UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10- K

✓ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2012
OR
❑ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______
Commission file number 1- 4119

NUCOR CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**13- 1860817**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1915 Rexford Road, Charlotte, North Carolina	**28211**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (704) 366- 7000
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, par value $0.40 per share	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well- known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ✓ No ❑
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ❑ No ✓
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No ❑
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S- T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ✓ No ❑
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S- K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10- K or any amendment to this Form 10- K. ✓
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non- accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b- 2 of the Exchange Act. (Check one):

Large accelerated filer ✓ Accelerated filer ❑ Non- accelerated filer ❑ Smaller reporting company ❑
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b- 2 of the Act). Yes ❑ No ✓
Aggregate market value of common stock held by non- affiliates was approximately $11.96 billion based upon the closing sales price of the registrant's common stock on the last business day of our most recently completed second fiscal quarter, June 29, 2012.
317,678,664 shares of common stock were outstanding at February 22, 2013.
Documents incorporated by reference include: Portions of the registrant's 2012 Annual Report (Parts I, II and IV), and portions of the registrant's Proxy Statement for its 2013 Annual Meeting of Stockholders (Part III) to be filed within 120 days after the registrant's fiscal year end.

Nucor Corporation
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PART I

Item 1. Business

Overview

Nucor Corporation and its affiliates ("Nucor" or the "Company") manufacture steel and steel products. The Company also produces direct reduced iron ("DRI") for use in the Company's steel mills. Through The David J. Joseph Company and its affiliates ("DJJ"), which the Company acquired in 2008, the Company also processes ferrous and nonferrous metals and brokers ferrous and nonferrous metals, pig iron, hot briquetted iron ("HBI") and DRI. Most of the Company's operating facilities and customers are located in North America, but increasingly, Nucor is doing business outside of North America as well. The Company's operations include several international trading companies that buy and sell steel and steel products manufactured by the Company and others.

Nucor is North America's largest recycler, using scrap steel as the primary raw material in producing steel and steel products. In 2012, we recycled approximately 19.2 million tons of scrap steel.

General Development of our Business in Recent Years

Nucor has employed a multi- pronged growth strategy in recent years that allows for the ability to capitalize on a variety of growth opportunities as they arise. The five prongs of that growth strategy are: (1) optimizing and continually improving our existing operations, (2) executing on our raw materials strategy, (3) growing through developing greenfield projects that capitalize on new technologies and unique marketplace opportunities, (4) acquiring other companies that will strengthen Nucor's position as North America's most diversified producer of steel and steel products and (5) growing internationally with an emphasis on leveraging strategic partnerships and new technologies.

Optimizing our existing operations primarily has involved spending a significant portion of our capital expenditures each year on projects that enhance productivity and improve costs as well as allow us to produce more value- added and typically higher margin products at our existing facilities. The heat treat line at our Hertford County, North Carolina mill became operational in 2010, which has allowed Nucor to grow its presence in higher margin products where greater strength and abrasion resistance is required. The heat treat line allows us to improve the product mix allocation between our two plate mills and four sheet mills to improve margins at those facilities. Also at the Hertford County mill, we commissioned a vacuum tank degasser in 2012, and we expect to begin operating a new normalizing line in 2013. Early in 2012, Nucor announced plans to spend approximately $290 million for projects at our Tennessee, Nebraska and South Carolina bar mills that should expand Nucor's special bar quality ("SBQ") and wire rod capacity by one million tons. The projects, which we expect to be completed between the end of 2013 and the first half of 2014, will allow us to produce engineered bar for the most demanding applications while maintaining our market share in commodity bar products by shifting production to our other bar mills. Other planned value- added projects at existing operations include the vacuum tank degasser that began operating at our Hickman, Arkansas mill in late 2012 and the modernization of casting, hot rolling and downstream operations that will allow us to produce wider and lighter gauge hot- rolled and cold- rolled steel products at our Berkeley, South Carolina mill beginning in early 2014.

Executing on our raw materials strategy involves putting the pieces into place to meet our goal of controlling between six and seven million tons of annual capacity in high quality scrap substitutes. Our 2,500,000 metric tons- per- year DRI facility in St. James Parish, Louisiana is scheduled to start- up in mid- 2013. Between our existing DRI plant in Trinidad, which we expanded in 2011 to increase the annual capacity from 1,800,000 to 2,000,000 metric tons, and our new facility in Louisiana, we will be approximately two- thirds of the way towards that goal.

The DRI- making process requires significant volumes of natural gas. To provide the new DRI plant in Louisiana with a sustainable advantage from lower natural gas costs, Nucor entered into a long- term, onshore natural gas working interest drilling program in U.S.- based proven reserves with Encana Oil & Gas (USA) Inc.

("Encana") in 2010. Nucor entered into a second and more significant drilling program with Encana in late 2012. The natural gas produced by these two programs will be sold to offset our exposure to the volatility of the price of natural gas consumed by the Louisiana DRI facility and our other operations. We believe these drilling programs will allow us to better manage our exposure to natural gas pricing volatility and our overall energy demand for our operations.

Growth through greenfield projects has included the construction of our SBQ steel mill in Memphis, Tennessee, which we completed in 2009. We also began commercial production in 2009 at a new facility in Blytheville, Arkansas, which uses breakthrough Castrip® technology to strip cast molten steel into near final shape and thickness with minimal hot or cold rolling. This allows for lower investment and operating costs and reduces the environmental impact of producing steel.

Although the pace at which we have been acquiring other companies has slowed in the past few years, the acquisition of Skyline Steel LLC ("Skyline") in 2012 was a notable exception. The Skyline acquisition is an important strategic investment as it pairs Skyline's leadership position in the steel piling distribution market with our Nucor- Yamato Steel Company ("Nucor- Yamato") joint venture's position as the market leader in steel piling manufacturing. To build upon the synergies in the piling market serviced by Skyline, Nucor announced that Nucor- Yamato will be expanding to broaden its range of hot- rolled piling products. Upon completion in 2014, this project will add several new sheet piling sections, increasing the single sheet widths by 22% and providing a lighter, stronger sheet covering more area at a lower installed cost.

In 2010, we entered into an agreement with Mitsui & Co. (U.S.A.) to form NuMit LLC ("NuMit"), in which we own a 50% economic and voting interest. NuMit owns 100% of the equity interest in Steel Technologies LLC ("Steel Technologies"), which operates 25 sheet processing facilities located throughout the United States, Canada and Mexico. Steel Technologies recently finished construction on a flat- rolled steel processing operation in Celaya, Mexico, that became operational in late 2012. The new 125,000- square- foot facility is equipped with two slitting lines. Additionally, construction is well underway on a new flat- rolled steel processing facility that is expected to open in mid- 2013 in the Bajio region of Mexico. These new investments should allow us to capitalize on the rapid growth in the Mexican automotive industry.

Segments

Nucor reports its results in three segments: steel mills, steel products and raw materials. Net sales to external customers, intercompany sales, depreciation expense, amortization expense, earnings before income taxes and noncontrolling interests, assets and capital expenditures by segment for each of the three fiscal years in the three- year period ended December 31, 2012 are set forth in Note 22 of the Notes to Consolidated Financial Statements included in Nucor's 2012 Annual Report, which is hereby incorporated by reference. The steel mills are Nucor's dominant segment representing approximately 69% of the Company's sales to external customers in the fiscal year ended December 31, 2012.

Principal Products Produced

In the steel mills segment, Nucor produces and distributes sheet steel (hot- rolled, cold- rolled and galvanized), plate steel, structural steel (wide- flange beams, beam blanks, H- piling and sheet piling) and bar steel (blooms, billets, concrete reinforcing bar, merchant bar and SBQ). Nucor manufactures steel principally from scrap steel and scrap steel substitutes using electric arc furnaces, continuous casting and automated rolling mills. The steel mills segment also includes Nucor's equity method investments in Duferdofin Nucor S.r.l. and NuMit. In the steel products segment, Nucor produces steel joists and joist girders, steel deck, fabricated concrete reinforcing steel, cold finished steel, steel fasteners, metal building systems, steel grating and expanded metal, and wire and wire mesh. In the raw materials segment, the Company produces DRI; brokers ferrous and nonferrous metals, pig iron, HBI and DRI; supplies ferro- alloys; and processes ferrous and nonferrous scrap metal. The raw materials segment also includes our natural gas working interest drilling programs with Encana and certain equity method investments.

Markets and Marketing

The steel mills segment sells its products primarily to steel service centers, fabricators and manufacturers located throughout the United States, Canada, Mexico and, increasingly, elsewhere in the world. Nucor produces hot- rolled and cold- rolled sheet steel in standard grades and to customers' specifications while maintaining inventories to fulfill anticipated orders. We estimate that slightly more than 55% of our sheet steel sales in 2012 were to contract customers. The balance of our sheet steel sales was made in the spot market at prevailing prices at the time of sale. The proportion of tons sold to contract customers at any given time depends on a variety of factors, including our consideration of current and future market conditions, our strategy to appropriately balance spot and contract tons to maximize profitability, our desire to sustain a diversified customer base, and our end- use customers' perceptions about future market conditions. These sheet sales contracts permit price adjustments to reflect changes in prevailing raw material costs and typically have terms ranging from six to twelve months. Steel contract sales outside of our sheet operations are not significant.

Our plate, structural, reinforcing and merchant bar steel come in standard sizes and grades, which allows us to maintain inventory levels of these products to meet our customers' expected orders. In addition, our bar mill group manufactures hot- rolled SBQ products to exacting specifications primarily servicing the automotive, energy, agricultural, heavy equipment and transportation sectors. Almost all of our plate, structural, and bar steel sales occur in the spot market at prevailing market prices.

In 2012, we sold approximately 85% of the production by our steel mills segment to external customers. The balance of the steel mill segment's production went to our piling distributor and our downstream joist, deck, rebar fabrication, fastener, metal buildings and cold finish operations.

In the steel products segment, we sell steel joists and joist girders, and steel deck to general contractors and fabricators located throughout the United States and Canada. We make these products to the customers' specifications and do not maintain inventories of these finished steel products. The majority of these contracts are firm, fixed- price contracts that are in most cases competitively bid against other suppliers. Longer- term supply contracts may permit us to adjust our prices to reflect changes in prevailing raw materials costs. We sell fabricated reinforcing products only on a construction contract bid basis. These products are used by contractors in constructing highways, bridges, reservoirs, utilities, hospitals, schools, airports, stadiums and high- rise buildings. We manufacture cold finished steel, steel fasteners, steel grating, wire and wire mesh in standard sizes and maintain inventories of these products to fulfill anticipated orders. We sell cold finished steel and steel fasteners primarily to distributors and manufacturers located throughout the United States and Canada.

We market products from the steel mills and steel products segments mainly through in- house sales forces. The markets for these products are largely tied to capital and durable goods spending and are affected by changes in general economic conditions.

In the raw materials segment, we process ferrous and nonferrous scrap metal for use in our steel mills and for sale to various domestic and international external customers. We also broker ferrous and nonferrous metals and scrap substitutes, supply ferro- alloys, and provide transportation, material handling and other services to users of scrap metals. Our primary external customers for ferrous scrap are electric arc furnace steel mills and foundries that use ferrous scrap as a raw material in their manufacturing process. External customers purchasing nonferrous scrap metal include aluminum can producers, secondary aluminum smelters, steel mills and other processors and consumers of various nonferrous metals. We market scrap metal products and related services to our external customers through in- house sales forces. In 2012, approximately 11% of the ferrous and nonferrous metals and scrap substitutes tons we processed were sold to external customers. We used the balance in our steel mills.

Also within the raw materials segment is our existing DRI plant in Trinidad that produces iron inputs exclusively for use in the Nucor mills, our DRI facility that we are constructing in Louisiana, and our working interest drilling programs. All natural gas produced by the working interest drilling programs is and will be sold to outside parties, and as a result the revenues from these sales are a small but increasing amount of our revenues.

The Company's other operations include international trading companies that buy and sell steel and steel products that Nucor and other steel producers have manufactured.

Backlog

In the steel mills segment, Nucor's backlog of orders was approximately $1.64 billion and $1.80 billion at December 31, 2012 and 2011, respectively. Nucor's backlog of orders in the steel products segment was approximately $1.18 billion and $1.11 billion at December 31, 2012 and 2011, respectively. Order backlogs for the steel mills segment include orders attributable to Nucor's downstream businesses in addition to orders from outside customers. The majority of these orders will be filled within one year. Order backlog within our raw materials segment is not significant because the majority of the raw materials that segment produces are used internally.

Sources and Availability of Raw Materials

The primary raw materials for our steel mills segment are ferrous scrap and scrap substitutes such as pig iron, DRI and HBI. On average, it takes approximately 1.1 tons of scrap and scrap substitutes to produce a ton of steel. As of December 31, 2012, DJJ operated nearly 70 scrap recycling facilities, and our annual scrap processing capability exceeded five million tons. DJJ acquires ferrous scrap from numerous sources including manufacturers of products made from steel, industrial plants, scrap dealers, peddlers, auto wreckers and demolition firms. We purchase pig iron as needed from a variety of sources and operate a DRI plant in Trinidad with a capacity of 2,000,000 metric tons annually. The primary raw material for our DRI facility in Trinidad is iron ore, which we purchase from various international suppliers. We are constructing a second DRI facility in Louisiana with an annual capacity of 2,500,000 metric tons. This Louisiana DRI facility is the first phase of a multi- phase plan that is expected to include additional operations in Louisiana.

In 2010, Nucor entered into an agreement with Encana that involves drilling and completing onshore natural gas wells in U.S.- based proven reserves over an approximate seven- year period that began in June 2010. Nucor entered into a second and more extensive drilling agreement with Encana in late 2012 that is projected to span more than 20 years. Natural gas produced by these working interest drilling programs is being sold to offset our exposure to the volatility of the price of gas consumed by our Louisiana DRI facility. In addition to our natural gas needs at the new DRI facility, Nucor is also a substantial consumer of natural gas at our steel mill operations. The drilling of natural gas wells under the two agreements is expected to provide enough natural gas to equal Nucor's demand at all of its steel mills in the United States plus the demand of two DRI plants or, alternatively, at three DRI plants.

The primary raw material for our steel products segment is steel produced by Nucor's steel mills.

DJJ generally purchases ferrous and nonferrous scrap for sale to external customers from the same variety of sources it purchases ferrous scrap for use as a raw material in Nucor's steel mills. DJJ does not purchase a significant amount of scrap metal from a single source or from a limited number of major sources. The availability and price of ferrous scrap are affected by changes in the global supply and demand for steel and steel products. Ferrous scrap and scrap substitutes are our single largest cost of products sold. A key part of our business strategy is to control a significant portion of the supply of high quality metallics needed to operate our steel mills.

Energy Consumption and Costs

Our steel mills are large consumers of electricity and natural gas. Our DRI facility in Trinidad is, and our Louisiana DRI facility will be, large consumers of natural gas. Consequently, we use a variety of strategies to manage our exposure to price risk of natural gas, including cash flow hedges and our natural gas working interest drilling programs.

Historically, manufacturers in the United States have benefitted from relatively stable and competitive energy costs that have allowed them to compete on an equal footing in the increasingly global marketplace. The availability and prices of electricity and natural gas are influenced today, however, by many factors including changes in supply and demand, advances in drilling technology and, increasingly, changes in public policy relating to energy production and use. Because energy is such a significant cost of products sold for Nucor, we strive continually to make our operations in all three of our business segments more energy efficient. We also closely monitor developments in public policy relating to energy production and consumption. When appropriate, we work to shape those developments in ways that we believe will allow us to continue to be a competitive producer of steel and steel products in an increasingly competitive global market place.

Competition

We compete in a variety of steel and metal markets, including markets for finished steel products, unfinished steel products, and raw materials. These markets are highly competitive with many domestic and foreign firms participating, and, as a result of this highly competitive environment, we find that we primarily compete on price and service.

Our electric- arc furnace steel mills face many different forms of competition, including integrated steel producers (who use iron ore converted into liquid form in a blast furnace as their basic raw material instead of scrap steel), other electric- arc furnace mills, foreign imports and alternative materials. Large integrated steel producers have the ability to manufacture a wide variety of products but face significantly higher energy costs and are often burdened with higher capital and fixed operating costs. Electric- arc furnace mill producers such as Nucor are sensitive to increases in scrap prices but tend to have lower capital and fixed operating costs compared with integrated steel producers.

Recently we have experienced increased competition in the U.S. sheet steel market stemming from significant domestic capacity increases. Despite the closure of some sheet mill assets in 2012, oversupply is still a significant issue. Also contributing to the excess capacity is the high level of imports that came into our country in 2012. These artificially- priced imports make it very difficult for us to maintain sales prices and profit levels. Our average sales price per ton for sheet products dropped by 12% from the first quarter of 2012 to the fourth quarter of 2012 in response to the increased competition.

Competition from foreign steel and steel product producers presents unique challenges for us. Imported steel and steel products often benefit from government subsidies, either directly or indirectly through government- owned enterprises or government- owned or controlled financial institutions. Foreign imports accounted for approximately 24% of the U.S. steel market in 2012. In particular, competition from steel imported from China, which accounts for more than 45% of the steel produced annually in the world, is a major challenge. Chinese producers, many of whom are government-owned in whole or in part, continue to benefit from their government's manipulation of foreign currency exchange rates and from the receipt of government subsidies, which allow them to sell their products below cost. These distorting trade practices are widely recognized as being unfair and have been challenged successfully as violating world trade rules. Examples of successful challenges include the imposition of antidumping duty orders on imports of line pipe, oil country tubular goods, rebar, cut- to- length plate and hot- rolled sheet from China.

China's aggresive trade practices seriously undermine the ability of the Company and other domestic producers to compete on price when left unchallenged. That country's artificially lowered production costs have significantly contributed to the exodus of manufacturing jobs from the United States. When such a flight occurs, the U.S. economy is weakened and Nucor's customer base is diminished, thereby providing us with fewer opportunities to supply steel to those shuttered businesses. Rigorous trade law enforcement is critical to our ability to maintain our competitive position against foreign producers that engage in unlawful trade practices. Nucor has been active in calling on policymakers to enforce global trade agreements and address the jobs crisis in the United States.

We also experience competition from other materials. Depending on our customers' end use of our products, there are sometimes other materials, such as concrete, aluminum, plastics, composites and wood that compete with our steel products. When the price of steel relative to other raw materials rises, these alternatives become more attractive to our customers.

Competition in our scrap and raw materials business is also vigorous. The scrap metals market consists of many firms and is highly fragmented. Firms typically compete on price and geographic proximity to the sources of scrap metal.

Environmental Laws and Regulations

Our business operations are subject to numerous federal, state and local laws and regulations intended to protect the environment. The principal federal environmental laws include the Clean Air Act ("CAA") that regulates air emissions; the Clean Water Act ("CWA") that regulates water discharges; the Resource Conservation and Recovery Act ("RCRA") that addresses solid and hazardous waste treatment, storage and disposal; and the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") that governs releases of, and remediation of sites contaminated by, hazardous substances. Our operations are also subject to state laws and regulations that are patterned on these and other federal laws.

We believe that we are in substantial compliance with the provisions of all federal and state environmental laws and regulations applicable to our business operations. However, both federal and state laws and regulations are becoming increasingly stringent, making compliance with them increasingly expensive and burdensome. In many instances the total costs of compliance are not readily quantifiable because compliance is so engrained in our operating philosophy that these costs are simply considered part of our standard operating procedures.

The United States Environmental Protection Agency ("USEPA") has proposed or promulgated many new national ambient air quality standards and toxic air emissions rules for which it has recently or not yet issued guidance or compliance deadlines. While we begin immediately to plan for compliance with such standards and rules, we cannot fully assess their impact on our operations until the guidance has been fully developed or issued and compliance deadlines have been established. In other cases where environmental regulations are proposed or promulgated that may regulate previously unregulated aspects of our operations, it is impossible for us to fully determine the impact of these regulations until protracted legal challenges have been concluded and USEPA or other regulatory agencies have developed and issued technical guidance. Despite this atmosphere of regulatory uncertainty, at this time we do not believe that compliance with these new environmental regulations will have a material adverse effect on our results of operations, cash flows or financial condition.

The CAA imposes stringent limits on air emissions with a federally mandated operating permit program administered by the states with civil and criminal enforcement sanctions. Each of our steel mills is required to operate in compliance with its permit or potentially incur sanctions for failing to do so. Our Louisiana DRI facility under construction was permitted under the CAA in January 2011. This permit included an evaluation and determination of Best Available Control Technology ("BACT") for USEPA's new "Greenhouse Gasses" ("GHGs") rule. Because of the size of our steelmaking operations, they are also subject to these new GHG regulations and will be required to do GHG BACT evaluations if their permits are modified in the future. There is still uncertainty and very little guidance from USEPA as to what is or may be considered GHG BACT for steelmaking operations. Our operations are currently properly permitted, and we will not need to make these determinations unless and until these permits are modified. Based on current guidance, we do not expect these requirements to have a material adverse effect on our results of operations, cash flows or financial condition.

Nucor uses electric arc furnaces ("EAF") to recycle scrap metal into new steel products. These EAFs use electricity as their primary source of energy. As the new GHG regulations, air toxics rules and other new environmental regulations are imposed on electric utilities, it is reasonable to expect that the cost of electricity produced by these utilities will increase. See Item 1A "Risk Factors" for more information about the potential impact of GHG regulations on Nucor's business.

The CWA regulates water discharges and withdrawals. Nucor maintains discharge and withdrawal permits as appropriate at its facilities under the national pollutant discharge elimination system program of the CWA and conducts its operations in compliance with those permits. Nucor also maintains permits from local governments for the discharge of water into publicly owned treatment works where available.

RCRA establishes standards for the management of solid and hazardous wastes. RCRA also addresses the environmental impact of contamination from waste disposal activities and from recycling of and storage of most wastes. While Nucor believes it is in substantial compliance with these regulations, past waste disposal activities that were legal when conducted but now may pose a contamination threat are periodically discovered. These and off- site properties that USEPA has determined are contaminated, for which Nucor may be potentially responsible at some level, are quickly evaluated and corrected. While Nucor has conducted and is in the final stages of completing some cleanups under RCRA, these liabilities either are identified already and being resolved or have been fully resolved.

Because Nucor long ago implemented environmental practices that have resulted in the responsible disposal of waste materials, Nucor is also not presently considered a major contributor to any major cleanups under CERCLA for which Nucor has been named a potentially responsible party. Nucor continually evaluates these types of potential liabilities and, if appropriate, maintains reserves sufficient to remediate the identified liabilities. Under RCRA, private citizens may also bring an action against the operator of a regulated facility for potential damages and payment of cleanup costs. Nucor is confident that its system of internal evaluation and due diligence has sufficiently identified these types of potential liabilities so that compliance with these regulations will not have a material adverse effect on our results of operations, cash flows or financial condition beyond that already reflected in the reserves established for them.

The primary raw material of Nucor's steelmaking operations is scrap metal. The process of recycling scrap metal brings with it many contaminants such as paint, zinc, chrome and other metals that produce air emissions which are captured in specialized emission control equipment. This filtrant (EAF dust) is classified as a listed hazardous waste under the RCRA. Because these contaminants contain valuable metals, this filtrant is recycled to recover those metals. Nucor sends all but a small fraction of the EAF dust it produces to recycling facilities that recover the zinc, lead, chrome and other valuable metals from this dust. By recycling this material, Nucor is not only acting in a sustainable, responsible manner but is also substantially limiting its potential for future liability under both CERCLA and RCRA.

Nucor operates an aggressive and sustainable environmental program that incorporates the concept of individual employee as well as management responsibility for environmental performance. All of Nucor's steelmaking operations are ISO 14001 certified. Achieving ISO 14001 certification means that each of Nucor's steel mills has put an environmental management system in place with measurable targets and objectives, such as reducing the use of oil and grease and minimizing electricity use, and has implemented site- wide recycling programs. These environmental management systems make environmental commitment each Nucor teammate's responsibility. Nucor's environmental program maintains a high level of training, commitment, outreach and visibility.

Capital expenditures at our facilities that are associated with environmental regulation compliance for 2013 and 2014 are estimated to be less than $100 million per year.

Employees

Nucor has a simple, streamlined organizational structure to allow our employees to make quick decisions and be innovative. Our organization is highly decentralized, with most day- to- day operating decisions made by our division general managers and their staff. We have fewer than 100 employees in our executive office. The majority of Nucor's 22,200 employees are not represented by labor unions.

Available Information
Nucor's annual report on Form 10- K, quarterly reports on Form 10- Q, Current Reports on Form 8- K, and any amendments to these reports, are available on our website at www.nucor.com, as soon as reasonably practicable after Nucor files these reports electronically with, or furnishes them to, the Securities and Exchange Commission ("SEC"). Except as otherwise stated in these reports, the information contained on our website or available by hyperlink from our website is not incorporated into this Annual Report on Form 10- K or other documents we file with, or furnish to, the SEC.

Item 1A. Risk Factors
Many of the factors that affect our business and operations involve risk and uncertainty. The factors described below are some of the risks that could materially negatively affect our business, financial condition and results of operations.
Recovery from the global recession and credit crisis has and likely will continue to adversely affect our business.
The sluggish pace of the recovery from the deep global recession that began in the United States in December 2007 and officially ended in June 2009 is continuing to have an adverse effect on demand for our products and consequently the results of our operations, financial condition and cash flows. In addition, uncertainties in Europe regarding the financial sector and sovereign debt and the potential impact on banks in other regions of the world will continue to weigh on global and domestic growth.
Although domestic credit markets have largely stabilized from the height of the financial crisis in the fourth quarter of 2008 and the first half of 2009, the effects of the financial crisis continue to present additional risks to us, our customers and suppliers. In particular, there is no guarantee that the credit markets or liquidity will not once again be restricted. Additionally, stricter lending standards have made it more difficult and costly for some firms to access the credit markets. Although we believe we have adequate access to several sources of contractually committed borrowings and other available credit facilities, these risks could temporarily restrict our ability to borrow money on acceptable terms in the credit markets and potentially could affect our ability to draw on our credit facility. In addition, restricted access to the credit markets is also continuing to make it difficult or, in some cases, impossible for our customers to borrow money to fund their operations. Lack of, or limited access to, capital would adversely affect our customers' ability to purchase our products or, in some cases, to pay for our products on a timely basis.
Long- term unemployment for those unemployed for more than six months remains at historically high levels and the housing market and nonresidential construction market remain depressed. High unemployment and a weak housing market have an impact on downstream demand for many of our products. Additionally, nonresidential construction, including publicly financed state and municipal projects, has slowed significantly due to overcapacity of commercial properties and the reluctance of state and local governments to borrow to spend on capital projects when their operating expenses are in many cases growing faster than their revenues from taxes and other sources.
Our industry is cyclical and both recessions and prolonged periods of slow economic growth could have a material adverse effect on our business.
Demand for most of our products is cyclical in nature and sensitive to general economic conditions. Our business supports cyclical industries such as the commercial construction, energy, appliance and automotive industries. As a result, downturns in the United States economy or any of these industries could materially adversely affect our results of operations, financial condition and cash flows. The global economic recession of 2008-2009 and subsequent anemic economic recovery period, coupled with the lingering effects of the global financial and credit market disruptions, have had a historic negative impact on the steel industry and Nucor. These events contributed to an unprecedented decline in pricing for steel and steel products, weak end- markets

and continued depressed demand, resulting in extraordinary volatility in our financial results since the last up- cycle. In 2009, we reported a net loss of $293.6 million, the first in the Company's history. Although we have since returned to profitability, the economic outlook remains uncertain both in the United States and globally. While we believe that the long- term prospects for the steel industry remain bright, we are unable to predict the duration of the depressed economic conditions that are contributing to reduced demand for our products. Future economic downturns or a prolonged slow- growth or stagnant economy could materially adversely affect our business, results of operations, financial condition and cash flows.

Overcapacity in the global steel industry could increase the level of steel imports, which may negatively affect our business, results of operations and cash flows.

Global steelmaking capacity exceeds global consumption of steel products. During periods of global economic weakness this overcapacity is amplified because of weaker global demand. This excess capacity often results in manufacturers in certain countries exporting significant amounts of steel and steel products at prices that are at or below their costs of production. In some countries the steel industry is subsidized or owned in whole or in part by the government, giving imported steel from those countries certain cost advantages. These imports, which are also affected by demand in the domestic market, international currency conversion rates and domestic and international government actions, can result in downward pressure on steel prices, which could materially adversely affect our business, results of operations, financial condition and cash flows. Over capacity has also led to greater protectionism as is evident in raw material and finished product border tariffs put in place by China, Brazil and other countries.

In particular, steel production in China, the world's largest producer and consumer of steel, continues to exceed Chinese demand. This rising overcapacity in China has the potential to result in a further increase in imports of artificially low- priced steel and steel products to the United States that could put our steel products at a competitive disadvantage. A continuation of this unbalanced growth trend or a significant decrease in China's rate of economic expansion could result in increasing steel exports from China.

The recent addition of new capacity and expansion or restarting of existing sheet steel production in the United States has exacerbated this issue domestically as well as globally.

Competition from other producers, imports or alternative materials may have a material adverse effect on our business.

We face strong competition from other steel producers and imports that compete with our products on price and service. The steel markets are highly competitive and a number of firms, domestic and foreign, participate in the steel and raw materials markets. Depending on a variety of factors, including raw materials, energy, labor and capital costs, government control of currency exchange rates and government subsidies of foreign steel producers, our business may be materially adversely affected by competitive forces.

In many applications, steel competes with other materials, such as concrete, aluminum, composites, plastic and wood. Increased use of these materials in substitution for steel products could have a material adverse effect on prices and demand for our steel products.

In 2011, automobile producers began taking steps towards complying with new Corporate Average Fuel Economy ("CAFE") mileage requirements for new cars and light trucks that they produce. As automobile producers work to produce vehicles in compliance with these new standards, they may reduce the amount of steel in cars and trucks to improve fuel economy, thereby reducing demand for steel and resulting in further over- supply of steel in North America.

The results of our operations are sensitive to volatility in steel prices and the cost of raw materials, particularly scrap steel.

We rely to an extent on outside vendors to supply us with raw materials, including both scrap and scrap substitutes, that are critical to the manufacture of our products. Although we have vertically integrated our business by constructing our DRI facilities in Trinidad and Louisiana and also acquiring DJJ, we still must purchase most of our primary raw material, steel scrap, from numerous other sources located throughout the United States. Although we believe that the supply of scrap and scrap substitutes is adequate to operate our facilities, prices of these critical raw materials are volatile and are influenced by changes in scrap exports in response to changes in the scrap demands of our global competitors. At any given time, we may be unable to obtain an adequate supply of these critical raw materials with price and other terms acceptable to us. The availability and prices of raw materials may also be negatively affected by new laws and regulations, allocation by suppliers, interruptions in production, accidents or natural disasters, changes in exchange rates, worldwide price fluctuations, and the availability and cost of transportation. Many countries that export steel into our markets restrict the export of scrap, protecting the supply chain of some foreign competitors. This trade practice creates artificial competitive advantage for foreign producers that could limit our ability to compete in the U.S. market.

If our suppliers increase the prices of our critical raw materials, we may not have alternative sources of supply. In addition, to the extent that we have quoted prices to our customers and accepted customer orders for our products prior to purchasing necessary raw materials, we may be unable to raise the price of our products to cover all or part of the increased cost of the raw materials, although we have successfully used a raw material surcharge in the steel mills segment since 2004. Also, if we are unable to obtain adequate and timely deliveries of our required raw materials, we may be unable to timely manufacture sufficient quantities of our products. This could cause us to lose sales, incur additional costs and suffer harm to our reputation.

Changes in the availability and cost of electricity and natural gas are subject to volatile market conditions that could adversely affect our business.

Our steel mills are large consumers of electricity and natural gas. In addition, our DRI facilities are also large consumers of natural gas. We rely upon third parties for our supply of energy resources consumed in the manufacture of our products. The prices for and availability of electricity, natural gas, oil and other energy resources are subject to volatile market conditions. These market conditions often are affected by weather, political and economic factors beyond our control, and we may be unable to raise the price of our products to cover increased energy costs. Disruptions in the supply of our energy resources could temporarily impair our ability to manufacture our products for our customers. Increases in our energy costs resulting from regulations that are not equally applicable across the entire global steel market could materially adversely affect our business, results of operations, financial condition and cash flows.

A substantial or extended decline in natural gas prices could have a material adverse effect on our natural gas working interest drilling programs.

