HALLADOR ENERGY CO
Form 10-K
March 13, 2018

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, 2017** OR

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

Commission file number: 001-3473

"COAL KEEPS YOUR LIGHTS ON""COAL KEEPS YOUR LIGHTS ON"

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

Securities registered pursuant to Section 12(b) of the Exchange Act: Name of each Exchange on which registered

Common Stock, par value $.01 per share	Nasdaq Capital Market

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

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

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. þ

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 þ No ¨

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.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

Yes ¨ No þ

The aggregate market value of the common stock held by non-affiliates (public float) on June 30, 2017 was $124.5 million based on the closing price reported that date by the NASDAQ of $7.77 per share.

As of March 9, 2018, we had 29,955,713 shares outstanding.

Portions of our Proxy Statement to be filed with the SEC in connection with our annual stockholders' meeting are incorporated by reference into Part III of this Form 10-K. Our Annual Meeting of Shareholders will be held on May 23, 2018 in New York City, NY.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute "forward-looking statements." These statements are based on our beliefs as well as assumptions made by, and information currently available to us. When used in this document, the words "anticipate," "believe," "continue," "estimate," "expect," "forecast," "may," "project," similar expressions identify forward-looking statements. Without limiting the foregoing, all statements relating to our outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- changes in competition in coal markets and our ability to respond to such changes;
- changes in coal prices, which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- legislation, regulations, and court decisions and interpretations thereof, including those relating to the environment, mining, miner health and safety and health care;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- changing global economic conditions or in industries in which our customers operate;
- liquidity constraints, including those resulting from any future unavailability of financing;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- adjustments made in price, volume or terms to existing coal supply agreements;
- fluctuations in coal demand, prices and availability;
- our productivity levels and margins earned on our coal sales;
- changes in raw material costs;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs, adverse changes in work rules, or cash payments or projections associated with post-mine reclamation and workers' compensation claims;
- increases in transportation costs and risk of transportation delays or interruptions;
- operational interruptions due to geologic, permitting, labor, weather-related or other factors;
- risks associated with major mine-related accidents, such as mine fires, or interruptions;
- results of litigation, including claims not yet asserted;
- difficulty maintaining our surety bonds for mine reclamation;
- the coal industry's share of electricity generation, including as a result of environmental concerns related to coal mining and combustion and the cost and perceived benefits of other sources of electricity, such as natural gas, nuclear energy and renewable fuels;
- uncertainties in estimating and replacing our coal reserves;
- a loss or reduction of benefits from certain tax deductions and credits;

- difficulty obtaining commercial property insurance;
- difficulty in making accurate assumptions and projections regarding future revenue and costs associated with equity investments in companies we do not control; and
- other factors, including those discussed in “Item 1A. Risk Factors.”

2

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in "Item 1A. Risk Factors" below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the U.S. Securities and Exchange Commission ("SEC"); our press releases; our website ***http://www.halladorenergy.com*** and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

ITEM 1. BUSINESS.

See Item 7- MDA for a discussion of our business.

Regulation and Laws

The coal mining industry is subject to extensive regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways or wetlands;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- discharge of materials;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that mining has on groundwater quality and availability.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has adversely affected demand for coal. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be interpreted differently or more stringently enforced, any of which could have a significant impact on our mining operations or our customers' ability to use coal. For more information, please see risk factors described in "Item 1A. Risk Factors" below.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration ("MSHA") where citations can be issued without regard to fault, and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition immediately. While we have not quantified all the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if these accruals were insufficient.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation and must address a variety of environmental, health and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. Meeting all requirements imposed by any of these authorities may be costly and time-consuming, and may delay or prevent commencement or continuation of mining operations.

The permitting process for certain mining operations can extend over several years and can be subject to administrative and judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We cannot assure you that we will not experience difficulty or delays in obtaining mining permits in the future or that a current permit will not be revoked.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations that have outstanding environmental violations. Although like other coal companies, we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since the Federal Coal Mine Health and Safety Act of 1969 (“CMHSA”) was adopted. The Federal Mine Safety and Health Act of 1977 (“FMSHA”), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed extensive and detailed safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and numerous other matters. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, the states where we operate have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the U.S. for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

The FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires imposition of a civil penalty for each cited violation. Negligence and gravity assessments, and other factors can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. The FMSHA also contains criminal liability provisions. For example, criminal liability may be imposed upon corporate operators who knowingly and willfully authorize, order or carry out violations of the FMSHA, or its mandatory health and safety standards.

The Federal Mine Improvement and New Emergency Response Act of 2006 (“MINER Act”) significantly amended the FMSHA, imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, MSHA has issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training, and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground “refuge alternatives” capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belts, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards.

In 2014, MSHA began implementation of a finalized new regulation titled "Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors." The final rule implements a reduction in the allowable respirable coal mine dust exposure limits, requires the use of sampling data taken from a single sample rather than an average of samples, and increases oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine, all of which increase mining costs. The second phase of the rule began in February 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor technology, which provides real-time dust exposure information to the miner. Phase three of the rule began in August 2016 and resulted in lowering the current respirable dust level of 2.0 milligrams per cubic meter to 1.5 milligrams per cubic meter of air. Compliance with these rules can result in increased costs on our operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations.

Additionally, in July 2014, MSHA proposed a rule addressing the "criteria and procedures for assessment of civil penalties." Public commenters have expressed concern that the proposed rule exceeds MSHA's rulemaking authority and would result in substantially increased civil penalties for regulatory violations cited by MSHA. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, civil penalties increased significantly. The notice-and-comment period for this proposed rule has closed, and it is uncertain when MSHA will present a final rule addressing these civil penalties.

In January 2015, MSHA published a final rule requiring mine operators to install proximity detection systems on continuous mining machines, over a staggered time frame ranging from November 2015 through March 2018. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner. MSHA subsequently proposed a rule requiring mine operators to also install proximity detection systems on other types of underground mobile mining equipment. The comment period for this proposed rule closed on April 10, 2017, and it is uncertain when MSHA will promulgate a final rule addressing the issue of proximity detection systems on underground mobile mining equipment, other than continuous mining machines.

In June 2016, MSHA published a request for information on Exposure of Underground Miners to Diesel Exhaust. Following a comment period that closed in November 2016, MSHA received requests for MSHA and the National Institute for Occupational Safety and Health to hold a Diesel Exhaust Partnership to address the issues covered by MSHA's request for information. The comment period for the request for information was reopened and closed in January 2018. It is uncertain whether MSHA will present a proposed rule pertaining to exposure of underground miners to diesel exhaust, after completing its evaluation of the comments received.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. Other states may pass similar legislation or administrative regulations in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we have not quantified the full impact, implementing and complying with these new state and federal safety laws and regulations have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981 ("BLBA") requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease and to some survivors of a miner who dies from this disease. The BLBA levies a tax on production of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, the BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. We are also liable under state statutes for black lung claims. Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business, results of operations and financial position.

The revised BLBA regulations took effect in January 2001, relaxing the stringent award criteria established under previous regulations and thus potentially allowing new federal claims to be awarded and allowing previously denied claimants to re-file under the revised criteria. These regulations may also increase black lung related medical costs by broadening the scope of conditions for which medical costs are reimbursable and increase legal costs by shifting more of the burden of proof to the employer.

The Patient Protection and Affordable Care Act enacted in 2010, includes significant changes to the federal black lung program, retroactive to 2005, including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program.

Workers' Compensation

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment-related deaths. States in which we operate consider changes in workers' compensation laws from time to time.

Surface Mining Control and Reclamation Act

The Federal Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and similar state statutes establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. Although we have minimal surface mining activity and no mountaintop removal mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The tax for surface-mined and underground-mined coal is $0.28 per ton and $0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies that are deemed, according to the regulations, to have “owned” or “controlled” the third-party violator. Sanctions against the “owner” or “controller” are quite severe and can include being blocked from receiving new permits and having any permits revoked that were issued after the time of the violations or after the time civil penalties or reclamation fees became due. We are not aware of any currently pending or asserted claims against us relating to the “ownership” or “control” theories discussed above. However, we cannot assure you that such claims will not be asserted in the future.

The U.S. Office of Surface Mining Reclamation (“OSM”) published in November 2009 an Advance Notice of Proposed Rulemaking, announcing its intent to revise the Stream Buffer Zone (“SBZ”) rule published in December 2008. The SBZ rule prohibits mining disturbances within 100 feet of streams if there would be a negative effect on water quality. Environmental groups brought lawsuits challenging the rule, and in a March 2010 settlement, the OSM agreed to rewrite the SBZ rule. In January 2013, the environmental groups reopened the litigation against OSM for failure to abide by the terms of the settlement. Oral arguments were heard on January 31, 2014. OSM published a notice on December 22, 2014, to vacate the 2008 SBZ rule to comply with an order issued by the U.S. District Court for the District of Columbia. OSM reimplemented the 1983 SBZ rule.

OSM issued its final Stream Protection Rule ("SPR") in December 2016 to replace the vacated SBZ rule. The rule would have generally prohibited the approval of permits issued pursuant to SMCRA where the proposed operations would result in "material damage to the hydrologic balance outside the permit area." Pursuant to the rule, permittees would have also been required to restore any perennial or intermittent streams that a permittee mined through. Finally, the rule would have also imposed additional baseline data collection, surface/groundwater monitoring, and bonding and financial assurance requirements. However, in February 2017, both the U.S. House of Representatives and the Senate passed resolutions disapproving the SPR under the Congressional Review Act ("CRA"). President Trump signed the resolution on February 16, 2017, and, pursuant to the CRA, the SPR "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new SPR rule remains uncertain.

Following the spill of coal combustion residues (“CCRs”) in the Tennessee Valley Authority impoundment in Kingston, Tennessee, in December 2009, the EPA issued proposed rules on CCRs in 2010. This final rule was published on December 19, 2014. The EPA's final rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites. OSM has announced their intention to release a proposed rule to regulate placement and use of CCRs at coal mine sites, but, to date, no further action has been taken. These actions by OSM, potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow.

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other coal-burning facilities. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under applicable state and federal laws and regulations related to air emissions will make it costlier to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of individual state implementation plans ("SIPs"), could make coal a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in coal's share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations. Since 2010, utilities have formally announced the retirement or conversion of over 600 coal-fired electric generating units through 2030.

In addition to the greenhouse gas ("GHG") issues discussed below, the air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the following:

- The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower-sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule ("CAIR"), discussed below.

7

· The CAIR calls for power plants in 28 states and Washington, D.C. to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), a replacement rule for CAIR, which would have required 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Under CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would have commenced in 2012 with further reductions effective in 2014. However, in August 2012, the D.C. Circuit Court of Appeals vacated CSAPR, finding the EPA exceeded its statutory authority under the CAA and striking down the EPA's decision to require federal implementation plans ("FIPs"), rather than SIPs, to implement mandated reductions. In its ruling, the D.C. Circuit Court of Appeals ordered the EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The U.S. Supreme Court granted the EPA's certiorari petition appealing the D.C. Circuit Court of Appeals' decision and heard oral arguments on December 10, 2013. In April 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals' decision, concluding that the EPA's approach is lawful. CSAPR has been reinstated and the EPA began implementation of Phase 1 requirements in January 2015. In September 2016, the EPA finalized the CSAPR Update to respond to the remand by the D.C. Circuit Court of Appeals. Implementation of Phase 2 began in 2017. Further litigation is expected against the CSAPR Update in the D.C. Circuit Court of Appeals. The impacts of CSAPR Update are unknown at the present time due to the implementation of Mercury and Air Toxic Standards ("MATS"), discussed below, and the significant number of coal retirements that have resulted and that potentially will result from MATS.

· In February 2012, the EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, the EPA finalized a reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits to levels attainable by existing control technologies. Appeals were filed, and oral arguments were heard by the D.C. Circuit Court of Appeals in December 2013. On April 15, 2014, the D.C. Circuit Court of Appeals upheld MATS. On June 29, 2015, the Supreme Court remanded the final rule back to the D.C. Circuit holding that the agency must consider cost before deciding whether regulation is necessary and appropriate. On December 1, 2015, the EPA issued, for comment, the proposed Supplemental Finding. In April 2016, the EPA issued a final supplemental finding upholding the rule and concluding that a cost analysis supports the MATS rule. In April 2017, the D.C Circuit Court of Appeals granted EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the supplemental finding. Many electric generators have already announced retirements due to the MATS rule. Although various issues surrounding the MATS rule remain subject to litigation in the D.C. Circuit, the MATS will force generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, or Congress may decrease the future demand for coal. We continue to evaluate the possible scenarios associated with CSAPR and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

· In January 2013, the EPA issued final Maximum Achievable Control Technology ("MACT") standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters ("Boiler MACT"), which require owners of industrial, commercial, and institutional boilers to comply with standards for air pollutants, including mercury and other metals, fine particulates, and acid gases such as hydrogen chloride. Businesses and environmental groups have filed legal challenges to Boiler MACT in the D.C. Circuit Court of Appeals and petitioned the EPA to reconsider the rule. On December 1, 2014, the EPA announced a reconsideration of the standard and will accept public comment on five issues for its standards on area sources, will review three issues related to its major-source boiler standards, and four issues relating to commercial and solid waste incinerator units. Before reconsideration, the EPA estimated the rule would affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. While some owners would make capital expenditures to retrofit boilers and process heaters, a number of boilers and process heaters could be prematurely retired. Retirements are likely to reduce the demand for coal. In August 2016, the D.C. Circuit Court of Appeals vacated a portion of the rule while remanding portions back to the EPA. In December 2016, the D.C. Circuit Court of Appeals agreed to the EPA request to remand the rule back to the EPA without vacatur. The impact of the regulations will depend on the EPA's reconsideration and the outcome of subsequent legal challenges. The impact of the regulations will depend on the EPA’s reconsideration and the outcome of subsequent legal challenges.

