserve for our workers’ compensation benefits are adequate. We have a safety conscious work force and our worker’s compensation injuries have been minimal. Our mine has been in operation for about four years.

(8) Other long-term assets and other income (loss)

	2010	2009
Long-term assets:		
Undeveloped oil and gas leases	$1,232	$431
Developed oil and gas properties, net	512	534
Investment in Sunrise Energy	2,375	
Advance coal royalties	1,863	1,515
Deferred financing costs, net	616	938
Miscellaneous	725	(647)
	$7,323	$2,771
Other income (loss):		
Exploration and dry hole costs	$(1,302)	$(443)
Oil and gas sales, net of expenses	172	109
Gain on sale of oil and gas properties		604
Miscellaneous	358	271
	$(772)	$541

(9) Self Insurance

In late August 2010 we decided to drop the property insurance on $76 million (historical cost) of our underground mining equipment. We feel comfortable with this decision as such equipment is allocated among four mining units spread out over eight miles.

(10) Fair Value Measurements

We account for certain assets and liabilities at fair value. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. We categorize each of our fair value measurements in one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. These levels are:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. We have no Level 1 instruments.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. We have no Level 2 instruments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our Level 3 instruments are comprised of interest rate swaps. The fair values of our swaps were estimated using discounted cash flow calculations based upon forward interest-rate yield curves. Although we utilize third party broker quotes to assess the reasonableness of our prices and valuation, we do not have sufficient corroborating market evidence to support classifying these liabilities as Level 2.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls

We maintain a system of disclosure controls and procedures that are designed for the purposes of ensuring that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our CEO and CFO as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our CEO and CFO of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective for the purposes discussed above.

Internal Control Over Financial Reporting (ICFR)

We are responsible for establishing and maintaining adequate ICFR. We assessed the effectiveness of our ICFR based on criteria for effective ICFR described in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment, we concluded that we maintained effective ICFR as of December 31, 2010.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include an attestation report from Ehrhardt Keefe Steiner & Hottman PC (EKSH), our auditors, regarding ICFR. Our report was not subject to attestation by EKSH pursuant to existing rules of the SEC that permits us to provide only our report in this annual report.

ITEM 9B. OTHER INFORMATION

Our principles are safety, honesty, and compliance. We firmly believe that these values compose a dedicated workforce and with that, come high production. The core to this is our strong training programs that include accident prevention, workplace inspection and examination, emergency response, and compliance. We have currently budgeted over $250,000 over the next nine months for management and employee safety and compliance training. We work with the Federal and State regulatory agencies to help eliminate safety and health hazards from our workplace and increase safety and compliance awareness throughout the mining industry. Sunrise has not had a fatality since its establishment in 2005.

Sunrise is regulated by the MSHA under the Federal Mine Safety and Health Act of 1977 (“Mine Act”). MSHA inspects our mine on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. We present information below regarding certain violations which MSHA has issued with respect to our mine. While assessing this information please consider that the number and cost of violations will vary depending on the MSHA inspector and can be contested and appealed, and in that process, and are often reduced in severity and amount, and are sometimes dismissed. We are currently contesting 26 citations with MSHA; some involve the amount of the assessments and some involve the citation itself.

The disclosures listed below are provided pursuant to the recently enacted Dodd-Frank Act. We believe that the following disclosures comply with the requirements of the Dodd-Frank Act; however, it is possible that future SEC rule making may require disclosures to be filed in a different format than the following.

Sunrise has not been issued written notice from MSHA of a pattern of, or the potential to have a pattern of, violations of mandatory health or safety standards that are of such a nature as could significantly and substantially cause and effect health or safety standards under section 104(e) of the Mine Act.

The table that follows outlines citations and orders issued to us by MSHA during the fourth quarter 2010. The citations and orders outlined below may differ from MSHA`s data retrieval system due to timing, special assessed citations, and other factors.