The financial performance and condition of our natural gas drilling programs are substantially dependent on the prevailing prices of natural gas and liquids. Fluctuations in natural gas or liquids prices could have an adverse effect on the Company's natural gas operations and financial condition and the value and recovery of its reserves in the working interest drilling programs. Prices for natural gas and liquids fluctuate in response to changes in the supply and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond the Company's control. A substantial or extended decline in the price of natural gas could result in a delay or cancellation of existing or future drilling programs or curtailment in production at some properties, all of which could have an adverse effect on the Company's revenues, profitability and cash flows.

Our steelmaking and DRI processes, and the manufacturing processes of many of our suppliers and customers, are energy intensive and generate carbon dioxide and other GHGs, and regulation of GHGs, through new regulations or legislation in an onerous form, could have a material adverse impact on our results of operations, financial condition and cash flows.

Carbon is an essential raw material in Nucor's production processes. As a carbon steel producer, Nucor will be increasingly affected both directly and indirectly as GHG regulations are further implemented. Because these operations are subject to most of these new GHG regulations, we have already begun to feel the impact in the permit modification and reporting processes. Both GHG regulations and recently promulgated National Ambient Air Quality Standards ("NAAQS"), which are more restrictive than previous standards, make it significantly more difficult to obtain new permits and to modify existing permits. If one of our permits is revoked or if we experience significant delays in obtaining a permit modification, we could experience operational delays at one or more of our facilities, causing a negative impact on our results of operations and cash flows.

These same regulations have indirectly increased the costs to manufacture our products as they have increased the cost of energy, primarily electricity, which we use extensively in the steelmaking process. The discovery of new natural gas reserves utilizing the practice of horizontal drilling and hydraulic fracturing is dampening some of this indirect impact, as some utilities switch fuels to natural gas from coal thereby reducing their emissions significantly. To the extent that these regulations cause an increase in the cost of energy, they will have an impact on Nucor's ability to compete.

The USEPA continues to press forward with new regulations that control GHG and other NAAQS pollutants. Most of these and other related regulations are already, or we expect will shortly be, challenged in court. Until all proposed GHG emission regulations are adopted in final form and all legal challenges are resolved, we cannot reliably estimate their full impact on our financial condition, operating performance or ability to compete. Because some foreign steel producers are not subject to these same indirect cost increases, our products could be at a further competitive disadvantage. In addition to increased costs of production, we could also incur costs to defend and resolve legal claims and other litigation related to new air and water quality regulations and the alleged impact of our operations on climate change.

Environmental compliance and remediation could result in substantially increased costs and materially adversely impact our competitive position.

Our operations are subject to numerous federal, state and local laws and regulations relating to protection of the environment, and we, accordingly, make provision in our financial statements for the estimated costs of compliance. These laws are becoming increasingly stringent, resulting in inherent uncertainties in these estimates. To the extent that competitors, particularly foreign steel producers and manufacturers of competitive products, are not required to incur equivalent costs, our competitive position could be materially adversely impacted.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress has considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process, and other legislation regulating hydraulic fracturing has been considered, and in some cases adopted, at various levels of government. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale and tight sand formations, including all of those in our drilling program. This process involves the injection of water, chemicals and, at times, sand under pressure into rock formations to stimulate the production of natural gas, oil and natural gas liquids. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and/or that hydraulic fracturing could pose a variety of other risks. Any onerous governmental regulations could lead to operational delays, increased operating costs that could make it more difficult to perform hydraulic fracturing and possibly even the cessation of drilling.

We plan to continue to implement our acquisition strategy and may encounter difficulties in integrating businesses we acquire.

We plan to continue to seek attractive opportunities to acquire businesses, enter into joint ventures and make other investments that are complementary to our existing strengths. Realizing the anticipated benefits of acquisitions or other transactions will depend on our ability to operate these businesses and integrate them with our operations and to cooperate with our strategic partners. Our business, results of operations, financial condition and cash flows could be materially adversely affected if we are unable to successfully integrate these businesses.

In addition, we may enter into joint ventures or acquisitions located outside the U.S., which may be adversely affected by foreign currency fluctuations, changes in economic conditions and changes in local government regulations and policies.

Our operations are subject to business interruptions and casualty losses.

The steelmaking business is subject to numerous inherent risks, particularly unplanned events such as explosions, fires, other accidents, natural or man- made disasters, acts of terrorism, inclement weather and transportation interruptions. While our insurance coverage could offset losses relating to some of those types of events, our results of operations and cash flows could be adversely impacted to the extent any such losses are not covered by our insurance.

Our business requires substantial capital investment and maintenance expenditures, and our capital resources may not be adequate to provide for all of our cash requirements.

Our operations are capital intensive. For the five- year period ended December 31, 2012, our total capital expenditures, excluding acquisitions, were approximately $3.23 billion. Our business also requires substantial expenditures for routine maintenance. Although we expect requirements for our business needs, including the funding of capital expenditures, debt service for financings and any contingencies, will be financed by internally generated funds or from borrowings under our $1.5 billion unsecured revolving credit facility, we cannot assure you that this will be the case. Additional acquisitions could require financing from external sources.

Changes in foreign currency may adversely affect our financial results.

Because of our international expansion efforts, we are increasingly exposed to changes in foreign exchange rates. Generally, each of our foreign operations both produces and sells in its local currency, limiting our exposure to foreign currency transactions. We monitor our exposures and, from time to time, may use forward currency contracts to hedge certain forecasted currency transactions. In addition to potential transaction losses, our reported results of operations and financial position could be negatively affected by exchange rates when the activities and balances of our foreign operations are translated into U.S. dollars for financial reporting purposes.

The accounting treatment of equity method investments, goodwill and other long- lived assets could result in future asset impairments, which would reduce our earnings.

We periodically test our equity method investments, goodwill and other long- lived assets to determine whether their estimated fair value is less than their value recorded on our balance sheet. The results of this testing for potential impairment may be adversely affected by the continuing uncertain market conditions for the steel industry, as well as changes in interest rates and general economic conditions. If we determine that the fair value of any of these long- lived assets is less than the value recorded on our balance sheet, and in the case of equity method investments the decline is other than temporary, we would likely incur a non- cash impairment loss that would negatively impact our results of operations.

Tax increases and changes in tax rules could adversely affect our financial results.

The steel industry and our business are sensitive to changes in taxes. As a company based in the U.S., Nucor is more exposed to the effects of changes in U.S. tax laws than some of our major competitors. Our provision for income taxes and cash tax liability in the future could be adversely affected by changes in U.S. tax laws. Potential changes that would adversely affect us include, but are not limited to, current proposals for corporate tax reform which would lower tax rates and eliminate most tax expenditures (repealing LIFO (last- in, first- out treatment of inventory), accelerated depreciation, and the domestic production activity deduction) and decreasing the ability of U.S. companies to receive a tax credit for foreign taxes paid or to defer the U.S. deduction of expenses in connection with investments made in other countries.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

We own all of our principal operating facilities. These facilities, by segment, are as follows:

Location	Approximate square footage of facilities	Principal products
Steel mills:		
Blytheville, Arkansas	2,560,000	Steel shapes, flat- rolled steel
Berkeley County, South Carolina	2,170,000	Flat- rolled steel, steel shapes
Decatur, Alabama	2,000,000	Flat- rolled steel
Crawfordsville, Indiana	1,880,000	Flat- rolled steel
Hickman, Arkansas	1,450,000	Flat- rolled steel
Norfolk, Nebraska	1,440,000	Steel shapes
Plymouth, Utah	1,190,000	Steel shapes
Hertford County, North Carolina	1,110,000	Steel plate
Jewett, Texas	1,080,000	Steel shapes
Darlington, South Carolina	940,000	Steel shapes
Seattle, Washington	640,000	Steel shapes
Memphis, Tennessee	570,000	Steel shapes
Auburn, New York	450,000	Steel shapes
Marion, Ohio	440,000	Steel shapes
Kankakee, Illinois	430,000	Steel shapes
Jackson, Mississippi	410,000	Steel shapes
Kingman, Arizona	380,000	Steel shapes
Tuscaloosa, Alabama	370,000	Steel plate
Birmingham, Alabama	280,000	Steel shapes
Wallingford, Connecticut	240,000	Steel shapes
Steel products:		
Norfolk, Nebraska	1,080,000	Joists, deck, cold finished bar
Brigham City, Utah	730,000	Joists, cold finished bar
Grapeland, Texas	680,000	Joists, deck
St. Joe, Indiana	550,000	Joists, deck
Chemung, New York	550,000	Joists, deck
Florence, South Carolina	540,000	Joists, deck
Fort Payne, Alabama	470,000	Joists, deck

Our steel mills segment also includes Skyline, our steel foundation distributor with U.S. manufacturing facilities in seven states and one facility in Canada. Additionally, we have a distribution center in Pompano Beach, Florida.

In the steel products segment, we have 77 additional operating facilities in 37 states and 28 operating facilities in Canada. Our affiliate, Harris Steel, also operates multiple sales offices in Canada and certain other foreign locations.

In the raw materials segment, DJJ has 76 operating facilities in 16 states along with multiple brokerage offices in the U.S. and certain other foreign locations. Nucor's raw materials segment also includes our DRI facilities. Nucor has a DRI facility in operation in Point Lisas, Trinidad, and a DRI facility under construction in St. James Parish, Louisiana. A significant portion of the DRI production process occurs outdoors. The Trinidad site including leased land is approximately 1.84 million square feet. The Louisiana site, which is expected to begin operations in mid- 2013, has approximately 169.8 million square feet of owned land with buildings under construction that will total approximately 72,000 square feet when completed.

During 2012, the average utilization rates of all operating facilities in the steel mills, steel products and raw materials segments were approximately 74%, 60% and 63% of production capacity, respectively.

We also own our principal executive office in Charlotte, North Carolina.

Item 3. Legal Proceedings

Nucor has been named, along with other major steel producers, as a co- defendant in several related antitrust class- action complaints filed by Standard Iron Works and other steel purchasers in the United States District Court for the Northern District of Illinois. The majority of these complaints were filed in September and October of 2008, with two additional complaints being filed in July and December of 2010. Two of these complaints have been voluntarily dismissed and are no longer pending. The plaintiffs allege that from April 1, 2005 through December 31, 2007, eight steel manufacturers, including Nucor, engaged in anticompetitive activities with respect to the production and sale of steel. The plaintiffs seek monetary and other relief. Although we believe the plaintiffs' claims are without merit and will vigorously defend against them, we cannot at this time predict the outcome of this litigation or estimate the range of Nucor's potential exposure.

Nucor is involved in various other judicial and administrative proceedings as both plaintiff and defendant, arising in the ordinary course of business. Nucor maintains liability insurance for certain risks that arise that are also subject to certain self- insurance limits. Although the outcome of the claims and proceedings against us cannot be predicted with certainty, we believe that there are no existing claims or proceedings that are likely to have a material adverse effect on the consolidated financial statements.

Item 4. Mine Safety Disclosures

Executive Officers of the Registrant

James R. Darsey (57)- Mr. Darsey has been an Executive Vice President of Nucor since September 2010. He was promoted to Vice President in 1996 and to President of the Vulcraft/Verco Group in 2007. He was General Manager of Nucor Steel, Jewett, Texas from 1999 to 2007; General Manager of Vulcraft, Grapeland, Texas from 1995 to 1999; Engineering Manager of Vulcraft, Grapeland, Texas from 1987 to 1995; and Engineering Manager of Vulcraft, Brigham City, Utah from 1986 to 1987. He began his Nucor career in 1979 as a Design Engineer at Vulcraft, Grapeland, Texas.

Daniel R. DiMicco (62)- Mr. DiMicco has served as Executive Chairman of Nucor since January 2013 and has been a director of Nucor since September 2000. Previously, Mr. DiMicco served as Chairman of Nucor from May 2006 to December 2012, Chief Executive Officer from September 2000 to December 2012 and President from September 2000 to December 2010. Mr. DiMicco also served as Vice Chairman of Nucor from June 2001 to May 2006, Executive Vice President from 1999 to 2000 and Vice President from 1992 to 1999, serving as General Manager of Nucor-Yamato Steel Company. Mr. DiMicco began his career with Nucor in 1982 at Nucor Steel, Plymouth, Utah.

John J. Ferriola (60)- Mr. Ferriola has served as Chief Executive Officer and President of Nucor since January 2013 and has been a director of Nucor since January 2011. Previously, Mr. Ferriola served as President and Chief Operating Officer from January 2011 to December 2012 and, prior to that, as Chief Operating Officer of Steelmaking Operations from 2007 to 2010, Executive Vice President from 2002 to 2007 and Vice President from 1996 to 2001. He was General Manager of Nucor Steel, Crawfordsville, Indiana from 1998 to 2001; General Manager of Nucor Steel, Norfolk, Nebraska from 1995 to 1998; General Manager of Vulcraft, Grapeland, Texas in 1995; and Manager of Maintenance and Engineering at Nucor Steel, Jewett, Texas from 1992 to 1995.

James D. Frias (56)- Mr. Frias has been Chief Financial Officer, Treasurer and Executive Vice President since January 2010. He was a Vice President of Nucor from 2006 to 2009. Mr. Frias previously served as Corporate Controller from 2001 to 2009; Controller of Nucor Steel, Crawfordsville, Indiana from 1994 to 2001; and Controller of Nucor Building Systems, Waterloo, Indiana from 1991 to 1994.

Keith B. Grass (56)- Mr. Grass became an Executive Vice President of Nucor in February 2008 when Nucor acquired DJJ. He has served as Chief Executive Officer of DJJ since 2000 and served as President of DJJ from 2000 until December 2012. Prior to 2000, Mr. Grass held the following positions with DJJ: President and Chief Operating Officer of the Metal Recycling Division during 1999; President of the International Division from 1996 to 1998; Vice President of Trading from 1992 to 1996; District Manager of the Chicago trading office from 1988 to 1992; District Manager of the Detroit office from 1986 to 1988; and District Manager of the Omaha office from 1985 to 1986. Mr. Grass began his career as a brokerage representative in DJJ's Chicago office in 1978.

Ladd R. Hall (56)- Mr. Hall has been an Executive Vice President of Nucor since September 2007. He was Vice President and General Manager of Nucor Steel, Berkeley County, South Carolina from 2000 to 2007; Vice President and General Manager of Nucor Steel, Darlington, South Carolina from 1998 to 2000; Vice President of Vulcraft, Brigham City, Utah from 1994 to 1998 and General Manager there from 1993 to 1994; General Manager of Vulcraft, Grapeland, Texas in 1993; Sales Manager of Vulcraft, Brigham City, Utah from 1988 to 1993; and Inside Sales at Nucor Steel Plymouth, Utah from 1981 to 1988.

Hamilton Lott, Jr. (63)- Mr. Lott has been an Executive Vice President of Nucor since September 1999 and was a Vice President from 1988 to 1999. He was General Manager of Vulcraft, Florence, South Carolina from 1993 to 1999; General Manager of Vulcraft, Grapeland, Texas from 1987 to 1993; Sales Manager of Vulcraft, St. Joe, Indiana from January 1987 to May 1987 and Engineering Manager there from 1982 to 1986. Mr. Lott began his career with Nucor as Design Engineer at Vulcraft, Florence, South Carolina in 1975.

R. Joseph Stratman (56)- Mr. Stratman has been an Executive Vice President of Nucor since September 2007 and was Vice President and General Manager of Nucor- Yamato Steel Company from 1999 to 2007. He was Vice President of Nucor Steel, Norfolk, Nebraska in 1999 and General Manager there from 1998 to 1999; Controller of Nucor- Yamato Steel Company from 1991 to 1998; and Controller of Nucor Building Systems, Waterloo, Indiana from 1989 to 1991.

PART II

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

Nucor has increased its base cash dividend every year since the Company began paying dividends in 1973. Nucor paid a total dividend of $1.46 per share in 2012 compared with $1.45 per share in 2011. In December 2012, the board of directors increased the base quarterly cash dividend on Nucor's common stock to $0.3675 per share from $0.365 per share. In February 2013, the board of directors declared Nucor's 160th consecutive quarterly cash dividend of $0.3675 per share payable on May 10, 2013 to stockholders of record on March 28, 2013.

Additional information regarding the market for Nucor's common stock, quarterly market price ranges, the number of stockholders and dividend payments is incorporated by reference to Nucor's 2012 Annual Report, page 72.

Item 6. Selected Financial Data

Historical financial information is incorporated by reference to Nucor's 2012 Annual Report, page 41.

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

Information required by this item is incorporated by reference to Nucor's 2012 Annual Report, page 2 (Forward- looking Statements) and pages 20 through 37.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

In the ordinary course of business, Nucor is exposed to a variety of market risks. We continually monitor these risks and develop appropriate strategies to manage them.

Interest Rate Risk- Nucor manages interest rate risk by using a combination of variable- rate and fixed- rate debt. At December 31, 2012, 28% of Nucor's long- term debt was in industrial revenue bonds that have variable interest rates that are adjusted weekly or annually. The remaining 72% of Nucor's debt is at fixed rates. Future changes in interest rates are not expected to significantly impact earnings. Nucor also makes use of interest rate swaps to manage net exposure to interest rate changes. As of December 31, 2012, there were no such contracts outstanding. Nucor's investment practice is to invest in securities that are highly liquid with short maturities. As a result, we do not expect changes in interest rates to have a significant impact on the value of our investment securities recorded as short- term investments.

Commodity Price Risk- In the ordinary course of business, Nucor is exposed to market risk for price fluctuations of raw materials and energy, principally scrap steel, other ferrous and nonferrous metals, alloys and natural gas. We attempt to negotiate the best prices for our raw materials and energy requirements and to obtain prices for our steel products that match market price movements in response to supply and demand. We employ a raw material surcharge as a component of pricing steel to facilitate the passing through of increased costs of scrap steel and other raw materials. In periods of stable demand for our products, our surcharge mechanism has worked effectively to reduce the normal time lag in passing through higher raw material costs so that we can maintain our gross margins. When demand for and cost of raw materials is lower, however, the surcharge impacts our sales prices to a lesser extent.

Our natural gas working interest drilling programs are affected by volatility of natural gas prices in an inverse manner to natural gas costs at our steel production and DRI facilities. This relationship is part of the value proposition and why these drilling programs serve as a natural hedge to price volatility of the natural gas we use in our steel production and DRI facilities.

Nucor also uses derivative financial instruments from time to time to hedge a portion of our exposure to price risk related to natural gas purchases used in the production process and to hedge a portion of our scrap, aluminum and copper purchases and sales. Gains and losses from derivatives designated as hedges are deferred in accumulated other comprehensive income (loss) on the consolidated balance sheets and recognized into earnings in the same period as the underlying physical transaction. At December 31, 2012, there are no amounts in accumulated other comprehensive income (loss) related to derivative instruments as all of our previously held positions have settled. Changes in the fair values of derivatives not designated as hedges are recognized in earnings each period. The following table presents the negative effect on pre- tax earnings of a hypothetical change in the fair value of derivative instruments outstanding at December 31, 2012, due to an assumed 10% and 25% change in the market price of each of the indicated commodities (in thousands):

Commodity Derivative	10% Change	25% Change
Aluminum	$ 1,910	$ 4,774
Copper	1,109	2,772

Any resulting changes in fair value would be recorded as adjustments to other comprehensive income (loss), net of tax, or recognized in net earnings, as appropriate. These hypothetical losses would be partially offset by the benefit of lower prices paid or higher prices received for the physical commodities.

Foreign Currency Risk- Nucor is exposed to foreign currency risk primarily through its operations in Canada, Europe, Trinidad and Colombia. We periodically use derivative contracts to mitigate the risk of currency fluctuations. Open foreign currency derivative contracts at December 31, 2012 and 2011 were insignificant.

Item 8. Financial Statements and Supplementary Data

Information required by this item is incorporated by reference to Nucor's 2012 Annual Report, pages 42 through 68.

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

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures- As of the end of the period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the evaluation date.

Changes in Internal Control Over Financial Reporting- There were no changes in our internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report on Internal Control Over Financial Reporting- Management's report on internal control over financial reporting required by Section 404 of the Sarbanes- Oxley Act of 2002 and the attestation report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, on the effectiveness of Nucor's internal control over financial reporting as of December 31, 2012 are incorporated by reference to Nucor's 2012 Annual Report, pages 42 and 43.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item about Nucor's executive officers is contained in Part I of this Form 10- K. The other information required by this Item is contained in the sections of Nucor's Proxy Statement for the 2013 Annual Meeting of Stockholders (the "Proxy Statement") captioned *Election of Directors, Section 16(a) Beneficial Ownership Reporting Compliance* and *Corporate Governance and Board of Directors*, which sections are incorporated by reference.

Nucor has adopted a Code of Ethics for Senior Financial Professionals ("Code of Ethics") that applies to the Company's Chief Executive Officer, Chief Financial Officer, Corporate Controller and other senior financial professionals, as well as Corporate Governance Principles for our Board of Directors and charters for our board committees. These documents are publicly available on our website, www.nucor.com. If we make any substantive amendments to the Code of Ethics or grant any waiver, including any implicit waiver, from a provision of the Code of Ethics, we will disclose the nature of such amendment or waiver on our website.

Item 11. Executive Compensation

The information required by this item is included under the headings *Compensation Discussion and Analysis*, *Corporate Governance and Board of Directors*, *Report of the Compensation and Executive Development Committee* in Nucor's Proxy Statement and is incorporated herein by reference.

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

Information required by this item with respect to security ownership of certain beneficial owners and management is incorporated by reference to Nucor's Proxy Statement under the heading *Security Ownership of Management and Certain Beneficial Owners.*

The information regarding the number of securities issuable under equity compensation plans and the related weighted average exercise price is incorporated by reference to the Proxy Statement under the heading *Equity Compensation Plan Information*.

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

Information required by this item is incorporated by reference to Nucor's Proxy Statement under the heading *Corporate Governance and Board of Directors*.

Item 14. Principal Accountant Fees and Services

Information about the fees in 2012 and 2011 for professional services rendered by our independent registered public accounting firm is incorporated by reference to Nucor's Proxy Statement under the heading *Fees Paid to Independent Registered Public Accounting Firm*. The description of our audit committee's policy on pre- approval of audit and permissible non- audit services of our independent registered public accounting firm is also incorporated by reference from the same section of the Proxy Statement.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

Financial Statements:

The following consolidated financial statements and the report of independent registered public accounting firm are incorporated by reference to Nucor's 2012 Annual Report, pages 42 through 68:

Management's Report on Internal Control Over Financial Reporting

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets- December 31, 2012 and 2011

Consolidated Statements of Earnings- Years ended December 31, 2012, 2011 and 2010

Consolidated Statements of Comprehensive Income- Years ended December 31, 2012, 2011, and 2010

Consolidated Statements of Stockholders' Equity- Years ended December 31, 2012, 2011 and 2010

Consolidated Statements of Cash Flows- Years ended December 31, 2012, 2011 and 2010

Notes to Consolidated Financial Statements

Financial Statement Schedules:

The following financial statement schedule is included in this report as indicated:

	Page
Report of Independent Registered Public Accounting Firm on Financial Statement Schedule	25
Schedule II- Valuation and Qualifying Accounts- Years ended December 31, 2012, 2011 and 2010	26

All other schedules are omitted because they are not required, not applicable, or the information is furnished in the consolidated financial statements or notes.

Exhibits:

3	Restated Certificate of Incorporation (incorporated by reference to Form 8- K filed September 14, 2010)
3(i)	Bylaws as amended and restated September 11, 2012 (incorporated by reference to Form 8- K filed September 13, 2012)
4	Indenture, dated as of January 12, 1999, between Nucor Corporation and The Bank of New York Mellon (formerly known as The Bank of New York), as trustee (incorporated by reference to Form S- 4 filed December 13, 2002)
4(i)	Second Supplemental Indenture, dated as of October 1, 2002, between Nucor Corporation and The Bank of New York Mellon (formerly known as The Bank of New York), as trustee (incorporated by reference to Form S- 4 filed December 13, 2002)
4(ii)	Third Supplemental Indenture, dated as of December 3, 2007, between Nucor Corporation and The Bank of New York Mellon (formerly known as The Bank of New York), as trustee (incorporated by reference to Form 8- K filed December 4, 2007)
4(iii)	Fourth Supplemental Indenture, dated as of June 2, 2008, between Nucor Corporation and The Bank of New York Mellon (formerly known as The Bank of New York), as trustee (incorporated by reference to Form 8- K filed June 3, 2008)
4(iv)	Fifth Supplemental Indenture, dated as of September 21, 2010, between Nucor Corporation and The Bank of New York Mellon (formerly known as The Bank of New York), as trustee (incorporated by reference to Form 8- K filed September 21, 2010)

4(v)	Form of 5.75% Notes due December 2017 (included in Exhibit 4(ii) above) (incorporated by reference to Form 8- K filed December 4, 2007)
4(vi)	Form of 6.40% Notes due December 2037 (included in Exhibit 4(ii) above) (incorporated by reference to Form 8- K filed December 4, 2007)
4(vii)	Form of 5.00% Notes due June 2013 (included in Exhibit 4(iii) above) (incorporated by reference to Form 8- K filed June 3, 2008)
4(viii)	Form of 5.85% Notes due June 2018 (included in Exhibit 4(iii) above) (incorporated by reference to Form 8- K filed June 3, 2008)
4(ix)	Form of 4.125% Notes due September 2022 (included in Exhibit 4(iv) above) (incorporated by reference to Form 8- K filed September 21, 2010)
10	2005 Stock Option and Award Plan (incorporated by reference to Form 8- K filed May 17, 2005) (#)
10(i)	2005 Stock Option and Award Plan, Amendment No. 1 (incorporated by reference to Form 10- Q for quarter ended September 29, 2007) (#)
10(ii)	2010 Stock Option and Award Plan (incorporated by reference to Form 10- Q for quarter ended July 3, 2010) (#)
10(iii)	Form of Restricted Stock Unit Award Agreement- time- vested awards (incorporated by reference to Form 10- K for year ended December 31, 2005) (#)
10(iv)	Form of Restricted Stock Unit Award Agreement- retirement- vested awards (incorporated by reference to Form 10- K for year ended December 31, 2005) (#)
10(v)	Form of Restricted Stock Unit Award Agreement for Non- Employee Directors (incorporated by reference to Form 10- Q for quarter ended April 1, 2006) (#)
10(vi)	Form of Award Agreement for Annual Stock Option Grants (incorporated by reference to Form 10- Q for quarter ended June 30, 2012) (#)
10(vii)	Employment Agreement of Daniel R. DiMicco (incorporated by reference to Form 10- Q for quarter ended June 30, 2001) (#)
10(viii)	Amendment to Employment Agreement of Daniel R. DiMicco (incorporated by reference to Form 10- K for year ended December 31, 2007) (#)
10(ix)	Employment Agreement of James D. Frias (incorporated by reference to Form 10- K for year ended December 31, 2009) (#)
10(x)	Employment Agreement of Hamilton Lott, Jr. (incorporated by reference to Form 10- Q for quarter ended June 30, 2001) (#)
10(xi)	Amendment to Employment Agreement of Hamilton Lott, Jr. (incorporated by reference to Form 10- K for year ended December 31, 2007) (#)
10(xii)	Employment Agreement of John J. Ferriola (incorporated by reference to Form 10- K for year ended December 31, 2001) (#)
10(xiii)	Amendment to Employment Agreement of John J. Ferriola (incorporated by reference to Form 10- K for year ended December 31, 2007) (#)
10(xiv)	Employment Agreement of Ladd R. Hall (incorporated by reference to Form 10- Q for quarter ended September 29, 2007) (#)
10(xv)	Employment Agreement of R. Joseph Stratman (incorporated by reference to Form 10- Q for quarter ended September 29, 2007) (#)

10(xvi)	Employment Agreement of Keith B. Grass (incorporated by reference to Form 10- K for the year ended December 31, 2011) (#)
10(xvii)	Employment Agreement of James R. Darsey (incorporated by reference to Form 10- K for year ended December 31, 2010) (#)
10(xviii)	Severance Plan for Senior Officers and General Managers as Amended and Restated Effective February 18, 2009 (incorporated by reference to Form 10- Q for quarter ended April 4, 2009) (#)
10(xix)	Senior Officers Annual Incentive Plan As Amended and Restated Effective February 18, 2009 (incorporated by reference to Form 10- Q for quarter ended April 4, 2009) (#)
10(xx)	Senior Officers Long- Term Incentive Plan As Amended and Restated Effective February 18, 2009 (incorporated by reference to Form 10- Q for quarter ended April 4, 2009) (#)
10(xxi)	Senior Officers Long- Term Incentive Plan Amendment No. 1 Adopted May 13, 2010 (incorporated by reference to Form 10- Q for quarter ended July 3, 2010) (#)
10(xxii)	Underwriting Agreement dated September 16, 2010 among Nucor Corporation, Banc of America Securities LLC, Citigroup Capital Markets Inc. and J.P. Morgan Securities, Inc. (incorporated by reference to Form 8- K filed September 21, 2010)
10(xxiii)*	BJU Carry and Earning Agreement dated October 31, 2012, among Nucor Corporation, Nucor Energy Holdings, Inc. and Encana Oil & Gas (USA) Inc.
12*	Computation of Ratio of Earnings to Fixed Charges
13*	2012 Annual Report (portions incorporated by reference)
21*	Subsidiaries
23*	Consent of Independent Registered Public Accounting Firm
24	Power of attorney (included on signature page)
31*	Certification of Principal Executive Officer Pursuant to Rule 13a- 14(a)/15d- 14(a), as Adopted Pursuant to Section 302 of the Sarbanes- Oxley Act of 2002
31(i)*	Certification of Principal Financial Officer Pursuant to Rule 13a- 14(a)/15d- 14(a), as Adopted Pursuant to Section 302 of the Sarbanes- Oxley Act of 2002
32**	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes- Oxley Act of 2002
32(i)**	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes- Oxley Act of 2002
101*	Nucor Corporation Annual Report on Form 10- K for the fiscal year ended December 31,2012, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Earnings, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Stockholders' Equity, and (vi) the Notes to Consolidated Financial Statements.

* Filed herewith.

** Furnished (and not filed) herewith pursuant to Item 601(b)(32)(ii) of the SEC's Regulation S- K.

Certain portions of this exhibit have been omitted pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.

(#) Indicates a management contract or compensatory plan or arrangement.

SIGNATURES

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

NUCOR CORPORATION

By: /s/ JOHN J. FERRIOLA
John J. Ferriola
Chief Executive Officer and President

Dated: February 28, 2013

POWER OF ATTORNEY

KNOW ALL PERSON BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints James D. Frias and A. Rae Eagle, or either of them, his or her attorney- in- fact, for such person in any and all capacities, to sign any amendments to this report and to file the same, with exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that either of said attorney- in- fact, or substitute or substitutes, may do or cause to be done by virtue hereof.

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

/s/ JOHN J. FERRIOLA
John J. Ferriola
Chief Executive Officer, President and Director
(Principal Executive Officer)

/s/ JAMES D. FRIAS
James D. Frias
Chief Financial Officer, Treasurer and Executive Vice President
(Principal Financial Officer)

/s/ MICHAEL D. KELLER
Michael D. Keller
Vice President and Corporate Controller
(Principal Accounting Officer)

/s/ PETER C. BROWNING
Peter C. Browning
Lead Director

/s/ CLAYTON C. DALEY, JR.
Clayton C. Daley, Jr.
Director

/s/ DANIEL R. DIMICCO
Daniel R. DiMicco
Executive Chairman

/s/ HARVEY B. GANTT
Harvey B. Gantt
Director

/s/ VICTORIA F. HAYNES
Victoria F. Haynes
Director

/s/ JAMES D. HLAVACEK
James D. Hlavacek
Director

/s/ Bernard L. Kasriel
Bernard L. Kasriel
Director

/s/ Christopher J. Kearney
Christopher J. Kearney
Director

/s/ Raymond J. Milchovich
Raymond J. Milchovich
Director

/s/ John H. Walker
John H. Walker
Director

Dated: February 28, 2013

NUCOR CORPORATION
Index to Financial Statement Schedule

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule

To the Board of Directors and Stockholders of
Nucor Corporation:

Our audits of the consolidated financial statements and of the effectiveness of internal control over financial reporting referred to in our report dated February 28, 2013 appearing in the 2012 Annual Report to Stockholders of Nucor Corporation (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10- K) also included an audit of the financial statement schedule listed in Item 15 of this Form 10- K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PricewaterhouseCoopers LLP
Charlotte, North Carolina
February 28, 2013

NUCOR CORPORATION
Financial Statement Schedule
SCHEDULE II- VALUATION AND QUALIFYING ACCOUNTS (in thousands)

Description	Balance at beginning of Year	Additions charged to costs and expenses	Deductions	Balance at end of year
Year ended December 31, 2012 LIFO Reserve	$ 763,176	$ -	$ (155,936)	$ 607,240
Year ended December 31, 2011 LIFO Reserve	$ 620,414	$ 142,762	$ -	$ 763,176
Year ended December 31, 2010 LIFO Reserve	$ 456,448	$ 163,966	$ -	$ 620,414

NUCOR CORPORATION
List of Exhibits to Form 10- K- December 31, 2012

Exhibit No.	Description of Exhibit
10(xxiii)	BJU Carry and Earning Agreement dated October 31, 2012, among Nucor Corporation, Nucor Energy Holdings, Inc. and Encana Oil & Gas (USA) Inc.
12	Computation of Ratio of Earnings to Fixed Charges
13	2012 Annual Report (portions incorporated by reference)
21	Subsidiaries
23	Consent of Independent Registered Public Accounting Firm
31	Certification of Principal Executive Officer Pursuant to Rule 13a- 14(a)/15d- 14(a), as Adopted Pursuant to Section 302 of the Sarbanes- Oxley Act of 2002
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101	Nucor Corporation Annual Report on Form 10- K for the fiscal year ended December 31, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Earnings, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Stockholders' Equity, and (vi) the Notes to Consolidated Financial Statements.