8

The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards ("NAAQS") should be revised. Pursuant to this process, the EPA has adopted more stringent NAAQS for fine particulate matter ("PM"), ozone, nitrogen oxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards and other states will be required to develop new SIPs for areas that were previously in "attainment" but do not attain the new standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Initial non-attainment determinations related to the revised sulfur dioxide standard became effective in October 2013. In addition, in January 2013, the EPA updated the NAAQS for fine particulate matter emitted by a wide variety of sources including power plants, industrial facilities, and gasoline and diesel engines, tightening the annual PM 2.5 standard to 12 micrograms per cubic meter. The revised standard became effective in March 2013. In November 2013, the EPA proposed a rule to clarify PM 2.5 implementation requirements to the states for current 1997 and 2006 non-attainment areas. In July 2016, the EPA issued a final rule for states to use in creating their plans to address the particulate matter. On October 26, 2015, the EPA published a final rule that reduced the ozone NAAQS from 75 to 70 ppb. Murray Energy filed a challenge to the final rule in the D.C. Circuit. Since that time, other industry and state petitioners have filed challenges as have several environmental groups. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In April 2017, the D.C. Court of Appeals granted EPA's request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the 2015 Rule. In July 2009, the D.C. Circuit Court of Appeals vacated part of a rule implementing the ozone NAAQS and remanded certain other aspects of the rule to the EPA for further consideration. In June 2013, the EPA proposed a rule for implementing the 2008 ozone NAAQS. Under a consent decree published in the Federal Register in January 2017, the EPA has agreed to review the NAAQS for nitrogen oxides with a final decision due by 2018 and review the NAAQS for sulfur oxide with a final decision due by 2019. In July 2017, the EPA proposed to retain the current NAAQS for nitrogen oxides. The comment period for the proposal closed in September 2017. New standards may impose additional emissions control requirements on new and expanded coal-fired power plants and industrial boilers. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and sulfur dioxide, our mining operations and our customers could be affected when the new standards are implemented by the applicable states, and developments might indirectly reduce the demand for coal.

The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas, and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in sulfur dioxide and nitrogen oxide emissions from coal-fueled electric plants. In recent cases, the EPA has decided to negate the SIPs and impose stringent requirements through FIPs. The regional haze program, including particularly the EPA's FIPs, and any future regulations 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.

The EPA's new source review ("NSR") program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for coal could be affected.

9

Carbon Dioxide Emissions

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide, which is considered a GHG. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by the EPA. Congress has considered various proposals to reduce GHG emissions, and it is possible federal legislation could be adopted in the future. Internationally, the Kyoto Protocol set binding emission targets for developed countries that ratified it (the U.S. did not ratify, and Canada officially withdrew from its Kyoto commitment in 2012) to reduce their global GHG emissions. The Kyoto Protocol was nominally extended past its expiration date of December 2012, with a requirement for a new legal construct to be put into place by 2015. The United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement (Paris Agreement). Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. These commitments could further reduce demand and prices for our coal. In June of 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement, which has a four-year exit process.   Future participation in the Paris Agreement by the U.S. remains uncertain. However, many states, regions and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted, which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has begun to regulate GHG emissions under the CAA based on the U.S. Supreme Court's 2007 decision in *Massachusetts v. Environmental Protection Agency* that the EPA has authority to regulate GHG emissions. In 2009, the EPA issued a final rule, known as the "Endangerment Finding"," declaring that GHG emissions, including carbon dioxide and methane, endanger public health and welfare and that six GHGs, including carbon dioxide and methane, emitted by motor vehicles endanger both the public health and welfare.

In May 2010, the EPA issued its final "tailoring rule" for GHG emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. The EPA's rule phases in various GHG-related permitting requirements beginning in January 2011. Beginning July 1, 2011, the EPA requires facilities that must already obtain NSR permits (new or modified stationary sources) for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. These permits require that the permittee adopt the Best Available Control Technology ("BACT"). In June 2012, the D.C. Circuit Court of Appeals upheld these permitting regulations. In June 2014, the U.S. Supreme Court invalidated the EPA's position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO2 BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO2).

As a result of revisions to its preconstruction permitting rules that became fully effective in 2011, the EPA now requires new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominantly carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants. The EPA has also issued final rules requiring the monitoring and reporting of greenhouse gas emissions from certain sources.

In March 2012, the EPA proposed New Source Performance Standards (“NSPS”) for carbon dioxide emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a carbon dioxide emissions standard of 1,000 lbs. CO2/MWh, which is equivalent to the carbon dioxide emitted by a natural gas combined cycle unit. In January 2014, the EPA formally published its re-proposed NSPS for carbon dioxide emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lbs. CO2/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage (“CCS”) technology. In August 2015, the EPA released final rules requiring newly constructed coal-fired steam electric generating units (“EGUs”) to emit no more than 1,400 lbs CO2/MWh (gross) and be constructed with CCS to capture 16% of CO2 produced by an electric generating unit burning bituminous coal. At the same time, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources required reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. In April 2017, the EPA published notice in the federal register that the agency has initiated a review of the NSPS for new and modified fossil fuel-fired power plants and that, following the review, the EPA will initiate reconsideration proceedings to suspend, revise or rescind this NSPS. Challenges to the NSPS have been filed in U.S. Court of Appeal for the D.C. Circuit and oral arguments were set for April 2017; however, in April 2017, the U.S Court of Appeal for the D.C. Circuit ordered the NSPS case held in abeyance for an EPA review of the rule. It is likely than any repeal or revisions to the NSPS will be subject to legal challenges as well. Future implementation of the NSPS is uncertain at this time.

In August 2015, the EPA issued its final Clean Power Plan ("CPP") rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia ("Circuit Court") even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court's stay applies only to EPA's regulations for CO_2 emissions from existing power plants and will not affect EPA's standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 the EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with this proposed repeal, the EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of this appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted.

Collectively, these requirements have led to premature retirements and could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has rejected legislation to restrict carbon dioxide emissions from existing power plants, and it is unclear whether the EPA has the legal authority to regulate carbon dioxide emissions for existing and modified power plants as proposed in the NSPS and CPP. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce.

There have been numerous protests of and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state regulatory authorities have rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fueled power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over thirty states have currently adopted "renewable energy standards" or "renewable portfolio standards," which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards generally range from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal. Finally, a federal appeals court allowed a lawsuit pursuing federal common law claim to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court overturned that decision in June 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions. The Supreme Court did not, however, decide whether similar claims can be brought under state common law. As a result, despite this favorable ruling, tort-type liabilities remain a concern.

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the National Environmental Policy Act ("NEPA"). These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. In December 2014, the Council on Environmental Quality ("CEQ") released updated draft guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their NEPA evaluations. The guidance encourages agencies to provide a more detailed discussion of the direct, indirect, and cumulative impacts of a proposed action's reasonably foreseeable emissions and effects. This guidance could create additional delays and costs in the NEPA review process or in our operations, or even an inability to obtain necessary federal approvals for our future operations, including due to the increased risk of legal challenges from environmental groups seeking additional analysis of climate impacts. In April 2017, CEQ withdrew its final 2016 guidance on how federal agencies should incorporate climate change and GHG considerations into NEPA reviews of federal actions.

Many states and regions have adopted GHG initiatives, and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten Northeastern states entered into the Regional Greenhouse Gas Initiative agreement ("RGGI"), calling for the implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. The members of RGGI have established in statutes and/or regulations a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers. New Jersey has announced its intention to rejoin RGGI following the change in state government administrations.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate, and implement collective and cooperative methods of reducing GHG in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with coal production and consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition, and results of operations.

Water Discharge

The Federal Clean Water Act ("CWA") and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future "fill" permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

The U.S. Army Corps of Engineers ("Corps of Engineers") maintains two permitting programs under CWA Section 404 for the discharge of dredged or fill material: one for "individual" permits and a more streamlined program for "general" permits. In June 2010, the Corps of Engineers suspended the use of "general" permits under Nationwide Permit 21 ("NWP 21") in the Appalachian states. In February 2012, the Corps of Engineers reissued the final 2012 NWP 21. The Center for Biological Diversity later filed a notice of intent to sue the Corps of Engineers based on allegations the 2012 NWP 21 program violated the Endangered Species Act ("ESA"). The Corps of Engineers and National Marine Fisheries Service ("NMFS") have completed their programmatic ESA Section 7 consultation process on the Corps of

Engineers' 2012 NWP 21 package, and NMFS has issued a revised biological opinion finding that the NWP 21 program does not jeopardize the continued existence of threatened and endangered species and will not result in the destruction or adverse modification of designated critical habitat. However, the opinion contains 12 additional protective measures the Corps of Engineers will implement in certain districts to "enhance the protection of listed species and critical habitat." While these measures will not affect previously verified permit activities where construction has not yet been completed, several Corps of Engineers districts with mining operations will be impacted by the additional protective measures going forward. These measures include additional reporting and notification requirements, potential imposition of new regional conditions and additional actions concerning cumulative effects analyses and mitigation. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

The EPA also has statutory “veto” power over a Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an “unacceptable adverse effect.” In January 2011, the EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to the EPA’s exercise of this authority was made in the U.S. District Court for the District of Columbia, and in March 2012, that court ruled that the EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. In April 2013, the D.C. Circuit Court of Appeals reversed this decision and authorized the EPA to retroactively veto portions of a Section 404 permit. The U.S. Supreme Court denied a request to review this decision. Any future use of the EPA’s Section 404 “veto” power could create uncertainly with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenue. In addition, the EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow the EPA to bypass the state permitting process and engage in watershed and land use planning.

Total Maximum Daily Load (“TMDL”) regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an antidegradation review before approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. Additionally, EPA has promulgated a final rule that extends the applicability date of the 2015 rule for another two years in order to allow EPA to undertake a rulemaking on the question of what constitutes a water of the United States. In the meantime, judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the recent rulemaking that extends the applicability date of the 2015 rule. For now, EPA and the Corps of Engineers will continue to apply the existing standard for what constitutes a water of the United States as determined by the Supreme Court in the Rapanos case and post-Rapanos guidance. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the United States be promulgated as a result of EPA and the Corps of Engineers' rulemaking process, we could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), otherwise known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liabilities under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The Federal Resource Conservation and Recovery Act ("RCRA") and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations.

In June 2010, the EPA released a proposed rule to regulate the disposal of certain coal combustion by-products ("CCB"). The proposed rule set forth two very different options for regulating CCB under RCRA. The first option called for regulation of CCB as a hazardous waste under Subtitle C, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option utilized Subtitle D, which would give the EPA authority to set performance standards for waste management facilities and would be enforced primarily through citizen suits. The proposal leaves intact the Bevill exemption for beneficial uses of CCB. In April 2012, several environmental organizations filed suit against the EPA to compel the EPA to take action on the proposed rule. Several companies and industry groups intervened. A consent decree was entered on January 29, 2014.

The EPA finalized the CCB rule on December 19, 2014, setting nationwide solid, nonhazardous waste standards for CCB disposal. On April 17, 2015, the EPA finalized regulations under the solid waste provisions ("Subtitle D") of RCRA and not the hazardous waste provisions ("Subtitle C") which became effective on October 19, 2015. EPA affirms in the preamble to the final rule that "this rule does not apply to CCR placed in active or abandoned underground or surface mines." Instead, "the U.S. Department of Interior ("DOI") and EPA will address the management of CCR in mine fills in a separate regulatory action(s)." While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal.

On November 3, 2015, EPA published the final rule Effluent Limitations Guidelines and Standards ("ELG"), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCR and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal-burning power plants that cannot comply with the new standards. These regulations add costs to the operation of coal-burning power plants on top of other regulations like the 2014 regulations issued under Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. Individually and collectively, these regulations could, in turn, impact the market for our products. In April 2017, EPA granted petitions for reconsideration and an administrative stay of all future compliance deadlines for the ELG rule. In August 2017, EPA granted petitions for reconsideration of the CCR rule.

Endangered Species Act

The federal Endangered Species Act ("ESA") and counterpart state legislation protect species threatened with possible extinction. The U.S. Fish and Wildlife Service (the "USFWS") works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from mining-related impacts. If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered, we could be subject to additional regulatory and permitting requirements.

Other Environmental, Health and Safety Regulations

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above ground storage tanks in which we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our properties are subject to federal, state, and local regulation. In addition, our use of explosives is subject to the Federal Safe Explosives Act. We are also required to comply with the Federal Safe Drinking Water Act, the Toxic Substance Control Act, and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these regulations should not have a material adverse effect on our business, financial condition or results of operations.

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 electricity. The supplier base providing mining materials has been relatively consistent in recent years. Purchases of certain underground mining equipment are concentrated with one principle supplier; however, supplier competition continues to develop.

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 re-opened 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). 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 major coal production basins in the U.S. include Central Appalachia (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB) and the Western Bituminous region (WB). CAPP includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. NAPP includes Maryland, Ohio, Pennsylvania and northern West Virginia. The ILB includes Illinois, Indiana and western Kentucky. The PRB is located in northeastern Wyoming and southeastern Montana. The WB 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. The primary underground mining techniques are longwall mining and continuous (room-and-pillar) mining. The geological conditions dictate which technique to use. Our mines use 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.

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. We compete against large producers such as Peabody Energy Corporation (NYSE: BTU) and Alliance (Nasdaq: ARLP) and small producers.

Employees

We have 742 employees, of which 736 are Sunrise Coal employees.

Other

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

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

ITEM 1A. RISK FACTORS.

Risks Related to our Business

Global economic conditions or economic conditions in any of the industries in which our customers operate as well as sustained uncertainty in financial markets may have material adverse impacts on our business and financial condition that we currently cannot predict.

Weakness in global economic conditions or economic conditions in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the U.S. may decline if economic conditions deteriorate, which may negatively impact the revenue, margins, and profitability of our business;
- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including the development of our coal reserves.

A substantial or extended decline in coal prices could negatively impact our results of operations.

Our results of operations are primarily dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. The prices we receive for our production depends upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions and patterns;
- the proximity to and capacity of transportation facilities;
- competition from other coal suppliers;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption, including the impact of technological advances on energy consumption; and
- prevailing economic conditions.