Definitions:

Section 104(a) Significant and Substantial Citations “S&S”: An alleged violation of a mining safety or health standard or regulation where there exists a reasonable likelihood that the hazard outlined will result in an injury or illness of a serious nature.

Section 104(b) Orders: Failure to abate a 104(a) citation within the period of time prescribed by MSHA. The result of which is an order of immediate withdraw of non-essential persons from the affected area until MSHA determines the violation has been corrected.

Section 104(d) Citations and Orders: An alleged unwarrantable failure to comply with mandatory health and safety standards.

Section 107(a) Orders: An order of withdraw for situations where MSHA has determined that an imminent danger exists.

Section 110(b)(2) Violations: An alleged flagrant violation issued by MSHA under section 110(b)(2) OF THE Mine Act.

Pattern or Potential Pattern of Violations: A pattern of violations of mandatory health or safety standards that are of such a nature as could have significantly and substantially contributed to the cause and effect of coal mine health or safety hazards under section 104(e) of the Mine Act or a potential to have such a pattern.

Contest of Citations, Orders, or Proposed Penalties: A contest proceeding may be filed with the Commission by the operator or miners/miners representative to challenge the issuance or penalty of a citation or order issued by MSHA.

Month	Section 104(a) Citations	Section 104(b) Orders	Section 104(d) Citation/Orders	Section 107(a) Orders	Section 110(b)(2) Violations	Proposed MSHA Assessments (in thousands)
January	6	0	0	0	0	$19.5
February	4	0	0	0	0	8.1
March	3	0	0	0	0	8.2
April	2	0	0	0	0	3.3
May	6	0	0	0	0	9.8
June	6	0	3	0	0	45.6
July	7	0	0	0	0	14.8
August	6	0	0	1	0	54.3
September	1	0	0	0	0	2.3
October	3	0	0	0	0	11.6
November	1	0	0	0	0	0.2
December	3	0	0	0	0	4.5

PART III

The information required for Items 10-14 are hereby incorporated by reference to that certain information in our Information Statement to be filed with the SEC on or before April 29, 2011.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

See Item 8 for an index of our financial statements.

Because we are a smaller reporting company we are not required to provide financial statement schedules.

Our exhibit index is as follows:

3.1	Second Restated Articles of Incorporation of Hallador Energy Company effective December 24, 2009. (1)
3.2	By-laws of Hallador Energy Company, effective December 24, 2009 (1)
10.1	Purchase and Sale Agreement dated December 31, 2005 between Hallador Petroleum Company, as Purchase and Yorktown Energy Partners II, L.P., as Seller relating to the purchase and sale of limited partnership interests in Savoy Energy Limited Partnership (2)
10.2	Letter of Intent dated January 5, 2006 between Hallador Petroleum Company and Sunrise Coal, LLC (3)
10.3	Subscription Agreement - by and between Hallador Petroleum Company and Yorktown Energy Partners VI, L.P., et al dated February 22, 2006. (2)
10.4	Subscription Agreements - by and between Hallador Petroleum Company and Hallador Alternative Assets Fund LLC, et al dated February 14, 2006. (3)
10.5	Continuing Guaranty, dated April 19, 2006, by Hallador Petroleum Company in favor of Old National Bank (6)
10.6	Collateral Assignment of Hallador Master Purchase/Sale Agreement, dated April 19, 2006, among Hallador Petroleum Company, Hallador Petroleum, LLLP, and Hallador Production Company and Old National Bank (6)
10.7	Reimbursement Agreement, dated April 19, 2006, between Hallador Petroleum Company and Sunrise Coal, LLC (6)
10.8	Membership Interest Purchase Agreement dated July 31, 2006 by and between Hallador Petroleum Company and Sunrise Coal, LLC. (7)
10.9	Subscription Agreements - by and between Hallador Petroleum Company and Yorktown Energy Partners VII, L.P., et al dated October 5, 2007 (7)