Certain portions of this exhibit have been omitted pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.

Exhibit 10(xxiii)

BJU CARRY AND EARNING AGREEMENT

THIS BJU CARRY AND EARNING AGREEMENT (this "Agreement") executed October 31, 2012 but effective as of November 1, 2012 (the "Effective Date") is between ENCANA OIL & GAS (USA) INC., a Delaware corporation ("Encana"), with an address of 370 17th Street, Suite 1700, Denver, Colorado 80202, and NUCOR ENERGY HOLDINGS INC., a Delaware corporation ("Nucor"), and NUCOR CORPORATION ("Parent"), a Delaware corporation, both with an address of 1915 Rexford Road, Charlotte, North Carolina 28211. Encana and Nucor may be referred to herein, individually, as a "Party" and, collectively, as the "Parties."

RECITALS

A. Encana owns oil and gas leasehold and mineral interests and may acquire additional interests (collectively, the "Oil and Gas Interests") in certain lands comprising the Big Jimmy Unit in the Piceance Basin in Garfield and Rio Blanco Counties, Colorado, within the area outlined on Exhibit A attached hereto, from the surface to the base of the Formation (the "Property").

B. Nucor desires to participate in the development of Encana's Oil and Gas Interests in the Property by paying a portion of the costs incurred by Encana associated with the drilling, completing, and equipping of Carry Wells in exchange for an undivided fifty percent (50%) of Encana's interest from the surface to the base of the Formation in and to the wellbores of such Carry Wells, the oil and gas production therefrom, and the tubulars and equipment therein and thereon. Nucor may propose and participate in additional Head's Up Wells as described below.

C. The Parties desire to enter into this Agreement to govern their rights and obligations with respect to exploration and development of the Property.

AGREEMENT

IN CONSIDERATION OF ONE HUNDRED DOLLARS ($100) and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

Definitions

For purposes of this Agreement, the following terms and phrases shall have the following meanings:

"Acquiring Party" is defined in Section 22.2.

"Acquisition Costs" is defined in Section 22.2

"AFE" means that Authority for Expenditure to be tendered by Encana to Nucor for each Carry Well or Head's Up Well reflecting the estimated costs to drill, complete, and equip, or plug and abandon, each Nucor Well.

[***] Certain confidential information contained in this document, marked by bracketed asterisks, has been omitted and filed separately with the Securities and Exchange Commission pursuant to Rule 24b- 2 of the Securities Exchange Act of 1934, as amended.

"Affiliate" means, as to the Person specified, any Person controlling, controlled by or under common control with such specified Person. The concept of control, controlling, or controlled as used with respect to any Person means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract, or otherwise. No Person shall be deemed an Affiliate of any Person solely by reason of the exercise or existence of rights, interests, or remedies created or arising under this Agreement.

"AMI Area" means all of the lands coextensive with the area outlined on Exhibit A attached hereto.

"AMI Interests" means royalty interests, overriding royalty interests, nonparticipating royalty interests, net profits interests, and similar interests in effect during the AMI Term over any of the lands comprising the AMI Area. AMI Interests do not include leasehold or mineral interests.

"AMI Purchase Price" is defined in Section 22.2.

"Applicable Law" means any applicable statute, law (including common law), regulation, rule, ruling, order, writ, injunction, or decree of or by any Governmental Authority.

"Base Price" is defined in Section 2.3 A.

"Business Day" means a day, other than Saturday or Sunday, on which commercial banks are open for business with the public in New York, New York.

"Carried working interest" is defined in Section 4.2.

"Carry Price" is defined in Section 2.2 C.

"Carry Well Threshold" is defined in Section 2.4 C.

"Carry Wells" means the oil and gas wells contemplated to be drilled to the Formation on the Property by the Parties under this Agreement pursuant to Section 2.2.

"Change of Control" means (a) with respect to Encana, (i) a sale of all or substantially all of the assets of Encana or (ii) a transaction which results in Encana no longer being an Affiliate of Encana Corporation or any successor to Encana Corporation, and (b) with respect to Nucor, (i) a sale of all or substantially all of the assets of Nucor or (ii) a transaction which results in Nucor no longer being an Affiliate of Nucor Corporation or any successor to Nucor Corporation.

"Commencement of drilling operations" or "commence drilling operations" means, with respect to any Nucor Well, the date that a drilling rig capable of reaching the Formation is rigged up and rotating under power on the Well Location for such well.

"Completed, complete, or completing" with respect to any Nucor Well, means that point in time when a Nucor Well is (i) drilled to a depth sufficient to test the Member; and (ii) either (a) equipped for oil and gas production from the Formation (including, without limitation, setting production casing and installing, if applicable, downhole safety valves, packers, and tubing and an appropriate wellhead / Christmas tree), or (b) plugged and abandoned in accordance with Applicable Law.

"Composite PPI" means Composite Producer Price Index. The Composite PPI is the weighted average of the Producer Price Indices shown on Exhibit B, weighted in the proportions shown on Exhibit B.

"Costs of completing" a Nucor Well means all actual direct costs plus per well drilling well rate overhead charges under the New Operating Agreement incurred in completing such well, including but not limited to, the costs of fracture stimulation, installing lines for frac fluid, and the drilling out of frac plugs with respect to such well, regardless of when such cost is incurred.

"Costs of drilling" a Nucor Well means all actual direct costs plus per well drilling well rate overhead charges under the New Operating Agreement relating to the drilling of such well incurred from and after the date two (2) years prior to the Effective Date hereof (except that the two (2) year requirement shall not apply with respect to the costs of drilling the Pre- Effective Date Carry Wells), including but not limited to, costs of constructing and upgrading access roads, obtaining and preparing the Wellpad, obtaining permits and title opinions, obtaining drilling contractor services and consultants necessary for the drilling of such well, obtaining mud chemicals, pipe and supplies and all other costs and expenses associated with or incurred in moving in, rigging up, drilling, logging and testing so that a decision can be made to either attempt to set pipe and complete such well or to plug and abandon it as a dry hole.

"Costs of equipping" a Nucor Well means all actual direct costs plus per well drilling well rate overhead charges to the extent properly chargeable under the New Operating Agreement incurred in the acquisition and installation of the initial equipment for such well, including but not limited to, the acquisition and installation of wellhead and Wellpad equipment (including but not limited to, associated flowlines, Wellpad separation facilities, Wellpad tanks and storage facilities, measurement/metering equipment, power lines and electrical facilities, and expansions and improvements of such wellhead and Wellpad equipment), regardless of when such cost is incurred.

"Cumulative Amount" is defined in Section 2.2 D.

"Damages" means losses, damages (whether compensatory, punitive, consequential, or special in nature, but excluding a Party's own exemplary or punitive damages), obligations, liabilities, demands, claims, costs and expenses (including, but not limited to, reasonable attorneys' fees, expenses, and court costs).

"Defaulting Party" is defined in Section 9.

"Effective Date" is defined in the heading.

"Encana" means Encana Oil & Gas (USA) Inc.
"Environmental Condition" means (a) any release of any Hazardous Materials into the air or into or on the soil, sediments, surface water, or groundwater on, under, or from, or migrating from, the Oil and Gas Interests (or adjoining lands) or any Nucor Well or other well, or (b) any breach, in any material respect, of any Environmental Law.
"Environmental Damages" means Damages arising with respect to any Environmental Condition including, without limitation, those relating to the presence, release, discharge, or threatened discharge of any Hazardous Material in or into the air, surface water, ground water, soil, land surface, or subsurface strata; Damages incurred in investigating and remediating such presence, release, discharge, or threatened discharge; and Damages relating to Hazardous Materials. Environmental Damages include investigatory costs mandated by a Government Authority based upon suspected contamination by Hazardous Materials, and any reasonable consultant and lab fees that arise out of or relate to any actual or suspected Environmental Condition involving the Well Locations or the Nucor Wells or under any Environmental Laws.
"Environmental Laws" means all applicable laws, statutes, regulations, rules, ordinances, codes, licenses, permits, orders, approvals, plans, authorizations, concessions, franchises, and similar items, as amended, of all governmental agencies, departments, commissions, boards, bureaus, or instrumentalities of the United States, and the states and political subdivisions thereof, and all principles of common law, pertaining to the health, safety, or protection of the environment, and/or Damages thereto, including, without limitation, CERCLA, the Clean Air Act, the Federal Water Pollution Control Act, the Resource Conservation and Recovery Act, the Safe Drinking Water Act, the Toxic Substances Control Act, the Hazardous Materials Transportation Act, and the Oil Pollution Act.
"Excess Well Costs" is defined in Section 2.2 B.
"Existing Drilling Program" is defined in Section 2.1 F.
"Force majeure event" is defined in Section 6.
"Force- pooled Owner" is defined in Section 2.1 H(v).
"Governmental Authority" means any federal, state, tribal or local government or any court, arbitral tribunal, administrative or regulatory agency or commission or other governmental authority instrumentality or political subdivision thereof.
"Hazardous Materials" means any substance, product, waste, or other material which is, or becomes identified, listed, published, or defined as a hazardous substance, hazardous waste, hazardous material, toxic substance, solid waste or pollutant, or which is otherwise regulated or restricted under any Applicable Law (including any Environmental Law) or permits, licenses, or other Government Authority approvals, including the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), the Superfund Amendments and Reauthorization

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

Act (SARA), the Hazardous Materials Transportation Act, the Resources Conservation and Recovery Act (RCRA), the Toxic Substances Control Act (TSCA), the Clean Water Act and the Oil Pollution Act of 1990 (OPA 90). Without limitation, Hazardous Materials includes hydrocarbons, asbestos, and polychlorinated biphenyls.

"Head's Up Well" means a well proposed by either Party to be drilled to the Formation on the Oil and Gas Interests in the Property in excess of the number of Carry Wells described in Section 2.2.

"HUW Restriction" is defined in Section 2.4 B.

"Individual Carry Well Cap" is defined in Section 2.2 B.

"JIB" means Joint Interest Billing.

"Knowledge," of a Party shall mean, for purposes of this Agreement, the actual knowledge of the Party at the time the assertion regarding knowledge is made. If the Party is a corporation or other entity other than a natural person, knowledge of such Party shall mean the actual knowledge on the part of the person having authority over the matters to which such knowledge pertains. An individual will be deemed to have actual knowledge of a particular matter if such individual is actually aware of such fact or other matter, or has an awareness or an understanding of such information as would lead a reasonable person to inquire further.

"Member" means the Williams Fork Member of the Formation.

"New Operating Agreement" is defined in Section 4.1.

"Nucor Carry," with respect to any Carry Well, means the difference between fifty percent (50%) of the Individual Nucor Well Cost and the Nucor Cost Share, without consideration of Excess Well Costs.

"Nucor Cost Share" is defined in Section 2.2 B.

"Nucor Head's Up Share" means Nucor's share of all costs for a Head's Up Well.

"Nucor Wells" means (i) the Carry Wells to be drilled by the Parties pursuant to this Agreement and (ii) the Head's Up Wells in which Nucor elects to participate, the number of which shall not exceed the Well Limit, subject to Section 2.4 E.

"NYMEX" means New York Mercantile Exchange, and the NYMEX website is www.cmegroup.com.

"Oil and Gas Interests" is defined in Recital A.

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

"Parent" means Nucor Corporation.
"Party" and "Parties" are defined in the heading.
"Permitted Encumbrances" means (i) lessor's royalties, overrides and all other burdens of record as of the Effective Date under the Oil and Gas Interests including, without limitation, the Encana overriding royalty interest under Sections 2.1 H (i)(c) and 2.1 H (i)(d) and the Encana royalty interest under Section 2.1 H (iv); (ii) all federal, state, local, and tribal regulatory orders and rules to which the Oil and Gas Interests are presently subject, and the express terms and provisions of the Oil and Gas Interests; (iii) preferential rights to purchase and required Third Party consents to assignments and similar agreements with respect to which (A) waivers or consents have been obtained from the appropriate parties, or (B) notice has been given to the holders of such rights and the appropriate time period for asserting such rights has expired without an exercise of such rights; (iv) liens for taxes or assessments not due or not delinquent as of the Effective Date of this Agreement; (v) all rights to consent by, required notices to, filings with, or other actions by Governmental Authority in connection with the drilling and development of the Oil and Gas Interests that are customarily obtained prior to the commencement of drilling operations; (vi) surface estates, leases, easements, rights- of- way, servitudes, permits, and other rights in respect of surface operations, pipelines, or the like; and easements for pipelines, and other easements and rights- of- way, on, over or in respect of any of the Oil and Gas Interests; (vii) liens of Third Party vendors or service providers over the Oil and Gas Interests relating to obligations not yet due or pursuant to which Encana is not delinquent; (viii) the terms of the royalty payment formula for certain Oil and Gas Interests referred to in the Memorandum of Agreement recorded as Reception Number 767957 in Garfield County, Colorado and as Reception Number 295765 in Rio Blanco County, Colorado; and (ix) title problems commonly encountered in the oil and gas business which would not be considered material by a reasonable and prudent operator in the Colorado Piceance Basin engaged in the business of the ownership, drilling, development, and operation of oil and gas interests with knowledge of all the facts and appreciation of their legal significance.
"Person" means any Governmental Authority or any individual, firm, partnership, limited partnership, corporation, limited liability company, joint venture, trust, unincorporated organization, or other entity or organization.
"Pre- Effective Date Carry Wells" is defined in Section 2.2 A.
"Price" is defined in Section 2.3 A.
"Property" is defined in Recital A.
"Rig Limitation Period" is defined in Section 2.2 A.
"Spud Date" means, with respect to any Nucor Well, the date of commencement of setting surface casing with a surface casing rig.
"Suspension Notice" is defined in Section 2.3 A.
"Term" of this Agreement is set forth in Section 7.

"Third Party" means any Person other than Encana, Nucor, or any of their Affiliates.
"Undivided Interest" is defined in Section 22.3.
"Well Location" means the legal location selected for each Nucor Well on the Oil and Gas Interests in the Property.
"Wellbore Assignment" is defined in Section 2.1 H, and shall cover all depths from the surface to the deepest depth drilled in a Nucor Well.
"Wellpad" means the location of wellheads and associated production facilities for one or more Nucor Wells.

Section 1.
Exhibits and Schedules

The following Exhibits and Schedules are attached hereto and shall be considered part of this Agreement:

1.1 Exhibit A Property

1.2 Exhibit B Producer Price Index Data

1.3 Exhibit C Form of Wellbore Assignment for Carry Wells

1.4 Exhibit D Tax Partnership Agreement

1.5 Exhibit E Form of New Operating Agreement

1.6 Schedule 2.2 A Pre- Effective Date Carry Wells

1.7 Schedule 5.2 Encana and Affiliate Burdens over the Property

Section 2.
Drilling of Nucor Wells

2.1 General Provisions Relating to Nucor Wells.

A. Well Locations and Depth. Encana shall act in good faith with regard to the best interests of each of the Parties hereto to determine the optimum Well Locations for all Nucor Wells on the Oil and Gas Interests in the Property based upon its analysis of the anticipated total estimated recovery, Individual Nucor Well Costs, the status of title, and the absence of Environmental Conditions. Prior to commencing drilling operations for any Nucor Well, Encana will present to Nucor its selected Well Location, together with any relevant geological, geophysical, engineering, title and environmental materials, information, and reports, applicable Third Party joint operating agreements and any other Third Party agreements burdening or in effect over the Well Location. All Well Locations shall be at legal locations in accordance with

Applicable Law. Each Carry Well shall be drilled to a depth sufficient to test adequately the Member, or as otherwise agreed by the Parties. Once Encana has commenced drilling operations on any Nucor Well, it shall diligently proceed with the drilling and completing of such well.

B. Periodic Planning Meetings. On or before June 1 of each year, commencing in 2013, the Parties shall meet to discuss drilling plans with respect to the Property, including the number of Carry Wells proposed by Encana and proposed well locations, the number of Head's Up Wells proposed by each Party (subject to the restrictions in Section 2.4) and proposed well locations, an estimate of Encana's drilling schedule and Spud Dates, and the estimated costs of the proposed wells. Nucor may not propose a Head's Up Well on a wellpad from which wells have been drilled for the Existing Drilling Program. Nucor shall not be required to provide the exact bottomhole location of a Head's Up Well but shall provide at least a proposed section, township and range. The Parties shall consult to determine and approve the Well Locations; provided, however, that if Encana and Nucor are unable to agree on any Well Location, Encana shall determine the Well Location. Encana shall also determine the Spud Dates for Nucor Wells. With respect to Nucor Wells drilled in calendar year 2015 and thereafter, if Encana has proposed fewer than [***] Carry Wells and Nucor has proposed Head's Up Wells, then at Encana's election, the first [***] Nucor Wells drilled shall be Carry Wells.

C. AFEs for Nucor Wells. At least thirty (30) days prior to the anticipated Spud Date for a Carry Well and at least ninety (90) days prior to the anticipated Spud Date for a Head's Up Well, Encana shall issue to Nucor an Authorization for Expenditure ("AFE") for each Nucor Well

(i) identifying each such well as a Carry Well or a Head's Up Well (together with a specific description of the Well Locations and the survey plat and wellbore diagram for such well), (ii) showing the Nucor Carry (if such well is a Carry Well), (iii) setting forth Encana's best estimate of the Individual Nucor Well Cost based upon historical costs and current market information and any Third Party bids, (iv) providing the total that Nucor is expected to pay by virtue of each AFE, and (v) setting forth the anticipated Spud Date of the Nucor Well.

D. Proportionate Reduction; Third Party Nonconsent Costs. If Encana owns less than one hundred percent (100%) of the Oil and Gas Interests comprising any Nucor Well, then the interests of Encana and Nucor in such Nucor Well, and in the case of a Carry Well, the Individual Carry Well Cap and Nucor Cost Share, shall be reduced in proportion to the actual Oil and Gas Interest owned by Encana in each such Nucor Well. With respect to a Carry Well or a Head's Up Well in which both Parties have elected to participate, Nucor and Encana shall bear equally the costs of drilling, completing, and equipping any such well which are attributable to the interest of any Third Party working interest owner who has elected not to participate in the drilling of such well under any applicable Third Party joint operating agreement, or otherwise, and shall be entitled to the corresponding amount of any interest or right to production occurring by reason of the failure of such working interest owner to participate. With respect to a Head's Up Well in which Encana has elected not to participate, Encana shall not bear any of the costs of drilling, completing, and equipping any such well which are attributable to the interest of a Third Party working interest owner who has elected not to participate in the drilling of such well, but Encana shall be entitled to any interest or right to production with respect to its carried working interest percentage as set forth in Section 4.2. The case of a Force- pooled Owner who does not participate in the drilling of a well is addressed in Section 2.1 H(v).

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

E. Land Costs; Affiliated Services. With respect to each Well Location, during the Term of this Agreement, Nucor shall not bear any acquisition costs or lease bonuses for any Oil and Gas Interests owned by Encana or any of its Affiliates. In addition, Nucor may elect to participate in geologic and geophysical activities and data gathering on or related to the Property, but Nucor shall not be required to participate. If Nucor elects to participate, it shall bear its share of the cost of such activity and shall be provided with any resulting data. If Nucor does not bear its share of the costs of such activity, it shall not be entitled to the data. For the avoidance of doubt, Nucor shall bear its share of the costs of downhole microseismic or other downhole geophysical activity. Furthermore, if Encana (or any of its Affiliates) conducts or provides any of the drilling, completing, or equipping operations, services, equipment, or materials on any Nucor Well, then it shall do so in a prudent and efficient manner, and it shall charge no more than the prevailing market rate for such operations, services, equipment, or materials which would be charged by a Third Party contractor in a bona fide arm's length transaction. If there are costs related to both Nucor Wells and non- Nucor Wells, such costs shall be pro- rated as applicable. After the Effective Date, if either Party, or any of its Affiliates, acquires any mineral or leasehold interest within the boundaries of the Property, then such interest will be subject to this Agreement. Only Head's Up Wells shall be proposed and drilled on any mineral or leasehold interest within the boundaries of the Property acquired by Nucor or any of its Affiliates. In any such Head's Up Well drilled on a Nucor mineral or leasehold interest, Encana will receive from Nucor a wellbore assignment in substantially the form attached hereto as Exhibit C of (i) an undivided fifty percent (50%) interest, (ii) one hundred percent (100%) interest, or (iii) two and one- half percent (2.5%) interest, as applicable, depending upon Encana's level of participation in any such well.

F. Restriction on Other Drilling Programs. Except for the presently existing drilling program with a Third Party that includes up to one hundred fifty (150) wells to be drilled on the Property (the "Existing Drilling Program"), until the Nucor Wells reach the Well Limit, (i) Encana shall not enter into any other drilling program with any party other than Nucor for the drilling and completion of wells above the base of the Formation on the Property, and (ii) Encana shall not increase the number of wells to be drilled to the Formation on the Property in the Existing Drilling Program to more than one hundred fifty (150) wells. Furthermore, until the Well Limit is reached, Encana shall not drill and complete any well on the Property above the base of the Formation for its own account unless such wells are Head's Up Wells proposed by Encana in which Nucor elects not to participate.

G. Payment of Nucor Cost Share and Nucor Head's Up Share. Except as provided in Section 4.2, Nucor shall pay Encana the Nucor Cost Share and Nucor Head's Up Share by wire transfer to Encana by the fifteenth (15th) day of the month following Nucor's receipt of a JIB invoice from Encana. If the fifteenth (15th) day of the month falls on a weekend or holiday, then payment shall be made on the preceding Business Day. The proceeds of each payment shall be used by Encana solely and exclusively for Individual Nucor Well Costs. After spudding a Nucor Well, Encana shall drill and complete such Nucor Well with due diligence and in a good and workmanlike manner, in accordance with good oil field practice as a reasonable and prudent Piceance Basin oil and gas operator.

H. Wellbore Assignment in Nucor Wells.

(i) Provided Nucor has paid the Nucor Cost Share and the Nucor Head's Up Share then due and owing, then on or before the thirtieth (30th) day after the end of each calendar quarter for each Nucor Well drilled and completed as a producer in the prior calendar quarter, Encana shall execute, acknowledge, and deliver to Nucor sufficient counterparts of a wellbore assignment which shall comply with the recordation requirements of any Governmental Authority with whom Encana would appropriately record such wellbore assignment on behalf of Nucor, and which shall otherwise be in substantially the form attached hereto as Exhibit C (the "Wellbore Assignment"). Each Wellbore Assignment shall:

(a) be effective as of the date of first production of each Nucor Well,

(b) be subject only to those lessor's royalties, overrides and other burdens of record in existence on the later of the Effective Date or the date of acquisition of the Oil and Gas Interest, those royalties described in (iv) below, or, in the case of overrides owned by Encana or its Affiliates, be subject only to those which are disclosed in Schedule 5.2,

(c) with respect to a Carry Well, assign to Nucor an undivided fifty percent (50%) of Encana's interest, but not including any royalty or overriding royalty interest owned by Encana, in and to (A) the wellbore of such Carry Well, and (B) all oil and gas production therefrom, and a like interest in the oil and gas leases associated with such wellbore, insofar and only insofar as are sufficient to produce and own an undivided fifty percent (50%) of Encana's interest in and to the oil, gas, gas condensate, casinghead gas and other liquid and gaseous hydrocarbons produced from the wellbore of the Carry Well, and (C) all casing, tubulars, downhole pumps, fixtures and equipment and wellhead and surface equipment (limited only to equipment for such Carry Well), and

(d) with respect to a Head's Up Well, assign to Nucor either an undivided fifty percent (50%) of Encana's interest, or ninety- seven and one- half percent (97.5%) of Encana's interest if Encana has elected not to participate in such well, as applicable, but in either case not including any royalty or overriding royalty interest owned by Encana, in and to (A) the wellbore of such Head's Up Well, and (B) all oil and gas production therefrom, and a like interest in the oil and gas leases associated with such wellbore, insofar and only insofar as are sufficient to produce and own an undivided fifty percent (50%), or ninety- seven and one- half percent (97.5%), as applicable, of Encana's interest in and to the oil, gas, gas condensate, casinghead gas and other liquid and gaseous hydrocarbons produced from the wellbore of the Head's Up Well in which Encana has elected not to participate, and (C) a like interest in and to all casing, tubulars, downhole pumps, fixtures and equipment and wellhead and surface equipment (limited only to equipment for such Head's Up Well).

(ii) The Wellbore Assignment shall be in recordable form, and shall contain legally- sufficient property descriptions.

(iii) The Wellbore Assignment shall contain a special warranty of title by, through, or under Encana, but not otherwise.
(iv) If any Nucor Well includes a mineral interest owned by Encana or an Affiliate that is not subject to a lease, then such mineral interest will receive a royalty interest payable to Encana or such Affiliate of 16.67% (which royalty interest shall be borne (a) equally by Nucor and Encana, (b) by Encana as the sole participating Party if Nucor elects not to participate in a Head's up Well, or (c) in the proportions set forth in Section 4.2, as applicable), which interest shall be proportionately reduced if the Encana mineral interest covers less than the full interest in the wellbore of the Nucor Well.
(v) Nucor and Encana shall each bear fifty percent (50%) of the drilling, completing, and equipping costs attributable to the interest of any working interest owner pooled pursuant to the provisions of Colorado Revised Statutes §34- 60- 116, as amended (a "Force- pooled Owner") who does not participate in the drilling of a Carry Well or a Head's up Well in which both Parties have elected to participate (subject to the interest of any other Third Party working interest owner who has elected to participate). The Wellbore Assignment to Nucor shall include the right to receive one- half (1/2) of the revenue attributable to the interest of such Force- pooled Owner, and the interest reflected in the Wellbore Assignment for casing, tubulars, downhole pumps, fixtures and equipment will be increased to reflect Nucor's interest. Nucor shall bear one hundred percent (100%) of the drilling, completing, and equipping costs attributable to the interest of any Force- pooled Owner in any Head's Up Well in which Encana has elected not to participate in accordance with Section 4.2 below.
(vi) The Wellbore Assignment shall be made subject to the terms and conditions of any existing operating agreement with a Third Party, any pooling or unitization agreement and any applicable Third Party agreements. Nucor's interest in the Nucor Wells shall include the right to participate, in accordance with the terms of the New Operating Agreement, for its proportionate interest in any subsequent completions or recompletions in the wellbore.
(vii) It is expressly agreed and understood that the interest to be assigned to Nucor in any Nucor Well shall be proportionately reduced to the extent that Encana owns less than an undivided 100% working interest in the Carry Well.
I. Well Takeover. If any Nucor Well is determined by Encana to be a dry hole or cannot otherwise be completed as a producer to the Formation and Encana elects to continue drilling operations below the Formation, then Nucor may elect to participate in such drilling operation. If Nucor elects to participate, then (i) with respect to a Carry Well, Nucor shall pay the Nucor Cost Share of such Nucor Well without regard to the Individual Carry Well Cap, and (ii) with respect to a Head's Up Well, Nucor shall pay its proportionate share of costs. Encana shall make a wellbore assignment to Nucor in accordance with Section 2.1 H, provided that such assignment shall be made to the total depth drilled. Nucor shall make its election with regard to participation within forty- eight hours (48) hours of telephone notice from Encana. If Nucor does not elect to participate in such drilling operation, then Encana promptly shall reimburse Nucor all costs of drilling paid by Nucor with respect to such Nucor Well, and shall indemnify and hold Nucor harmless from any losses or liability with respect to such well including, without limitation, plugging and abandonment obligations or Environmental Damages with respect to such well.

J. Use of Nucor Steel and Steel Products. Encana shall use its commercially reasonable best efforts to utilize Nucor steel and steel products, provided such products are readily available, meet Encana's requirements, and are competitively priced, for tubulars and other downhole equipment to be installed in all Nucor Wells. For greater clarity, such consideration shall not in any way disadvantage the cost of a proposed Nucor Well.

K. Operation of Nucor Wells. After a Nucor Well is drilled, completed, and equipped, Encana and Nucor shall each bear and pay its working interest share of the costs and expenses of such Nucor Well in accordance with the New Operating Agreement. Subject to Section 9 and provided Nucor has paid the Nucor Cost Share or Nucor Head's Up Share, as applicable, of costs of such well then due and owing, Nucor shall be entitled to, and Encana shall tender to Nucor, its net revenue interest share of production (or the proceeds from the sale thereof) from each such Nucor Well from the date of first production, notwithstanding that the applicable Wellbore Assignment has not yet been made.

L. Tax Partnership. On the date of execution of this Agreement, the Parties shall enter into a tax partnership agreement in the form set forth in Exhibit D.

2.2 Carry Wells.

A. Number of Carry Wells; Rig Limitation Period; Pre- Effective Date Carry Wells. Unless otherwise agreed by the Parties, Encana shall not (i) spud more than [***] Carry Wells (including the Pre- Effective Date Carry Wells) in calendar year 2012 or (ii) conduct drilling operations for Carry Wells with an average of more than [***] drilling rigs throughout calendar year 2013, and shall not conduct drilling operations for Carry Wells with an average of more than [***] drilling rigs throughout calendar year 2014 (the "Rig Limitation Period"); provided, however, if the average price for natural gas as reported by Platts Inside FERC's Gas Market Report (Platts IFERC) Colorado Interstate Gas Co. Rocky Mountains for the three (3) months preceding the then- current month exceeds $[***], then Encana shall have the option to operate one (1) additional drilling rig to drill Carry Wells for the remaining term of the Rig Limitation Period. For calendar year 2015 and thereafter, Encana shall spud a minimum of [***] and a maximum of [***] Carry Wells in each calendar year until such time as the Carry Well Threshold has been met. The Parties recognize and acknowledge that, prior to the date of execution of this Agreement, Encana has spud or drilled, but not completed or equipped, those wells described in Schedule 2.2 A (the "Pre- Effective Date Carry Wells"). The wells described in Schedule 2.2 A shall be considered as Carry Wells for all purposes hereunder and costs with respect to such wells shall be paid by Nucor as provided in Section 2.2 B. Encana shall diligently complete the Pre-Effective Date Carry Wells and, in accordance with Section 2.1 H, Encana shall execute, acknowledge, and deliver to Nucor appropriate Wellbore Assignments for the Pre- Effective Date Carry Wells.