Any adverse change in these factors could result in weaker demand and lower prices for our products. A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenue to the extent we are not protected by the terms of existing coal supply agreements.

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

We compete with other coal producers for domestic coal sales. The most important factors on which we compete are delivered price (*i.e.*, the cost of coal delivered to the customer, including transportation costs, which are generally paid by our customers either directly or indirectly), coal quality characteristics, contract flexibility (*e.g.*, volume optionality and multiple supply sources) and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract customers and could adversely impact our revenue and cash from operations. In addition, declining prices from an oversupply of coal in the market could reduce our revenue and cash from operations.

Changes in consumption patterns by utilities regarding the use of coal have affected our ability to sell the coal we produce. Since 2000, coal's share of U.S. electricity production has fallen from 53% to 30%, while natural gas' share has increased from 16% to 32%.

The domestic electric utility industry accounts for over 93% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the U.S. to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain.

Future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. In addition, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. For example, the EPA’s CPP will likely incentivize additional electric generation from natural gas and renewable sources, and Congress has extended tax credits for renewables. In addition, a number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources in generating a certain percentage of power. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash from operations.

Extensive environmental laws and regulations affect coal consumers and have corresponding effects on the demand for coal as a fuel source.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. These laws and regulations may affect demand and prices for coal. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by the EPA in the last five years, such as CSAPR and MATS, have led to the premature retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the U.S.

Increased regulation of GHG emissions could result in increased operating costs and reduced demand for coal as a fuel source, which could reduce demand for our products, decrease our revenue and reduce our profitability.

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, the EPA published the Endangerment Finding asserting that emissions of carbon dioxide and other GHGs present an endangerment to public health and the environment, and the EPA has begun to regulate GHG emissions pursuant to the CAA. The EPA has finalized an NSPS to regulate GHG emissions from new power plants. The finalized standard requires CCS, a technology that is not yet commercially feasible without government subsidies and that has not been demonstrated in the marketplace. This requirement effectively prevents the construction of new coal-fired power plants. The EPA published notice in the federal register in April 2017 that the agency has initiated a review of the NSPS for new and modified fossil fuel-fired power plants and that, following the review, the EPA will initiate reconsideration proceedings to suspend, revise or rescind this NSPS. In August 2015, the EPA issued its final CPP rules that establish carbon pollution standards for existing power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the Circuit Court even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court's stay applies only to EPA's regulations for CO_2 emissions from existing power plants and will not affect EPA's standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with this proposed repeal, the EPA issued an ANPRM in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules were upheld at the conclusion of this appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted. Please read “Item 1. Business—Regulation and Laws—*Air Emissions*” and “—*Carbon Dioxide Emissions*.”

Numerous political and regulatory authorities and governmental bodies, as well as environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by lending institutions and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants.

Federal, state and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. The CPP is one of a number of recent developments aimed at limiting GHG emissions which could limit the market for some of our products by encouraging electric generation from sources that do not generate the same amount of GHG emissions. Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., states, or other countries, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. For example, the agreement resulting from the 2015 United Nations Framework Convention on Climate Change contains voluntary commitments by numerous countries to reduce their GHG emissions and could result in additional firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium to long-term.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, several major banks enacted such policies. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. Collectively, these actions and campaigns could adversely impact our future financial results, liquidity and growth prospects.

Government regulations have resulted and could continue to result in significant retirements of coal-fired electric generating units. Retirements of coal-fired electric generating units decrease the overall capacity to burn coal and negatively impact coal demand.

Since 2010, utilities have formally announced the retirement or conversion of over 600 coal-fired electric generating units through 2030. These retirements and conversions amount to over 111,000 megawatts ("MW") or approximately 35% of the 2010 total coal electric generating capacity. At the end of 2017 retirement and conversions affecting 69,000 MW, or approximately 22% of the 2010 total coal electric generating capacity, is estimated to have occurred. Most of these announced and completed retirements and conversions have been attributed to the EPA regulations, although other factors such as an aging coal fleet and low natural gas prices have also played a role. The reduction in coal electric capacity negatively impacts overall coal demand. Additional regulations and other factors could lead to additional retirements and conversions and, thereby, additional reductions in the demand for coal.

***Plaintiffs in federal court litigation have attempted to pursue tort claims based on the alleged effects of climate change*.**

In 2004, eight states and New York City sued five electric utility companies in *Connecticut v. American Electric Power Co.* Invoking the federal and state common law of public nuisance; plaintiffs sought an injunction requiring defendants to abate their contribution to the nuisance of climate change by capping carbon dioxide emissions and then reducing them. In June 2011, the U.S. Supreme Court issued a unanimous decision holding that the plaintiffs' federal common law claims were displaced by federal legislation and regulations. The U.S. Supreme Court did not address the plaintiffs' state law tort claims and remanded the issue of preemption for the district court to consider. While the U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, tort-type liabilities remain a possibility and a source of concern. The proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations.

The stability and profitability of our operations could be adversely affected if our customers do not honor existing contracts or do not extend existing or enter into new long-term contracts for coal.

In 2017, approximately 50% of our sales were under contracts having a term greater than one year, which we refer to as long-term contracts. Long-term sales contracts have historically provided a relatively secure market for the amount of production committed under the terms of the contracts. From time to time industry conditions may make it more difficult for us to enter into long-term contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

Some of our long-term coal sales contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term contracts contain provisions that allow for the purchase price to be renegotiated at periodic intervals. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term contracts may provide only limited protection during adverse market conditions. In some circumstances, failure of the parties to agree on a price under a reopener provision can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer's reasonable control. Such events may include labor disputes, mechanical malfunctions and changes in government regulations, including changes in environmental regulations rendering use of our coal inconsistent with the customer's environmental compliance strategies. Additionally, most of our long-term contracts contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. In the event of early termination of any of our long-term contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition and results of operations could be adversely affected.

We depend on a few customers for a significant portion of our revenue, and the loss of one or more significant customers could affect our ability to maintain the sales volume and price of the coal we produce.

During 2017, we derived 92% of our revenue from five customers and at least 10% of our revenue from each of them. If we were to lose any of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

Litigation resulting from disputes with our customers may result in substantial costs, liabilities, and loss of revenue.

From time to time we have disputes with our customers over the provisions of long-term coal supply contracts relating to, among other things, coal pricing, quality, quantity and the existence of specified conditions beyond our or our customers' control that suspend performance obligations under the particular contract. Disputes may occur in the future, and we may not be able to resolve those disputes in a satisfactory manner, which could have a material adverse effect on our business, financial condition and results of operations.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenue will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

Our profitability may decline due to unanticipated mine operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

Our mining operations are influenced by changing conditions or events that can affect production levels and costs at particular mines for varying lengths of time and, as a result, can diminish our profitability. These conditions and events include, among others:

- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other natural events affecting operations, transportation or customers;
- accidental mine water discharges and other geological conditions;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;

- fires;
- employee injuries or fatalities;
- labor-related interruptions;
- increased reclamation costs;
- inability to acquire, maintain or renew mining rights or permits in a timely manner, if at all;
- fluctuations in transportation costs and the availability or reliability of transportation; and
- unexpected operational interruptions due to other factors.

These conditions have the potential to significantly impact our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenue and profitability, which could materially adversely impact our quarterly or annual results.

Although none of our employees are members of unions, our workforce may not remain union-free in the future.

None of our employees are represented under collective bargaining agreements. However, all of our workforce may not remain union-free in the future, and legislative, regulatory or other governmental action could make it more difficult to remain union-free. If some or all of our currently union-free operations were to become unionized, it could adversely affect our productivity and increase the risk of work stoppages at our mining complexes. In addition, even if we remain union-free, our operations may still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

Our mining operations are subject to extensive and costly laws and regulations, and such current and future laws and regulations could increase current operating costs or limit our ability to produce coal.

We are subject to numerous federal, state and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge or release of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability, either through direct impacts on our mining operations, or indirect impacts that discourage or limit our customers' use of coal. Please read "Item 1. Business—Regulations and Laws."

State and federal laws addressing mine safety practices impose stringent reporting requirements and civil and criminal penalties for violations. Federal and state regulatory agencies continue to interpret and implement these laws and propose new regulations and standards. Implementing and complying with these laws and regulations has increased and will continue to increase our operational expense and to have an adverse effect on our results of operation and financial position. For more information, please read "Item 1. Business—Regulation and Laws—*Mine Health and Safety Laws*."

We may be unable to obtain and renew permits necessary for our operations, which could reduce our production, cash flow and profitability.

Mining companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required to conduct our operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow, and profitability. Please read "Item 1. Business—Regulations and Laws—*Mining Permits and Approvals*."

The EPA has begun reviewing permits required for the discharge of overburden from mining operations under Section 404 of the CWA. Various initiatives by the EPA regarding these permits have increased the time required to obtain and the costs of complying with such permits. In addition, the EPA previously exercised its “veto” power to withdraw or restrict the use of previously issued permits in connection with one of the largest surface mining operations in Appalachia. The EPA’s action was ultimately upheld by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read “Item 1. Business—Regulations and Laws—*Water Discharge*.”

In addition, some of our permits could be subject to challenges from the public, which could result in additional costs or delays in the permitting process, or even an inability to obtain permits, permit modifications or permit renewals necessary for our operations.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenue by causing us to reduce our production or by impairing our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer’s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenue. If there are disruptions of the transportation services provided by our primary rail carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern U.S. inherently more expensive on a per-mile basis than coal shipments originating in the western U.S. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower rail rates from the western coal producing areas to markets served by eastern U.S. coal producers have created major competitive challenges for eastern coal producers. In the event of further reductions in transportation costs from western coal producing areas, the increased competition with certain eastern coal markets could have a material adverse effect on our business, financial condition and results of operations.

It is possible that states in which our coal is transported by truck may modify or increase enforcement of their laws regarding weight limits or coal trucks on public roads. Such legislation and enforcement efforts could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or to maintain production and could adversely affect revenue.

We may not be able to successfully grow through future acquisitions.

We have expanded our operations by adding and developing mines and coal reserves in existing, adjacent and neighboring properties. We continually seek to expand our operations and coal reserves. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are unknown. Moreover, any acquisition could be dilutive to earnings. Our ability to make acquisitions in the future could require significant amounts of financing that may not be available to us under acceptable terms and may be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

Expansions and acquisitions involve a number of risks, any of which could cause us not to realize the anticipated benefits.

If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline, and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition transactions involve various inherent risks, including:

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- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, expansion and acquisition opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition;
- problems that could arise from the integration of the new operations; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or acquisition opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion or acquisition. Any expansion or acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future expansions or acquisitions could result in us assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous expansions and/or acquisitions.

Completion of growth projects and future expansion could require significant amounts of financing that may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flows from operations, borrowings under credit facilities and cash provided from the issuance of debt or equity. Weakness in the energy sector in general and coal, in particular, has significantly impacted access to the debt and equity capital markets. Accordingly, our funding plans may be negatively impacted by this constrained environment as well as numerous other factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current credit facilities when they expire or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth and future expansions as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

The estimates of our coal reserves may prove inaccurate and could result in decreased profitability.

The estimates of our coal reserves may vary substantially from actual amounts of coal we are able to recover economically. All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation and taxes by governmental agencies;
- future improvements in mining technology; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on the risk of recovery 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 substantially. Actual production, revenue, and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Any inaccuracy in the estimates of our reserves could result in higher than expected costs and decreased profitability.

Mining in certain areas in which we operate is more difficult and involves more regulatory constraints than mining in other areas of the U.S., which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those characteristics of the depleting mines. In addition, permitting, licensing and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and our customers' ability to use coal produced by, our mines.

Unexpected increases in raw material costs could significantly impair our operating profitability.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products, and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts required by the room-and-pillar method of mining. Steel prices and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. There may be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products or other raw materials will impact our operational expenses and could result in significant fluctuations in our profitability. In March, 2018, President Trump announced that his administration would be assessing tariffs on steel imports which could increase our costs significantly.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our financing arrangements.

Terrorist attacks or cyber-incidents could result in information theft, data corruption, operational disruption and/or financial loss.

Like most companies, we have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our business partners, analyze mine and mining information, estimate quantities of coal reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the U.S. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties, or cloud-based applications could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations and cash flows. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Certain federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.

In past years, members of Congress have indicated a desire to eliminate certain key U.S. federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. No legislation with that effect has been proposed, but the elimination of those provisions would negatively impact our financial statements or results of operations.

Risks Related to Our Indebtedness and Liquidity

If we are unable to comply with the covenants contained in our credit agreement, the lenders could declare all amounts outstanding to be due and payable and foreclose on their collateral, which could materially adversely affect our financial condition and operations.

As disclosed in Note 3 to our financial statements, there are two key ratio covenants stated in our credit agreement: (i) a minimum debt service coverage ratio of 1.25 to 1 and (ii) a current maximum leverage ratio (Sunrise funded debt/adjusted EBITDA) not to exceed 4.25 to 1, which also decreases in future periods further reducing the maximum leverage permitted. On December 31, 2017, our debt service coverage ratio was 1.90, and our leverage ratio was 2.40. Therefore, we were in compliance with these two ratios.

Our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

On December 31, 2017, our debt was $202 million. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;
- limit our ability to pursue acquisitions and other business opportunities; and
- make our results of operations more susceptible to adverse economic or operating conditions.

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Risk Related to Possible Future Impairment Charge

Carlisle Mine

In December 2016, the deterioration of the North End of the Carlisle Mine, coupled with lower coal prices led us to determine that the northern end of the Carlisle Mine no longer could be safely and profitably mined. The sealing of the North End was completed in March 2017. In connection therewith, we identified specific assets totaling $16.6 million ($15.1 million of property and equipment and $1.5 million of advanced royalties) that were written off in 2016.