10.10	Purchase and Sale Agreement dated effective as of October 5, 2007 between Hallador Petroleum Company, as Purchaser and Savoy Energy Limited Partnership, as Seller (11)
10.11	First Amendment to Credit Agreement, Waiver and Ratification of Loan Documents dated June 28, 2007 by and between Sunrise Coal, LLC, Hallador Petroleum Company and Old National Bank (9)
10.12	Amended and Restated Continuing Guaranty, dated as of June 28, 2007, between Hallador Petroleum Company, Sunrise Coal, LLC, and Old National Bank. (10)
10.13	Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated as of June 28, 2007, between Hallador Petroleum Company and Victor P. Stabio(10)*
10.14	Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated as of July 19, 2007, between Hallador Petroleum Company and Brent Bilsland(11)*
10.15	Hallador Petroleum Company 2008 Restricted Stock Unit Plan. (12)*
10.16	Form of Amended and Restated Purchase and Sale Agreement dated July 24, 2008 to purchase additional minority interest from Sunrise Coal, LLC's minority members (13)
10.17	Form of Hallador Petroleum Company Restricted Stock Unit Issuance Agreement dated July 24, 2008 (13)*
10.18	Credit Agreement dated December 12, 2008, by and among Sunrise Coal, LLC, Hallador Petroleum Company as a Guarantor, PNC Bank, National Association as administrative agent for the lenders, and the other lenders party thereto. (14)
10.19	Continuing Agreement of Guaranty and Suretyship dated December 12, 2008, by Hallador Petroleum Company in favor of PNC Bank, National Association (14)
10.20	Amended and Restated Promissory Note dated December 12, 2008, in the principal amount of $13,000,000, issued by Sunrise Coal, LLC in favor of Hallador Petroleum Company (14)
10.21	Form of Purchase and Sale Agreement dated September 16, 2009 (15)
10.22	Form of Subscription Agreement dated September 15, 2009 (15)
10.23	Form of Hallador Petroleum Company Restricted Stock Unit Issuance Agreement. (15)*
10.24	2009 Stock Bonus Plan(16)*
14	Code Of Ethics For Senior Financial Officers. (5)
21.1	List of Subsidiaries (17)
23.1	Consent of Independent Registered Public Accounting Firm (17)
31	SOX 302 Certifications (17)
32	SOX 906 Certification (17)

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(1) IBR to Form 8-K dated December 31, 2009.
(2) IBR to Form 8-K dated January 3, 2006.
(3) IBR to Form 8-K dated January 6, 2006.
(4) IBR to Form 8-K dated February 27, 2006.
(5) IBR to the 2005 Form 10-KSB.
(6) IBR to Form 8-K dated April 25, 2006.
(7) IBR to Form 8-K dated August 1, 2006.
(8) IBR to Form 10-QSB dated September 30, 2007.
(9) IBR to Form 10-QSB dated June 30, 2007.
(10) IBR to Form 8-K dated July 2, 2007.
(11) IBR to Form 10-KSB dated December 31, 2007.
(12) IBR to March 31, 2007 Form 10-Q.
(13) IBR to Form 8-K dated July 24, 2008.
(14) IBR to Form 8-K dated December 12, 2008.
(15) IBR to Form 8-K dated September 18, 2009.
(16) IBR to Form S-8 dated December 1, 2009.
(17) Filed herewith.

* Management contracts or compensatory plans.

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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.

HALLADOR ENERGY COMPANY

Date: March 4, 2011 /S/W. ANDERSON BISHOP
W. Anderson Bishop, CFO and CAO

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

/s/DAVID HARDIE David Hardie	Chairman	March 4, 2011
/s/VICTOR P. STABIO Victor P. Stabio	CEO and Director	March 4, 2011
/s/BRYAN LAWRENCE Bryan Lawrence	Director	March 4, 2011
/s/BRENT BILSLAND Brent Bilsland	President and Director	March 4, 2011
/s/JOHN VAN HEUVELEN John Van Heuvelen	Director	March 4, 2011