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

B. Costs of Carry Wells. Except as provided in Section 2.2 D, Nucor shall pay not less than [***] and not more than [***] of the Individual Nucor Well Cost for each Carry Well (the "Nucor Cost Share") as further described in Section 2.2 C; provided that if the Individual Nucor Well Cost exceeds $[***] for a Carry Well (the "Individual Carry Well Cap"), then the Individual Nucor Well Cost for such Carry Well in excess of the Individual Carry Well Cap (the "Excess Well Costs") will be borne fifty percent (50%) by Encana and fifty percent (50%) by Nucor. From and after the Effective Date, Nucor shall pay the Nucor Cost Share (subject to Section 2.2 D) and fifty percent (50%) of Excess Well Costs, as applicable, of the Pre- Effective Date Carry Wells. The provisions of this Section 2.2 B regarding the Individual Carry Well Cap and adjustments thereto shall apply to the Pre- Effective Date Carry Wells, and all costs incurred for such wells, regardless of when they are incurred, shall be included when determining if the Individual Carry Well Cap has been reached. Except as provided in Section 2.2 D, the Nucor Cost Share shall be [***] for Carry Wells spud in 2012.
[***]
C. Determination of Nucor Carry. [***]
D. 100% Nucor Cost Share Period. Notwithstanding the foregoing, the Nucor Cost Share for Carry Wells spud after the Effective Date shall be [***] until the cumulative amount of the Nucor Carry paid by Nucor equals the sum of (i) [***] of the costs of drilling, completing and equipping the Pre-Effective Date Carry Wells (but not costs in excess of the Individual Carry Well Cap) incurred prior to the Effective Date, plus (ii) [***] of the Excess Well Costs of drilling, completing and equipping the Pre- Effective Date Carry Wells incurred prior to the Effective Date. The foregoing amount is referred to as the "Cumulative Amount." The Individual Carry Well Cap shall not apply to the cost of Carry Wells until the Cumulative Amount is reached.
E. Horizontal Wells. The Parties acknowledge that the provisions of this Section 2.2 with respect to number of Carry Wells and the amount of the Individual Carry Well Cap and the provisions of Section 2.4 with respect the number of Head's Up Wells do not apply to horizontal wells. If horizontal wells are drilled, the Individual Carry Well Cap shall be no less than [***] of the actual Individual Nucor Well Cost for such horizontal well. For the purpose of determining the number of Nucor Wells counted toward the Well Limit if a horizontal well is drilled, the Parties shall endeavor to agree upon the number of vertical wells displaced by such horizontal well and such agreed upon number shall be used in the calculation of the Well Limit. For the avoidance of doubt, the provisions of Section 2.4 E shall also apply in the calculation of the Well Limit.

2.3 Ability to Suspend Funding of Carry Wells. [***]

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

2.4 Head's Up Wells.

A. Election to Participate in Head's Up Wells. At least sixty- five (65) days prior to the anticipated Spud Date of a Head's Up Well, each Party shall notify the other Party whether it elects to participate in such well. Failure of a Party to elect to participate in a Head's Up Well shall be deemed an election not to participate in such well. At its discretion, Encana may simultaneously conduct drilling operations for Carry Wells and Head's Up Wells subject to the Rig Limitation Period.

B. HUW Restriction. At the planning meeting to be held in 2014 in accordance with Section 2.1 B to establish the well selection and drilling schedule for calendar year 2015 and continuing each year thereafter until the Carry Well Threshold is paid by Nucor, Nucor shall have the right to propose to Encana Head's Up Wells to the Formation on the Oil and Gas Interests in the Property in excess of the number of Carry Wells described in Section 2.2; provided, however, that (i) the number of additional wells to be spudded pursuant to this section in calendar year 2015 and subsequent calendar years until the Carry Well Threshold is paid by Nucor shall not exceed [***] of the number of Carry Wells spudded in the prior calendar year (the "HUW Restriction"). Prior to meeting the Carry Well Threshold, if, due to a Suspension Notice delivered to Nucor by Encana in the prior (or any previous) year, the Parties have drilled fewer than [***] Carry Wells, then Nucor may propose up to [***] Head's Up Wells to be drilled in a subsequent calendar year. Until the Well Limit is reached, in any calendar year, Encana shall not propose more than [***] Head's Up Wells until the Carry Well Threshold is paid by Nucor and no more than [***] Head's Up Wells after the Carry Well Threshold is paid by Nucor.

C. Satisfaction of Carry Well Threshold. Nucor shall have satisfied its obligation to fund Carry Wells under this Agreement from and after the time that the cumulative amount of the Nucor Carry paid by Nucor equals $[***] with respect to the Carry Wells (the "Carry Well Threshold"). Thereafter, Nucor may schedule a planning meeting and propose to Encana the drilling of additional wells to the Formation in the current calendar year without regard to the HUW Restriction; provided, however, that Nucor may propose no more than [***] Head's Up Wells to be drilled in any calendar year. The maximum number of Head's Up Wells that Nucor may propose in the calendar year in which the Carry Well Threshold has been achieved shall be determined by multiplying [***] by a fraction, the numerator of which is the number of days remaining in the calendar year, and the denominator of which is three hundred sixty- five (365). Encana shall use its reasonable best efforts to spud all proposed Head's Up Wells in the calendar year reflected in the annual drilling schedule determined by the Parties at the annual planning meeting under Section 2.1 B or as set forth above. If Encana is unable to spud all scheduled Head's Up Wells within a particular calendar year, then it shall not commence drilling operations on any Carry Wells for the next calendar year until all previously scheduled Head's Up Wells have been spud. Notwithstanding the foregoing, in no event shall the number of Carry Wells and Head's Up Wells in which Nucor elects to participate exceed the Well Limit.

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

D. Withdrawal of Election to Participate. Nucor may withdraw its election to participate in any Head's Up Well in which Encana has elected not to participate on or before sixty (60) days prior to the Spud Date of such well as set forth on the AFE for such well; provided, however, Nucor shall bear any and all costs incurred with respect to such well, including penalties imposed by contracted service providers such as rig operators and completion service companies. Encana may withdraw its election to participate in any Head's Up Well in which Nucor has elected not to participate at any time prior to the Spud Date of such well as set forth on the AFE for such well, and Encana shall bear any and all costs incurred with respect to such well, including penalties imposed by contracted service providers such as rig operators and completion service companies

E. Calculation of the Number of Nucor Wells. The total number of Nucor Wells spudded shall not exceed the Well Limit. A Head's Up Well in which Encana elects not to participate shall be counted twice for the purpose of determining the number of Nucor Wells. Any Head's Up Well proposed by Encana in which Nucor elects not to participate shall not be counted toward the Well Limit. The Parties acknowledge that if Nucor elects not to participate in a substantial number of Head's Up Wells proposed by Encana, there may not be sufficient Well Locations available to allow Nucor to propose Head's Up Wells to reach the Well Limit.

F. Participation in Head's Up Wells. The costs for Head's Up Wells in which both Parties participate shall be borne fifty percent (50%) by Encana and fifty percent (50%) by Nucor. If Nucor elects not to participate in a Head's Up Well, then it shall pay no portion of the drilling, completing, or equipping costs for such well, and shall own no interest in such well. If Encana elects not to participate in a Head's Up Well and Nucor elects to proceed with such well, then the Parties shall proceed in accordance with Section 4.2 below.

Section 3.
Title and Other Information

Prior to the commencement of drilling operations on any Nucor Well, Encana will conduct, or cause to be conducted, title examination of the applicable Well Location and the relevant Oil and Gas Interests and conduct any necessary title curative work. When Encana provides Nucor with an AFE, Encana shall deliver to Nucor copies of all title documentation relating to the Nucor Well in Encana's files or to which Encana has access, including, without limitation, all title opinions and reports, title curative documents, and any applicable Third Party joint operating agreements. Such title information shall be provided to Nucor without warranty as to accuracy. Encana shall have no obligation to purchase new or supplemental abstracts. Encana will undertake curative work in connection with title to the Carry Wells which is required by the New Operating Agreement or any other operating agreement applicable to such Carry Well and which a reasonable and prudent Piceance Basin oil and gas operator would undertake in a similar situation.

Section 4.
Operations

4.1 New Operating Agreement.

Encana and Nucor shall enter into the form of operating agreement attached hereto as Exhibit E ("New Operating Agreement") which shall govern all operations for the Nucor Wells as between the Parties. Encana shall be designated as operator of all Nucor Wells, and upon the spudding of a Nucor Well, the New Operating Agreement shall be deemed amended to include such Nucor Well. In addition, the Parties intend that the New Operating Agreement shall govern each Party's election to participate in subsequent operations on all of the Nucor Wells in which both Parties have an interest. For the avoidance of doubt, any subsequent operations under the New Operating Agreement with respect to any Carry Well shall be conducted on a well- by- well basis, and the costs for the subsequent operations shall be borne fifty percent (50%) by Encana and fifty percent (50%) by Nucor in accordance with the New Operating Agreement.

4.2 Operation of Head's Up Wells in which Encana Does Not Participate.
If Encana elects not to participate in a Head's Up Well and Nucor elects to proceed with such well, then Encana shall serve as operator of such well under the New Operating Agreement. Notwithstanding anything to the contrary in this Agreement, (i) at least thirty (30) days prior to the anticipated Spud Date of a Head's Up Well in which Encana elects not to participate, Nucor shall pay to Encana the amount of the AFE for costs of drilling such well, and (ii) at least thirty (30) days prior to the anticipated commencement of completion operations for such well, Nucor shall pay to Encana the amount of the AFE for costs of completing and costs of equipping such well, such payments to be made by wire transfer. As compensation for its services as operator of a Head's Up Well in which Encana has elected not to participate (in addition to applicable overhead rates set forth in the New Operating Agreement), Encana shall receive or reserve, as applicable, an undivided two and one- half percent (2.5%) of 8/8ths carried working interest in and to such well, proportionately reduced if the Parties own less than the full leasehold or mineral interest in such well. As used herein, the term "carried working interest" means that Encana shall bear none of the costs of drilling, completing, or equipping any Head's Up Well in which Encana has elected not to participate, but Encana shall bear two and one- half percent (2.5%) of 8/8ths (proportionately reduced if the Parties' collective operating interest covers less than one hundred percent (100%) of the mineral or leasehold estate) of (i) the monthly well operating costs, (ii) royalty, severance, ad valorem, and property taxes and other burdens assessed or imposed against the well or the oil and gas production therefrom, (iii) the costs of any subsequent operations on said well, and (iv) the plugging and abandonment costs of any such well which was completed as a well capable of producing in paying quantities, all in accordance with the New Operating Agreement.

4.3 Conflicts with Existing Operating Agreements.
If any of the Nucor Wells is subject to an existing joint operating agreement with a Third Party, such existing joint operating agreement shall control as to such Third Party, and the Wellbore Assignment shall be subject to such existing joint operating agreement; however, as between Nucor and Encana, this Agreement and the New Operating Agreement shall control. In the event of any conflict or inconsistency between the terms of this Agreement and the New Operating Agreement, this Agreement shall prevail to the extent of such conflict. If Nucor and/or Encana acquire the entire Oil and Gas Interest governed by an existing Third Party joint operating agreement, then such Third Party joint operating agreement shall terminate and be superseded and replaced in its entirety by the New Operating Agreement.
4.4 Payment of Burdens.

After the Effective Date, if Encana or Nucor creates any additional burdens on the Property, the Party creating such additional burden shall be solely responsible for and shall pay such additional burden; provided however, any Oil and Gas Interest in a Nucor Well owned by Encana or its Affiliate that is not subject to an oil and gas lease will be subject to a royalty payable to Encana or such Affiliate of 16.67%, which shall be borne (i) equally by Nucor and Encana, (ii) by Encana as the sole participating Party in a Head's Up Well, or (iii) in the proportions set forth in Section 4.2, as applicable. Subject to the foregoing sentence, Encana shall make payment of all burdens affecting the Nucor Wells, and Nucor shall reimburse Encana for Nucor's portion of all burdens. Encana shall make shut- in royalty payments, minimum royalty payments, delay rentals, and similar payments in order to maintain the Oil and Gas Interests on which Nucor Wells are located in force and effect. The Parties shall bear all of such payments in proportion to their interest in the Nucor Wells affected. Encana shall not be liable for any damages resulting from the failure to make proper payment if such failure is a result of mistake or oversight.

Section 5.
Representations, Warranties and Agreements

5.1 Representations and Warranties.

Each Party, with respect to itself only, hereby represents and warrants to the other Party the following:

A. Each Party is duly organized, validly existing and in good standing under the Applicable Law of the State of its incorporation or formation, and is qualified to do business and is in good standing in the State of Colorado and in every other jurisdiction where the failure to so qualify would have a material adverse effect on its ability to execute, deliver, and perform this Agreement and the other agreements contemplated herein.

B. Each Party has all requisite power and authority to (i) own, lease or operate its assets and properties and to carry on the business as contemplated hereunder, and (ii) enter into and perform its obligations under this Agreement and to carry out the transactions contemplated hereby, including the ownership of interests in federal oil and gas leases.

C. Without diminishing the effects of the specific representations, warranties and covenants contained in this Agreement, each Party has conducted the necessary inquiries and due diligence in support of the commitments made hereunder with full knowledge of the risks and obligations inherent in the ownership and operation of oil and gas interests.

D. Each Party has taken (or caused to be taken) all acts and other proceedings required to be taken by such Party to authorize the execution, delivery and performance by such Party of this Agreement and the other agreements contemplated herein. This Agreement has been duly executed and delivered by each Party and constitutes the valid and binding obligation of each Party, enforceable against such Party in accordance with its terms, except as enforceability may be limited by applicable bankruptcy, moratorium, reorganization or similar laws affecting the rights of creditors generally and by principles of equity, whether considered in a proceeding at law or in equity. The execution, delivery, and performance of this Agreement by each Party

does not and will not (i) conflict with, or result in any violation of, or constitute a breach or default (with notice or lapse of time, or both) under (A) any provision of the organizational documents of such Party, or (B) any applicable statute, law, rule, regulation, order, agreement, instrument or license applicable to such Party, except as would not have a material adverse effect, or (ii) require the submission of any notice, report, consent or other filing with or from any Governmental Authority or Third Parties, other than such consents as are customarily obtained after assignment of interests similar to the Wellbore Assignments.
E. There are no actions, suits or proceedings pending or, to such Party's Knowledge, threatened against a Party which if decided unfavorably to such Party could have a material adverse effect on the ability of such Party to execute, deliver, or perform this Agreement or could materially affect its title to, or ownership or operation of, the Oil and Gas Interests, the Well Locations, or the Carry Wells.
F. No Party has incurred any obligation or liability, contingent or otherwise, for any fee payable to a broker or finder with respect to the matters provided for in this Agreement or the other agreements contemplated herein which could be attributable to or charged to the other Party. Each Party shall indemnify, defend, and hold harmless the other Party from any claims, damages, liabilities, costs and expenses, including reasonable attorney's fees in the event the prior sentence should be or become untrue as to such Party.

5.2 Representations and Warranties of Encana.
Encana hereby represents and warrants to Nucor the following:
A. Schedule 5.2.
attached hereto sets forth all of the overriding royalty, royalty, net profits, production payment, and other similar interests owned by Encana or its Affiliates in the Oil and Gas Interests, except that the Oil and Gas Interests subject to a royalty payable to Encana or its Affiliate of 16.67% in accordance with Section 4.4 are not set forth in Schedule 5.2. Encana's interest in the Oil and Gas Interests comprising the Well Locations on which the Nucor Wells are drilled will not be subject to any liens or encumbrances of any type or nature other than the Permitted Encumbrances. As long as Nucor is taking its share of production from the Oil and Gas Interests in kind, there will be no calls on production or contracts for sale of production encumbering the Nucor Wells which provide for the delivery of oil and gas at a price below the prevailing market price. Prior to drilling a Nucor Well, Encana shall obtain the waiver of all preferential purchase rights and all consents to assignment that must be obtained from any Third Parties in order to make a Wellbore Assignment of such Nucor Well to Nucor.
B. All Oil and Gas Interests comprising the Well Locations on which the Nucor Wells are drilled will be in full force and effect. Operations with respect to the Oil and Gas Interests insofar as they pertain to the Nucor Wells will be in compliance with applicable rules, regulations, statutes, and laws of any Governmental Authority.
C. Prior to the commencement of drilling operations on any Nucor Well hereunder, Encana shall have obtained all consents, approvals, certificates, licenses, permits, and other authorizations of all Third Parties and the necessary Governmental Authority required for Encana to own, drill, develop, operate, and maintain the Oil and Gas Interests comprising the Well Location for such Nucor Well

D. Each Nucor Well shall be drilled within the boundaries of the applicable Oil and Gas Interest(s) at a legal location in accordance with all spacing and density regulations of any Governmental Authority. None of the Nucor Wells shall be subject to penalties or reduced allowables because of any violation of Applicable Law, rules, regulations, permits, or judgments, orders or decrees of any court or Governmental Authority.

With respect to each Nucor Well and Well Location, the foregoing representations and warranties contained in this Section 5.2 shall terminate two (2) years after the date of each Wellbore Assignment to Nucor of an interest in such Nucor Well and shall thereafter have no further force and effect.

Section 6.
Force Majeure

If a Party is rendered unable, wholly or in part, by a force majeure event to carry out its obligations under this Agreement (other than the obligations to make monetary payments and to deliver Wellbore Assignments of interests in the Nucor Wells) the affected Party shall give the other Party prompt written notice describing the force majeure event in reasonable detail. Thereupon, the obligations of the Party giving notice, so far as it is affected by the force majeure event, shall be suspended and any time periods provided for in this Agreement shall be extended for a period equal to the period of the continuance of the force majeure event. The affected Party shall use all reasonable diligence to remove the force majeure event as quickly as practicable. The requirement that any force majeure event be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts or other labor difficulty by the Party affected, contrary to its wishes, and settlement or resolution of such matters shall be within the discretion of the affected Party. The term "force majeure event" as used herein, shall mean an act of God, act of terrorism, strike, lockout, or other industrial disturbance, act of the public enemy, war, blockade, public riot, lightning, fire, storm, flood, explosion, the actions of Governmental Authority, restraint or inaction, the interruption or suspension of the receipt or delivery of natural gas (or any of its constituents) or water due to the inability or failure of any Third Party who is not a party to this Agreement (other than an Affiliate of either Party hereto), to receive or deliver such gas or water, unavailability of equipment, or inability to gain access, ingress or egress to conduct operations (including without limitation delays in or inability to obtain permits, approvals or clearances from Governmental Authority, so long as the Party claiming such force majeure event uses its commercially reasonable best efforts to obtain any such permits, approvals or clearances from such Governmental Authority), or other event beyond the reasonable control of the affected Party.

Section 7.
Term

The term of this Agreement (the "Term") shall begin on the Effective Date and shall terminate upon the earlier to occur of (i) the first day of the month after the Parties, or their successors or permitted assigns, reach the Well Limit for Nucor Wells and Nucor has paid all amounts for the drilling, completing, and equipping of Nucor Wells required hereunder, or (ii) 75 years from the Effective Date hereof.

Section 8.
Assignability

8.1 Restrictions on Assignment.
Neither Party may assign or transfer, by assignment, sale, farmout or otherwise, or pledge or encumber in any way, in whole or in part, any of its rights or obligations under this Agreement without the express prior written consent of the other Party, which may be withheld in such other Party's sole discretion; provided, however, that the foregoing provision shall not apply to a Change of Control or an assignment to one (1) or more of a Party's Affiliates. Encana hereby unconditionally guarantees to Nucor, its successors and assigns, the payment and performance of all of Encana's obligations and covenants hereunder in the case of an assignment, in whole or in part, to any of its Affiliates. Prior written consent of the other Party shall not, however, be required for the assignment or transfer of a Party's interest in a Nucor Well and the associated equipment, provided that (i) such assignment or transfer is subject to the provisions of this Agreement (including all Exhibits hereto) and the New Operating Agreement and (ii) any such assignment or transfer may be made only after delivery of the Wellbore Assignment to Nucor. The foregoing sentence shall not prevent the assignment or transfer by Encana of its interest in a Head's Up Well in which Nucor did not participate. Any assignment or transfer of operations of a Nucor Well by Encana may be made only to a Third Party with sufficient operating expertise and financial capability to operate such Nucor Well as a reasonable and prudent operator in the Piceance Basin. Other than as provided above, until the Well Limit is reached, Encana shall not assign or transfer a portion of its interest in the Formation in the Property without the prior written consent of Nucor, which consent Nucor may withhold in its sole discretion. Any assignee of any interest hereunder shall expressly assume in writing the obligations and liabilities under all agreements applicable to such interest, including this Agreement and the New Operating Agreement.

8.2 Change of Control.
Notwithstanding anything to the contrary in this Agreement, in the event that a Change of Control of either Party (the "First Party") occurs, the other Party (the "Other Party") shall have the option to terminate its obligation to fund additional Carry Wells or to drill additional Nucor Wells, as applicable, under this Agreement. The First Party shall deliver written notice to the Other Party of a Change of Control along with information reasonably available to the First Party regarding the financial position and operational experience of its successor- in- interest. The Other Party shall have thirty (30) days from the receipt of such notice to make a one- time election to terminate its obligation to fund additional Carry Wells or drill additional Nucor Wells, as applicable. If Nucor elects to cease funding Carry Wells, then it shall not have any further right to propose or to participate in Head's Up Wells. If the Other Party fails to deliver timely written notice to the First Party advising the First Party of the Other Party's election, the Other Party shall be obligated to continue to fund additional Carry Wells or to drill Nucor Wells, as applicable, pursuant to the terms of this Agreement. If the Other Party elects to terminate its obligation to fund additional Carry Wells or drill additional Nucor Wells, this Agreement (including all Exhibits hereto) shall continue in full force and effect as to all Nucor Wells that have been funded in whole or in part prior to such election.

Section 9.
Payment Offset

If a Party fails to make any payment to the other when due under this Agreement (the "defaulting Party"), then in addition to, and not in lieu of, other available remedies, the non- defaulting Party may offset any other amount arising under this Agreement owed by the non- defaulting Party against the amount owed under this Agreement by the defaulting Party. Notwithstanding the foregoing, the non- defaulting Party may not offset any amount that the defaulting Party has contested in good faith within thirty (30) days of the date of its receipt of the disputed billing statement, and as to which the defaulting Party has provided the non- defaulting Party with written notice of defaulting Party's position, including the basis therefor and supporting documentation, if any.

Section 10.
Notices

All notices and communications required or permitted under this Agreement shall be in writing addressed as indicated below, and any communication or delivery hereunder shall be deemed to have been duly delivered upon the earliest of: (a) actual receipt by the Party to be notified; (b) three days after deposit with the US Postal Service, certified mail, postage prepaid, return receipt requested; (c) if by facsimile transmission, upon confirmation by the recipient of receipt, or if by e- mail, upon receipt of a confirming e- mail from the recipient of the e- mail; or (d) by Federal Express overnight delivery (or other reputable overnight delivery service), two days after deposited with such service. Addresses for all such notices and communication shall be as follows:

To Encana: Encana Oil & Gas (USA) Inc.
Denver, Colorado 80202
Attention: Team Lead Land, South Rockies
Phone: 720.876.3644
Email: helen.capps@encana.com
With a copy of notices to:
Encana Oil & Gas (USA) Inc.
Denver, Colorado 80202
Attention: Legal Department
Fax: 720.876.3655

To Nucor: Nucor Energy Holdings Inc.
1915 Rexford Road
Charlotte, North Carolina 28211
Attention: Chief Financial Officer
Fax: 704.362.4208
Email: jim.frias@nucor.com

Either Party may, upon written notice to the other Party, change the address and person to whom such communications are to be directed.

Section 11.
Relationship of the Parties

This Agreement is not intended to create, and shall not be construed to create, an association for profit, a trust, a joint venture, a mining partnership or other relationship of partnership, or entity of any kind between the Parties. Notwithstanding anything to the contrary contained herein, the Parties understand and agree that the arrangement and undertakings evidenced by this Agreement, taken together, result in a partnership for purposes of federal income taxation and for purposes of certain state income tax laws which incorporate or follow federal income tax principles as to tax partnerships. For these purposes, the Parties agree to be governed by the tax partnership provisions attached as Exhibit D, which are incorporated herein and made a part of this Agreement by this reference. For every purpose other than the above- described income tax purposes, however, the Parties understand and agree that the liabilities of the Parties shall be individual, not joint or collective, and that each Party shall be solely responsible for its own obligations. In the case of any conflict or inconsistency between the terms and conditions of this Agreement and the terms and conditions of any attachment or exhibit hereto (other than Exhibit D), the terms and conditions of this Agreement shall govern and control. In the event of any conflict or inconsistency between the terms and conditions of Exhibit D and the terms and conditions of this Agreement or any other attachment or Exhibit hereto, the terms and conditions of Exhibit D shall govern and control.

Section 12.
Entire Agreement

This Agreement, and the exhibits and schedules hereto and thereto, contain the entire agreement of the Parties with respect to the subject matter hereof and supersede all previous agreements or communications between the Parties, verbal or written, with respect to the subject matter hereof.

Section 13.
Governing Law

This Agreement shall be governed by and construed and interpreted in accordance with the laws of the State of Colorado, without reference to its conflicts of laws provisions.

Section 14.

Amendments; Waiver

No amendments or other modifications or changes to this Agreement shall be effective or binding on either Party unless the same shall be in a writing executed by both Parties. No waiver by either Party of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or different nature.

Section 15.

Public Announcements

Except as required by Applicable Law or the listing agreement or other requirements of a national securities exchange, neither Party shall issue a public statement or press release with respect to the transactions contemplated herein . Nucor and Encana acknowledge and agree that Nucor intends to make disclosures of the transaction described herein to the Securities and Exchange Commission as required by Applicable Law contemporaneously with the execution hereof and thereafter, and will issue a press release with respect to the transaction described herein. Nucor shall provide Encana with copies of such disclosures and releases prior to filing same.

Section 16.

Severability

If a court of competent jurisdiction determines that any clause or provision of this Agreement is void, illegal, unenforceable or unconscionable under any present or future law (or interpretation thereof), the remainder of this Agreement shall remain in full force and effect, and the clauses or provisions that are determined to be void, illegal, unenforceable, or unconscionable shall be deemed severed from this Agreement as if this Agreement had been executed with the invalid provisions eliminated; provided, however, that notwithstanding the foregoing, if the removal of such provisions destroys the legitimate purposes of this Agreement, then this Agreement shall no longer be of any force or effect. The Parties shall negotiate in good faith for any required modifications to this Agreement required as a result of this provision.

Section 17.

Mutuality

The Parties acknowledge and declare that this Agreement is the result of extensive negotiations between them. Accordingly, if there is any ambiguity in this Agreement, then there shall be no presumption that this instrument was prepared solely by either Party.

Section 18.

Dispute Resolution

The Parties agree to resolve all disputes concerning or relating to this Agreement pursuant to the provisions of this <u>Section 18</u>. The Parties agree to submit all disputes to binding arbitration in Denver, Colorado. The arbitration will be conducted according to the procedure that follows. The arbitration proceedings shall be governed by Colorado law and shall be conducted in accordance with the rules for Non- Administered Arbitration of Business Disputes published by The Center for Public Resources, Inc., with discovery to be conducted in accordance with the Federal Rules of Civil Procedure, and with any disputes over the scope of discovery to be determined by the Arbitrators. The arbitration shall be before a single Arbitrator chosen by the mutual agreement of the Parties, or if no agreement as to the identity of the Arbitrator can be reached within ten days, a three person panel of neutral Arbitrators, consisting of one person chosen by each Party, and the two Arbitrators so selected choosing the third. The panel so chosen or the single person are referred to herein as the "Arbitrators." The Arbitrators shall conduct a hearing no later than sixty (60) days after submission of the matter to arbitration, and the Arbitrators shall render a written decision within thirty (30) days of the hearing. At the hearing, the Parties shall present such evidence and witnesses as they may choose, with or without counsel. Adherence to formal rules of evidence shall not be required, but the Arbitrators shall consider any evidence and testimony that they determine to be relevant, in accordance with procedures that they determine to be appropriate. Any award entered in the arbitration shall be made by a written opinion stating the reasons and basis for the award made and any payment due pursuant to the arbitration shall be made within fifteen (15) days of the decision by the Arbitrators. The decision of the Arbitrators shall be binding on the Parties, final and non- appealable, and may be filed in a court of competent jurisdiction and may be enforced by either Party as a final judgment of such court. Each Party shall bear its own costs and expenses of the arbitration, provided, however, that the costs of employing the Arbitrators shall by shared equally by the Parties.

Section 19.
Waiver of Exemplary and Punitive Damages

NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT AND FOR THE AVOIDANCE OF DOUBT, EACH PARTY HEREBY EXPRESSLY DISCLAIMS, WAIVES AND RELEASES THE OTHER PARTY FROM ITS OWN EXEMPLARY AND PUNITIVE DAMAGES. NO LAW, THEORY, OR PUBLIC POLICY SHALL BE GIVEN EFFECT WHICH WOULD UNDERMINE, DIMINISH, OR REDUCE THE EFFECTIVENESS OF THE FOREGOING WAIVER, IT BEING THE EXPRESS INTENT, UNDERSTANDING, AND AGREEMENT OF THE PARTIES THAT SUCH DAMAGE WAIVER IS TO BE GIVEN THE FULLEST EFFECT, NOTWITHSTANDING THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT), GROSS NEGLIGENCE, WILLFUL MISCONDUCT, STRICT LIABILITY OR OTHER LEGAL FAULT OF EITHER PARTY.

Section 20.
Indemnification

20.1 Indemnification of Nucor by Encana.

Encana shall RELEASE, DEFEND, PROTECT, INDEMNIFY, and HOLD HARMLESS Nucor, its Affiliates, and all of their stockholders, officers, employees, directors, and agents from and against any Damages including, without limitation, any Damages on account of illness, injury, or death suffered by any Person, or the loss or damage to the property of any Person, arising out of, in connection with, or relating to (i) any grossly negligent or willful conduct of Encana, its Affiliates, or any of their officers, employees, directors, or agents with respect to the performance of Encana's obligations under this Agreement, (ii) Encana's breach of any representation or warranty contained in this Agreement, (iii) Encana's breach of any covenant or agreement contained in this Agreement, (iv) all wells operated by Encana on the Property that are not Nucor Wells, and (v) the plugging and abandonment liability for all wells on the Property that are not Nucor Wells.

20.2 Environmental Indemnification of Nucor by Encana.

Encana shall RELEASE, DEFEND, PROTECT, INDEMNIFY, and HOLD HARMLESS Nucor, its Affiliates, and all of their stockholders, officers, employees, directors, and agents from and against any Environmental Damages arising out of, in connection with, or relating to any Environmental Condition in, on, under or with respect to any Well Location (or the relevant Oil and Gas Interests comprising such Well Location) in existence prior to the commencement of drilling operations for a Nucor Well on such Well Location.

20.3 Indemnification of Encana by Nucor.

Nucor shall RELEASE, DEFEND, PROTECT, INDEMNIFY, and HOLD HARMLESS Encana, its Affiliates, and all of their stockholders, officers, employees, directors, and agents from and against any Damages including, without limitation, any Damages on account of illness, injury, or death suffered by any Person, or the loss or damage to the property of any Person, arising out of, in connection with, or relating to (i) any grossly negligent or willful conduct of Nucor, its Affiliates, or any of their officers, employees, directors, or agents with respect to the performance of Nucor's obligations under this Agreement, (ii) Nucor's breach of any representation or warranty contained in this Agreement, and (iii) Nucor's breach of any covenant or agreement contained in this Agreement.

Section 21.
Insurance Matters

All policies of insurance carried for the joint account as set forth in Exhibit D of the New Operating Agreement shall include the following: (i) except for Worker's Compensation policies, all such policies shall include Nucor as an additional insured; (ii) all such policies shall provide that such insurance is primary and not excess or contributory to any other policy of insurance carried by Nucor for its own account; and (iii) all such policies shall provide that, to the maximum extent permissible by Applicable Law, the insurers shall waive all rights of subrogation against Nucor, and all of its stockholders, officers, employees, directors, and agents. The costs of all policies of insurance carried for the joint account will be borne in proportion to the Parties' interests in the Nucor Wells.

Section 22.
AMI Area and AMI Interests

22.1 General.

The Parties hereby designate the AMI Area as an area of mutual interest to acquire AMI Interests. The AMI Area shall be in force and effect for a period of fifteen (15) years from the Effective Date hereof (the "AMI Term"), unless earlier terminated by a written agreement signed by each of the Parties hereto.

22.2 AMI Interest Acquisition.
During the AMI Term, if either Party, or any Affiliate of a Party, acquires any AMI Interest (the "Acquiring Party"), then such Acquiring Party shall within five (5) Business Days provide the other Party with written notice of such acquisition. The notice shall include (A) a statement of the purchase price for the AMI Interest (the "AMI Purchase Price") and all of the Acquiring Party's actual Third Party out- of- pocket costs incurred to acquire the AMI Interest (the "Acquisition Costs"), together with reasonable support for the statement, (B) the portion of (i) the AMI Purchase Price and (ii) the Acquisition Costs to be paid by the other Party if such other Party elects to acquire the portion of the AMI Interest described below, and (C) a copy of all instruments of acquisition including, by way of example but not of limitation, copies of the oil and gas leases, assignments, subleases, farmouts, or other contracts creating or affecting the AMI Interest. If the AMI Purchase Price is not paid in cash, then the AMI Purchase Price shall be the value allocated to the AMI Interest by the Acquiring Party and the Third Party.