The Carlisle Mine assets had an aggregate net carrying value of $110 million at December 31, 2017. With the Carlisle Mine remaining in hot idle status, we conducted a review of the Carlisle Mine assets as of December 31, 2017, based on estimated future net cash flows, and determined that no further impairment was necessary; however, if future expectations and assumptions change we may incur possible impairment in future periods.

Bulldog Reserves

In October 2017, we entered into an agreement to sell land associated with the Bulldog Mine for $4.9 million. As part of the transaction, we will hold the rights to repurchase the property for 8 years. Because of the likelihood of exercising the repurchase option, we are accounting for the sale as a financing transaction. The Bulldog Mine assets had an aggregate net carrying value of $15 million at December 31, 2017. Also in October 2017, the Illinois Department of Natural Resources (ILDNR) notified us that our mine application, along with modifications, was acceptable. The permit will be issued upon submittal of a fee and bond which are required within 12 months of the notification. We have determined that no impairment is necessary. If estimates inherent in the assessment change, it may result in future impairment of the assets.

ITEM 1B. UNRESOLVED STAFF COMMENTS. None.

ITEM 2. PROPERTIES.

See Item 7 MDA for a discussion of our mines.

Coal Reserve Estimates

“Reserves” are defined by the SEC Industry 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.

Our reserve estimates are prepared by Scott McGuire, one of our mining engineers. Mr. McGuire is a licensed Professional Engineer in the State of Indiana and Kentucky and has sixteen years’ experience estimating coal reserves.

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. Only tons greater than 4’ in thickness are included in our underground reserves. All reserves are stated as a final salable product.

Prior to acquiring coal mineral leases, title abstractors conduct a preliminary title search on the property. This information provides a strong indication of the coal owner, with whom we will enter into a lease. The next step is to execute a lease with the owner, giving us the rights to explore and mine the property. Prior to mining, attorneys review the chain of mineral ownership to verify the lessor is the mineral owner. Prior to purchasing coal properties, we follow a similar process

ITEM 3. LEGAL PROCEEDINGS. None

ITEM 4. MINE SAFETY DISCLOSURES:

Safety is a core value for us. As such we have dedicated a great deal of time, energy, and resources to creating a culture of safety. Thus, we are very proud of the mine rescue team at Sunrise Coal whose current list of achievements includes reigning National Champions of the Nationwide Mine Rescue Skills Championship and Governor's Award recipient (1st place) at the 2017 Indiana Mine Rescue Association Contest.

See Exhibit 95 to this Form 10-K for a listing of our mine safety violations.

PART II

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

Stock Price Information

Our common stock is traded on the NASDAQ Capital Market under the symbol HNRG, and 46% is held by our officers, directors and their affiliates. The following table sets forth the dividends paid and the high and low closing sales price for the periods indicated:

	Dividends Paid	High	Low
2018			
January 1 through March 9	$ 0.04	$7.31	$5.96
2017			
Fourth quarter	.04	6.56	4.87
Third quarter	.04	8.34	5.40
Second quarter	.04	8.32	6.30
First quarter	.04	9.79	7.48
2016			
Fourth quarter	.04	10.02	7.24
Third quarter	.04	8.26	4.50
Second quarter	.04	5.10	4.03
First quarter	.04	5.68	4.05

At March 8, 2018, we had 205 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 5,000 street name holders.

Equity Compensation Plan Information

See Note 5 to our consolidated financial statements.

Stock Performance

The following performance compares Hallador Energy (Nasdaq: HNRG), the Russell 2000 Index, the SNL Coal Index, Alliance Resource Partners LP (NYSE: ARLP), Cloud Peak Energy (NYSE: CLD), and Foresight Energy (NYSE: FELP).

The graph assumes that you invested $100 in our common stock and in each company and index at the closing price on December 31, 2012, that all dividends were reinvested, and that you continued to hold your investment through December 31, 2017.

	Period Ended					
Company / Index	12/31/12	12/31/13	12/31/14	12/31/15	12/31/16	12/31/17
Hallador Energy Company	100.00	99.14	137.64	58.09	119.20	81.70
Russell 2000 Index	100.00	138.82	145.62	139.19	168.85	193.58
Alliance Resource Partners LP	100.00	141.46	167.02	57.64	107.98	103.62
SNL Coal Index	100.00	98.12	72.68	18.19	37.61	37.92
Foresight Energy LP		100.00	90.66	21.51	39.43	27.41
Cloud Peak Energy Inc.	100.00	93.12	47.49	10.76	29.02	23.02

Source: S&P Global Market Intelligence

ITEM 6. SELECTED FINANCIAL DATA.

For the years ended December 31,

(in thousands, except per share data)

	2017	2016	2015	2014	2013
Revenue:					
Coal sales	$268,202	$278,924	$339,490	$233,902	$137,436
Equity (loss) income – Savoy	460	(1,187)	(1,532)	5,272	5,827
Equity (loss) income - Sunrise Energy	(95)	(249)	(74)	248	629
Liability extinguishment					4,300
Other	3,066	3,962	2,236	1,749	5,678
	271,633	281,450	340,120	241,171	153,870
Net income before impairment and income taxes*	13,882	25,044	27,570	10,701	29,598
Asset impairment	-	16,560	-	-	-
Income tax expense (benefit)	(19,194)	(4,026)	7,438	482	7,175
Net income	$33,076	$12,510	$20,132	$10,219	$22,423
Net income per share :					
Basic and diluted	$1.08	$0.42	$0.68	$0.34	$0.78
Cash dividends per share	$0.16	$0.16	$0.16	$0.16	$0.12
Balance Sheet Information (end of period):					
Total assets	$518,193	$531,323	$540,378	$579,585	$259,199
Total bank debt*	201,992	238,617	249,470	306,345	16,000

* Non-GAAP measurement. See Note 2, Note 3, and Note 4 to the consolidated financial statements.

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

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

<u>Overview</u>

The largest portion of our business is devoted to coal mining in the State of Indiana through Sunrise Coal, LLC (a wholly owned subsidiary) serving the electric power generation industry. We own a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana. We also own a 30.6% equity interest in Savoy Energy, L.P., a private oil and gas exploration company with operations in Michigan. We account for our interest in Savoy and Sunrise Energy using the equity method. We have reached an agreement for Savoy to redeem our entire partnership interest for $8 million, which we expect to finalize in mid-March 2018. Our net after commissions paid will be $7.5 million.

We operate two underground mines and one surface mine in southwestern Indiana. The underground mines, Oaktown 1 and Oaktown 2 are in Oaktown, Indiana, 43 miles south of Terre Haute, Indiana. The Ace in the Hole surface mine is in Clay City, Indiana, 30 miles southeast of Terre Haute, Indiana. We also own the Carlisle Mine located near Carlisle, Indiana, 36 miles south of Terre Haute. The Carlisle reserve is contiguous to Oaktown 2. The Carlisle Mine is developed, but currently idle.

Oaktown 1, Oaktown 2 and Carlisle are one large underground mining complex representing 121 million tons of controlled reserves, with three slopes, one elevator, two wash plants, and two rail facilities, located on the CSX railroad. We anticipate total capacity for the three mines to be roughly 10.5 million tons annually. Additionally, the capacity of our Ace in the Hole mine is .4 million tons annually. Thus, our total mining capacity is 10.9 million tons annually. The addition of our Princeton Rail Loop, expected to come online in the spring of 2018, will also provide us new access to coal markets served by the Norfolk Southern Railway Company.

For 2017, over 67% of our coal sales were to customers with large scrubbed coal-fired power plants in the State of Indiana. Our mines and coal reserves are strategically located in close proximity to our primary customers, which reduces transportation costs and thus provides us with a competitive advantage with respect to those customers; our closest customer’s plant is 13 miles away, and the farthest Indiana customer is 80 miles away. We have access to our primary customers directly through either the CSX railroad (NYSE: CSX) or the Indiana Rail Road which is majority owned by the CSX. Beginning in Q2 2018, our new Princeton Loop will be operational and allow us to access the NS Railroad (NYSE: NS), increasing our coal markets.

The majority of our coal is sold to investment grade customers who have scrubbed power plants; thus, we expect to be supplying these plants for many years.

President Trump Promotes Coal

Below is a timeline of some of the milestones accomplished for the coal industry thus far under the Trump administration:

November 8, 2016

Donald Trump was elected President of the United States of America. His administration has dramatically improved the regulatory environment in which we operate.

January 20, 2017

Donald Trump was inaugurated as the 45th President of the United States.

February 15, 2017

Both the U.S. House of Representatives and the Senate passed resolutions disapproving the Stream Protection Rule (SPR) under the Congressional Review Act (CRA). President Trump signed the resolution on February 16, 2017, and, pursuant to the CRA, the SPR "shall have no force or effect" and the Office of Surface Mining (OSM) cannot promulgate a substantially similar rule absent future legislation.

Currently, the Federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) is implemented by each State's respective State agency, which is the Department of Reclamation in Indiana. The SPR would have mandated additional approvals from Federal Agencies, such as U.S. Fish and Wildlife. The rule would have also imposed additional baseline data collection, surface/groundwater monitoring, financial assurance requirements and numerous other requirements.

February 17, 2017

Scott Pruitt was confirmed as Administrator of the Environmental Protection Agency (EPA). As former Attorney General of the state of Oklahoma, he joined a coalition of state attorney generals in suing the EPA concerning the Clean Power Plan, the principal Obama-era policy aimed at reducing U.S. greenhouse gas emissions from the electricity sector.

February 28, 2017

President Trump signed an Executive Order regarding the "waters of the US" (WOTUS) rule. The order requires the EPA and the Army Corps of Engineers to review the WOTUS rule and publish a proposed rule that rescinds or revises the rule as appropriate and consistent with law, keeps the Nation's navigable waters free from pollution, promotes economic growth, minimizes regulatory uncertainty, and shows due regard for the roles of the Congress and the States under the Constitution.

In President Trump's first full official speech to a joint session of Congress, he stated: "We're going to stop the regulations that threaten the future and livelihood of our great coal miners."

March 28, 2017

President Trump signed an Executive Order to dismantle many of the climate change policies enacted during the Obama era. The order takes steps to downplay the future costs of carbon emissions, walks back tracking of the federal government's carbon emissions, rescinds a 2016 moratorium on coal leases on federal lands. It also begins the process of rescinding the EPA's Clean Power Plan to reduce carbon dioxide emissions from new and existing power plants.

April 13, 2017

The EPA said it would review and reconsider the effluent limitations guidelines (ELG) rule which targets coal combustion generators' ash transport wastewater, and wastewater discharges from flue-gas desulfurization and mercury control systems and would require power plants to install new treatment technologies. The rule has been challenged in court by a coalition of utilities. The EPA has issued an administrative stay to delay the compliance deadlines for the ELG rule as long as litigation is ongoing.

June 1, 2017

President Trump announced that the U.S. would pull out of the Paris Agreement steering away from a group of 194 other countries that have promised to curb planet-warming greenhouse gas emissions.

October 10, 2017

EPA Administrator Scott Pruitt announced that the EPA would seek to repeal the Clean Power Plan in its entirety.

January 25, 2018

The Trump administration eliminated a policy dictating how certain major sources of hazardous air pollutants are regulated. The repeal of the agency's "once in, always in" policy. Under the new interpretation of the policy, "major sources" can be reclassed as "area sources," which are subject to different standards when their emissions reach an enforceable limit.

These actions are encouraging and will be important to us and the U.S. energy sector.

Our Coal Contracts

We sell coal to the following customers: Duke Energy Corporation (NYSE: DUK), Hoosier Energy, an electric cooperative, Indianapolis Power & Light Company (IPL), a wholly-owned subsidiary of The AES Corporation (NYSE: AES), Vectren Corporation (NYSE: VVC), and Orlando Utility Commission (OUC). In 2018, we have signed new sales contracts with two plants we have never shipped to before. One of the new customers is certainly due to the addition of our Princeton Rail Loop on the Norfolk Southern Railroad. The other is to a plant located in the Carolinas. We attribute the latter to the trend of ILB coals replacing coals from higher cost eastern basins.

The table below reflects our projected tons. Some of our contracts contain language that allow our customers to increase or decrease tonnages throughout the year. In some cases, our customers are required to purchase their additional tonnage needs from us. We have 17.7 million tons committed for the next 5 years (2018 to 2022), which represents 51% of our current projected sales.

Year	Targeted tons (millions)	Committed tons (millions)	% Committed	Estimated price per ton
2018	6.8	6.4	94 %	$ 40.00
2019	7.0	4.5	64 %	$ 41.00

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. 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.

Asset Impairment Review

See Note 2 to our consolidated financial statements.

Reserve Table - Controlled Tons (in millions):

	Tons Sold	2017 Year-End Reserves Annual Capacity	Proven	Probable	Total	Sulphur #	BTU
Oaktown 1 (assigned)	3.771	4.0	41.5	9.6	51.1	5.9	11,600
Oaktown 2 (assigned)	2.552	4.0	30.7	12.2	42.9	5.7	11,600
Carlisle (assigned)	-	2.5	21.8	5.5	27.3	4.4	11,500
Ace in the Hole (assigned)	0.240	0.4	0.9	-	0.9	2.0	10,900
Bulldog (unassigned)	-	-	19.6	16.2	35.8	4.5	11,300
Total	6.563	10.9	114.5	43.5	158.0		
Assigned					122.2		
Unassigned					35.8		
Total					158.0		

Our assigned underground coal reserves are high sulfur (4.0# – 6.5#) with an average BTU content in the 11,500 -11,600 range. Our reserves have lower chlorine (<0.12%) than average ILB reserves of 0.22%. Much of the ILB's new production is located in Illinois and possesses chlorine content in excess of .30%. The relatively low chlorine content of our reserves is attractive to buyers given their desire to limit the corrosive effects of chlorine in their power plants. As discussed below, the Ace surface mine is low sulfur (2.0#) with an average BTU content of 10,900. We have no metallurgical coal reserves, only steam (thermal) coal reserves. Below is a discussion of our current projects. Only tons greater than 4 feet in thickness are included in our underground reserves.