22.3 Computation of AMI Interest Offered and the Purchase Price.
The portion of an AMI Interest that may be acquired by other Party (the "Undivided Interest") and the portion of the AMI Purchase Price and the Acquisition Costs to be paid for such AMI Interest is set forth below:
A. If the AMI Interest does not include depths below the base of the Formation, then the other Party may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the offered AMI Interest, and shall bear fifty percent (50%) of the AMI Purchase Price and fifty percent (50%) of the Acquisition Costs.
B. If the AMI Interest does not include any interest in producing wells and includes formations below the base of the Formation, then
(i) if Nucor is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation, and shall bear twenty- five percent (25%) of the AMI Purchase Price and twenty- five percent (25%) of the Acquisition Costs, or
(ii) if Encana is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation and all of the AMI Interest below the base of the Formation, and shall bear seventy- five percent (75%) of the AMI Purchase Price and seventy- five percent (75%) of the Acquisition Costs.
C. If the AMI Interest includes an interest in producing wells above the base of the Formation and includes formations below the base of the Formation, then the Parties shall allocate a portion of the AMI Purchase Price to the producing formations based upon a net present value analysis or other mutually acceptable valuation methodology, and
(i) if Nucor is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation, and shall bear (1) fifty percent (50%) of the portion of AMI Purchase Price allocated to the producing formation, and (2) twenty- five percent (25%) of the remaining portion of the AMI Purchase Price and twenty- five percent (25%) of the Acquisition Costs, or

(ii) if Encana is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation and all of the AMI Interest below the base of the Formation, and shall bear (1) fifty percent (50%) of the portion of AMI Purchase Price allocated to the producing formation, and (2) seventy- five percent (75%) of the remaining portion of the AMI Purchase Price and seventy- five percent (75%) of the Acquisition Costs.

D. If the AMI Interest includes an interest in producing wells below the base of the Formation and includes formations above the base of the Formation, then the Parties shall allocate a portion of the AMI Purchase Price to the producing formations based upon a net present value analysis or other mutually acceptable valuation methodology, and

(i) if Nucor is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation, and shall bear (1) none (0%) of the portion of AMI Purchase Price allocated to the producing formation, and (2) twenty- five percent (25%) of the remaining portion of the AMI Purchase Price and twenty- five percent (25%) of the Acquisition Costs, or

(ii) if Encana is the other Party, then it may elect to acquire an undivided one- half (1/2), but not less than one- half (1/2), of the AMI Interest from the surface to the base of the Formation and all of the AMI Interest below the base of the Formation, and shall bear (1) one hundred percent (100%) of the portion of AMI Purchase Price allocated to the producing formation, and (2) seventy- five percent (75%) of the remaining portion of the AMI Purchase Price and seventy- five percent (75%) of the Acquisition Costs.

22.4 Other Party's Response Period.

The recipient of the notice of acquisition of an AMI Interest from the Acquiring Party shall have a period of twenty (20) Business Days after receipt of the Acquiring Party's acquisition notice to furnish the Acquiring Party with (i) written notice of its election to acquire the Undivided Interest, and (ii) a check in the amount of the recipient's portion of the AMI Purchase Price and the Acquisition Costs. The recipient of the notice of acquisition of an AMI Interest from the Acquiring Party shall not bear any of the Acquiring Party's or its Affiliates' internal overhead, land, legal, acquisition, or other costs incurred with respect to any AMI Interest.

22.5 Participation; Conveyances.

If the recipient of the notice of acquisition of an AMI Interest from the Acquiring Party fails or refuses to provide the Acquiring Party with written notice of its election to acquire the Undivided Interest within the twenty (20) Business Day response period, then such failure or refusal shall constitute an irrevocable election by such Party not to acquire the Undivided Interest. Upon timely receipt by the Acquiring Party of the recipient's notice to acquire the Undivided Interest and payment by check, the Acquiring Party shall execute and deliver to the recipient a legallysufficient conveyance in recordable form of the Undivided Interest. Any Conveyance made by the Acquiring Party shall contain a special warranty of title that the Undivided Interest is free and clear of any burdens or encumbrances placed thereon by, through, or under the Acquiring Party, but not otherwise.

Section 23.
Parent Guarantee

By its execution of this Agreement, Parent fully guarantees the performance by Nucor of this Agreement.

Section 24.
No Third Party Beneficiaries

This Agreement is for the sole benefit of the Parties, their respective successors and permitted assigns, and each Party's Affiliates, and all of their stockholders, officers, employees, directors, and agents who are designated as indemnitees under Section 20, and shall not inure to the benefit of any other Person whomsoever or whatsoever, it being the intention of the Parties that no other Third Party shall be deemed a third party beneficiary of this Agreement.

Section 25.
Conflicts

Except as otherwise provided in Section 11, if there is any conflict or inconsistency between any of the terms and provisions of this Agreement and the terms and provisions of any of the instruments attached as Exhibits hereto including, without limitation, Exhibit E- Form of New Operating Agreement, then the terms and provisions of this Agreement shall prevail and control.

Section 26.
Specific Performance

The Parties recognize that irreparable injury to the Parties will result from any breach of this Agreement and that money damages will be inadequate to fully remedy the injury. The Parties, in addition to any other available remedies at law for any breach hereof, will be entitled to enforcement of the provisions through specific performance, which may include obtaining one (1) or more preliminary or permanent orders (i) restraining or enjoining any act which would constitute a breach or (ii) compelling performance of any obligation which, if not performed, would constitute a breach.

Section 27.
Further Assurances

The Parties shall execute, acknowledge, and deliver or cause to be executed, acknowledged and delivered such instruments and take such other action as may be necessary or advisable to carry out their obligations under this Agreement and under any document or other instrument delivered pursuant hereto.

Section 28.

Counterpart Execution

This Agreement may be executed by signing an original or a counterpart thereof. If this Agreement is executed in counterparts, all counterparts taken together shall have the same effect as if all the Parties had signed the same instrument.

(Signature Page Follows)

Signature page to Carry and Earning Agreement

IN WITNESS WHEREOF, this Agreement is executed and effective as of the Effective Date first above written.

Encana Oil & Gas (USA) Inc.

By: /s/ Darrin Henke
Darrin Henke
Vice President, South Rockies

Nucor Energy Holdings Inc.

By: /s/ Joseph Stratman
Joseph Stratman
President

Nucor Corporation

By: /s/ Joseph Stratman
Joseph Stratman
Executive Vice President

Exhibit A Property

Attached to and made a part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012 by and between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.

[***]

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

Exhibit B
Attached to and made part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective as of November 1, 2012 by and between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.
U.S. Bureau of Labor Statistics - Producer Price Index Data
Industries and their products (NAICS Classifications)
Oil and Gas Industry Data- NAICS Series 211xxx and 213xxx
PRODUCER PRICE INDICES

O&G Industry- Drilling O&G Wells Indexes
Series Id: PCU213111- 213111 **Industry: Drilling oil and gas wells** **Product: Drilling oil and gas wells** **Base Date: 1985- 12**
Composite PPI Weighted Average- 20%:

O&G Industry- Oilfield Services Index:
Series Id: PCU213112- 213112 **Industry: Support Activities for oil and gas operations** **Product: Support Activities for oil and gas operations** **Base Date: 1985- 12**
Composite PPI Weighted Average- 65%:

Metal & Metal Products- Steel Pipe & Tube Index:
Series Id: WPU0101706- 0101706 **Commodity Group- Metal & Metal Products** **Product: Steel Pipe & Tube** **Base Date: 198206**
Composite PPI Weighted Average- 15%:

EXHIBIT C
Attached to and made a part of the BJU Carry & Earning Agreement executed October 31, 2012 but effective November 1, 2012 by and between EnCana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.
<u>Form of Wellbore Assignment and Conveyance</u>

THE STATE OF COLORADO §
§ **KNOW ALL MEN BY THESE PRESENTS:**
Section 29.COUNTY OF __________ §

THAT Encana Oil & Gas (USA) Inc., whose address is 370 17 th Street, Suite 1700, Denver, CO 80202 (hereinafter referred to as "Assignor") for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, does hereby GRANT, BARGAIN, SELL, TRANSFER, ASSIGN, AND CONVEY unto Nucor Energy Holdings Inc., whose address is 1915 Rexford Road, Charlotte, NC 28211 (hereinafter referred to as "Assignee") an undivided fifty percent (50.00%) of Assignor's right, title, interest, and estate in and to the following, subject to the limitations below (collectively, the "Assigned Interests"):

a. The wells and their associated wellbores described on Exhibit A (each, individually, a "Well" and collectively, the "Wells"):

b. The rights in and to the oil and gas leases described on the attached Exhibit B ("Leases"), insofar and only insofar as said Leases cover the lands described on Exhibit B, as are necessary to operate, maintain, produce and plug and abandon the Wells.

c. All personal property and fixtures associated with the Wells, including without limitation the following: all tubing, casing and other equipment in the wellbore, wellhead equipment and surface production facilities.

d. All hydrocarbons produced from the Wells.

Assignor and Assignee further agree as follows:

1. This Assignment is made and accepted subject to, and Assignee hereby assumes, its proportionate share of any and all royalties, overriding royalties, payments out of production, and other burdens or encumbrances of record as of November 1, 2012 to the extent the same cover and affect the Assigned Interests, except as may be otherwise provided in the Carry and Earning Agreement.

2. Assignee accepts the Assigned Interest subject to all of the express and implied covenants and obligations of the Leases, insofar as they relate to the Assigned Interests.

3. This Assignment is made by Assignor and accepted by Assignee without any warranty whatsoever and without warranty of title, either express or implied, and without recourse, except that Assignor warrants title as against all parties claiming an interest in the Assigned Interests by, through or under Assignor. This Assignment is made with full substitution and subrogation of Assignee in and to all covenants and warranties heretofore made or given by others.

4. This Assignment is made in accordance with, and is subject to all the terms, provisions, and conditions of, that certain BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1 , 2012, between Assignor and Assignee ("Carry and Earning Agreement") which is incorporated by this reference the same as though fully set out herein. However, this assignment is neither intended as, nor shall it be deemed to accomplish, a merger of the terms and provisions directly set out herein and the terms and provisions of said Carry and Earning Agreement. Should there be any conflict between this Assignment and the Carry and Earning Agreement, the terms and conditions set out in the Carry and Earning Agreement shall prevail.

5. This Assignment is subject to that certain unrecorded Joint Operating Agreement executed October 31, 2012 but effective November 1, 2012.

6. The Assigned Interests do not include, and Assignor does not intend to assign and Assignee does not intend to receive, any interest in the following to the extent that such items do not directly relate to the operation of, and production of hydrocarbons from, a Well: all lands, minerals, oil and gas leases and lands pooled therewith, units, working interests, executory interests, reversionary interests, net profits interests, net revenue interests, term interests, royalty and overriding royalty interests, fee interests, surface interests, and any other interests of a similar nature, all contracts, agreements, licenses, and servitudes, all easements, leases, surface use, and right- of- way agreements, all other property and equipment not directly used in connection with the operation and production of the Wells and any and all rights not expressly herein conveyed as part of the Assigned Interests.

7. The Assigned Interests do not include, and Assignor does not intend to assign and Assignee does not intend to receive, any overriding royalty interest owned by Assignor in existence as of November 1, 2012, except as may be otherwise provided in the Carry and Earning Agreement.

8. The Assigned Interest is hereby limited from the surface to the deepest depth drilled in each Well.

TO HAVE AND TO HOLD the Assigned Interests unto Assignee and its successors and assigns, subject to all the express and implied covenants and obligations of the Leases and this assignment.

EXECUTED this ______ day of ______ 2012, but effective as of the date of first production for each Well as set forth on Exhibit A.

ENCANA OIL & GAS (USA) INC. **NUCOR ENERGY HOLDINGS INC.**

By: ________ By: ________
Ricardo D. Gallegos,
VP, Bus. Dev. Negotiations
& Lead Rockies & Intl. Land

ACKNOWLEDGEMENTS

STATE OF COLORADO §
§
CITY AND COUNTY OF DENVER §

BEFORE ME, the undersigned authority, on this day personally appeared Ricardo D. Gallegos, VP, Bus. Dev. Negotiations & Lead Rockies & Intl. Land for ENCANA OIL & GAS (USA) INC., known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledged to me that he executed the same for the purposes and consideration therein expressed and in the capacity therein stated.

GIVEN UNDER MY HAND AND OFFICIAL SEAL OF OFFICE on this ______ day of ______ 2012.

MY COMMISSION EXPIRES:

______________________________ ______________________________
Notary Public in and for the State of Colorado

STATE OF ________________ §
§
COUNTY OF ________________ §

BEFORE ME, the undersigned authority, on this day personally appeared, ______________________________ for NUCOR ENERGY HOLDINGS INC. known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledged to me that he executed the same for the purposes and consideration therein expressed and in the capacity therein stated.

GIVEN UNDER MY HAND AND OFFICIAL SEAL OF OFFICE on this ______ day of ______ 2012.

MY COMMISSION EXPIRES:

______________________________ ______________________________
Notary Public

<u>Recording Requested and when Recorded</u>

Return to:
Nucor Corporation
1915 Rexford Road
Charlotte, NC 28211
Attn: Brad True

Exhibit D

Attached to the BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012 by and between Nucor Energy Holdings Inc. and Encana Oil & Gas (USA) Inc.

TAX PARTNERSHIP PROVISIONS
OF THE ENCANA- NUCOR 2012 TAX PARTNERSHIP
EIN: [TBD]

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1. General Provisions

1.1. Designation of Documents.

This exhibit is referred to in, and is part of, the agreements identified above and, if so provided, a part of any agreement to which the agreements are an exhibit. Such agreements (including all exhibits thereto, other than this exhibit) shall be hereinafter referred to as the "Agreement;" and this exhibit is hereinafter referred to as the "Exhibit" or the "Tax Partnership Provisions" (the "TPPs"). Except as may be otherwise provided in this Exhibit, terms defined and used in the Agreement shall have the same meaning when used herein.

1.2. Relationship of the Parties.

The parties to the Agreement shall be hereinafter referred to as "Party" or "Parties." The Parties understand and agree that the arrangement and undertakings evidenced by the Agreement result in a partnership for purposes of Federal income taxation and certain State income tax laws which incorporate or follow Federal income tax principles as to tax partnerships. Such partnership for tax purposes is hereinafter referred to as the "Tax Partnership". For every other purpose of the Agreement, the Parties understand and agree that their legal relationship to each other under applicable State law with respect to all property subject to the Agreement is one of tenants in common, or undivided interest owners and not members in or partners of a partnership; that the liabilities of the Parties shall be several and not joint or collective; and that each Party shall be responsible solely for its own obligations.

1.3. Priority of Provisions of this Exhibit.

If there is a conflict or inconsistency, whether direct or indirect, actual or apparent, between the terms and conditions of this Exhibit and the terms and conditions of the Agreement, or any other exhibit or any part thereof, the terms and conditions of this Exhibit shall govern and control.

1.4. Survivorship.

1.4.1. Any termination of the Agreement shall not affect the continuing application of the TPPs for the termination and liquidation of the Tax Partnership.

1.4.2. Any termination of the Agreement shall not affect the continuing application of the TPPs for the resolution of all matters regarding Federal and State income reporting.
1.4.3. These TPPs shall inure to the benefit of, and be binding upon, the Parties hereto and their successors and assigns.
1.4.4. The effective date of the Agreement shall be the effective date of these TPPs. The Tax Partnership shall continue in full force and effect from, and after such date, until termination and liquidation pursuant to Sec. 7.1.

2. Tax Reporting Partner

Encana Oil & Gas (USA) Inc. as the Tax Reporting Partner ("TRP") is responsible for compliance with all tax reporting obligations of the Tax Partnership, see Sec. 3.1, below. In the event of any change in the TRP, the Party serving as TRP at the beginning of a given taxable year shall continue as TRP with respect to all matters concerning such year.

3. Income Tax Compliance and Capital Accounts

3.1. Tax Returns.

The TRP shall prepare and file all required Federal and State partnership income tax returns. Not less than thirty (30) days prior to the return due date (including extensions), the TRP shall submit to each Party for review a copy of the return as proposed.

3.2. Fair Market Value Capital Accounts.

The TRP shall establish and maintain for each Party a fair market value ("FMV") capital account and a tax basis capital account. Upon request, the TRP shall submit to each Party along with a copy of any proposed partnership income tax return an accounting of such Party's FMV capital account as of the end of the return period.

3.3. Information Requests.

In addition to any obligation under Sec. 2, each Party agrees to furnish to the TRP not later than sixty (90) days before the return due date (including extensions) such information relating to the operations conducted under the Agreement as may be required for the proper preparation of such returns. Similarly, each Party agrees to furnish timely to the TRP, as requested, any information and data necessary for the preparation and/or filing of other required reports and notifications, and for the computation of the capital accounts. As provided in Code §6050K(c), a Party transferring its interest must notify the TRP to allow compliance with Code §6050K(a) (see also Sec. 8.1).

3.4. Best Efforts Without Liability.

The TRP and the other Party shall use their best efforts to comply with responsibilities outlined in this Section, and with respect to the service as TRP as outlined Sec. 2, and in doing so shall incur no liability to any other Party.

3.5. Tax Matters Partner

The provisions of this Section 3.5 shall be applicable only if the Tax Partnership does not qualify for the "small partnership exception" from Subchapter C of Chapter 63 of Subtitle A (the "TEFRA rules") of the Internal Revenue Code of 1986, as amended (the "Code") or otherwise elects in Section 9.1 to be subject to the TEFRA Rules.

3.5.1 The TRP shall also be the Tax Matters Partner as defined in Code §6231(a) (the "TMP") and references to the TRP shall then include references to the TMP.

3.5.2 The TMP shall not be required to incur any expenses for the preparation for, or pursuance of, administrative or judicial proceedings, unless the Parties agree on a method for sharing such expenses.

3.5.3 The Parties shall furnish the TMP, within two weeks from the receipt of the request, the information the TMP may reasonably request to comply with the requirements on furnishing information to the Internal Revenue Service.

3.5.4 The TMP shall not agree to any extension of the statute of limitations for making assessments on behalf of the Tax Partnership without first obtaining the written consent of all Parties. The TMP shall not bind any other Party to a settlement agreement in tax audits without obtaining the written concurrence of any such Party.

3.5.5 Any Party who enters in a settlement agreement with the Secretary of the Treasury with respect to any "partnership items," as defined in Code §6231(a)(3), shall notify the other Parties of the terms within ninety (90) days from the date of such settlement.

3.5.6 If any Party intends to file a notice of inconsistent treatment under Code §6222(b), such Party shall, prior to the filing of such notice, notify the TMP of the (actual or potential) inconsistency of the Party's intended treatment of a partnership item with the treatment of that item by the Tax Partnership. Within one week of receipt the TMP shall remit copies of such notification to the other Parties. If an inconsistency notice is filed solely because a Party has not received a Schedule K- 1 in time for filing of its income tax return, the TMP need not be notified.

3.5.7 No Party shall file pursuant to Code §6227 a request for an administrative adjustment of partnership items (a "RFAA") without first notifying all other Parties. If all other Parties agree with the requested adjustment, the TMP shall file the RFAA on behalf of the Tax Partnership. If unanimous consent is not obtained within thirty (30) days from such notice, or within the period required to timely file the RFAA, if shorter, any Party, including the TMP, may file a RFAA on its own behalf.

3.5.8 Any Party intending to file with respect to any partnership item, or any other tax matter involving the Tax Partnership, a petition under Code §§6226, 6228, or any other provision, shall notify the other Parties prior to such filing of the nature of the contemplated proceeding. If the TMP is the Party intending to file such petition, such notice shall be given within a reasonable time to allow the other Parties to participate in the choice of the forum for such petition. If the Parties do not agree on the appropriate forum, then the forum shall be chosen by majority vote. Each Party shall have a vote in accordance with its percentage interest in the Tax Partnership for the year under audit. If a majority cannot agree, the TMP shall choose the forum. If a Party intends to seek review of any court decision rendered as a result of such proceeding, the Party shall notify the other Parties prior to seeking such review.

4. Tax and FMV Capital Account Elections

4.1. General Elections.

For both income tax return and capital account purposes, the Tax Partnership shall elect:

4.1.1. to deduct when incurred intangible drilling and development costs ("IDC");

4.1.2. to use the maximum allowable accelerated tax method and the shortest permissible tax life for depreciation;

4.1.3. the accrual method of accounting;

and the Tax Partnership shall also make any elections as specially noted in Sec. 9.1, below.

4.2. Depletion.

Solely for FMV capital account purposes, depletion shall be calculated by using simulated cost depletion within the meaning of Treas. Reg.§1.704-1(b)(2)(iv)(k)(2), unless the use of simulated percentage depletion is elected in Sec. 9.1, below. The simulated cost depletion allowance shall be determined under the principles of Code §612 and be based on the FMV capital account basis of each property. Solely for purposes of this calculation, remaining reserves shall be determined consistently by the TRP.

4.3. Election Out Under Code §761(a).

4.3.1. The Parties agree not to elect to be excluded from the application of Subchapter K of Chapter 1 of the Code. The TRP shall notify all Parties of an intended election to be excluded from the application of Subchapter K of Chapter 1 of the Code not later than sixty (60) days prior to the filing date or the due date (including extensions) for the Federal partnership income tax return, whichever comes earlier. Even after an effective election-out, the TRP's rights and obligations, other than the relief from tax return filing obligations of the Tax Partnership, shall continue.

4.3.2. After an election- out, to avoid an unintended impairment of the election- out: The Parties will avoid, without prior coordination, any operational changes which would terminate the qualification for the election- out status; all Parties will monitor the continuing qualification of the Tax Partnership for the election- out status and will notify the other Parties if, in their opinion, a change in operations will jeopardize the election-out; and, all Parties will use, unless agreed to by them otherwise, the cumulative gas balancing method as described in Treas. Reg. §1.761- 2(d)(3).

4.4. Consent Requirements For Subsequent Tax or FMV Capital Account Elections.

Future elections, in addition to or in amendment of those in this Exhibit, must be approved by the affirmative consent of the Parties.

5. Capital Contributions and FMV Capital Accounts

The provisions of this Sec. 5 and any other provisions of the TPPs relating to the maintenance of the capital accounts are intended to comply with Treas. Reg. §1.704- 1(b) and shall be interpreted and applied in a manner consistent with such regulations.

5.1. Capital Contributions.

The respective capital contributions of each Party to the Tax Partnership shall be (a) each Party's interest in the oil and gas lease(s), including all associated lease and well equipment, committed to the Tax Partnership, and (b) all amounts of money paid by each Party in connection with the acquisition, exploration, development, and operation of the lease(s), and all other costs characterized as contributions or expenses borne by such Party under the Agreement. The contribution of the leases and any other properties committed to the Tax Partnership shall be made by each Party's agreement to hold legal title to its interest in such leases or other property as nominee of the Tax Partnership.

5.2. FMV Capital Accounts.

The FMV capital accounts shall be increased and decreased as follows:
5.2.1. The FMV capital account of a Party shall be increased by:
(i) the amount of money and the FMV (as of the date of contribution) of any property contributed by such Party to the Tax Partnership (net of liabilities assumed by the Tax Partnership or to which the contributed property is subject);
(ii) that Party's share of Tax Partnership items of income or gain, allocated in accordance with Sec. 6.1; and

(iii) that Party's share of any Code §705(a)(1)(B) item.
5.2.2. The FMV capital account of a Party shall be decreased by:
(i) the amount of money and the FMV of property distributed to a Party (net of liabilities assumed by such Party or to which the property is subject);
(ii) that Party's Sec. 6.1 allocated share of Tax Partnership loss and deductions, or items thereof; and,
(iii) that Party's share of any Code §705(a)(2)(B) item.
5.2.3. "FMV" when it applies to property contributed by a Party to the Tax Partnership shall be assumed, for purposes of 5.2.1, to equal the adjusted tax basis, as defined in Code §1011, of that property unless the Parties agree otherwise as indicated in Sec. 9.1.
5.2.4. As provided in Treas. Reg. §1.704- 1(b)(2)(iv)(e*),* upon distribution of Tax Partnership property to a Party the capital accounts will be adjusted to reflect the manner in which the unrealized income, gain, loss and deduction inherent in distributed property (not previously reflected in the FMV capital accounts) would be allocated among the Parties if there were a taxable disposition of such property at its FMV as of the time of distribution. Furthermore, if so agreed to in Sec. 9.1, pursuant to the rules of Treas. Reg. § 1.704- 1(b)(2)(iv)(f*),* the FMV capital accounts shall be revalued at certain times to reflect value changes of the Tax Partnership property.

6. Partnership Allocations

6.1. FMV Capital Account Allocations.
Each item of income, gain, loss, or deduction shall be allocated to each Party as follows:
6.1.1. Actual or deemed income from the sale, exchange, distribution or other disposition of production shall be allocated to the Party entitled to such production or the proceeds from the sale of such production. The amount received from the sale of production and the amount of the FMV of production taken in kind by the Parties are deemed to be identical; accordingly, such items may be omitted from the adjustments made to the Parties' FMV capital accounts.
6.1.2. Exploration cost, IDC, operating and maintenance cost shall be allocated to each Party in accordance with its respective contribution, or obligation to contribute, to such cost.
6.1.3. Depreciation shall be allocated to each Party in accordance with its contribution, or obligation to contribute, to the cost of the underlying asset.

6.1.4. Simulated depletion shall be allocated to each Party in accordance with its FMV capital account adjusted basis in each oil and gas property of the Tax Partnership.
6.1.5. Loss (or simulated loss) upon the sale, exchange, distribution, abandonment or other disposition of depreciable or depletable property shall be allocated to the Parties in the ratio of their respective FMV capital account adjusted bases in the depreciable or depletable property.
6.1.6. Gain (or simulated gain) upon the sale, exchange, distribution, or other disposition of depreciable or depletable property shall be allocated to the Parties so that the FMV capital account balances of the Parties will most closely reflect their respective percentage or fractional interests in such property under the Agreement.
6.1.7. Costs or expenses of any other kind shall be allocated to each Party in accordance with its respective contribution, or obligation to contribute, to such costs or expense.
6.1.8. Any other income item shall be allocated to the Parties in accordance with the manner in which such income is realized by each Party.

6.2. Tax Return and Tax Basis Capital Account Allocations.

6.2.1. Unless otherwise expressly provided in this Sec. 6.2, the allocations of the Tax Partnership's items of income, gain, loss, or deduction for tax return and tax basis capital account purposes shall follow the principles of the allocations under Sec. 6.1. However, the Tax Partnership's gain or loss on the taxable disposition of a Tax Partnership property in excess of the gain or loss under Sec. 6.1, if any, is allocated to the contributing Party to the extent of such Party's pre- contribution gain or loss.
6.2.2. The Parties recognize that under Code §613A(c)(7)(D) the depletion allowance is to be computed separately by each Party. For this purpose, each Party's share of the adjusted tax basis in each oil and gas property shall be equal to its contribution to the adjusted tax basis of such property.
6.2.3. Under Code §613A(c)(7)(D) gain or loss on the disposition of an oil and gas property is to be computed separately by each Party. Pursuant to Treas. Reg. §1.704- 1(b)(4)(v), the amount realized shall be allocated as follows: (i) an amount that represents recovery of adjusted simulated depletion basis is allocated (without being credited to the FMV capital accounts) to the Parties in the same proportion as the aggregate simulated depletion basis was allocated to such Parties under Sec. 5.2; and (ii) any remaining realization is allocated in accordance with Sec. 6.1.6.
6.2.4. Depreciation shall be allocated to each Party in accordance with its contribution to the adjusted tax basis of the depreciable asset.

6.2.5. In accordance with Treas. Reg. §1.1245- 1(e), depreciation recapture shall be allocated, to the extent possible, among the Parties to reflect their prior sharing of the depreciation deductions.
6.2.6. In accordance with the principles of Treas. Reg. §1.1254- 5, any recapture of IDC shall be determined and reported by each Party separately. Similarly, any recapture of depletion shall be computed separately by each Party, in accordance with its depletion allowance computed pursuant to Sec. 6.2.2.
6.2.7. For Tax Partnership properties with FMV capital account values different from their adjusted tax bases the Parties intend that the allocations described in this Section 6.2 constitute a "reasonable method" of allocating gain or loss under Treas. Reg. §1.704- 3(a)(1).
If checked "Yes" in Sec. 9.1, below, each Party has the right to determine the market for its proportionate share of production. All items of income, deductions, and credits arising from such marketing of production shall be recognized by the Tax Partnership and shall be allocated to the Party whose production is so marketed.

7. Termination and Liquidating Distribution

7.1. Termination of the Tax Partnership.

The Tax Partnership shall terminate upon the first to occur of (a) a deemed termination of the Tax Partnership pursuant to Section 708(b)(1)(A) of the Code, (b) the effectiveness of an election by the Parties to be excluded from the application of Subchapter K of Chapter 1 of the Code (if and when all the Parties affirmatively agree to make such an election) or (c) the occurrence of any other event which causes the Tax Partnership to terminate as a matter of law.
7.1.1. Upon termination, as provided in Code §708(b)(1)(A), the business shall be wound- up and concluded, and the assets shall be distributed to the Parties as described below by the end of such calendar year (or, if later, within ninety (90) days after the date of such termination). The assets shall be valued and distributed to the Parties in the order provided in Secs. 7.1.2, 7.5, and 7.7
7.1.2. First, all cash representing unexpended contributions by any Party and any property in which no interest has been earned by any other Party under the Agreement shall be returned to the contributor.

7.2. Balancing of FMV Capital Accounts.

Second, the FMV capital accounts of the Parties shall be determined as described hereafter. The TRP shall take the actions specified under Secs. 7.2 through 7.5 in order to cause the Parties' FMV capital accounts to reflect, to the maximum extent possible, their interests under the

Agreement. These actions are hereafter referred to as the "balancing of the FMV capital accounts" and, when each Party's FMV capital account balance is equal to the fair market value of its interest under the Agreement, the FMV capital accounts of the Parties shall be referred to as "balanced."

7.3. Deemed Sale Gain/Loss Charge Back.

The FMV of all Tax Partnership properties shall be determined and the gain or loss for each property, which would have resulted if sold at such FMV, shall be allocated in accordance with Secs. 6.1.5 and 6.1.6. If each Party's FMV capital account balance following such allocation does not correspond to the fair market value of its respective interests under the Agreement, then income, gain, loss, and deduction for the taxable year in which the liquidation occurs shall be reallocated among the Parties to cause, to the maximum extent possible, the ratio of their positive FMV capital account balances to equal the fair market value of their respective interests under the Agreement.

7.4. Deficit Make- Up Obligation and Balancing Cash Contributions.

If hereafter a Party has a negative FMV capital account balance, that is a balance of less than zero, in accordance with Treas. Reg. §1.704-1(b)(2)(ii)(b)(3), such Party is obligated to contribute by the end of the taxable year or, if later, within 90 days from the Tax Partnership's liquidation, an amount of money to the Tax Partnership sufficient to achieve a zero balance FMV capital account (the "Deficit Make- Up Obligation"). Moreover, any Party may contribute an amount of cash to the Tax Partnership to facilitate the balancing of the FMV capital accounts. If after these adjustments the FMV capital accounts are not balanced, Sec. 7.5 shall apply.

7.5. Distribution to Balance Capital Accounts.

7.5.1. If the FMV capital accounts of the Parties are not balanced after the application of Sec. 7.3, (i) a Party may contribute cash in the amount required to cause its FMV capital account to be balanced, and/or (ii) if all Parties agree, any cash or an undivided interest in certain selected properties shall be distributed to any Party whose FMV capital account balance exceeds its interest in the fair market value of the Tax Partnership properties under the Agreement as necessary to cause, following such distribution, all FMV capital accounts to be balanced with respect to the remaining Tax Partnership properties.

7.5.2. Unless Sec.7.5.1 applies, an undivided interest in each and every property shall be distributed to one or more Parties in accordance with their FMV capital accounts.

7.6. FMV Determination.

If a property is to be valued for purposes of balancing the capital accounts and making a distribution under this Sec. 7, the Parties shall first attempt to agree on the FMV of the property; failing such an agreement, the TRP shall cause a nationally recognized independent engineering firm to prepare an appraisal of the FMV of such property.

7.7. Final Distribution.

After the FMV capital accounts of the Parties have been adjusted pursuant to Secs. 7.2 to 7.5, all remaining property and interests then held by the Tax Partnership shall be distributed to the Parties in accordance with their positive FMV capital account balances.

8. Transfers, Indemnification, and Correspondence

8.1. Transfer of Tax Partnership Interests.

Transfers of Tax Partnership interests shall be governed by the Agreement. A Party transferring its interest, or any part thereof, shall notify the TRP in writing within two (2) weeks after such transfer.