Oaktown 1 Mine (underground) – Assigned

We have 51.1 million controlled, salable tons of the Indiana #V coal seam. We began 2017 with 56.9 million tons controlled. Besides production, the remainder of the decrease relates to tons that were deemed unrecoverable due to geologic conditions combined with increases for new drilling and new leases. Oaktown 1 reserves are located in Knox County, IN.

Access to the Oaktown 1 Mine is via a 90-foot-deep box cut and a 2,200-foot slope, reaching coal in excess of 375 feet below the surface. In 2017, we added an elevator 7 miles from the slope allowing miners to enter closer to the active face, thereby reducing unproductive daily travel time.

Oaktown 2 Mine (underground) – Assigned

We have 42.9 million controlled, saleable tons of the Indiana #V coal seam. We began 2017 with 53.5 million controlled tons. Besides production, the remainder of the decrease relates to tons that were deemed unrecoverable due to geologic and economic conditions based on new drilling. Oaktown 2 reserves are located in both Knox County, Indiana and Lawrence County, Illinois.

Access to the Oaktown 2 Mine is via an 80-foot-deep box cut and a 2,600-foot slope, reaching coal in excess of 400 feet below the surface.

Our underground mines are room and pillar mines that utilize developed entries for ventilation and transportation. Continuous miners extract coal from rooms by removing coal from the seam, leaving pillars to support the roof. Coal haulers are used to transport coal to a conveyor belt for transport to the surface. The two Oaktown mines are separated by a sandstone channel. The coal seam thickness ranges from 4 feet to over 9 feet. The Oaktown mines share the same wash plant which is rated at 1,800 tons per hour. The two mines are connected to a rail loadout that can store two 120 car trains at once and is serviced by the CSX Railroad and Indiana Railroad. Coal is also transported via truck to customers.

Carlisle Mine (underground) – Assigned

We have 27.3 million controlled, saleable tons at our Carlisle Mine. The mine is located near the town of Carlisle, Indiana in Sullivan County and became operational in January 2007. The coal is accessed with a slope to a depth of 340'. The coal is mined in the Indiana #V coal seam which is highly volatile bituminous coal and has been extensively mined by underground and surface methods in the general area. The coal thickness in the project area is 4' to 7'. The Carlisle Mine is completely developed but was idle for the entirety of 2017.

Ace in the Hole Mine (Ace) (surface) – Assigned

The Ace mine is near Clay City, Indiana in Clay County and 42 road miles northeast of the Carlisle Mine. We control .9 million tons of proven coal reserves of which we own ..5 million tons in fee. The two primary seams are low sulfur coal (~2# SO_2), which make up .8 million of the .9 million tons controlled. Mine development began in late December 2012, and we began shipping coal in late August 2013. We truck low sulfur coal from Ace to Oaktown to blend with high sulfur coal. Many utilities in the southeastern U.S. have scrubbers with lower sulfur limits (4.5# SO_2)

which cannot accept the higher sulfur contents of the ILB (4.5# - 6.5# SO_2). Blending high sulfur coal to a lower sulfur specification enables us to market our high sulfur coals to more customers. We expect the maximum capacity of Ace to be 0.4 tons annually.

The Ace mine is a multi-seam open pit strip mine. The majority of the seams are sold raw, but some of the seams will be washed prior to sales depending on quality. To convert the tons sold raw, the in-place tonnage is multiplied by a pit recovery of 94% based on seam thickness. To convert the tons sold washed, the in-place tonnage is multiplied by a pit recovery based on seam thickness then reduced by the projected wash plant recovery of 72%.

Bulldog Reserves (underground) – Unassigned

We have leased roughly 19,300 acres in Vermilion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 35.8 million tons of coal. A considerable amount of our leased acres has yet to receive any exploratory drilling.

In October 2017, we entered into an agreement to sell land associated with the Bulldog Mine for $4.9 million. As part of the transaction, we will hold the rights to repurchase the property for eight years. Also in October 2017, the Illinois Department of Natural Resources (ILDNR) notified us that our mine application, along with modifications, was acceptable. The permit will be issued upon submittal of a fee and bond which is required to be submitted within 12 months of the notification.

Full-scale mine development will not commence until we have a sales commitment. We estimate the costs to develop this mine to be $150 million at full capacity of 3.0 million tons annually.

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.

Below is a map that shows the locations of our mines.

Railroad Legend:

CSX – CSX Railroad

INRD – Indiana Rail Road

ISRR – Indiana Southern Railroad

NS – Norfolk Southern Railway

Mine and Wash Plant Recovery and Capacity

	Mine recovery	Wash plant recovery*	Wash Plant Capacity (Clean Tons)
Oaktown 1	49 %	81 %	8.0 million**
Oaktown 2	49 %	81 %	
Carlisle	53 %	81 %	2.5 million
Bulldog	45 %	77 %	

* Does not include out-of-seam material extracted during the mining process.

** Oaktown 1 and Oaktown 2 share the wash plant.

Liquidity and Capital Resources

Contractual Obligations (in thousands)	Total	2018	2019-2021	2022-2024	2025 and thereafter
Long-term debt (matures August, 2019)	$ 201,992	$ 35,000	$ 166,992	$ -	$ -
Future interest obligations	15,700	10,100	5,600	-	-
Reclamation obligations	13,806	300	5,315	3,011	$ 5,180

$231,498	$45,400	$177,907	$ 3,011	$ 5,180

As set forth in our Statement of Cash Flows, cash provided by operations was $62 million for 2017. This amount was adequate to fund our maintenance capital expenditures for coal properties of $11.1 million, our debt service requirements of $36.6 million, and our dividend of $4.9 million. Our capex budget for 2018 is $31 million, of which $16 million is for maintenance capex. Cash from operations for 2018 should again fund our maintenance capital expenditures, debt service, and our dividend.

See Note 3 to our consolidated financial statements for discussion about our bank debt.

Other than our surety bonds for reclamation, we have no material off-balance sheet arrangements. Included in the contractual obligations table are reclamation obligations of $13.8 million, which are presented as asset retirement obligations (ARO) in our accompanying balance sheets. In the event we are not able to perform reclamation, we have surety bonds totaling $25 million to cover ARO.

Capital Expenditures (capex)

For 2017, our capex was $28.6 million allocated as follows (in millions):

Oaktown – investment	$10.1
Oaktown – maintenance capex	11.1
Princeton Rail Loop	6.3
Other projects	1.1
Capex per the Consolidated Statement of Cash Flows	$28.6

Results of Operations

The following table presenting our quarterly results of operations should be read in conjunction with the consolidated financial statements and related notes included in Item 8 of their Annual Report on Form 10-K. We have prepared the unaudited information on the same basis as our audited consolidated financial statements. Our operating results for any quarter are not necessarily indicative of results for any future quarters or for a full year.

The following table presents our unaudited quarterly results of operations for the eight quarters ended December 31, 2017. This table includes all adjustments, consisting only of normal recurring adjustments, that we consider necessary for fair presentation of our consolidated operating results for the quarters presented.

	Dec-31 2017	Sep-30 2017	Jun-30 2017	Mar-31 2017	Dec-31 2016	Sep-30 2016	Jun-30 2016	Mar-31 2016
Revenue:								
Coal sales	$68,922	$73,896	$62,829	$62,555	$71,495	$65,360	$66,274	$75,795
Equity income (loss) in equity method investments	(62)	169	27	231	(1,130)	(80)	174	(400)
Other	440	403	1,456	767	869	487	2,116	490
Total revenue	$69,300	$74,468	$64,312	$63,553	$71,234	$65,767	$68,564	$75,885
Costs and expenses:								
Operating costs and expenses	52,025	54,354	44,079	39,692	50,663	46,940	45,397	49,777
DD&A	9,962	9,729	9,101	9,703	9,385	7,942	9,056	9,182
ARO accretion	221	219	214	207	265	260	255	249
Coal exploration costs	288	152	275	139	505	354	395	419
SG&A	2,883	2,859	6,578	2,658	2,444	2,585	2,729	2,762
Interest	2,751	3,229	3,342	3,091	2,148	2,601	4,497	5,596
Asset impairment	-	-	-	-	16,560	-	-	-
Total cost and expenses	68,130	70,542	63,589	55,490	81,970	60,682	62,329	67,985
Income (loss) before income taxes	1,170	3,926	723	8,063	(10,736)	5,085	6,235	7,900
Less income taxes:								
Current	(1,590)	(2,532)	1,357	17	103	(270)	(768)	768
Deferred	(18,597)	2,542	(1,023)	632	(7,012)	1,033	1,150	970
Total income taxes	(20,187)	10	334	649	(6,909)	763	382	1,738
Net income (loss)	21,357	3,916	389	7,414	(3,827)	4,322	5,853	6,162
Net income (loss) per share:								
Basic and diluted	$0.69	$0.13	$0.01	$0.25	$(0.13)	$0.14	$0.19	$0.21

Weighted average shares outstanding:								
Basic and diluted	29,830	29,774	29,503	29,413	29,287	29,252	29,251	29,251

Oaktown’s operating costs were $27.59/ton and $30.44/ton for the year and quarter ended December 31, 2017, respectively. We expect Oaktown’s costs to range from $28 to $30 for 2018. For 2018, we expect our SG&A to be $11 million annually and costs associated with the Prosperity and Carlisle mines to be $6 million annually (reflected in operating costs and expenses).

36

Quarterly coal sales and cost data follow (in 000's, except for per ton data and wash plant recovery percentage):

	1st 2017	2nd 2017	3rd 2017	4th 2017	T4Qs
Tons produced	1,917	1,647	1,487	1,561	6,612
Tons sold	1,555	1,548	1,786	1,685	6,574
Coal sales	$62,555	$62,829	$73,896	$68,922	$268,202
Average price/ton	$40.23	$40.59	$41.38	$40.90	$40.80
Wash plant recovery in %	71 %	69 %	70 %	68 %	
Operating costs	$39,692	$44,079	$54,354	$52,025	$190,150
Average cost/ton	$25.53	$28.47	$30.43	$30.88	$28.92
Margin	$22,863	$18,750	$19,542	$16,897	$78,052
Margin/ton	$14.70	$12.11	$10.94	$10.03	$11.87
Capex	$5,144	$6,711	$9,473	$7,294	$28,622
Maintenance capex	$2,887	$3,032	$2,961	$2,520	$11,400
Maintenance capex/ton	$0.54	$4.25	$2.52	$1.50	$1.73

	1st 2016	2nd 2016	3rd 2016	4th 2016	T4Qs
Tons produced	1,524	1,448	1,501	1,640	6,113
Tons sold	1,629	1,464	1,485	1,739	6,317
Coal sales	$75,795	$66,274	$65,360	$71,495	$278,924
Average price/ton	$46.53	$45.27	$44.01	$41.11	$44.15
Wash plant recovery in %	65 %	63 %	68 %	67 %	
Operating costs	$49,777	$45,397	$46,940	$50,663	$192,777
Average cost/ton	$30.56	$31.01	$31.61	$29.13	$30.52
Margin	$26,018	$20,877	$18,420	$20,832	$86,147
Margin/ton	$15.97	$14.26	$12.40	$11.98	$13.64
Capex	$6,053	$1,822	$3,935	$8,022	$19,832
Maintenance capex	$2,984	$904	$1,709	$5,301	$10,898
Maintenance capex/ton	$1.83	$0.62	$1.15	$3.05	$1.73

2017 v. 2016

For 2017, we sold 6,574,000 tons at an average price of $40.80/ton. For 2016, we sold 6,317,000 tons at an average price of $44.15/ton. The decrease in average price per ton is the result of our contract mix, expiration of contracts, and acquisition of other contracts.

Operating costs and expenses averaged $28.92/ton ($27.59/ton at our operating Oaktown mines) in 2017 compared to $30.52/ton ($28.02/ton at our operating Oaktown mines) in 2016. The reduction in cost was due to two primary factors. First, we made a conscious effort to increase production in the first half of the year in anticipation of stronger market demand. Second, we added new haulage equipment to some of the units at the Oaktown mines creating production efficiencies of up to 30% to those units. Both of these factors combined led to an 8% increase in production. In Q4 2017, we also opened a new elevator at Oaktown 1 which reduces miner travel time, and we acquired additional haulage equipment which will continue to maintain our low-cost structure.

Our Sunrise Coal employees totaled 736 at December 31, 2017 compared to 742 at December 31, 2016.

SG&A costs increased in 2017 by $4.5 million due primarily to a stock bonus of $3.8 million awarded to executives as reported in our 8-K filed May 17, 2017, increased RSU amortization and employee pay increases in 2017.

2016 v. 2015

For 2016, we sold 6,317,000 tons at an average price of $44.15/ton. For 2015, we sold 7,447,000 tons at an average price of $45.59/ton.

Operating costs and expenses averaged $30.52/ton in 2016 compared to $31.95 in 2015. Our Sunrise Coal employees totaled 742 at December 31, 2016, compared to 740 at December 31, 2015.

SG&A costs were higher in 2015 due to amortization of RSUs and accruals of bonuses related to our Vectren Fuels acquisition in 2014. SG&A as a percentage of coal revenue remained consistent at 3.8% in 2016 and 3.7% in 2015.

We incurred an asset impairment of $16.6 million due to our decision to seal the north portal of the Carlisle mine. We determined that the North end had deteriorated to the point that it could no longer be safely and profitably mined.

At the beginning of 2016, we changed from the straight-line method to the units-of-production method in computing the depreciation for continuous miners. This change in estimate reduced our DD&A expense for the year ended December 31, 2016, by $2.6 million. This change better reflects the usage of our continuous miners considering our reduced production in 2016. Due to idle equipment at Carlisle, we stopped depreciating specific underground equipment resulting in a $4.4 million reduction in depreciation for the year ended December 31, 2016.

Current Projects

Princeton Rail Loop

Construction began in the fourth quarter of 2017 on the Princeton Loop, a truck to rail coal loading facility that will be located 6 miles west of Princeton, IN, on Highway 64 and 37 miles southwest of our Oaktown mining facility. The facility will include the ability to unload trucks, blend coals, load 135 car unit trains in four hours and store over 4.0 million tons of coal. The new facility will primarily serve utility coal plants served by the Norfolk Southern Railway Company once the rail facility is completed in the spring of 2018. The rail loop will provide access to new markets and customers.