8.2. Farmouts, Distributions and Contributions to Other Partnerships.

If any Party wishes to sell, farm out or exchange a portion of any property with a third party or contribute its interest in a property to a partnership or tax partnership with a third party to the extent allowed under the Agreement, the other Parties shall not unreasonably withhold consent to distribute the property from the Tax Partnership to each Party in proportion to its interest in such property, and shall execute within 30 days such documents as are necessary to effect the distribution; provided that the Party participating in such sale, farm out, exchange or contribution shall fully compensate the other Party or Parties for any accelerated recognition of gain to such Party or Parties resulting from the distribution, including any gain recognized under Code §704(c)(1)(B) and Code §737.

8.3. Correspondence.

All correspondence relating to the preparation and filing of the Tax Partnership's income tax returns and capital accounts shall be sent to:

(Attach separate list, if necessary)

TRP	"Att to:" reference
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, CO 80202	Tax Department

Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	Tax Department

9. Elections and Changes to above Provisions

9.1. Special Tax Elections.

With respect to Sec. 4.1, the Parties agree (if not agreed, insert "No"):

a) that the Tax Partnership shall elect to account for dispositions of depreciable assets under the general asset method to the extent permitted by Code §168(i)(4);	No
b) that the Tax Partnership shall elect under Code §754 to adjust the basis of Tax Partnership property, with the adjustments provided in Code §734 for a distribution of property and in Code §743 for a transfer of a partnership interest. In case of distribution of property the TRP shall adjust all tax basis capital accounts. In the case of a transfer of a partnership interest the acquiring party(ies) shall establish and maintain its (their) tax basis capital account(s);	Yes
c) that the Tax Partnership shall elect under Code §6231 to be subject to the TEFRA rules;	No
d) that the Tax Partnership shall elect under Code §709 to amortize over the shortest permissible period all deferred organizational expenses;	Yes
e) that the Tax Partnership shall elect under Code §195 to amortize over the shortest permissible period all deferred business start- up expenses;	Yes

f) with respect to Sec. 4.2, Depletion, the Parties agree that the Tax Partnership shall use simulated percentage depletion instead of simulated cost depletion;	No
g) with respect to Sec.5.2.4, under the rules of Treas. Reg. § 1.704- 1(b)(2)(iv)(f) the Parties agree that the FMV capital accounts shall be revalued to reflect value changes of the Tax Partnership property upon the occurrence of the events specified in (5)(i) through (iii) of said -1(b)(2)(iv)(f) regulations;	Yes
h) with respect to Sec. 6.2.8, the income attributable to take- in- kind production will be reflected on the tax return.	No

With respect to Sec. 5.2.3, the FMV for the listed properties are determined on Schedule 5.2.3, which shall describe each property that becomes subject to the Agreement and the agreed fair market value of such property at the time it becomes subject to the Agreement.

EXHIBIT E

Attached to and made a part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective as of November 1, 2012 by and between Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

A.A.P.L. FORM 610- 1989

MODEL FORM OPERATING AGREEMENT

OPERATING AGREEMENT

DATED EFFECTIVE

November 1, 2012

OPERATOR **Encana Oil & Gas (USA) Inc.**

CONTRACT AREA **All Carry Wells and/or Head's Up Wells drilled pursuant to the BJU Carry and Earning Agreement between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc. executed October 31, 2012 but effective November 1, 2012.**

29.1

COUNTY OR PARISH OF **Garfield and Rio Blanco**, STATE OF **Colorado**

A.A.P.L. NO. 610 1989

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OPERATING AGREEMENT

THIS AGREEMENT is entered into by and between Encana Oil & Gas (USA) Inc. ("Encana") and Nucor Energy Holdings Inc. ("Nucor"), with Encana being also referred to as "Operator." Nucor is the Non- operator herein. Encana and Nucor may be referred to herein individually as a "party" and together as the "parties."

WITNESSETH:

WHEREAS, the parties to this agreement are owners of the Carry Wells and/or Head's Up Wells designated and drilled pursuant to the BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012 between the parties and the parties hereto have reached an agreement regarding the production of Oil and Gas from the Carry Wells and/or Head's Up Wells as hereinafter provided.

ARTICLE I.

DEFINITIONS

As used in this agreement, the following words and terms shall have the meanings here ascribed to them:

A. The term "AFE" shall mean an Authority for Expenditure prepared by a party to this agreement for the purpose of estimating the costs to be incurred in conducting an operation hereunder.

B. The term "Completion" or "Complete" shall mean a single operation intended to complete a well as a producer of Oil and Gas in one or more Zones, including, but not limited to, the setting of production casing, perforating, well stimulation and production testing conducted in such operation.

C. The term "Contract Area" shall mean the area described in Exhibit "A".

D. The term "Deepen" shall mean a single operation whereby a well is drilled to an objective Zone below the deepest Zone in which the well was previously drilled, or below the Deepest Zone proposed in the associated AFE, whichever is the lesser.

E. The terms "Drilling Party" and "Consenting Party" shall mean a party who agrees to join in and pay its share of the cost of any operation conducted under the provisions of this agreement.

F. The term "Drilling Unit" shall mean the area fixed for the drilling of one well by order or rule of any state or federal body having authority. If a Drilling Unit is not fixed by any such rule or order, a Drilling Unit shall be the drilling unit as established by the pattern of drilling in the Contract Area unless fixed by express agreement of the Drilling Parties.

G. The term "Drillsite" shall mean the Oil and Gas Lease or Oil and Gas Interest on which a Carry Well and/or Head's Up Well is to be located

H. The term "Initial Well" shall mean the well required to be drilled by the parties hereto as provided in Article VI.A.

I. The term "Non- Consent Well" shall mean a well in which less than all parties have conducted an operation as provided in Article VI.B.2.

J. The terms "Non- Drilling Party" and "Non- Consenting Party" shall mean a party who elects not to participate in a proposed operation.

K. The term "Oil and Gas" shall mean oil, gas, casinghead gas, gas condensate, and/or all other liquid or gaseous hydrocarbons and other marketable substances produced therewith, unless an intent to limit the inclusiveness of this term is specifically stated.

L. The term "Oil and Gas Interests" or "Interests" shall mean unleased fee and mineral interests in Oil and Gas in tracts of land lying within the Contract Area which are owned by parties to this agreement.

M. The terms "Oil and Gas Lease," "Lease" and "Leasehold" shall mean the oil and gas leases or interests therein covering tracts of land lying within the Contract Area which are owned by the parties to this agreement.

N. The term "Plug Back" shall mean a single operation whereby a deeper Zone is abandoned in order to attempt a Completion in a shallower Zone.

O. The term "Recompletion" or "Recomplete" shall mean an operation whereby a Completion in one Zone is abandoned in order to attempt a Completion in a different Zone within the existing wellbore.

P. The term "Rework" shall mean an operation conducted in the wellbore of a well after it is Completed to secure, restore, or improve production in a Zone which is currently open to production in the wellbore. Such operations include, but are not limited to, well stimulation operations but exclude any routine repair or maintenance work or drilling, Sidetracking, Deepening, Completing, Recompleting, or Plugging Back of a well.

Q. The term "Sidetrack" shall mean the directional control and intentional deviation of a well from vertical so as to change the bottom hole location unless done to straighten the hole or drill around junk in the hole to overcome other mechanical difficulties.

R. The term "Zone" shall mean a stratum of earth containing or thought to contain a common accumulation of Oil and Gas separately producible from any other common accumulation of Oil and Gas.

S. "BJU Carry and Earning Agreement" shall mean that certain BJU Carry and Earning Agreement made by and between Encana and Nucor, executed October 31, 2012 but effective November 1, 2012.

T. "Carry Wells" and/or "Head's Up Wells" shall have the same meaning as provided in the BJU Carry and Earning Agreement.

Unless the context otherwise clearly indicates, words used in the singular include the plural, the word "person" includes natural and artificial persons, the plural includes the singular, and any gender includes the masculine, feminine, and neuter. Capitalized terms that are not otherwise defined herein shall have the same meaning as in the BJU Carry and Earning Agreement.

ARTICLE II.
EXHIBITS

The following exhibits, as indicated below and attached hereto, are incorporated in and made a part hereof:

__X__ A. Exhibit "A" shall include the following information:
(1) Description of Carry Wells and/or Head's Up Wells subject to this agreement,
(2) Restrictions, if any, as to depths, formations, previously existing wells, or substances,
(3) Percentages or fractional interests of parties to this agreement
(4) Leases, lands and agreements subject to this agreement, ,
(5) Parties to agreement with addresses and telephone numbers for notice purposes,
~~(6) Burdens on production.~~

_____ ~~B.~~ ~~Exhibit "B," Form of Lease.~~

__X__ C. Exhibit "C," Accounting Procedure.

__X__ D. Exhibit "D," Insurance.

__X__ E. Exhibit "E," Gas Balancing Agreement.

__X__ F. Exhibit "F," Non- Discrimination and Certification of Non- Segregated Facilities.

__X__ G. Exhibit "G," Tax Partnership.

__X__ H. Exhibit "H" Nucor Well Information Requirements.

__X__ I. Exhibit "I" Recording Supplement.

ARTICLE III.
INTERESTS OF PARTIES

A. Oil and Gas Interests:

If Encana owns an Oil and Gas Interest in the Contract Area that is not subject to an Oil and Gas Lease, that Interest shall be subject to a royalty payable to Encana of 16.67%.

B. Interests of Parties in Costs and Production:

Unless changed by other provisions, all costs and liabilities incurred in operations under this agreement shall be borne and paid, and all equipment and materials acquired in operations on the Contract Area shall be owned, by the parties as their interests are set forth in Exhibit "A." In the same manner, the parties shall also own all production of Oil and Gas from the Contract Area subject, however, to the payment of royalties and other burdens on production as described hereafter.

Regardless of which party has contributed any Oil and Gas Lease or Oil and Gas Interest on which royalty or other burdens may be payable and except as otherwise expressly provided in this agreement, each party shall pay or deliver, or cause to be paid or delivered, all burdens on its share of the production up to, but not in excess of, of those burdens SEE ARTICLE XVI.D. and shall indemnify, defend and hold the other parties free from any liability therefore. Except as otherwise expressly provided in this agreement, if any party has contributed hereto any Lease or Interest which is burdened with any royalty, overriding royalty, production payment or other burden on production in excess of the amounts stipulated above, such party so burdened shall assume and alone bear all such excess obligations and shall indemnify, defend and hold the other parties hereto harmless from any and all claims attributable to such excess burden. However, so long as the Drilling Unit for the productive Zone(s) is identical with the Contract Area, each party shall pay or deliver, or cause to be paid or delivered, all burdens on production from the Contract Area due under the terms of the Oil and Gas Lease(s) which such party has contributed to this agreement, and shall indemnify, defend and hold the other parties free from any liability therefore.

No party shall ever be responsible, on a price basis higher than the price received by such party, to any other party's lessor or royalty owner, and if such other party's lessor or royalty owner should demand and receive settlement on a higher price basis, the party contributing the affected Lease shall bear the additional royalty burden attributable to such higher price.

Nothing contained in this Article III.B. shall be deemed an assignment or cross- assignment of interests covered hereby, and in the event two or more parties contribute to this agreement jointly owned Leases, the parties' undivided interests in said Leaseholds shall be deemed separate leasehold interests for the purposes of this agreement.

C. Subsequently Created Interests:

If any party has contributed hereto a Lease or Interest that is burdened with an assignment of production given as security for the payment of money, or if, after the effective date of the BJU Carry and Earning Agreement, any party creates an overriding royalty, production payment, net profits interest, assignment of production or other burden payable out of production attributable to its working interest hereunder, such burden shall be deemed a "Subsequently Created Interest." Further, regardless of the date such burden was created, any overriding royalty, production payment, net profits interest, or other burden payable out of production and owned by Operator or its Affiliates shall be treated as a Subsequently Created Interest unless such burden is disclosed on Schedule 5.2 to the BJU Carry and Earning Agreement~~, to the extent such burdens causes the burdens on such party's Lease or Interest to exceed the amount stipulated in Article III.B. above~~.

The party whose interest is burdened with the Subsequently Created Interest (the "Burdened Party") shall assume and alone bear, pay and discharge the Subsequently Created Interest and shall indemnify, defend and hold harmless the other parties from and against any liability therefore. Further, if the Burdened Party fails to pay, when due, its share of expenses chargeable hereunder, all provisions of Article VII.B. shall be enforceable against the Subsequently Created Interest in the same manner as they are enforceable against the working interest of the Burdened Party. If the Burdened Party is required under this agreement to assign or relinquish to any other party, or parties, all or a portion of its working interest and/or the production attributable thereto, said other party, or parties, shall receive said assignment and/or production free and clear of said Subsequently Created Interest, and the Burdened Party shall indemnify, defend and hold harmless said other party, or parties, from any and all claims and demands for payment asserted by owners of the Subsequently Created Interest.

ARTICLE IV.
TITLES

A. Title Examination:

Title examination shall be made on the Drillsite of any proposed well prior to commencement of drilling operations and, if a majority in interest of the Drilling Parties so request or Operator so elects, title examination shall be made on the entire Drilling Unit, or maximum anticipated Drilling Unit, of the well. The opinion will include the ownership of the working interest, minerals, royalty, overriding royalty and production payments under the applicable Leases. Each party contributing Leases and/or Oil and Gas Interests to be included in the Drillsite or Drilling Unit, if appropriate, shall furnish to Operator all abstracts (including federal lease status reports), title opinions, title papers and curative material in its possession free of charge. All such information not in the possession of or made available to Operator by the parties, but necessary for the examination of the title, shall be obtained by Operator. Operator shall cause title to be examined by attorneys on its staff or by outside attorneys. Copies of all title opinions shall be furnished to each Drilling Party. Costs incurred by Operator in procuring abstracts, fees paid outside attorneys for title examination (including preliminary, supplemental, shut- in royalty opinions and division order title opinions) and other direct charges as provided in Exhibit "C" shall be borne by the Drilling Parties in the proportion that the interest of each Drilling Party bears to the total interest of all Drilling Parties as such interests appear in Exhibit "A." Operator shall make no charge for services rendered by its staff attorneys or other personnel in the performance of the above functions.

Operator shall be responsible for using its reasonable efforts to secure curative matter and pooling amendments or agreements required in connection with Leases or Oil and Gas Interests contributed by such party. Operator shall be responsible for the preparation and recording of pooling designations or declarations and communitization agreements as well as the conduct of hearings before governmental agencies for the securing of spacing or pooling orders or any other orders necessary or appropriate to the conduct of operations hereunder. This shall not prevent any party from appearing on its own behalf at such hearings. Costs incurred by Operator, including fees paid to outside attorneys, which are associated with hearings before governmental agencies, and which costs are necessary and proper for the activities contemplated under this agreement, shall be direct charges to the joint account and shall not be covered by the administrative overhead charges as provided in Exhibit "C."

Operator shall make no charge for services rendered by its staff attorneys or other personnel in the performance of the above functions.

No well shall be drilled on the Contract Area until after (1) the title to the Drillsite or Drilling Block, if appropriate, has been examined as above provided, and (2) the title has been approved by the Operator, examining attorney or title has been accepted by all of the Drilling Parties in such well.

B. Loss or Failure of Title:

1. <u>Failure of Title</u>: Should any Oil and Gas Interest or Oil and Gas Lease be lost through failure of title, which results in a reduction of interest from that shown on Exhibit "A" the party credited with contributing the affected Lease or Interest (including, if applicable, a successor in interest to such party) shall have ninety (90) days from final determination of title failure to acquire a new lease or other instrument curing the entirety of the title failure, which acquisition will not be subject to Article VIII.B., and failing to do so, this agreement, nevertheless, shall continue in force as to all remaining Oil and Gas Leases and Interests; and,

(a) The party credited with contributing the Oil and Gas Lease or Interest affected by the title failure (including, if applicable, a successor in interest to such party) shall bear alone the entire loss and it shall not be entitled to recover from Operator or the other parties any development or operating costs which it may have previously paid or incurred, but there shall be no additional liability on its part to the other parties hereto by reason of such title failure;

(b) There shall be no retroactive adjustment of expenses incurred or revenues received from the operation of the Lease or Interest which has failed, but the interests of the parties contained on Exhibit "A" shall be revised on an acreage basis, as of the time it is determined finally that title failure has occurred, so that the interest of the party whose Lease or Interest is affected by the title failure will thereafter be reduced in the Contract Area by the amount of the Lease or Interest failed;

(c) If the proportionate interest of the other parties hereto in any producing well previously drilled on the Contract Area is increased by reason of the title failure, the party who bore the costs incurred in connection with such well attributable to the Lease or Interest which has failed shall receive the proceeds attributable to the increase in such interest (less costs and burdens attributable thereto) until it has been reimbursed for unrecovered costs paid by it in connection with such well attributable to such failed Lease or Interest;

(d) Should any person not a party to this agreement, who is determined to be the owner of any Lease or Interest which has failed, pay in any manner any part of the cost of operation, development, or equipment, such amount shall be paid to the party or parties who bore the costs which are so refunded;

(e) Any liability to account to a person not a party to this agreement for prior production of Oil and Gas which arises by reason of title failure shall be borne severally by each party (including a predecessor to a current party) who received production for which such accounting is required based on the amount of such production received, and each such party shall severally indemnify, defend and hold harmless all other parties hereto for any such liability to account;

(f) No charge shall be made to the joint account for legal expenses, fees or salaries in connection with the defense of the Lease or Interest claimed to have failed, but if the party contributing such Lease or Interest hereto elects to defend its title it shall bear all expenses in connection therewith; and

(g) If any party is given credit on Exhibit "A" to a Lease or Interest which is limited solely to ownership of an interest in the wellbore of any well or wells and the production therefrom, such party's absence of interest in the remainder of the Contract Area shall be considered a Failure of Title as to such remaining Contract Area unless that absence of interest is reflected on Exhibit "A".

2. Loss by Non- Payment or Erroneous Payment of Amount Due: If, through mistake or oversight, any rental, shut- in well payment, minimum royalty or royalty payment, or other payment necessary to maintain all or a portion of an Oil and Gas Lease or interest is not paid or is erroneously paid, and as a result a Lease or Interest terminates, there shall be no monetary liability against the party who failed to make such payment. Unless the party who failed to make the required payment secures a new Lease or Interest covering the same interest within ninety (90) days from the discovery of the failure to make proper payment, which acquisition will not be subject to Article VIII.B., the interests of the parties reflected on Exhibit "A" shall be revised on an acreage basis, effective as of the date of termination of the Lease or Interest involved, and the party who failed to make proper payment will no longer be credited with an interest in the Contract Area on account of ownership of the Lease or Interest which has terminated. If the party who failed to make the required payment shall not have been fully reimbursed, at the time of the loss, from the proceeds of the sale of Oil and Gas attributable to the lost Lease or Interest, calculated on an acreage basis, for the development and operating costs previously paid on account of such Lease or Interest, it shall be reimbursed for unrecovered actual costs previously paid by it (but not for its share of the cost of any dry hole previously drilled or wells previously abandoned) from so much of the following as is necessary to effect reimbursement:

(a) Proceeds of Oil and Gas produced prior to termination of the Lease or Interest, less operating expenses and lease burdens chargeable hereunder to the person who failed to make payment, previously accrued to the credit of the lost Lease or Interest, on an acreage basis, up to the amount of unrecovered costs;

(b) Proceeds of Oil and Gas, less operating expenses and lease burdens chargeable hereunder to the person who failed to make payment, up to the amount of unrecovered costs attributable to that portion of Oil and Gas thereafter produced and marketed (excluding production from any wells thereafter drilled) which, in the absence of such Lease or Interest termination, would be attributable to the lost Lease or Interest on an acreage basis and which as a result of such Lease or Interest termination is credited to other parties, the proceeds of said portion of the Oil and Gas to be contributed by the other parties in proportion to their respective interests reflected on Exhibit "A"; and,

(c) Any monies, up to the amount of unrecovered costs, that may be paid by any party who is, or becomes, the owner \of the Lease or Interest lost, for the privilege of participating in the Contract Area or becoming a party to this agreement.

3. Other Losses: All losses of Leases or Interests committed to this agreement, other than those set forth in Articles IV.B.1.and IV.B.2. above, shall be joint losses and shall be borne by all parties in proportion to their interests shown on Exhibit "A." This shall include but not be limited to the loss of any Lease or Interest through failure to develop or because express or implied covenants have not been performed (other than performance which requires only the payment of money), and the loss of any Lease by expiration at the end of its primary term if it is not renewed or extended. There shall be no readjustment of interests in the remaining portion of the Contract Area on account of any joint loss.

4. Curing Title: In the event of a Failure of Title under Article IV.B.1. or a loss of title under Article IV.B.2. above, any Lease or Interest acquired by any party hereto (other than the party whose interest has failed or was lost) during the ninety (90) day period provided by Article IV.B.1. and Article IV.B.2. above covering all or a portion of the interest that has failed or was lost shall be offered at cost to the party whose interest has failed or was lost, and the provisions of Article VIII.B. shall not apply to such acquisition.

ARTICLE V.
OPERATOR

A. Designation and Responsibilities of Operator:

Encana shall be the Operator of the Contract Area and shall conduct and direct and have full control of all operations in the Contract Area as permitted and required by, and within the limits this agreement. In its performance of services hereunder for the Non- Operators, Operator shall be an independent contractor not subject to the control or direction of the Non- Operators except as to the type of operation to be undertaken in accordance with the election procedures contained in this agreement. Operator shall not be deemed, or hold itself out as, the agent of the Non- Operators with authority to bind them to any obligation or liability assumed or incurred by Operator as to any third party. Operator shall conduct its activities under this agreement as a reasonable prudent operator, in a good and workmanlike manner, with due diligence and dispatch, in accordance with good oilfield practice, and in compliance with applicable law and regulation, but in no event shall it have any liability as Operator to the other parties for losses sustained or liabilities incurred except such as may result from gross negligence or willful misconduct.

B. Resignation or Removal of Operator and Selection of Successor:

1. Resignation or Removal of Operator: Operator may resign at any time by giving written notice thereof to Non- Operators. If Operator terminates its legal existence, no longer owns an interest hereunder in the Contract Area, or is no longer capable of serving as Operator, Operator shall be deemed to have resigned without any action by Non- Operators, except the selection of a successor. Operator may be removed only for good cause by the affirmative vote of Non- Operators owning a majority interest based on ownership as shown on Exhibit "A", as appropriate in context, remaining after excluding the voting interest of Operator; such vote shall not be deemed effective until a written notice has been delivered to the Operator by a Non- Operator detailing the alleged default and Operator has failed to cure the default within thirty (30) days from its receipt of the notice or, if the default concerns an operation then being conducted, within forty- eight (48) hours of its receipt of the notice. For purposes hereof, "good cause" shall mean not only gross negligence or willful misconduct but also the material breach of or inability to meet the standards of operation contained in Article V.A. or material failure or inability to perform its obligations under this agreement.
Subject to Article VII.D.1., such resignation or removal shall not become effective until 7:00 o'clock A.M. on the first day of the calendar month following the expiration of ninety (90) days after the giving of notice of resignation by Operator or action by the Non- Operators to remove Operator, unless a successor Operator has been selected and assumes the duties of Operator at an earlier date. Operator, after effective date of resignation or removal, shall be bound by the terms hereof as a Non- Operator. A change of a corporate name or structure of Operator or transfer of Operator's interest to any single subsidiary, parent or successor corporation shall not be the basis for removal of Operator.
2. Selection of Successor Operator: Upon the resignation or removal of Operator under any provision of this agreement, a successor Operator shall be selected by the parties. The successor Operator shall be selected from the parties owning an interest in the Contract Area at the time such successor Operator is selected. The successor Operator shall be selected by the affirmative vote of two (2) or more parties owning a majority interest based on ownership as shown on Exhibit "A" , as appropriate in context; provided, however, if an Operator which has been removed or is deemed to have resigned fails to vote, or votes only to succeed itself, the successor Operator shall be selected by the affirmative vote of the party or parties owning a majority interest based on ownership as shown on Exhibit "A" , as appropriate in context, remaining after excluding the voting interest of the Operator that was removed or resigned. The former Operator shall promptly deliver to the successor Operator all records and data relating to the operations conducted by the former Operator to the extent such records and data are not already in the possession of the successor operator. Any cost of obtaining or copying the former Operator's records and data shall be charged to the joint account.
3. Effect of Bankruptcy: If Operator becomes insolvent, bankrupt or is placed in receivership, it shall be deemed to have resigned without any action by Non- Operators, except the selection of a successor. If a petition for relief under the federal bankruptcy laws is filed by or against Operator, and the removal of Operator is prevented by the federal bankruptcy court, all Non- Operators and Operator shall comprise an interim operating committee to serve until Operator has elected to reject or assume this agreement pursuant to the Bankruptcy Code, and an election to reject this agreement by Operator as a debtor in possession, or by a trustee in bankruptcy, shall be deemed a resignation as Operator without any action by Non- Operators, except the selection of a successor. During the period of time the operating committee controls operations, all actions shall require the approval of two (2) or more parties owning a majority interest based on ownership as shown on Exhibit "A."
In the event there are only two (2) parties to this agreement, during the period of time the operating committee controls operations, a third party acceptable to Operator, Non- Operator and the federal bankruptcy court shall be selected as a member of the operating committee, and all actions shall require the approval of two (2) members of the operating committee without regard for their interest in the Contract Area based on Exhibit "A" , as appropriate in context.

C. Employees and Contractors:

The number of employees or contractors used by Operator in conducting operations hereunder, their selection, and the hours of labor and the compensation for services performed shall be determined by Operator, and all such employees or contractors shall be the employees or contractors of Operator.

D. Rights and Duties of Operator:

~~1. Competitive Rates and Use of Affiliates: All wells drilled on the Contract Area shall be drilled on a competitive contract basis at the usual rates prevailing in the area. If it so desires, Operator may employ its own tools and equipment in the drilling of wells, but its charges therefor shall not exceed the prevailing rates in the area and the rate of such charges shall be agreed upon by the parties in writing before drilling operations are commenced, and such work shall be performed by Operator under the same terms and conditions as are customary and usual in the area in contracts of independent contractors who are doing work of a similar nature. All work performed or materials supplied by affiliates or related parties of Operator shall be performed or supplied at competitive rates, pursuant to written agreement, and in accordance with customs and standards prevailing in the industry.~~

2. Discharge of Joint Account Obligations: Except as herein otherwise specifically provided, Operator shall promptly pay and discharge expenses incurred in the development and operation of the Contract Area pursuant to this agreement and shall charge each of the parties hereto with their respective proportionate shares upon the expense basis provided in Exhibit "C." Operator shall keep an accurate record of the joint account hereunder, showing expenses incurred and charges and credits made and received.
3. Protection from Liens: Operator shall pay, or cause to be paid, as and when they become due and payable, all accounts of contractors and suppliers and wages and salaries for services rendered or performed, and for materials supplied on, to or in respect of the Contract Area or any operations for the joint account thereof, and shall keep the Contract Area free from liens and encumbrances resulting therefrom except for those resulting from a bona fide dispute as to services rendered or materials supplied.
4. Custody of Funds: Operator shall hold for the account of the Non- Operators any funds of the Non- Operators advanced or paid to the Operator, either for the conduct of operations hereunder or as a result of the sale of production from the Contract Area, and such funds shall remain the funds of the Non- Operators on whose account they are advanced or paid until used for their intended purpose or otherwise delivered to the Non- Operators or applied toward the payment of debts as provided in Article VII.B. Nothing in this paragraph shall be construed to establish a fiduciary relationship between Operator and Non- Operators for any purpose other than to account for Non- Operator funds as herein specifically provided. Nothing in this paragraph shall require the maintenance by Operator of separate accounts for the funds of Non- Operators unless the parties otherwise specifically agree.
5. Access to Contract Area and Records: Operator shall, except as otherwise provided herein, permit each Non- Operator or its duly authorized representative, at the Non- Operator's sole risk and cost, full and free access at all reasonable times to all operations of every kind and character being conducted for the joint account on the Contract Area and to the records of operations conducted thereon or production therefrom, including Operator's books and records relating thereto. Such access rights shall not be exercised in a manner interfering with Operator's conduct of an operation hereunder and shall not obligate Operator to furnish any geologic or geophysical data of an interpretive nature unless the cost of preparation of such interpretive data was charged to the joint account. Operator will furnish to each Non- Operator upon request copies of any and all reports and information obtained by Operator in connection with production and related items, including, without limitation, meter and chart reports, production purchaser statements, run tickets and monthly gauge reports, but excluding purchase contracts and pricing information to the extent not applicable to the production of the Non- Operator seeking the information. Any audit of Operator's records relating to amounts expended and the appropriateness of such expenditures shall be conducted in accordance with the audit protocol specified in Exhibit "C."
6. Filing and Furnishing Governmental Reports: Operator will file, and upon written request promptly furnish copies to each requesting Non- Operator not in default of its payment obligations, all operational notices, reports or applications required to be filed by local, State, Federal or Indian agencies or authorities having jurisdiction over operations hereunder. Each Non- Operator shall provide to Operator on a timely basis all information necessary to Operator to make such filings.
7. Drilling and Testing Operations: The following provisions shall apply to each well drilled / completed, reworked, recompleted, sidetracked or plugged back hereunder~~, including but not limited to the Initial Well:~~
(a) Operator will promptly advise Non- Operators of the date on which the well is spudded, or the date on which drilling operations are commenced.
(b) Operator will send to Non- Operators such reports, test results and notices regarding the progress of operations on the well as the Non- Operators shall reasonably request, including, but not limited to, daily drilling reports, completion reports, and well logs.
(c) Operator shall adequately test all Zones encountered which may reasonably be expected to be capable of producing Oil and Gas in paying quantities as a result of examination of the electric log or any other logs or cores or tests conducted hereunder.
8. Cost Estimates: Upon request of any Consenting Party, Operator shall furnish estimates of current and cumulative costs incurred for the joint account at reasonable intervals during the conduct of any operation pursuant to this agreement. Operator shall not be held liable for errors in such estimates so long as the estimates are made in good faith.
9. Insurance: At all times while operations are conducted hereunder, Operator shall comply with the workers compensation law of the state where the operations are being conducted; provided, however, that Operator may be a self- insurer for liability under said compensation laws in which event the only charge that shall be made to the joint account shall be as provided in Exhibit "C." Operator shall also carry or provide insurance for the benefit of the joint account of the parties as outlined in Exhibit "D" attached hereto and made a part hereof. Operator shall require all contractors engaged in work on or for the Contract Area to comply with the workers compensation law of the state where the operations are being conducted and to maintain such other insurance as Operator may require.
In the event automobile liability insurance is specified in said Exhibit "D," or subsequently receives the approval of the parties, no direct charge shall be made by Operator for premiums paid for such insurance for Operator's automotive equipment.

ARTICLE VI.
DRILLING AND DEVELOPMENT

~~**A. Initial Well:**~~

~~On or before the ______ day of _____________, ______, Operator shall commence the drilling of the Initial Well at the following location:~~

NOT APPLICABLE.

~~and shall thereafter continue the drilling of the well with due diligence to~~

~~The drilling of the Initial Well and the Head's Up therein by all parties is obligatory, subject to Article VI.C.1. as to participation in Completion operations and Article VI.F. as to termination of operations and Article XI as to occurrence of force majeure.~~

B. Subsequent Operations:

1. Proposed Operations: If any party hereto should desire to drill a Head's Up well on the Contract Area, or if any party should desire to Rework, Sidetrack, Deepen, Recomplete or Plug Back a dry hole or a well no longer capable of producing in paying quantities (whether a Carry Well or a Head's Up Well) in which such party has not otherwise relinquished its interest in the proposed objective Zone under this agreement, the party desiring to drill, Rework, Sidetrack, Deepen, Recomplete or Plug Back such a well shall give written notice of the proposed operation to the parties who have not otherwise relinquished their interest in such objective Zone under this agreement and to all other parties in the case of a proposal for Sidetracking or Deepening, specifying the work to be performed, the location, proposed depth, objective Zone and the estimated cost of the operation. The parties to whom such a notice is delivered shall have thirty (30) days after receipt of the notice within which to notify the party proposing to do the work whether they elect to participate in the cost of the proposed operation. If a drilling rig is on location, notice of a proposal to Rework, Sidetrack, Recomplete, Plug Back or Deepen may be given by telephone and the response period shall be limited to forty- eight (48) hours~~, exclusive of Saturday, Sunday and legal holidays~~. Failure of a party to whom such notice is delivered to reply within the period above fixed shall constitute an election by that party not to participate in the cost of the proposed operation. Any proposal by a party to conduct an operation conflicting with the operation initially proposed shall be delivered to all parties within the time and in the manner provided in Article VI.B.6.