Hourglass Sands

In February 2018, we formed and made an initial investment of $4 million in Hourglass Sands, LLC, a frac sand mining company in the State of Colorado. We own 100% of the Class A units and will account for Hourglass Sands LLC as a wholly owned subsidiary of Hallador Energy Company. Class A units are entitled to 100% of profit until our capital investment and interest is returned, then 90% of profits are allocated to Class A Units with the remainder to Class B units. A Yorktown company associated with one of our directors also invested $4 million for a royalty interest in the sand project.

We currently control a permitted sand reserve near Colorado Springs. We are negotiating to have a third party wash our sand and expect to truck test shipments to customers in the DJ Basin this summer. We believe we control the only permitted frac sand mine in the State of Colorado. We do not anticipate Hourglass Sands, LLC to be profitable in 2018, but are excited about its growth potential in future years.

MSHA Reimbursements

Some of our legacy coal contracts allow us to pass on to our customers certain costs incurred resulting from changes in costs to comply with mandates issued by MSHA or other government agencies. We do not recognize any revenue until our customers have notified us that they accept the charges.

We submitted our incurred costs for 2012 in June 2015 and received $1.75 million from one of our customers in June 2016. We received an additional payment of $1.25 million in Q2 2017 for 2012 costs. We also received payments in 2017 from several customers for smaller regulation changes that went into effect in 2016. As stated above we do not record such reimbursements as revenue until they have been agreed to by our customers.

Incurred costs for 2013 – 2017 will be submitted in 2018. 2013 costs are expected to be between $2.0 million and $2.7 million. Such reimbursable costs for 2014 through 2017 are not expected to be material.

Income Taxes

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (Tax Act). The Tax Act reduces the corporate tax rate to 21 percent, effective January 1, 2018. Because ASC 740-10-25-47 requires the effect of a change in tax laws or rates to be recognized as of the date of enactment, we are required to adjust deferred tax assets and liabilities as of December 22, 2017. Accordingly, we have recorded a deferred income tax benefit of $16.4 million for the year ended December 31, 2017.

Our effective tax rate (ETR) for 2017 was (138)% compared to (48)% for 2016 and 27% for 2015. The negative ETR in 2017 is due primarily to the effects of the Tax Act adjustment to our deferred taxes and prior year tax return reconciliation which were all recorded discretely for the year ended December 31, 2017. The negative ETR in 2016 is due to the combination of the reduction in book income before taxes because of the asset impairment expense, permanent tax benefits of statutory depletion in excess of tax basis in the mining properties, the captive insurance company effects, and stock based compensation expense. The tax rate for the years ended December 31, 2017 and 2016 are not predictive of future tax rates due to the deferred income tax benefit of the Tax Act. The tax rate would have been 9% without the effects of the deferred income tax benefit of the Tax Act and the prior year tax return reconciliation. Historically, our actual effective tax rates have been lower than the statutory effective rate primarily due to the benefit received from statutory depletion allowances. The deduction for statutory depletion does not necessarily change proportionately to changes in income before income taxes.

Critical Accounting Estimates

We believe that the estimates of our coal reserves, our business acquisitions, our interest rate swaps, our deferred tax accounts, and the estimates used in our impairment analysis are our only critical accounting estimates.

The reserve estimates are used in the DD&A calculation 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.

We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items.

The fair value of our interest rate swaps is determined using a discounted future cash flow model based on the key assumption of anticipated future interest rates.

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. 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.

New Accounting Standards

See "Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies" for a discussion of new accounting standards.

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

Substantially all our business is conducted in Indiana, so we have no foreign exchange currency risk.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of coal production such as steel, electricity and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. We do not utilize any commodity price-hedges or other derivatives related to these risks. The Trump administration recently announced that they would like to assess tariffs on steel imports in the future which would add to this risk.

Borrowings under our credit agreement are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. As disclosed in Note 3 to our consolidated financial statements we entered into swap agreements to fix the LIBOR component of the interest rate to achieve an effective fixed rate of no greater than 5% on the original term loan balance and on $100 million of the revolver. Quarterly, we mark-to-market the value of the swaps. For 2017, the change in value was $723,000 and not considered material. As short-term interest rates rise (especially the two-year U.S. treasury note) the value of the swap increases and as they fall the value decreases.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors

Hallador Energy Company

Denver, Colorado

OPINIONS ON THE FINANCIAL STATEMENTS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

We have audited the accompanying consolidated balance sheets of Hallador Energy Company (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each year in the three-year period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). We have also audited the Company's internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework: (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each year in the three-year period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework: (2013) issued by COSO.

BASIS FOR OPINIONS

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

DEFINITION AND LIMITATIONS OF INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

/s/ EKS&H LLLP

March 12, 2018
Denver, Colorado

We have served as the Company's auditor since 2003.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Hallador Energy Company

Consolidated Balance Sheets

As of December 31,

(in thousands, except per share data)

	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$12,483	$9,788
Restricted cash (Note 8)	3,811	2,817
Certificates of deposit	1,495	7,315
Marketable securities	1,907	1,763
Accounts receivable	16,762	22,307
Prepaid income taxes	2,899	-
Coal inventory	12,804	10,100
Parts and supply inventory	10,043	10,091
Purchased coal contracts	-	8,922
Prepaid expenses	9,433	9,647
Total current assets	71,637	82,750
Coal properties, at cost:		
Land and mineral rights	129,724	126,303
Buildings and equipment	356,911	339,999
Mine development	136,762	126,037
Total coal properties, at cost	623,397	592,339
Less - accumulated DD&A	(203,391)	(169,579)
Total coal properties, net	420,006	422,760
Investment in Savoy (Note 11)	8,037	7,577
Investment in Sunrise Energy (Note 11)	3,853	4,122
Other assets (Note 7)	14,660	14,114
Total assets	$518,193	$531,323
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt, net (Note 3)	$33,171	$28,796
Accounts payable and accrued liabilities (Note 14)	21,115	19,918
Total current liabilities	54,286	48,714
Long-term liabilities:		

Bank debt, net (Note 3)	165,773	204,944
Deferred income taxes	28,728	45,174
Asset retirement obligations (ARO)	13,506	13,115
Other	6,577	2,486
Total long-term liabilities	214,584	265,719
Total liabilities	268,870	314,433
Stockholders' equity:		
Preferred stock, $.10 par value, 10,000 shares authorized; none issued	-	-
Common stock, $.01 par value, 100,000 shares authorized; 29,955 and 29,413 shares outstanding, respectively	299	294
Additional paid-in capital	97,873	93,816
Retained earnings	150,236	122,052
Accumulated other comprehensive income	915	728
Total stockholders’ equity	249,323	216,890
Total liabilities and stockholders’ equity	$518,193	$531,323

See accompanying notes.

44

Hallador Energy Company

Consolidated Statements of Comprehensive Income

For the years ended December 31,

(in thousands, expect per share data)

	2017	2016	2015
Revenue:			
Coal sales	$268,202	$278,924	$339,490
Equity income (loss) - Savoy	460	(1,187)	(1,532)
Equity income (loss) - Sunrise Energy	(95)	(249)	(74)
Other (Note 7)	3,066	3,962	2,236
Total revenue	271,633	281,450	340,120
Costs and expenses:			
Operating costs and expenses	190,150	192,777	237,897
DD&A	38,495	35,565	43,942
ARO accretion	861	1,029	498
Coal exploration costs	854	1,673	2,039
SG&A	14,978	10,520	12,617
Interest [(1)]	12,413	14,842	15,557
Asset impairment (Note 2)	-	16,560	-
Total costs and expenses	257,751	272,966	312,550
Income before income taxes	13,882	8,484	27,570
Less income tax expense (benefit)			
Current	(2,748)	(167)	(14)
Deferred	(16,446)	(3,859)	7,452
Total income tax expense (benefit)	(19,194)	(4,026)	7,438
Net income *	$33,076	$12,510	$20,132
Net income per share (Note 9):			
Basic and diluted	$1.08	$0.42	$0.68
Weighted average shares outstanding:			
Basic and diluted	29,661	29,260	29,031

*There is no material difference between net income and comprehensive income.

(1) Included in interest expense is the change in the estimated fair value of our interest rate swaps. Such amounts were $(723), $(637) and $159 for 2017, 2016 and 2015, respectively.

See accompanying notes.

45

Hallador Energy Company

Consolidated Statement of Cash Flows

For the years ended December 31,

(in thousands)

	2017	2016	2015
Operating activities:			
Net income	$33,076	$12,510	$20,132
Deferred income taxes	(16,446)	(3,859)	7,452
Equity (income) loss – Savoy and Sunrise Energy	(365)	1,436	1,606
Cash distributions - Savoy and Sunrise Energy	175	3,977	-
DD&A	38,495	35,565	43,942
Asset impairment	-	16,560	-
Loss on sale of assets	45	197	-
Change in fair value of interest rate swaps	(723)	(637)	159
Amortization and write off of deferred financing costs	1,829	2,325	1,394
Amortization of purchased coal contracts	8,922	1,593	-
Accretion of ARO	861	1,029	498
Stock-based compensation	7,266	2,539	3,134
Taxes paid on vesting of RSUs	(3,209)	(1,098)	(1,029)
Change in current assets and liabilities:			
Accounts receivable	5,533	(5,632)	10,627
Coal inventory	(2,704)	4,815	4,807
Parts and supply inventory	48	1,164	3,664
Prepaid income taxes	(3,226)	5,312	448
Prepaid expenses	(4,823)	(2,567)	370
Accounts payable and accrued liabilities	(815)	(11,193)	(1,686)
Other	(2,371)	(3,118)	(862)
Cash provided by operating activities	61,568	60,918	94,656
Investing activities:			
Capital expenditures	(28,622)	(19,832)	(31,167)
Proceeds from sale of equipment	506	-	-
Purchase of Freelandville and Log Creek assets	-	(22,358)	-
Proceeds from maturities of certificates of deposit	5,820	-	-
Purchase of certificates of deposit	-	(7,315)	-
Other	-	189	641
Cash used in investing activities	(22,296)	(49,316)	(30,526)
Financing activities:			
Payments of bank debt	(36,625)	(34,855)	(56,875)
Bank borrowings	-	24,000	-
Deferred financing costs	-	(2,090)	-
Proceeds from Bulldog property	4,940	-	-

Dividends	(4,892)	(4,799)	(4,794)
Cash used in financing activities	(36,577)	(17,744)	(61,669)
Increase (decrease) in cash and cash equivalents	2,695	(6,142)	2,461
Cash and cash equivalents, beginning of year	9,788	15,930	13,469
Cash and cash equivalents, end of year	$12,483	$9,788	$15,930
Supplemental cash flow information:			
Cash paid for interest	$11,663	$12,429	$14,149
Cash (received) paid for income taxes, net	1,562	(5,594)	(956)
Capital expenditures included in accounts payable and prepaid expense	7,615	(1,616)	804

See accompanying notes.

Hallador Energy Company

Consolidated Statement of Stockholders' Equity

(in thousands)

	Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	AOCI*	Total
Balance January 1, 2015	28,962	$ 289	$ 90,218	$ 99,003	$ 365	$ 189,875
Stock-based compensation	14	-	3,134	-	-	3,134
Stock issued on vesting of RSUs	411	3	-	-	-	3
Taxes paid on vesting of RSUs	(136)	-	(1,029)	-	-	(1,029)
Dividends	-	-	-	(4,794)	-	(4,794)
Net income	-	-	-	20,132	-	20,132
Other	-	-	(48)	-	(453)	(501)
Balance, December 31, 2015	29,251	292	92,275	114,341	(88)	206,820
Stock-based compensation	-	-	2,539	-	-	2,539
Stock issued on vesting of RSUs	272	2	-	-	-	2
Taxes paid on vesting of RSUs	(126)	-	(1,098)	-	-	(1,098)
Dividends	-	-	-	(4,799)	-	(4,799)
Net income	-	-	-	12,510	-	12,510
Other	16	-	100	-	816	916
Balance December 31, 2016	29,413	294	93,816	122,052	728	216,890
Stock-based compensation	-	-	7,266	-	-	7,266
Stock issued on vesting of RSUs	991	5	-	-	-	5
Taxes paid on vesting of RSUs	(449)	-	(3,209)	-	-	(3,209)
Dividends	-	-	-	(4,892)	-	(4,892)
Net income	-	-	-	33,076	-	33,076
Other	-	-	-	-	187	187
Balance, December 31, 2017	29,955	$ 299	$ 97,873	$ 150,236	$ 915	$ 249,323

*Accumulated Other Comprehensive Income (loss)

See accompanying notes.

47

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) and Sunrise’s wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. We are engaged in the production of steam coal from mines located in western Indiana. We own a 50% interest in Sunrise Energy, LLC, a private entity engaged in natural gas operations in the same vicinity as the Carlisle Mine. We also own 30.6% equity interest in Savoy Energy, L.P., a private oil and gas company that has operations in Michigan. We have reached an agreement for Savoy to redeem our entire partnership interest for $8 million, which we expect to finalize in mid-March 2018. Our net after commissions paid will be $7.5 million.

Reclassification

To maintain consistency and comparability, certain amounts in the 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 (including depreciation thereto) 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. Advance royalties are included in other assets.

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 most mining equipment, coal properties are depreciated using the units-of-production method over the estimated recoverable reserves. Most surface and underground mining equipment is depreciated using estimated useful lives ranging from three to twenty-five years. At the beginning of 2016, we changed from the straight-line method to the units-of-production method in computing the depreciation for continuous miners. This change in estimate reduced our DD&A expense for the year ended December 31, 2016, by $2.6 million. Due to idle equipment at Carlisle, we stopped depreciating specific underground equipment resulting in a $4.4 million reduction in depreciation for the year ending December 31, 2016.

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. See Note 2 for further discussion of impairments.

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 reserves.

Asset Retirement Obligations (ARO) - 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 and surface mines and include reclamation of support facilities, refuse areas and slurry ponds.

Obligations are reflected at the present value of their future cash flows. We reflect accretion of the obligations for the period from the date they are incurred through the date they are extinguished. The ARO assets are amortized using the units-of-production method over estimated recoverable (proved and probable) reserves. We are using discount rates ranging from 5.0% to 10%. Federal and state laws require that mines be reclaimed 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 review our ARO at least annually and reflect revisions for permit changes, changes in our estimated reclamation costs and changes in the estimated timing of such costs. In the event we are not able to perform reclamation, we have surety bonds totaling $25 million to cover ARO.

The table below (in thousands) reflects the changes to our ARO:

	2017	2016
Balance, beginning of year	$13,260	$12,231
Accretion	861	1,029
Revisions	(112)	-
Payments	(203)	-
Balance, end of year	13,806	13,260
Less current portion	(300)	(145)
Long-term balance, end of year	$13,506	$13,115

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.

Net Income per Share

Basic net income per share is computed on the basis of the weighted average number of shares of common stock outstanding during the period using the two-class method for our common shares and RSUs which share in the Company's earnings. Diluted net income 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. Dilutive potential common shares include restricted stock units and are included in basic net income per share, using the two-class method.

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 relate to: (i) fair value estimates relating to business combinations, (ii) deferred income tax accounts, (iii) coal reserves, (iv) depreciation, depletion, and amortization, and (v) estimates used in our impairment analysis.

Business Combinations

We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items.

Revenue Recognition

We recognize revenue from coal sales at the time title and risk of loss passes to the customer at contracted amounts and amounts are deemed collectible. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped and are recorded in the period of shipment. As discussed below, we do not expect the new revenue recognition standard introduced by ASU 2014-09, Revenue from Contracts with Customers (ASU 2014-09) will result in a material change to our pattern of revenue recognition when it becomes effective.

Long-term Contracts

As of December 31, 2017, we are committed to supplying our customers a maximum of 26.1 million tons of coal through 2024 of which 13.5 million tons are priced.

For 2017, we derived 92% of our coal sales from five customers, each representing at least 10% of our coal sales. 83% of our accounts receivable were from four of these customers, each representing more than 10% of the December 31, 2017 balance.

For 2016, we derived 90% of our coal sales from five customers each representing at least 10% of our coal sales. 78% of our accounts receivable were from four of these customers, each representing more than 10% of the December 31, 2016 balance.

For 2015, we derived 82% of our coal sales from four customers, each representing at least 10% of our coal sales.

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 two to four years) using the straight-line method.

New Accounting Standards Issued and Adopted

In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory (ASU 2015-11). ASU 2015-11 simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with the lower of cost or net realizable value test. Net realizable value is defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new standard was applied prospectively and effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods. The adoption of ASU 2015-11 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 increases transparency and comparability among organizations by requiring lessees to record right-to-use assets and corresponding lease liabilities on the balance sheet and disclosing key information about lease arrangements. The new guidance will classify leases as either finance or operating (similar to current standard's "capital" or "operating" classification), with classification affecting the pattern of income recognition in the statement of income. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We are currently in the process of accumulating all contractual lease arrangements in order to determine the impact on our financial statements and do not believe we have significant amounts of off- balance sheet leases; accordingly, we do not expect the adoption of ASU 2016-02 to have a material impact on our consolidated financial statements. We continue to monitor closely the activities of the FASB and various non-authoritative groups with respect to implementation issues that could affect our evaluation.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers." ASU 2014-09 is a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under current U.S. GAAP and replace it with a principle based approach for determining revenue recognition. ASU 2014-09 will require that companies recognize revenue based on the value of transferred goods or services as they occur in the contract. The ASU also will require additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. ASU 2014-09 is effective for interim and annual periods beginning after December 15, 2017. We have adopted the new standard as of January 1, 2018. Entities will be able to transition to the standard either retrospectively or as a cumulative-effect adjustment as of the date of adoption.

Our primary source of revenue is from the sale of coal through both short-term and long-term contracts with utility companies whereby revenue is currently recognized when risk of loss has passed to the customer. Under the new standard, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. As part of our assessment process, we applied the five-step analysis outlined in the new standard to certain contracts representative of the majority of our coal sales contracts and determined that our pattern of recognition is consistent between the new and existing standards. We also reviewed the expanded disclosure requirements under the new standard and have determined the additional information to be disclosed. In addition, we reviewed our business processes, systems and internal controls over financial reporting to support the new recognition and disclosure requirements under the new standard. Upon adoption of this new standard, we believe that the timing of revenue recognition related to our coal sales will remain consistent with our current practice, but expanded disclosures including presenting revenue for all periods presented and expected revenue by year for performance obligations that are unsatisfied or partially unsatisfied as of the date of presentation will be required. We have elected the modified retrospective transition method which allows a cumulative effect adjustment to equity as of the date of adoption. Because we do not anticipate a change in our pattern of revenue recognition, we anticipate that the transition will not have a material impact on our consolidated financial statements. Although we don’t consider it material, one source of variable consideration we receive relates to reimbursement from certain customers for expenses incurred for new government impositions adopted, which we may recognize sooner than our current recognition practice.

In November 2016, the FASB issued guidance regarding the presentation of restricted cash in the statement of cash flows (ASU 2016-18). This update is effective for annual reporting periods beginning after December 15, 2017, and early adoption is permitted. We have adopted the new standard as of January 1, 2018.

In January 2017, the FASB issued new guidance to assist in determining if a set of assets and activities being acquired or sold is a business (ASU 2017-01). It also provided a framework to assist entities in evaluating whether both an input and a substantive process are present, which at a minimum, must be present to be considered a business. This update is effective for annual reporting periods beginning after December 15, 2017, and early adoption is permitted in most circumstances. The standard does not have an impact to the Company's historical recognition of asset acquisitions and business combinations. However, we expect there will be an impact to how the Company accounts for assets acquired in the future.

Subsequent Events

In January 2018, we declared a dividend of $.04 per share to shareholders of record as of January 31, 2018. The dividend was paid on February 16, 2018.

In February 2018, we formed and made an initial investment of $4 million in Hourglass Sands, LLC, a frac sand mining company in the State of Colorado. We own 100% of the Class A units and will account for Hourglass Sands LLC as a wholly owned subsidiary of Hallador Energy Company. Class A units are entitled to 100% of profit until our capital investment and interest is returned, then 90% of profits are allocated to Class A Units with the remainder to Class B units. A Yorktown company associated with one of our directors also invested $4 million for a royalty interest in the sand project.

We currently control a permitted sand reserve near Colorado Springs. We are negotiating to have a third party wash our sand and expect to truck test shipments to customers in the DJ Basin this summer. We believe we control the only permitted frac sand mine in the State of Colorado. We do not anticipate Hourglass Sands, LLC to be profitable in 2018, but are excited about its growth potential in future years.

We have reached an agreement for Savoy Energy L.P. to redeem our entire partnership interest for $8 million, which we expect to finalize in mid-March 2018. Our net after commissions paid will be $7.5 million.

(2) Asset Impairment Review

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Carlisle Mine

In December 2016, the deterioration of the North End of the Carlisle Mine (the North End), coupled with lower coal prices led us to determine that the North End could no longer be mined safely and profitably. The sealing of the North End was completed in March 2017. In connection therewith, we identified specific assets totaling $16.6 million ($15.1 million of property and equipment and $1.5 million of advanced royalties) that were written off in 2016.

With the Carlisle Mine remaining in hot idle status, we conducted a review of the Carlisle Mine assets as of December 31, 2017, based on estimated future net cash flows, and determined that no further impairment was necessary.

The Carlisle Mine assets had an aggregate net carrying value of $110 million at December 31, 2017. If in future periods we reduce our estimate of the future net cash flows attributable to the Carlisle Mine, it may result in future impairment of such assets and such charges could be significant.

Bulldog Reserves

In October 2017, we entered into an agreement to sell land associated with the Bulldog Mine for $4.9 million. As part of the transaction, we will hold the rights to repurchase the property for 8 years. Because of the likelihood of exercising the repurchase option, we are accounting for the sale as a financing transaction. The Bulldog Mine assets had an aggregate net carrying value of $15 million at December 31, 2017. Also in October 2017, the Illinois Department of Natural Resources (ILDNR) notified us that our mine application, along with modifications, was acceptable. The permit will be issued upon submittal of a fee and bond which are required within 12 months of the notification. We have determined that no impairment is necessary. If estimates inherent in the assessment change, it may result in future impairment of the assets.

(3) Bank Debt

On March 18, 2016, we executed an amendment to our credit agreement with PNC, as administrative agent for our lenders, for the primary purpose of increasing liquidity and maintaining compliance through the maturity of the agreement in August 2019. The revolver was reduced from $250 million to $200 million, and the $175 million term loan remained the same. Our debt at December 31, 2017, was $202 million (term-$71 million, revolver-$131 million). As of December 31, 2017, we had additional borrowing capacity of $69 million and total liquidity of $85 million.

Bank fees and other costs incurred in connection with the initial facility and the amendment were $9.1 million, which were deferred and are being amortized over five years. The credit facility is collateralized by substantially all of Sunrise's assets, and we are the guarantor.

The amended credit facility increased the Maximum Leverage Ratio (Sunrise total funded debt/ trailing 12 months adjusted EBITDA) to those listed below:

Fiscal Periods Ending	Ratio
December 31, 2017 and March 31, 2018	4.25 X
June 30, 2018 and September 30, 2018	4.00 X
December 31, 2018	3.75 X
March 31, 2019 and June 30, 2019	3.50 X

The amended credit facility also requires a Debt Service Coverage Ratio minimum of 1.25X through the maturity of the credit facility. The amendment defines the Debt Service Coverage Ratio as trailing 12 months adjusted EBITDA/annual debt service.

At December 31, 2017, our Leverage Ratio was 2.40 and our Debt Service Coverage Ratio was 1.90. Therefore, we were in compliance with these two debt covenant ratios.

The interest rate on the facility ranges from LIBOR plus 2.25% to LIBOR plus 4%, depending on our leverage ratio. We entered into swap agreements to fix the LIBOR component of the interest rate to achieve an effective fixed rate of ~5% on the original term loan balance and on $100 million of the revolver. The revolver swap notional value steps down 10% each quarter which commenced on March 31, 2016. At December 31, 2017, these two interest rate swaps had an estimated net fair value of $.5 million included in other assets on our consolidated balance sheet. Notional values of the two interest rate swaps were $96 million and $30 million as of December 31, 2017.

At December 31, 2017, we were paying LIBOR at 1.57% plus 3% for a total interest rate of 4.57%.

New accounting standards adopted in 2016 required that our debt issuance costs be presented as a direct reduction from the related debt rather than as an asset. Our debt at December 31 is presented below (in thousands):

	2017	2016
Current debt	$35,000	$30,625
Less debt issuance cost	(1,829)	(1,829)
Net current portion	$33,171	$28,796
Long-term debt	$166,992	$207,992
Less debt issuance cost	(1,219)	(3,048)
Net long-term portion	$165,773	$204,944

Future Maturities (in thousands):

2018	$35,000
2019	166,992
Total	$201,992

(4) Income Taxes (in thousands)

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (Tax Act). The Tax Act makes broad and complex changes to the U.S. tax code including, but not limited to, (1) bonus depreciation that will allow for full expensing of qualified property; (2) reduction of the U.S. federal corporate tax rate; (3) elimination of the corporate alternative minimum tax; (4) a new limitation on deductible interest expense; (5) the repeal of the domestic production activity deduction; (6) limitations on the deductibility of certain executive compensation; and (7) limitations on net operating losses generated after December 31, 2017, to 80 percent of taxable income.

The SEC staff issued SAB 118, which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Act for which the accounting under ASC 740 is complete. To the extent that a company’s accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act. As we are not subject to either the international changes of the Tax Act or other applicable provisions, we believe that the income tax effects of the Tax Act applicable to our accounting under ASC 740 is substantially complete for the year ended December 31, 2017. Additional information that may affect the accounting under ASC 740 would include further clarification and guidance on how the Internal Revenue Service and state taxing authorities will implement the Tax Act. We do not believe potential adjustments in future periods would materially impact the Company’s financial condition or results of operations.

The Tax Act reduces the corporate tax rate to 21 percent, effective January 1, 2018. Because ASC 740-10-25-47 requires the effect of a change in tax laws or rates to be recognized as of the date of enactment, we are required to adjust deferred tax assets and liabilities as of December 22, 2017. Accordingly, we have recorded a decrease related to our net deferred tax liability of $16.4 million, with a corresponding net adjustment to deferred income tax benefit of $16.4 million for the year ended December 31, 2017.

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:

	2017	2016	2015
Expected amount	$4,868	$2,966	$9,653
Adjustment to deferred taxes from the Tax Act rate reduction	(17,974)		
Change in Indiana rate			(85)
State income taxes, net of federal benefit	115	(387)	612
Percentage depletion	(4,128)	(6,021)	(2,606)
Stock-based compensation	(204)	(238)	
Captive insurance	(379)	(418)	(419)
Adjustments to NOL carryforwards	(1,038)		
Return to provision adjustments	(205)		
Other	(249)	72	283
	$(19,194)	$(4,026)	$7,438

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

	2017	2016
Long-term deferred tax assets:		
Stock-based compensation	$251	$512
Investment in Savoy	781	1,031
Net operating loss	13,626	14,908
Alternative minimum tax credit	2,705	4,221
Other	943	564
Total long-term deferred tax assets	18,306	21,236
Long-term deferred tax liabilities:		
Coal properties	(47,034)	(50,439)
Oil and gas properties	-	(15,971)
Total long-term deferred tax liabilities	(47,034)	(66,410)
Net deferred tax liability	$(28,728)	$(45,174)

Our effective tax rate (ETR) for 2017 was (138)% compared to (48)% for 2016 and 27% for 2015. The negative ETR in 2017 is due primarily to the effects of the Tax Act adjustment to our deferred taxes and prior year tax return reconciliation which were all recorded discretely for the year ended December 31, 2017. The negative ETR in 2016 is due to the combination of the reduction in book income before taxes because of the asset impairment expense, permanent tax benefits of statutory depletion in excess of tax basis in the mining properties, the captive insurance company effects, and stock based compensation expense. The tax rate for the years ended December 31, 2017 and 2016 are not predictive of future tax rates due to the deferred income tax benefit of the Tax Act. The tax rate would have been 9% without the effects of the deferred income tax benefit of the Tax Act and the prior year tax return reconciliation. Historically, our actual effective tax rates have been lower than the statutory effective rate primarily due to the benefit received from statutory depletion allowances. The deduction for statutory depletion does not necessarily change proportionately to changes in income before income taxes.