If all parties to whom such notice is delivered elect to participate in such a proposed operation, the parties shall be contractually committed to participate therein provided such operations are commenced within the time period hereafter set forth, and Operator shall, no later than ninety (90) days after expiration of the notice period of thirty (30) days (or as promptly as practicable after the expiration of the forty- eight (48) hour period when a drilling rig is on location, as the case may be), actually commence the proposed operation and thereafter complete it with due diligence at the risk and expense of the parties participating therein; provided, however, said commencement date may be extended upon written notice of same by Operator to the other parties, for a period of up to thirty (30) additional days if, in the sole opinion of Operator, such additional time is reasonably necessary to obtain permits from governmental authorities, surface rights (including rights- of- way) or appropriate drilling equipment, or to complete title examination or curative matter required for title approval or acceptance. If the actual operation has not been commenced within the time provided (including any extension thereof as specifically permitted herein or in the force majeure provisions of Article XI) and if any party hereto still desires to conduct said operation, written notice proposing same must be resubmitted to the other parties in accordance herewith as if no prior proposal had been made. Those parties that did not participate in the drilling of a well for which a proposal to Deepen or Sidetrack is made hereunder shall, if such parties desire to participate in the proposed Deepening or Sidetracking operation, reimburse the Drilling Parties in accordance with Article VI.B.4. in the event of a Deepening operation and in accordance with Article VI.B.5. in the event of a Sidetracking operation.

2. Operations by Less Than All Parties:

(a) Determination of Participation. If any party to whom such notice is delivered as provided in Article VI.B.1. or VI.C.1. (Option No. 2) elects not to participate in the proposed operation, then, in order to be entitled to the benefits of this Article, the party or parties giving the notice and such other parties as shall elect to participate in the operation shall, no later than ninety (90) days after the expiration of the notice period of thirty (30) days (or as promptly as practicable after the expiration of the forty- eight (48) hour period when a drilling rig is on location, as the case may be) actually commence the proposed operation and complete it with due diligence. Operator shall perform all work for the account of the Consenting Parties; provided, however, if no drilling rig or other equipment is on location, and if Operator is a Non- Consenting Party, the Consenting Parties shall either: (i) request Operator to perform the work required by such proposed operation for the account of the Consenting Parties, or (ii) designate one of the Consenting Parties as Operator to perform such work provided however, Operator shall not be required to do so. The rights and duties granted to and imposed upon the Operator under this agreement are granted to and imposed upon the party designated as Operator for an operation in which the original Operator is a Non- Consenting Party. Consenting Parties, when conducting operations on the Contract Area pursuant to this Article VI.B.2., shall comply with all terms and conditions of this agreement.

If less than all parties approve any proposed operation, the proposing party, immediately after the expiration of the applicable notice period, shall advise all Parties of the total interest of the parties approving such operation and its recommendation as to whether the Consenting Parties should proceed with the operation as proposed. Each Consenting Party, within forty- eight (48) hours ~~(exclusive of Saturday, Sunday, and legal holidays)~~ after delivery of such notice, shall advise the proposing party of its desire to (i) limit participation to such party's interest as shown on Exhibit "A" or (ii) carry only its proportionate part (determined by dividing such party's interest in the Contract Area by the interests of all Consenting Parties in the Contract Area) of Non- Consenting Parties' interests, or (iii) carry its proportionate part (determined as provided in (ii)) of Non- Consenting Parties' interests together with all or a portion of its proportionate part of any Non- Consenting Parties' interests that any Consenting Party did not elect to take. Any interest of Non- Consenting Parties that is not carried by a Consenting Party shall be deemed to be carried by the party proposing the operation if such party does not withdraw its proposal. Failure to advise the proposing party within the time required shall be deemed an election under (i). In the event a drilling rig is on location, notice may be given by telephone, and the time permitted for such a response shall not exceed a total of forty- eight (48) hours ~~(exclusive of Saturday, Sunday and legal holidays)~~. The proposing party, at its election, may withdraw such proposal if there is less than 100% participation and shall notify all parties of such decision within ten (10) days, or within twenty- four (24) hours if a drilling rig is on location, following expiration of the applicable response period. If 100% subscription to the proposed operation is obtained, the proposing party shall promptly notify the Consenting Parties of their proportionate interests in the operation and the party serving as Operator shall commence such operation within the period provided in Article VI.B.1., subject to the same extension right as provided therein.

(b) Relinquishment of Interest for Non- Participation. The entire cost and risk of conducting such operations shall be borne by the Consenting Parties in the proportions they have elected to bear same under the terms of the preceding paragraph. Consenting Parties shall keep the leasehold estates involved in such operations free and clear of all liens and encumbrances of every kind created by or arising from the operations of the Consenting Parties. If such an operation results in a dry hole, then subject to Articles VI.B.6. and VI.E.3., the Consenting Parties shall plug and abandon the well and restore the surface location at their sole cost, risk and expense; ~~provided, however, that those Non- Consenting Parties that participated in the drilling, Deepening or Sidetracking of the well shall remain liable for, and shall pay, their proportionate shares of the cost of plugging and abandoning the well and restoring the surface location insofar only as those costs were not increased by the subsequent operations of the Consenting Parties.~~ If any well drilled, Reworked, Sidetracked, Deepened, Recompleted or Plugged Back under the provisions of this Article results in a well capable of producing Oil and/or Gas in paying quantities, the Operator shall Complete and equip the well on behalf of the Consenting Parties to produce at their sole cost and risk, and shall be operated by it at the expense and for the account of the Consenting Parties. In the event Operator elects not to participate in a Head's Up Well, Operator shall be entitled to a 2.5% of 8/8ths carried working interest in such well, proportionately reduced if the Parties own less than the full leasehold or mineral interest in such well. Upon commencement of operations for the ~~drilling,~~ Reworking, Sidetracking, Recompleting, Deepening or Plugging Back of any such well by Consenting Parties in accordance with the provisions of this Article, each Non- Consenting Party shall be deemed to have relinquished to Consenting Parties, and the Consenting Parties shall own and be entitled to receive, in proportion to their respective interests, all of such Non- Consenting Party's interest in the well and share of production therefrom or, in the case of a Reworking, Sidetracking, Deepening, Recompleting or Plugging Back, or a Completion pursuant to Article VI.C.1. Option No. 2, all of such Non- Consenting Party's interest in the production obtained from the operation in which the Non- Consenting Party did not elect to participate. Such relinquishment shall be effective until the proceeds of the sale of such share, calculated at the well, or market value thereof if such share is not sold (after deducting applicable ad valorem, production, severance, and excise taxes, royalty, overriding royalty and other interests not excepted by Article III.C. payable out of or measured by the production from such well accruing with respect to such interest until it reverts), shall equal the total of the following:

(i) 100 % of each such Non- Consenting Party's share of the cost of any newly acquired surface equipment beyond the wellhead connections (including but not limited to stock tanks, separators, treaters, pumping equipment and piping), plus 100% of each such Non- Consenting Party's share of the cost of operation of the well commencing with first production and continuing until each such Non- Consenting Party's relinquished interest shall revert to it under other provisions of this Article, it being agreed that each Non- Consenting Party's share of such costs and equipment will be that interest which would have been chargeable to such Non- Consenting Party had it participated in the well from the beginning of the operations; and

(ii) 300 % of (a) that portion of the costs and expenses of drilling*, Reworking, Sidetracking, Deepening, Plugging Back, testing, Completing, and Recompleting, after deducting any cash contributions received under Article VIII.C., and of (b) that portion of the cost of newly acquired equipment in the well (to and including the wellhead connections), which would have been chargeable to such Non- Consenting Party if it had participated therein.

~~Notwithstanding anything to the contrary in this Article VI.B., if the well does not reach the deepest objective Zone described in the notice proposing the well for reasons other than the encountering of granite or practically impenetrable substance or other condition in the hole rendering further operations impracticable, Operator shall give notice thereof to each Non- Consenting Party who submitted or voted for an alternative proposal under Article VI.B.6. to drill the well to a shallower Zone than the deepest objective Zone proposed in the notice under which the well was drilled, and each such Non- Consenting Party shall have the option to participate in the initial proposed Completion of the well by paying its share of the cost of drilling the well to its actual depth, calculated in the manner provided in Article VI.B.4. (a). If any such Non- Consenting Party does not elect to participate in the first Completion proposed for such well, the relinquishment provisions of this Article VI.B.2. (b) shall apply to such party's interest.~~

(c) Reworking, Recompleting or Plugging Back. An election not to participate in the drilling*, Sidetracking or Deepening of a well shall be deemed an election not to participate in any Reworking or Plugging Back operation proposed in such a well, or portion thereof, to which the initial non-consent election applied that is conducted at any time prior to full recovery by the Consenting Parties of the Non- Consenting Party's recoupment amount. Similarly, an election not to participate in the Completing or Recompleting of a well shall be deemed an election not to participate in any Reworking operation proposed in such a well, or portion thereof, to which the initial non- consent election applied that is conducted at any time prior to full recovery by the Consenting Parties of the Non- Consenting Party's recoupment amount. Any such Reworking, Recompleting or Plugging Back operation conducted during the recoupment period shall be deemed part of the cost of operation of said well and there shall be added to the sums to be recouped by the Consenting Parties 400% of that portion of the costs of the Reworking, Recompleting or Plugging Back operation which would have been chargeable to such Non- Consenting Party had it participated therein. If such a Reworking, Recompleting or Plugging Back operation is proposed during such recoupment period, the provisions of this Article VI.B. shall be applicable as between said Consenting Parties in said well.

(d) Recoupment Matters. During the period of time Consenting Parties are entitled to receive Non- Consenting Party's share of production, or the proceeds therefrom, Consenting Parties shall be responsible for the payment of all ad valorem, production, severance, excise, gathering and other taxes, and all royalty, overriding royalty and other burdens applicable to Non- Consenting Party's share of production not excepted by Article III.C. In the case of any Reworking, Sidetracking, Plugging Back, Recompleting or Deepening operation, the Consenting Parties shall be permitted to use, free of cost, all casing, tubing and other equipment in the well, but the ownership of all such equipment shall remain unchanged; and upon abandonment of a well after such Reworking, Sidetracking, Plugging Back, Recompleting or Deepening, the Consenting Parties shall account for all such equipment to the owners thereof, with each party receiving its proportionate part in kind or in value, less cost of salvage.

Within ninety (90) days after the completion of any operation under this Article, the party conducting the operations for the Consenting Parties shall furnish each Non- Consenting Party with an inventory of the equipment in and connected to the well, and an itemized statement of the cost of drilling*, Sidetracking, Deepening, Plugging Back, testing, Completing, Recompleting, and equipping the well for production; or, at its option, the operating party, in lieu of an itemized statement of such costs of operation, may submit a detailed statement of monthly billings. Each month thereafter, during the time the Consenting Parties are being reimbursed as provided above, the party conducting the operations for the Consenting Parties shall furnish the Non- Consenting Parties with an itemized statement of all costs and liabilities incurred in the operation of the well, together with a statement of the quantity of Oil and Gas produced from it and the amount of proceeds realized from the sale of the well's working interest production during the preceding month. In determining the quantity of Oil and Gas produced during any month, Consenting Parties shall use industry accepted methods such as but not limited to metering or periodic well tests. Any amount realized from the sale or other disposition of equipment newly acquired in connection with any such operation which would have been owned by a Non- Consenting Party had it participated therein shall be credited against the total unreturned costs of the work done and of the equipment purchased in determining when the interest of such Non- Consenting Party shall revert to it as above provided; and if there is a credit balance, it shall be paid to such Non- Consenting Party.

If and when the Consenting Parties recover from a Non- Consenting Party's relinquished interest the amounts provided for above, the relinquished interests of such Non- Consenting Party shall automatically revert to it as of 7:00 a.m. on the day following the day on which such recoupment occurs, and, from and after such reversion, such Non- Consenting Party shall own the same interest in such well, the material and equipment in or pertaining thereto, and the production therefrom *excluding_Carry_Wells as such Non- Consenting Party would have been entitled to had it participated in the drilling*, Sidetracking, Reworking, Deepening, Recompleting or Plugging Back of said well. Thereafter, such Non- Consenting Party shall be charged with and shall pay its proportionate part of the further costs of the operation of said well in accordance with the terms of this agreement and Exhibit "C" attached hereto.

3. Stand- By Costs: When a well which has been drilled or Deepened has reached its authorized depth and all tests have been completed and the results thereof furnished to the parties, or when operations on the well have been otherwise terminated pursuant to Article VI.F., stand- by costs incurred pending response to a party's notice proposing a Reworking, Sidetracking, Deepening, Recompleting, Plugging Back or Completing operation in such a well (including the period required under Article VI.B.6. to resolve competing proposals) shall be charged and borne as part of the drilling or Deepening operation just completed. Stand- by costs subsequent to all parties responding, or expiration of the response time permitted, whichever first occurs, and prior to agreement as to the participating interests of all Consenting Parties pursuant to the terms of the second grammatical paragraph of Article VI.B.2. (a), shall be charged to and borne as part of the proposed operation, but if the proposal is subsequently withdrawn because of insufficient participation, such stand- by costs shall be allocated between the Consenting Parties in the proportion each Consenting Party's interest as shown on Exhibit "A" bears to the total interest as shown on Exhibit "A", as appropriate in context, of all Consenting Parties.

In the event that notice for a Sidetracking operation is given while the drilling rig to be utilized is on location, any party may request and receive up to five (5) additional days after expiration of the forty- eight hour response period specified in Article VI.B.1. within which to respond by paying for all stand- by costs and other costs incurred during such extended response period; Operator may require such party to pay the estimated stand- by time in advance as a condition to extending the response period. If more than one party elects to take such additional time to respond to the notice, standby costs shall be allocated between the parties taking additional time to respond on a day- to- day basis in the proportion each electing party's interest as shown on Exhibit "A" bears to the total interest as shown on Exhibit "A" , as appropriate in context, of all the electing parties.

4. Deepening: If less than all parties elect to participate in a drilling*, Sidetracking, or Deepening operation proposed pursuant to Article VI.B.1., the interest relinquished by the Non- Consenting Parties to the Consenting Parties under Article VI.B.2. shall relate only and be limited to the lesser of (i) the total depth actually drilled or (ii) the objective depth or Zone of which the parties were given notice under Article VI.B.1. ("Initial Objective"). Such well shall not be Deepened beyond the Initial Objective without first complying with this Article to afford the Non- Consenting Parties the opportunity to participate in the Deepening operation.

In the event any Consenting Party desires to drill or Deepen a Non- Consent Well to a depth below the Initial Objective, such party shall give notice thereof, complying with the requirements of Article VI.B.1., to all parties (including Non- Consenting Parties). Thereupon, Articles VI.B.1. and 2. shall apply and all parties receiving such notice shall have the right to participate or not participate in the Deepening of such well pursuant to said Articles VI.B.1. and 2. If a Deepening operation is approved pursuant to such provisions, and if any Non- Consenting Party elects to participate in the Deepening operation, such Non- Consenting party shall pay or make reimbursement (as the case may be) of the following costs and expenses.

(a) If the proposal to Deepen is made prior to the Completion of such well as a well capable of producing in paying quantities, such Non- Consenting Party shall pay (or reimburse Consenting Parties for, as the case may be) that share of costs and expenses incurred in connection with the drilling of said well from the surface to the Initial Objective which Non- Consenting Party would have paid had such Non- Consenting Party agreed to participate therein, plus the Non- Consenting Party's share of the cost of Deepening and of participating in any further operations on the well in accordance with the other provisions of this Agreement; provided, however, all costs for testing and Completion or attempted Completion of the well incurred by Consenting Parties prior to the point of actual operations to Deepen beyond the Initial Objective shall be for the sole account of Consenting Parties.

(b) If the proposal is made for a Non- Consent Well that has been previously Completed as a well capable of producing in paying quantities, but is no longer capable of producing in paying quantities, such Non- Consenting Party shall pay (or reimburse Consenting Parties for, as the case may be) its proportionate share of all costs of drilling, Completing, and equipping said well from the surface to the Initial Objective, calculated in the manner provided in paragraph (a) above, less those costs recouped by the Consenting Parties from the sale of production from the well. The Non- Consenting Party shall also pay its proportionate share of all costs of re- entering said well. The Non- Consenting Parties' proportionate part (based on the percentage of such well Non- Consenting Party would have owned had it previously participated in such Non- Consent Well) of the costs of salvable materials and equipment remaining in the hole and salvable surface equipment used in connection with such well shall be determined in accordance with Exhibit "C." If the Consenting Parties have recouped the cost of drilling, Completing, and equipping the well at the time such Deepening operation is conducted, then a Non- Consenting Party may participate in the Deepening of the well with no payment for costs incurred prior to re-entering the well for Deepening.

The foregoing shall not imply a right of any Consenting Party to propose any Deepening for a Non- Consent Well prior to the drilling of such well to its Initial Objective without the consent of the other Consenting Parties as provided in Article VI.F.
5. Sidetracking: Any party having the right to participate in a proposed Sidetracking operation that does not own an interest in the affected wellbore at the time of the notice shall, upon electing to participate, tender to the wellbore owners its proportionate share (equal to its interest in the Sidetracking operation) of the value of that portion of the existing wellbore to be utilized as follows:
(a) If the proposal is for Sidetracking an existing dry hole, reimbursement shall be on the basis of the actual costs incurred in the initial drilling of the well down to the depth at which the Sidetracking operation is initiated.
(b) If the proposal is for Sidetracking a well which has previously produced, reimbursement shall be on the basis of such party's proportionate share of drilling and equipping costs incurred in the initial drilling of the well down to the depth at which the Sidetracking operation is conducted, calculated in the manner described in Article VI.B.4(b) above. Such party's proportionate share of the cost of the well's salvable materials and equipment down to the depth at which the Sidetracking operation is initiated shall be determined in accordance with the provisions of Exhibit "C."
* excluding Carry Wells
6. Order of Preference of Operations. Except as otherwise specifically provided in this agreement, if any party desires to propose the conduct of an operation that conflicts with a proposal that has been made by a party under this Article VI, such party shall have fifteen (15) days from delivery of the initial proposal, in the case of a proposal to drill a well or to perform an operation on a well where no drilling rig is on location, or twenty- four (24) hours, ~~exclusive of Saturday, Sunday and legal holidays,~~ from delivery of the initial proposal, if a drilling rig is on location for the well on which such operation is to be conducted, to deliver to all parties entitled to participate in the proposed operation such party's alternative proposal, such alternate proposal to contain the same information required to be included in the initial proposal. Each party receiving such proposals shall elect by delivery of notice to Operator within five (5) days after expiration of the proposal period, or within twenty- four (24) hours ~~(exclusive of Saturday, Sunday and legal holidays)~~ if a drilling rig is on location for the well that is the subject of the proposals, to participate in one of the competing proposals. Any party not electing within the time required shall be deemed not to have voted. The proposal receiving the vote of parties owning the largest aggregate percentage interest of the parties voting shall have priority over all other competing proposals; in the case of a tie vote, the initial proposal shall prevail. Operator shall deliver notice of such result to all parties entitled to participate in the operation within five (5) days after expiration of the election period (or within twenty- four (24) hours, exclusive of Saturday, Sunday and legal holidays, if a drilling rig is on location). Each party shall then have two (2) days (or twenty- four (24) hours if a rig is on location) from receipt of such notice to elect by delivery of notice to Operator to participate in such operation or to relinquish interest in the affected well pursuant to the provisions of Article VI.B.2.; failure by a party to deliver notice within such period shall be deemed an election not to participate in the prevailing proposal.
7. Conformity to Spacing Pattern. Notwithstanding the provisions of this Article VI.B.2., it is agreed that no wells shall be proposed to be drilled to or Completed in or produced from a Zone from which a well located elsewhere on the Contract Area is producing, unless such well conforms to the then- existing well spacing pattern or an approved exception thereto for such Zone.
8. Paying Wells. No party shall conduct any Reworking, Deepening, Plugging Back, Completion, Recompletion, or Sidetracking operation under this agreement with respect to any well then capable of producing in paying quantities except with the consent of all parties that have not relinquished interests in the well at the time of such operation.

C. Completion of Wells; Reworking and Plugging Back:

1. Completion: Without the consent of all parties, no well shall be ~~drilled,~~ Deepened or Sidetracked, except any well ~~Drilled,~~ Deepened or Sidetracked pursuant to the provisions of Article VI.B.2. of this agreement. Consent to the drilling*,
Deepening or Sidetracking shall include:

✓ Option No. 1: All necessary expenditures for the ~~drilling,~~ Deepening or Sidetracking, testing, Completing and equipping of the well, including necessary tankage and/or surface facilities.

❑ ~~Option No. 2: All necessary expenditures for the drilling, Deepening or Sidetracking and testing of the well. When such well has reached its authorized depth, and all logs, cores and other tests have been completed, and the results thereof furnished to the parties, Operator shall give immediate notice to the Non- Operators having the right to participate in a Completion attempt whether or not Operator recommends attempting to Complete the well, together with Operator's AFE for Completion costs if not previously provided. The parties receiving such notice shall have forty- eight (48) hours (exclusive of Saturday, Sunday and legal holidays) in which to elect by delivery of notice to Operator to participate in a recommended Completion attempt or to make a Completion proposal with an accompanying AFE. Operator shall deliver any such Completion proposal, or any Completion proposal conflicting~~

~~with Operator's proposal, to the other parties entitled to participate in such Completion in accordance with the procedures specified in Article VI.B.6. Election to participate in a Completion attempt shall include consent to all necessary expenditures for the Completing and equipping of such well, including necessary tankage and/or surface facilities but excluding any stimulation operation not contained on the Completion AFE. Failure of any party receiving such notice to reply within the period above fixed shall constitute an election by that party~~ not ~~to participate in the cost of the Completion attempt; provided, that Article VI.B.6. shall control in the case of conflicting Completion proposals. If one or more, but less than all of the parties, elect to attempt a Completion, the provision of Article VI.B.2. hereof (the phrase "Reworking, Sidetracking, Deepening, Recompleting or Plugging Back" as contained in Article VI.B.2. shall be deemed to include "Completing") shall apply to the operations thereafter conducted by less than all parties; provided, however, that Article VI.B.2. shall apply separately to each separate Completion or Recompletion attempt undertaken hereunder, and an election to become a Non- Consenting Party as to one Completion or Recompletion attempt shall not prevent a party from becoming a Consenting Party in subsequent Completion or Recompletion attempts regardless whether the Consenting Parties as to earlier Completions or Recompletion have recouped their costs pursuant to Article VI.B.2.; provided further, that any recoupment of costs by a Consenting Party shall be made solely from the production attributable to the Zone in which the Completion attempt is made. Election by a previous Non-Consenting party to participate in a subsequent Completion or Recompletion attempt shall require such party to pay its proportionate share of the cost of salvable materials and equipment installed in the well pursuant to the previous Completion or Recompletion attempt, insofar and only insofar as such materials and equipment benefit the Zone in which such party participates in a Completion attempt.~~

2. Rework, Recomplete or Plug Back: No well shall be Reworked, Recompleted or Plugged Back except a well Reworked, Recompleted, or Plugged Back pursuant to the provisions of Article VI.B.2. of this agreement. Consent to the Reworking, Recompleting or Plugging Back of a well shall include all necessary expenditures in conducting such operations and Completing and equipping of said well, including necessary tankage and/or surface facilities.

D. Other Operations:

Operator shall not undertake any single project reasonably estimated to require an expenditure in excess of Fifty Thousand Dollars ($50,000.00) except in connection with the drilling, Sidetracking, Reworking, Deepening, Completing, Recompleting or Plugging Back of a well that has been previously authorized by or pursuant to this agreement; provided, however, that, in case of explosion, fire, flood or other sudden emergency, whether of the same or different nature, Operator may take such steps and incur such expenses as in its opinion are required to deal with the emergency to safeguard life and property but Operator, as promptly as possible, shall report the emergency to the other parties. If Operator prepares an AFE for its own use, Operator shall furnish any Non- Operator so requesting an information copy thereof for any single project costing in excess of Fifty Thousand Dollars ($50,000.00). Any party who has not relinquished its interest in a well shall have the right to propose that * excluding Carry Wells Operator perform repair work or undertake the installation of artificial lift equipment or ancillary production facilities such as salt water disposal wells or to conduct additional work with respect to a well drilled hereunder or other similar project (but not including the installation of gathering lines or other transportation or marketing facilities, the installation of which shall be governed by separate agreement between the parties) reasonably estimated to require an expenditure in excess of the amount first set forth above in this Article VI.D. (except in connection with an operation required to be proposed under Articles VI.B.1. or VI.C.1. Option No. 2, which shall be governed exclusively be those Articles). Operator shall deliver such proposal to all parties entitled to participate therein. If within thirty (30) days thereof Operator secures the written consent of any party or parties owning at least 50% of the interests of the parties entitled to participate in such operation, each party having the right to participate in such project shall be bound by the terms of such proposal and shall be obligated to pay its proportionate share of the costs of the proposed project as if it had consented to such project pursuant to the terms of the proposal.

E. Abandonment of Wells:

1. Abandonment of Dry Holes: ~~Except for any well drilled or Deepened pursuant to Article VI.B.2.,~~ Any well which has been drilled or Deepened under the terms of this agreement and is proposed to be completed as a dry hole shall not be plugged and abandoned without the consent of all parties. Should Operator, after diligent effort, be unable to contact any party, or should any party fail to reply within forty- eight (48) hours ~~(exclusive of Saturday, Sunday and legal holidays)~~ after delivery of notice of the proposal to plug and abandon such well, such party shall be deemed to have consented to the proposed abandonment. All such wells shall be plugged and abandoned in accordance with applicable regulations and at the

cost, risk and expense of the parties who participated in the cost of drilling or Deepening such well. Any party who objects to plugging and abandoning such well by notice delivered to Operator within forty- eight (48) hours ~~(exclusive of Saturday, Sunday and legal holidays)~~ after delivery of notice of the proposed plugging shall take over the well as of the end of such forty- eight (48) hour notice period and conduct further operations in search of Oil and/or Gas subject to the provisions of Article VI.B.; failure of such party to provide proof reasonably satisfactory to Operator of its financial capability to conduct such operations or to take over the well within such period or thereafter to conduct operations on such well or plug and abandon such well shall entitle Operator to retain or take possession of the well and plug and abandon the well. The party taking over the well shall indemnify Operator (if Operator is an abandoning party) and the other abandoning parties against liability for any further operations conducted on such well except for the costs of plugging and abandoning the well and restoring the surface, for which the abandoning parties shall remain proportionately liable.

2. <u>Abandonment of Wells That Have Produced:</u> Except for any well in which a Non- Consent operation has been conducted hereunder for which the Consenting Parties have not been fully reimbursed as herein provided, any well which has been completed as a producer shall not be plugged and abandoned without the consent of all parties. If all parties consent to such abandonment, the well shall be plugged and abandoned in accordance with applicable regulations and at the cost, risk and expense of all the parties hereto. Failure of a party to reply within sixty (60) days of delivery of notice of proposed abandonment shall be deemed an election to consent to the proposal. If, within sixty (60) days after delivery of notice of the proposed abandonment of any well, all parties do not agree to the abandonment of such well, those wishing to continue its operation from the Zone then open to production shall be obligated to take over the well as of the expiration of the applicable notice period and shall indemnify Operator (if Operator is an abandoning party) and the other abandoning parties against liability for any further operations on the well conducted by such parties. Failure of such party or parties to provide proof reasonably satisfactory to Operator of their financial capability to conduct such operations or to take over the well within the required period or thereafter to conduct operations on such well, shall entitle operator to retain or take possession of such well and plug and abandon the well.

Parties taking over a well as provided herein shall tender to each of the other parties its proportionate share of the value of the well's salvable material and equipment, determined in accordance with the provisions of Exhibit "C," less the estimated cost of salvaging and the estimated cost of plugging and abandoning and restoring the surface; provided, however, that in the event the estimated plugging and abandoning and surface restoration costs and the estimated cost of salvaging are higher than the value of the well's salvable material and equipment, each of the abandoning parties shall tender to the parties continuing operations their proportionate shares of the estimated excess cost. Each abandoning party shall assign to the non- abandoning parties, without warranty, express or implied, as to title or as to quantity, or fitness for use of the equipment and material, all of its interest in the wellbore of the well and related equipment, together with its interest in the Leasehold insofar and only insofar as such Leasehold covers the right to obtain production from that wellbore in the Zone then open to production. If the interest of the abandoning party is or includes an Oil and Gas Interest, such party shall execute and deliver to the non- abandoning party or parties an oil and gas lease, limited to the wellbore and the Zone then open to production, for a term of one (1) year and so long thereafter as Oil and/or Gas is produced from the Zone covered thereby, such lease to be on the form mutually acceptable to the parties and provide for a 16.67% royalty. ~~attached as Exhibit "B."~~ The assignments or leases so limited shall encompass the Drilling Unit upon which the well is located. The payments by, and the assignments or leases to, the assignees shall be in a ratio based upon the relationship of their respective percentage of participation in the Contract Area to the aggregate of the percentages of participation in the Contract Area of all assignees. There shall be no readjustment of interests in the remaining portions of the Contract Area.

Thereafter, abandoning parties shall have no further responsibility, liability, or interest in the operation of or production from the well in the Zone then open other than the royalties retained in any lease made under the terms of this Article. Upon request, Operator shall continue to operate the assigned well for the account of the non- abandoning parties at the rates and charges contemplated by this agreement, plus any additional cost and charges which may arise as the result of the separate ownership of the assigned well. Upon proposed abandonment of the producing Zone assigned or leased, the assignor or lessor shall then have the option to repurchase its prior interest in the well (using the same valuation formula) and participate in further operations therein subject to the provisions hereof.

3. <u>Abandonment of Non- Consent Operations:</u> The provisions of Article VI.E.1. or VI.E.2. above shall be applicable as between Consenting Parties in the event of the proposed abandonment of any well excepted from said Articles; provided, however, no well shall be permanently plugged and abandoned unless and until all parties having the right to conduct further operations therein have been notified of the proposed abandonment and afforded the opportunity to elect to take over the well in accordance with the provisions of this Article VI.E.; and provided further, that Non-Consenting Parties who own an interest in a portion of the well shall pay their proportionate shares of abandonment and surface restoration cost for such well as provided in Article VI.B.2.(b).

F. Termination of Operations:
Upon the commencement of an operation for the drilling, Reworking, Sidetracking, Plugging Back, Deepening, testing, Completion or plugging of a well, ~~including but not limited to the Initial Well,~~ such operation shall not be terminated without consent of a party or parties bearing 50% of the costs of such operation; provided, however, that in the event granite or other practically impenetrable substance or condition in the hole is encountered which renders further operations impractical, Operator may discontinue operations and give notice of such condition in the manner provided in Article VI.B.1, and the provisions of Article VI.B. or VI.E. shall thereafter apply to such operation, as appropriate.
G. Taking Production in Kind:
✓ **Option No. 1: Gas Balancing Agreement Attached**
Each party shall take in kind or separately dispose of its proportionate share of all Oil and Gas produced from the Contract Area, exclusive of production which may be used in development and producing operations and in preparing and treating Oil and Gas for marketing purposes and production unavoidably lost. Any extra expenditure incurred in the taking in kind or separate disposition by any party of its proportionate share of the production shall be borne by such party. Any party taking its share of production in kind shall be required to pay for only its proportionate share of such part of Operator's surface facilities which it uses.
Each party shall execute such division orders and contracts as may be necessary for the sale of its interest in production from the Contract Area, and, except as provided in Article VII.B., shall be entitled to receive payment directly from the purchaser thereof for its share of all production.
If any party fails to make the arrangements necessary to take in kind or separately dispose of its proportionate share of the Oil and/ or Gas produced from the Contract Area, Operator shall have the right, subject to the revocation at will by the party owning it, but not the obligation, to purchase such Oil and/ or Gas or sell it to others at any time and from time to time, for the account of the non- taking party. Any such purchase or sale by Operator may be terminated by Operator upon at least ten (10) days written notice to the owner of said production and shall be subject always to the right of the owner of the production upon at least ten (10) days written notice to Operator to exercise at any time its right to take in kind, or separately dispose of, its share of all Oil and/ or Gas not previously delivered to a purchaser, provided, however, that the effective date of any such revocation may be deferred at Operator's election for a period not to exceed ninety (90) days if Operator has committed such production to a purchase contract having a term extending beyond such ten (10) day period.
Any purchase or sale by Operator of any other party's share of Oil shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one (1) year.
Any such sale by Operator shall be in a manner commercially reasonable under the circumstances but Operator shall have no duty to share any existing market or to obtain a price equal to that received under any existing market. The sale or delivery by Operator of a non- taking party's share of Oil and/ or Gas under the terms of any existing contract of Operator shall not give the non- taking party any interest in or make the non- taking party a party to said contract. No purchase shall be made by Operator without first giving the non- taking party at least ten (10) days written notice of such intended purchase or sale and the price to be paid or the pricing basis to be used.
All parties shall give timely written notice to Operator of their Gas marketing arrangements for the following month, excluding price, and shall notify Operator immediately in the event of a change in such arrangements. Operator shall maintain records of all marketing arrangements, and of volumes actually sold or transported, which records shall be made available to Non- Operators upon reasonable request.
In the event one or more parties' separate disposition of its share of the Gas causes split- stream deliveries to separate pipelines and/or deliveries which on a day- to- day basis for any reason are not exactly equal to a party's respective proportion- ate share of total Gas sales to be allocated to it, the balancing or accounting between the parties shall be in accordance with any Gas balancing agreement between the parties hereto, whether such an agreement is attached as Exhibit "E" or is a separate agreement. Operator shall give notice to all parties of the first sales of Gas from any well under this agreement.