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, to determine whether the positions will be more likely than not be sustained by the applicable tax authority. Tax positions not deemed to meet the more-likely-than-not threshold are not recorded as a tax benefit or expense in the current year. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. We believe that our income tax filing positions and deduction will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. While not material, we record any penalties and interest as SG&A. Tax returns filed with the IRS for the years 2014 through 2016 along with tax returns filed with numerous state entities remain subject to examination.

(5) Stock Compensation Plans

Restricted Stock Units (RSUs)

On May 16, 2017, our Compensation Committee authorized the issuance and immediate vesting of 495,000 RSUs to our Chairman, President, and CFO. These shares were valued at $3.8 million, based on the May 16, 2017, closing stock price of $7.74.

By shareholder approval on May 25, 2017, our 2008 Restricted Stock Unit Plan (RSU Plan) was amended and restated to add 1,000,000 shares and extend its term through May 25, 2027.

On June 6, 2017, our Compensation Committee approved a Four-Year Compensation Plan for our Chairman, President, and CFO that granted them 645,000 RSUs. Beginning December 16, 2018, these RSUs will vest/lapse 25% annually through December 16, 2021, or earlier based on the terms of the RSU Plan and the applicable award agreements. The closing stock price on the date of grant was $8.23.

The table below shows the number of RSUs available for issuance at December 31, 2017:

Total authorized RSUs in Plan approved by shareholders	4,850,000
Stock issued out of the Plan from vested grants	(2,512,432)
Non-vested grants	(944,500)
RSUs available for future issuance	1,393,068
Non-vested grants at January 1, 2015	1,042,000
Granted – share price on grant date was $11.52	2,000
Vested – weighted average share price on vesting date was $7.42	(410,500)
Forfeited	(27,000)
Non-vested grants at December 31, 2015	606,500
Granted – weighted average share price on grant date was $6.84	414,000
Vested – weighted average share price on vesting date was $8.72	(271,500)
Forfeited	(16,000)
Non-vested grants at December 31, 2016	733,000
Granted – weighted average share price on grant date was $7.98	1,211,500
Vested – weighted average share price on vesting date was $7.22	(990,500)
Forfeited	(9,500)
Non-vested grants at December 31, 2017 (1)	944,500

(1) RSU Vesting Schedule

Vesting Year	No. RSUs Vesting
2018	178,250
2019	373,750
2020	231,250
2021	161,250
	944,500

Vested shares had a value of $7.1 million for 2017, $2.4 million for 2016, and $3.0 million for 2015 on their vesting dates. Under our RSU plan, participants are allowed to relinquish shares to pay for their required statutory income taxes.

The outstanding RSUs have a value of $6.2 million based on the March 9, 2018, closing stock price of $6.53.

For the years ended December 31, 2017, 2016 and 2015 stock based compensation was $7.3 million, $2.5 million, and $3.1 million, respectively. For 2018, based on existing RSUs outstanding, stock-based compensation expense is estimated to be $2.0 million.

Stock Options

We have no stock options outstanding.

Stock Bonus Plan

Our stock bonus plan was authorized in late 2009 with 250,000 shares. Currently, we have 86,383 shares available for future issuance.

(6) Employee Benefits

We have no defined benefit pension plans or post-retirement benefit plans. We offer our employees a 401(k) Plan, where we match 100% of the first 4% that an employee contributes and a discretionary Deferred Bonus Plan for certain key employees. We also offer health benefits to all employees and their families. We have 2,289 participants in our employee health plan. The plan does not cover dental, vision, short-term or long-term disability. These coverages are available on a voluntary basis. We bear some of the risk of our employee health plans. Our health claims are capped at $200,000 per person with a maximum annual exposure of $14.4 million, not including premiums.

Our employee benefit expenses for the years ended December 31 are below (in thousands):

	2017	2016	2015
Health benefits, including premiums	$13,311	$12,672	$13,400
401(k) matching	1,892	1,458	2,267
Deferred bonus plan	677	588	445

Total	$15,880	$14,718	$16,112

Of the amounts in the above table, $15.5 million, $13.8 million, and $15.2 million for 2017, 2016, and 2015, respectively are recorded in operating costs and expenses with the remainder in SG&A.

Our mine employees are also covered by workers' compensation and such costs for 2017, 2016 and 2015 were approximately $2.8 million, $2.3 million and $4.6 million, respectively, of which $2.5 million, $2.3 million, and $4.6 million, respectively are recorded in operating costs and expenses with the remainder in SG&A. 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 includes 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 $1 million per occurrence with a $4 million aggregate deductible. Based on discussions and representations from our insurance carrier, we believe that our reserve for our workers' compensation benefits is adequate. We have a safety conscious workforce, and based on our experience modifier, our claims are averaging 27% below that of our peers in underground coal mining in the state of Indiana.

57

(7) Other Long-Term Assets and Other Income (in thousands)

	2017	2016
Long-term assets		
Advanced coal royalties	$9,720	$9,296
Marketable equity securities available for sale, at fair value (restricted)*	2,148	2,036
Other	2,792	2,782
Total other assets	$14,660	$14,114

*Held by Sunrise Indemnity, Inc., our wholly owned captive insurance company.

	2017	2016	2015
Other income:			
MSHA reimbursements**	$1,725	$1,753	$
Miscellaneous	1,341	2,209	2,236
	$3,066	$3,962	$2,236

**See “MSHA Reimbursements” in the MD&A section for a discussion of these amounts.

(8) Self Insurance

We self-insure our underground mining equipment. Such equipment is allocated among 10 mining units spread out over 22 miles. The historical cost of such equipment is about $258 million.

As of December 31, 2017, and 2016, restricted cash of $3.8 million and $2.8 million, respectively, represents cash held and controlled by a third party and is restricted for future workers’ compensation claim payments.

(9) Net Income per Share

We compute net income per share using the two-class method, which is an allocation formula that determines net income per share for common stock and participating securities, which for us are our outstanding RSUs.

The following table (in thousands, except per share amounts) sets forth the computation of net income per share:

	2017	2016	2015
Numerator:			
Net income	$33,076	$12,510	$20,132
Less earnings allocated to RSUs	(1,028)	(305)	(450)
Net income allocated to common shareholders	$32,048	$12,205	$19,682
Denominator:			
Weighted average number of common shares outstanding	29,661	29,260	29,031
Net income per share:			
Basic and diluted	$1.08	$0.42	$0.68

(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. Our marketable securities are 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 assets and liabilities as Level 2.

The following table summarizes our financial assets and liabilities measured on a recurring basis at fair value at December 31, 2017 and 2016 by respective level of the fair value hierarchy:

	Level 1	Level 2	Level 3	Total
	(in thousands)			
December 31, 2017				
Assets:				
Marketable securities	$1,907	$ -	$ -	$1,907
Marketable securities - restricted	2,148	-	-	2,148
Interest rate swaps	-	-	543	543
	$4,055	$ -	$ 543	$4,598
December 31, 2016				

Assets:				
Marketable securities	$1,763	$ -	$ -	$1,763
Marketable securities - restricted	2,036	-	-	2,036
Interest rate swaps	-	-	296	296
	$3,799	$ -	$ 296	$4,095
Liabilities:				
Interest rate swaps	$-	$ -	$ 476	$476

The table below highlights the change in fair value of the interest rate swaps:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Interest Rate Swaps (in thousands)
Ending balance, December 31, 2015	$ (817)
Change in estimated fair value	637
Ending balance, December 31, 2016	(180)
Change in estimated fair value	723
Ending balance, December 31, 2017	$ 543

(11) Equity Method Investments

We own a 50% interest in Sunrise Energy, LLC, which owns gas reserves and gathering equipment with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for oil, gas and coal-bed methane gas reserves on or near our underground coal reserves. We received distributions totaling $175,000 and $375,000 for the years ended December 31, 2017 and 2016, respectively.

We own a 30.6% interest in Savoy Energy, L.P., a private company engaged in the oil and gas business primarily in the state of Michigan.

On November 3, 2016, Lubar Equity Fund, LLC acquired a 25% interest in Savoy for $9.5 million in cash. Accordingly, our ownership interest was reduced from 40.8% to 30.6%. At closing, Savoy made a cash distribution of $4.4 million of which our share was $1.8 million and per our credit agreement was applied to our bank debt. Mr. Lubar, one of our directors, is affiliated with Lubar Equity Fund, LLC.

We did not receive any distributions in 2017 and received two distributions in 2016 totaling $3.6 million from Savoy. Both distributions were applied to our bank debt as required under our agreement.

Savoy also recorded impairments of $1.0 million, $2.0 million, and $2.6 million for the years ended December 31, 2017, 2016, and 2015, respectively.

We have reached an agreement for Savoy to redeem our entire partnership interest for $8 million, which we expect to finalize in mid-March 2018. Our net after commissions paid will be $7.5 million.

(12) Freelandville and Log Creek Purchases

On March 22, 2016, we completed the purchase of the Freelandville coal reserves, advanced royalties, and coal sales agreement for $18.25 million from Triad Mining LLC. These reserves totaled 14.2 million tons of fee and leased coal and will be mined from our Oaktown 1 portal. This purchase allowed us access to another 1.6 million tons of our own leased reserves that were previously inaccessible. The purchased coal sales agreement totaled 1,435,000 tons and was fulfilled in 2017. The purchase price allocation for the acquisition was as follows (in thousands):

Purchased coal contract	$6,407
Advanced coal royalties	1,690
Mineral rights and leases	10,153
Total	$18,250

On December 12, 2016, we completed a second transaction with Triad, the purchase of their Log Creek coal sales agreement for $4.1 million. The purchased coal sales agreement included 557,000 tons that were delivered in 2016 and 2017.

(13) Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	Three Months Ended			
	Dec-31	Sep-30	Jun-30	Mar-31
	(In thousands, except per share data)			
2017				
Revenue	$69,300	$74,468	$64,312	$63,553
Operating income	3,921	7,155	4,065	11,154
Net income (loss) *	21,357	3,916	389	7,414
Basic income per common share	$0.69	$0.13	$0.01	$0.25
2016				
Revenue	$71,234	$65,767	$68,564	$75,885
Operating income	7,972	7,686	10,732	13,496
Net income (loss) *	(3,827)	4,322	5,853	6,162
Basic income per common share	$(0.13)	$0.14	$0.19	$0.21

* See Note 2 related to asset impairment taken in December 2016 and Note 4 related to the effects of the Tax Act in December 2017.

(14) Accounts Payable and Accrued Liabilities

	2017	2016
Accounts payable	$4,008	$4,829
Goods received not yet invoiced	5,574	3,072
Accrued property taxes	2,751	2,992
Workers' compensation reserve and IBNR	2,969	2,658
Other	5,813	6,367
Total accounts payable and accrued liabilities	$21,115	$19,918

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)

Our management, including our CEO and CFO, is responsible for establishing and maintaining adequate ICFR. Our ICFR is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles in the United States. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance of achieving their control objectives. Management evaluated the effectiveness of our ICFR based on the framework in “Internal Control – Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in 2013.

Our management evaluated, with the participation of our CEO and CFO, the effectiveness of our ICFR as of December 31, 2017. Based on that evaluation, our management concluded that our ICFR was effective at December 31, 2017. EKS&H LLLP has audited and reported on our financial statements and our ICFR as of December 31, 2017. Their report is contained in this Form 10-K.

There were no significant changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2017, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION None.

PART III

The information required for Items 10-14 is hereby incorporated by reference to that certain information in our Proxy Statement to be filed with the SEC during April 2018.

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.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

See Item 8 for an index of our financial statements.

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)
10.2	2009 Stock Bonus Plan (2)*
10.3	Second Amended Restated Credit Agreement – August 29, 2014 (3)
10.4	First Amendment to the Second Amended and Restated Credit Agreement dated March 18, 2016 (4)
10.5	Form of Hallador Energy Company Restricted Stock Unit Issuance Agreement* (5)
10.6	Amended and Restated Hallador Energy Company 2008 Restricted Stock Unit Plan (6)
10.7	Hallador Energy Company Four-Year Plan* (7)
14	Code of Ethics for Senior Financial Officers. (8)*
21.1	List of Subsidiaries (9)
23.1	Consent of EKS&H LLLP (9)
31	SOX 302 Certifications (9)
32	SOX 906 Certification (9)
95	Mine Safety Disclosure (9)
101	Interactive data files. (9)

(1) IBR to Form 8-K dated December 31, 2009
(2) IBR to Form S-8 dated December 1, 2009
(3) IBR to Form 10-Q dated November 10, 2014
(4) IBR to Form 10-Q dated May 6, 2016
(5) IBR to Form 8-K dated May 17, 2017
(6) IBR to Form 10-Q dated August 8, 2017
(7) IBR to Form 10-Q dated May 6, 2016
(8) IBR to the 2005 Form 10-KSB.
(9) Filed herewith.

*Management Agreements

ITEM 16. Form 10-K Summary.

As this item is optional, no summary is presented.

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 12, 2018 /s/ LAWRENCE D. MARTIN
Lawrence D. Martin, 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	Director	March 12, 2018
/s/ BRYAN LAWRENCE Bryan Lawrence	Director	March 12, 2018
/s/ BRENT BILSLAND Brent Bilsland	Board Chairman, President and CEO	March 12, 2018
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	March 12, 2018