❑ ~~Option No. 2: No Gas Balancing Agreement:~~
~~Each party shall take in kind or separately dispose of its proportionate share of all Oil and Gas produced from the Contract Area, exclusive of production which may be used in development and producing operations and in preparing and treating Oil and Gas for marketing purposes and production unavoidably lost. Any extra expenditures incurred in the taking in kind or separate disposition by any party of its proportionate share of the production shall be borne by such party. Any party taking its share of production in kind shall be required to pay for only its proportionate share of such part of Operator's surface facilities which it uses.~~

~~Each party shall execute such division orders and contracts as may be necessary for the sale of its interest in production from the Contract Area, and, except as provided in Article VII.B., shall be entitled to receive payment directly from the purchaser thereof for its share of all production.~~

~~If any party fails to make the arrangements necessary to take in kind or separately dispose of its proportionate share of the Oil and/or Gas produced from the Contract Area, Operator shall have the right, subject to the revocation at will by the party owning it, but not the obligation, to purchase such Oil and/or Gas or sell it to others at any time and from time to time, for the account of the non- taking party. Any such purchase or sale by Operator may be terminated by Operator upon at least ten (10) days written notice to the owner of said production and shall be subject always to the right of the owner of the production upon at least ten (10) days written notice to Operator to exercise its right to take in kind, or separately dispose of, its share of all Oil and/or Gas not previously delivered to a purchaser; provided, however, that the effective date of any such revocation may be deferred at Operator's election for a period not to exceed ninety (90) days if Operator has committed such production to a purchase contract having a term extending beyond such ten (10) - day period. Any purchase or sale by Operator of any other party's share of Oil and/or Gas shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one (1) year.~~

~~Any such sale by Operator shall be in a manner commercially reasonable under the circumstances, but Operator shall have no duty to share any existing market or transportation arrangement or to obtain a price or transportation fee equal to that received under any existing market or transportation arrangement. The sale or delivery by Operator of a non- taking party's share of production under the terms of any existing contract of Operator shall not give the non- taking party any interest in or make the non- taking party a party to said contract. No purchase of Oil and Gas and no sale of Gas shall be made by Operator without first giving the non- taking party ten days written notice of such intended purchase or sale and the price to be paid or the pricing basis to be used. Operator shall give notice to all parties of the first sale of Gas from any well under this Agreement. All parties shall give timely written notice to Operator of their Gas marketing arrangements for the following month, excluding price, and shall notify Operator immediately in the event of a change in such arrangements. Operator shall maintain records of all marketing arrangements, and of volumes actually sold or transported, which records shall be made available to Non- Operators upon reasonable request.~~

ARTICLE VII.
EXPENDITURES AND LIABILITY OF PARTIES

A. Liability of Parties:

The liability of the parties shall be several, not joint or collective. Each party shall be responsible only for its obligations, and shall be liable only for its proportionate share of the costs of developing the operating the Contract Area commensurate with a party's interests reflected in Exhibit "A". Accordingly, the liens granted among the parties in Article VII.B. are given to secure only the debts of each severally, and no party shall have any liability to third parties hereunder to satisfy the default of any other party in the payment of any expense or obligation hereunder. It is not the intention of the parties to create, nor shall this agreement be construed as creating, a mining or other partnership, joint venture, agency relationship or association, or to render the parties liable as partners, co- venturers, or principals. In their relations with each other under this agreement, the parties shall not be considered fiduciaries or to have established a confidential relationship but rather shall be free to act on an arm's- length basis in accordance with their own respective self- interest, subject, however, to the obligation of the parties to act in good faith in their dealings with each other with respect to activities hereunder.

B. Liens and Security Interests:

Each party grants to the other parties hereto a lien upon any interest it now owns or hereafter acquires in a Carry and/or Head's Up Well, and a security interest and/or purchase money security interest in any interest it now owns or hereafter acquires in the personal property and fixtures on or used or obtained for use in connection therewith, to secure performance of all of its obligations under this agreement and/or the BJU Carry and Earning Agreement, including but not limited to payment of expense, interest and fees, the proper disbursement of all monies paid hereunder, the assignment or relinquishment of interest in Carry and/or Head's Up Wells required hereunder, and the proper performance of operations hereunder. Such lien and security interest granted by each party hereto shall include such party's working interests in the Carry and/or Head's Up Wells now owned or hereafter acquired, the Oil and Gas when extracted therefrom and equipment situated thereon or used or obtained for use in connection therewith (including, without limitation, all wells, tools, and tubular goods), and accounts (including, without limitation, accounts arising from gas imbalances or from the sale of Oil and/or Gas at the wellhead), contract rights, inventory and general intangibles relating thereto or arising therefrom, and all proceeds and products of the foregoing.

To perfect the lien and security agreement provided herein, each party hereto shall execute and acknowledge the recording supplement and/or any financing statement prepared and submitted by any party hereto in conjunction herewith or at any time following execution hereof, and Operator is authorized to file this agreement or the recording supplement executed herewith as a lien or mortgage in the applicable real estate records and as a financing statement with the proper officer under the Uniform Commercial Code in the state in which the Contract Area is situated and such other states as Operator shall deem appropriate to perfect the security interest granted hereunder. Any party may file this agreement, the recording supplement executed herewith, or such other documents as it deems necessary as a lien or mortgage in the applicable real estate records and/or a financing statement with the proper officer under the Uniform Commercial Code.

Each party represents and warrants to the other parties hereto that the lien and security interest granted by such party to the other parties shall be a first and prior lien, and each party hereby agrees to maintain the priority of said lien and security interest against all persons acquiring an interest in the Carry and/or Head's Up Wells covered by this agreement and/or the BJU Carry & Earning Agreement by, through or under such party. All parties acquiring an interest in the Carry and/or Head's Up Wells Covered_by_this_agreement, whether by assignment, merger, mortgage, operation of law, or otherwise, shall be deemed to have_taken_subject to the lien and security interest granted by this Article VII.B. as to all obligations attributable to such interest hereunder whether or not such obligations arise before or after such interest is acquired.

To the extent that parties have a security interest under the Uniform Commercial Code of the state in which the Contract Area is situated, they shall be entitled to exercise the rights and remedies of a secured party under the Code. The bringing of a suit and the obtaining of judgment by a party for the secured indebtedness shall not be deemed an election of remedies or otherwise affect the lien rights or security interest as security for the payment thereof. In addition, upon default by any party in the payment of its share of expenses, interests or fees, or upon the improper use of funds by the Operator, or upon default by any party in the payment of amounts due pursuant to, or performance under, the provisions of this agreement and/or the BJU Carry and Earning Agreement, the other parties shall have the right, without prejudice to other rights or remedies, to collect from the purchaser the proceeds from the sale of such defaulting party's share of Oil and Gas until the amount owed by such party, plus interest as provided in "Exhibit C," has been received, and shall have the right to offset the amount owed against the proceeds from the sale of such defaulting party's share of Oil and Gas. All purchasers of production may rely on a notification of default from the non- defaulting party or parties stating the amount due as a result of the default, and all parties waive any recourse available against purchasers for releasing production proceeds as provided in this paragraph.

If any party fails to pay its share of cost within one hundred twenty (120) days after rendition of a statement therefor by Operator, the non- defaulting parties, including Operator, shall upon request by Operator, pay the unpaid amount in the proportion that the interest of each such party bears to the interest of all such parties. The amount paid by each party so paying its share of the unpaid amount shall be secured by the liens and security rights described in Article VII.B., and each paying party may independently pursue any remedy available hereunder or otherwise.

If any party does not perform all of its obligations under this agreement and/or the BJU Carry and Earning Agreement, and the failure to perform subjects such party to foreclosure or execution proceedings pursuant to the provisions of this agreement and/or the BJU Carry and Earning Agreement, to the extent allowed by governing law, the defaulting party waives any available right of redemption from and after the date of judgment, any required valuation or appraisement of the mortgaged or secured property prior to sale, any available right to stay execution or to require a marshaling of assets and any required bond in the event a receiver is appointed. In addition, to the extent permitted by applicable law, each party hereby grants to the other parties a power of sale as to any property that is subject to the lien and security rights granted hereunder, such power to be exercised in the manner provided by applicable law or otherwise in a commercially reasonable manner and upon reasonable notice.

Each party agrees that the other parties shall be entitled to utilize the provisions of Oil and Gas lien law or other lien law of any state in which the Contract Area is situated to enforce the obligations of each party hereunder. Without limiting the generality of the foregoing, to the extent permitted by applicable law, Non- Operators agree that Operator may invoke or utilize the mechanics' or materialmen's lien law of the state in which the Contract Area is situated in order to secure the payment to Operator of any sum due hereunder for services performed or materials supplied by Operator.

C. Advances:

Operator, at its election, shall have the right from time to time to demand and receive from one or more of the other parties payment in advance of their respective shares of the estimated amount of the expense to be incurred in operations hereunder during the next succeeding month, which right may be exercised only by submission to each such party of an itemized statement of such estimated expense, together with an invoice for its share thereof. Each such statement and invoice for the payment in advance of estimated expense shall be submitted on or before the 20th day of the next preceding month. Each party shall pay to Operator its proportionate share of such estimate within fifteen (15) days after such estimate and invoice is received. If any party fails to pay its share of said estimate within said time, the amount due shall bear interest as provided in Exhibit "C" until paid. Proper adjustment shall be made monthly between advances and actual expense to the end that each party shall bear and pay its proportionate share of actual expenses incurred, and no more.

D. Defaults and Remedies:

If any party fails to discharge any financial obligation under the BJU Carry and Earning Agreement or this agreement, including without limitation the failure to make any advance under the preceding Article VII.C. or any other provision of this agreement, within the period required for such payment thereunder or hereunder, then in addition to the remedies provided in Article VII.B. or elsewhere in this agreement or in the BJU Carry and Earning Agreement, the remedies specified below shall be applicable. For purposes of this Article VII.D., all notices and elections shall be delivered only by Operator, except that Operator shall deliver any such notice and election requested by a non- defaulting Non- Operator, and when Operator is the party in default, the applicable notices and elections can be delivered by any Non- Operator. Election of any one or more of the following remedies shall not preclude the subsequent use of any other remedy specified below or otherwise available to a non- defaulting party.

1. Suspension of Rights: Any party may deliver to the party in default a Notice of Default, which shall specify the default, specify the action to be taken to cure the default, and specify that failure to take such action will result in the exercise of one or more of the remedies provided in this Article. If the default is not cured within thirty (30) days of the delivery of such Notice of Default, all of the rights of the defaulting party granted by this agreement may upon notice be suspended until the default is cured, without prejudice to the right of the non- defaulting party or parties to continue to enforce the obligations of the defaulting party previously accrued or thereafter accruing under this agreement. If Operator is the party in default, the Non- Operators shall have in addition the right, by vote of Non- Operators owning a majority in interest in the Contract Area after excluding the voting interest of Operator, to appoint a new Operator effective immediately. The rights of a defaulting party that may be suspended hereunder at the election of the non- defaulting parties shall include, without limitation, the right to receive information as to any operation conducted hereunder during the period of such default, the right to elect to participate in an operation proposed under Article VI.B. of this agreement, the right to participate in an operation being conducted under this agreement even if the party has previously elected to participate in such operation, and the right to receive proceeds of production from any well subject to this agreement.

2. Suit for Damages: Non- defaulting parties or Operator for the benefit of non- defaulting parties may sue (at joint account expense) to collect the amounts in default, plus interest accruing on the amounts recovered from the date of default \until the date of collection at the rate specified in Exhibit "C" attached hereto. Nothing herein shall prevent any party from suing any defaulting party to collect consequential damages accruing to such party as a result of the default.

3. Deemed Non- Consent: The non- defaulting party may deliver a written Notice of Non- Consent Election to the defaulting party at any time after the expiration of the thirty- day cure period following delivery of the Notice of Default, in which event if the billing is for the drilling a new well or the Plugging Back, Sidetracking, Reworking or Deepening of a well which is to be or has been plugged as a dry hole, or for the Completion or Recompletion of any well, the defaulting party will be conclusively deemed to have elected not to participate in the operation and to be a Non- Consenting Party with respect thereto under Article VI.B. or VI.C., as the case may be, to the extent of the costs unpaid by such party, notwithstanding any election to participate theretofore made. If election is made to proceed under this provision, then the non- defaulting parties may not elect to sue for the unpaid amount pursuant to Article VII.D.2.

Until the delivery of such Notice of Non- Consent Election to the defaulting party, such party shall have the right to cure its default by paying its unpaid share of costs plus interest at the rate set forth in Exhibit "C," provided, however, such payment shall not prejudice the rights of the non- defaulting parties to pursue remedies for damages incurred by the non- defaulting parties as a result of the default. Any interest relinquished pursuant to this Article VII.D.3. shall be offered to the non- defaulting parties in proportion to their interests, and the non- defaulting parties electing to participate in the ownership of such interest shall be required to contribute their shares of the defaulted amount upon their election to participate therein.

4. Advance Payment: If a default is not cured within thirty (30) days of the delivery of a Notice of Default, Operator, or Non- Operators if Operator is the defaulting party, may thereafter require advance payment from the defaulting party of such defaulting party's anticipated share of any item of expense for which Operator, or Non- Operators, as the case may be, would be entitled to reimbursement under any provision of this agreement, whether or not such expense was the subject of the previous default. Such right includes, but is not limited to, the right to require advance payment for the estimated costs of drilling a well or Completion of a well as to which an election to participate in drilling or Completion has been made. If the defaulting party fails to pay the required advance payment, the non- defaulting parties may pursue any of the remedies provided in the Article VII.D. or any other default remedy provided elsewhere in this agreement. Any excess of funds advanced remaining when the operation is completed and all costs have been paid shall be promptly returned to the advancing party.

5. Costs and Attorneys' Fees: In the event any party is required to bring legal proceedings to enforce any financial obligation of a party hereunder, the prevailing party in such action shall be entitled to recover all court costs, costs of collection, and a reasonable attorney's fee, which the lien provided for herein shall also secure.

E. Rentals, Shut- in Well Payments and Minimum Royalties:

Rentals, shut- in well payments and minimum royalties which may be required under the terms of any lease shall be paid by the Operator for the joint account of the parties. Any party may request, and shall be entitled to receive, proper evidence of all such payments. In the event of failure to make proper payment of any rental, shut- in well payment or minimum royalty through mistake or oversight where such payment is required to continue the lease in force, any loss which results from such non- payment shall be borne in accordance with the provisions of Article IV.B.2.

Operator shall notify Non- Operators of the anticipated completion of a shut- in well, or the shutting in or return to production of a producing well, at least five (5) days (excluding Saturday, Sunday, and legal holidays) prior to taking such action, or at the earliest opportunity permitted by circumstances, but assumes no liability for failure to do so. In the event of failure by Operator to so notify Non- Operators, the loss of any lease contributed hereto by Non- Operators for failure to make timely payments of any shut- in well payment shall be borne jointly by the parties hereto under the provisions of Article IV.B.3.

F. Taxes:

Beginning with the first calendar year after the effective date hereof, Operator shall render for ad valorem taxation all property subject to this agreement which by law should be rendered for such taxes, and it shall pay all such taxes assessed thereon before they become delinquent. Prior to the rendition date, each Non- Operator shall furnish Operator information as to burdens (to include, but not be limited to, royalties, overriding royalties and production payments) on Leases and Oil and Gas Interests contributed by such Non- Operator. If the assessed valuation of any Lease is reduced by reason of its being subject to outstanding excess royalties, overriding royalties or production payments, the reduction in ad valorem taxes resulting therefrom shall inure to the benefit of the owner or owners of such Lease, and Operator shall adjust the charge to such owner or owners so as to reflect the benefit of such reduction. If the ad valorem taxes are based in whole or in part upon separate valuations of each party's working interest, then notwithstanding anything to the contrary herein, charges to the joint account shall be made and paid by the parties hereto in accordance with the tax value generated by each party's working interest. Operator shall bill the other parties for their proportionate shares of all tax payments in the manner provided in Exhibit "C."

If Operator considers any tax assessment improper, Operator may, at its discretion, protest within the time and manner prescribed by law, and prosecute the protest to a final determination, unless all parties agree to abandon the protest prior to final determination. During the pendency of administrative or judicial proceedings, Operator may elect to pay, under protest, all such taxes and any interest and penalty. When any such protested assessment shall have been finally determined, Operator shall pay the tax for the joint account, together with any interest and penalty accrued, and the total cost shall then be assessed against the parties, and be paid by them, as provided in Exhibit "C."

Each party shall pay or cause to be paid all production, severance, excise, gathering and other taxes imposed upon or with respect to the production or handling of such party's share of Oil and Gas produced under the terms of this agreement.

ARTICLE VIII.
ACQUISITION, MAINTENANCE OR TRANSFER OF INTEREST

~~**A. Surrender of Leases:**~~

~~The Leases covered by this agreement, insofar as they embrace acreage in the Contract Area, shall not be surrendered in whole or in part unless all parties consent thereto.~~

~~However, should any party desire to surrender its interest in any Lease or in any portion thereof, such party shall give written notice of the proposed surrender to all parties, and the parties to whom such notice is delivered shall have thirty (30) days after delivery of the notice within which to notify the party proposing the surrender whether they elect to consent thereto. Failure of a party to whom such notice is delivered to reply within said 30-day period shall constitute a consent to the surrender of the Leases described in the notice. If all parties do not agree or consent thereto, the party desiring to surrender shall assign, without express or implied warranty of title, all of its interest in such Lease, or portion thereof, and any well, material and equipment which may be located thereon and any rights in production thereafter secured, to the parties not consenting to such surrender. If the interest of the assigning party is or includes an Oil and Gas Interest, the assigning party shall execute and deliver to the party or parties not consenting to such surrender an oil and gas lease covering such Oil and Gas Interest for a term of one (1) year and so long thereafter as Oil and/or Gas is produced from the land covered thereby., such lease to be on the form attached hereto as Exhibit "B."~~

~~Upon such assignment or lease, the assigning party shall be relieved from all obligations thereafter accruing, but not theretofore accrued, with respect to the interest assigned or leased and the operation of any well attributable thereto, and the assigning party shall have no further interest in the assigned or leased premises and its equipment and production. other than the royalties retained in any lease made under the terms of this Article. The party assignee or lessee shall pay to the party assignor or lessor the reasonable salvage value of the latter's interest in any well's salvable materials and equipment attributable to the assigned or leased acreage. The value of all salvable materials and equipment shall be determined in accordance with the provisions of Exhibit "C," less the estimated cost of salvaging and the estimated cost of plugging and abandoning and restoring the surface. If such value is less than such costs, then the party assignor or lessor shall pay to the party assignee or lessee the amount of such deficit. If the assignment or lease is in favor of more than one party, the interest shall be shared by such parties in the proportions that the interest of each bears to the total interest of all such parties. If the interest of the parties to whom the assignment is to be made varies according to depth, then the interest assigned shall similarly reflect such variances.~~

~~Any assignment, lease or surrender made under this provision shall not reduce or change the assignor's, lessor's or surrendering party's interest as it was immediately before the assignment, lease or surrender in the balance of the Contract Area; and the acreage assigned, leased or surrendered, and subsequent operations thereon, shall not thereafter be subject to the terms and provisions of this agreement but shall be deemed subject to an Operating Agreement in the form of this agreement.~~

~~B. Renewal or Extension of Leases:~~

~~If any party secures a renewal or replacement of an Oil and Gas Lease or Interest subject to this agreement, then all other parties shall be notified promptly upon such acquisition or, in the case of a replacement Lease taken before expiration of an existing Lease, promptly upon expiration of the existing Lease. The parties notified shall have the right for a period of thirty (30) days following delivery of such notice in which to elect to participate in the ownership of the renewal or replacement Lease, insofar as such Lease affects lands within the Contract Area, by paying to the party who acquired it their proportionate shares of the acquisition cost allocated to that part of such Lease within the Contract Area, which shall be in proportion to the interest held at that time by the parties in the Contract Area. Each party who participates in the purchase of a renewal or replacement Lease shall be given an assignment of its proportionate interest therein by the acquiring party. If some, but less than all, of the parties elect to participate in the purchase of a renewal or replacement Lease, it shall be owned by the parties who elect to participate therein, in a ratio based upon the relationship of their respective percentage of participation in leases described in Exhibit "A" to the aggregate of the percentages of participation in the Contract Area of all parties participating in the purchase of such renewal or replacement Lease. (Not applicable to the Encana Contract Area.) The acquisition of a renewal or replacement Lease by any or all of the parties hereto shall not cause a readjustment of the interests of the parties stated in Exhibit "A" but any renewal or replacement Lease in which less than all parties elect to participate shall not be subject to this agreement but shall be deemed subject to a separate Operating Agreement in the form of this agreement.~~

~~If the interests of the parties in the Contract Area vary according to depth, then their right to participate proportionately in renewal or replacement Leases and their right to receive an assignment of interest shall also reflect such depth variances.~~

~~The provisions of this Article shall apply to renewal or replacement Leases whether they are for the entire interest covered by the expiring Lease or cover only a portion of its area or an interest therein. Any renewal or replacement Lease taken before the or nominated for sale expiration of its predecessor Lease, or taken or contracted for or becoming effective / within six (6) months after the expiration of the existing Lease, shall be subject to this provision so long as this agreement is in effect at the time of such acquisition or at the time or nominated for sale the renewal or replacement Lease becomes effective; but any Lease taken or contracted for / more than six (6) months after the expiration of an existing Lease shall not be deemed a renewal or replacement Lease and shall not be subject to the provisions of this agreement.~~

~~The provisions in this Article shall also be applicable to extensions of Oil and Gas Leases.~~

~~C. Acreage or Cash Contributions:~~

~~While this agreement is in force, if any party contracts for a contribution of cash towards the drilling of a well or any other operation on the Contract Area, such contribution shall be paid to the party who conducted the drilling or other operation and shall be applied by it against the cost of such drilling or other operation. If the contribution be in the form of acreage, the party to whom the contribution is made shall promptly tender an assignment of the acreage, without warranty of title, to the Drilling Parties in the proportions said Drilling Parties shared the cost of drilling the well. Such acreage shall become a separate Contract Area and, to the extent possible, be governed by provisions identical to this agreement. Each party shall promptly notify all other parties of any acreage or cash contributions it may obtain in support of any well or any other operation on the Contract Area. The above provisions shall also be applicable to optional rights to earn acreage outside the Contract Area which are in support of well drilled inside Contract Area.~~

D. Assignment; ~~Maintenance of Uniform Interest:~~

~~For the purpose of maintaining uniformity of ownership in the Contract Area in the Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production covered by this agreement no party shall sell, encumber, transfer or make other disposition of its interest in the Oil and Gas Leases and Oil and Gas Interests embraced within the Contract Area or in wells, equipment and production unless such disposition covers either:~~
~~1. the entire interest of the party in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production; or~~
~~2. an equal undivided percent of the party's present interest in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production in the Contract Area.~~

Every sale, encumbrance, transfer or other disposition made by any party shall be made expressly subject to this agreement and the BJU Carry and Earning Agreement and shall be made without prejudice to the right of the other parties, and any transferee of an ownership interest in any Carry and/or Head's Up Well shall be deemed a party to this agreement as to the interest conveyed from and after the effective date of the transfer of ownership; provided, however, that the other parties shall not be required to recognize any such sale, encumbrance, transfer or other disposition for any purpose hereunder until thirty (30) days after they have received a copy of the instrument of transfer or other satisfactory evidence thereof in writing from the transferor or transferee. No assignment or other disposition of an interest in a Carry and/or Head's Up Well by a party shall relieve such party of obligations previously incurred by such party hereunder with respect to the interest transferred, including without limitation the obligation of a party to pay all costs attributable to an operation conducted hereunder in which such party has agreed to participate prior to making such assignment, and the lien and security interest granted by Article VII.B. shall continue to burden the interest transferred to secure payment of any such obligations.

Every sale, encumbrance, transfer or other disposition by any party of any Carry and/or Head's Up Well covered by this agreement shall be made expressly subject to this agreement and to the provisions of Exhibit G hereto, and shall be made without prejudice to the rights of the other parties, and any transferee of any Carry and/or Head's Up Well shall be deemed a party to this agreement as to the interest conveyed from and after the effective date of the transfer of ownership; provided, however that the other parties shall not be required to recognize any such sale, encumbrance, transfer or other disposition for any purpose hereunder, and no such transfer shall be deemed effective for any purpose, until thirty (30) days after the other parties have received a copy of the instrument of transfer or other satisfactory evidence thereof from the transferor or transferee and an executed copy of an undertaking by the transferee to abide and be bound by the terms of this agreement and Exhibit G hereto.

If, at any time the interest of any party is divided among and owned by two ~~four~~ or more co- owners, Operator, at its discretion, may require such co-owners to appoint a single trustee or agent with full authority to receive notices, approve expenditures, receive billings for and approve and pay such party's share of the joint expenses, and to deal generally with, and with power to bind, the co- owners of such party's interest within the scope of the operations embraced in this agreement and/or the BJU Carry and Earning Agreement; however, all such co- owners shall have the right to enter into and execute all contracts or agreements for the disposition of their respective shares of the Oil and Gas produced from the Carry and/or Head's Up Wells and they shall have the right to receive, separately, payment of the sale proceeds thereof.

E. Waiver of Rights to Partition:

If permitted by the laws of the state or states in which the property covered hereby is located, each party hereto owning an undivided interest in the Contract Area waives any and all rights it may have to partition and have set aside to it in severalty its undivided interest therein.

Preferential Right to Purchase: NOT APPLICABLE

ARTICLE IX.
INTERNAL REVENUE CODE ELECTION

This Agreement is not intended to create, and shall not be construed to create, an association for profit, a trust, a joint venture, a mining partnership or other relationship of partnership, or entity of any kind between the Parties. Notwithstanding anything to the contrary contained herein, the Parties understand and agree that the arrangement and undertakings evidenced by this Agreement, taken together, result in a partnership for purposes of federal income taxation and for purposes of certain state income tax laws which incorporate or follow federal income tax principles as to tax partnerships. For these purposes, the Parties agree to be governed by the tax partnership provisions attached as Exhibit "G" which are incorporated herein and made a part of this Agreement by this reference. For every purpose other than the above- described income tax purposes, however, the Parties understand and agree that the liabilities of the Parties shall be several, not joint or collective, and that each Party shall be solely responsible for its own obligations. In the event of any conflict or inconsistency between the terms and conditions of Exhibit "G" and the terms and conditions of this Agreement or any attachment or exhibit hereto (other than Exhibit "G") the terms and conditions of Exhibit "G" shall govern and control.

ARTICLE X.
CLAIMS AND LAWSUITS

Operator may settle any single uninsured third party damage claim or suit arising from operations hereunder if the expenditure does not exceed Fifty Thousand Dollars ($50,000.00) and if the payment is in complete settlement of such claim or suit. If the amount required for settlement exceeds the above amount, the parties hereto shall assume and take over the further handling of the claim or suit, unless such authority is delegated to Operator. All costs and expenses of handling settling, or otherwise discharging such claim or suit shall be a the joint expense of the parties participating in the operation from which the claim or suit arises. If a claim is made against any party or if any party is sued on account of any matter arising from operations hereunder over which such individual has no control because of the rights given Operator by this agreement, such party shall immediately notify all other parties, and the claim or suit shall be treated as any other claim or suit involving operations hereunder.

ARTICLE XI.
FORCE MAJEURE

29.2 If a Party is rendered unable, wholly or in part, by a force majeure event to carry out its obligations under this Agreement, other than the obligations to make money payments and to deliver Wellbore Assignments of interests in the Carry and/or Head's Up Wells, the affected Party shall give the other Party prompt written notice describing the force majeure event in reasonable detail. Thereupon, the obligations of the Party giving notice, so far as it is affected by the force majeure event, shall be suspended and any time periods provided for in this Agreement shall be extended for a period equal to the period of the continuance of the force majeure event. The affected Party shall use all reasonable diligence to remove the force majeure event as quickly as practicable. The requirement that any force majeure event be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts or other labor difficulty by the Party affected, contrary to its wishes, and settlement or resolution of such matters shall be within the discretion of the affected Party. The term "force majeure event" as used herein, shall mean an act of God, act of terrorism, strike, lockout, or other industrial disturbance, act of the public enemy, war, blockade, public riot, lightning, fire, storm, flood, explosion, the actions of Governmental Authority, restraint or inaction, the interruption or suspension of the receipt or delivery of natural gas (or any of its constituants) or water due to the inability or failure of any Third Party who is not a party to this Agreement (other than an Affiliate of either Party hereto), to receive or deliver such gas or water, unavailability of equipment, inability to gain access, ingress or egress to conduct operations (including without limitation delays in or inability to obtain permits, approvals or clearances from governmental bodies).

ARTICLE XII.
NOTICES

All notices authorized or required between the parties by any of the provisions of this agreement, unless otherwise specifically provided, shall be in writing and delivered in person or by United States mail, courier service, email or other electronic means, telecopier or any other form of facsimile, postage or charges prepaid, and addressed to such parties at the addresses listed on Exhibit "A." All telephone, email or oral notices permitted by this agreement shall be confirmed immediately thereafter by written notice. The originating notice given under any provision hereof shall be deemed delivered only when received by the party to whom such notice is directed, and the time for such party to deliver any notice in response thereto shall run from the date the originating notice is received. "Receipt" for purposes of this agreement with respect to written notice delivered hereunder shall be actual delivery of the notice to the address of the party to be notified specified in accordance with this agreement, or to the telecopy, facsimile or telex machine of such party. The second or any responsive notice shall be deemed delivered when deposited in the United States mail or at the office of the courier or telegraph service, or upon transmittal by telex, telecopy or facsimile, or when personally delivered to the party to be notified, provided, that when response is required within 24 or 48 hours, such response shall be given orally or by telephone, telex, telecopy or other facsimile within such period. Each party shall have the right to change its address at any time, and from time to time, by giving written notice thereof to all other parties. If a party is not available to receive notice orally or by telephone when a party attempts to deliver a notice required to be delivered within 24 or 48 hours, the notice may be delivered in writing by any other method specified herein and shall be deemed delivered in the same manner provided above for any responsive notice.

ARTICLE XIII.
TERM OF AGREEMENT

This agreement shall remain in full force and effect until one year after there are no longer any producing Carry and/or Head's Up Wells in which Nucor or its successors or assigns holds an interest, or until all Carry and/or Head's Up Wells have been plugged and abandoned, whichever is later.

~~Option No. 1: So long as any of the lands and associated Oil and Gas Leases and Oil and Gas Interests subject to this agreement remain or are continued in force as to any part of the Contract Area, whether by production, extension, renewal or otherwise.~~

- ❑ ~~Option No. 2: In the event the well described in Article VI.A., or any subsequent well drilled under any provision of this agreement, results in the Completion of a well as a well capable of production of Oil and/or Gas in paying quantities, this agreement shall continue in force so long as any such well is capable of production, and for an additional period of ______ days thereafter; provided, however, if, prior to the expiration of such additional period, one or more of the parties hereto are engaged in drilling, Reworking, Deepening, Sidetracking, Plugging Back, testing or attempting to Complete or Re- complete a well or wells hereunder, this agreement shall continue in force until such operations have been completed and if production results therefrom, this agreement shall continue in force as provided herein. In the event the well described in Article VI.A., or any subsequent well drilled hereunder, results in a dry hole, and no other well is capable of producing Oil and/or Gas from the Contract Area, this agreement shall terminate unless drilling, Deepening, Sidetracking, Completing, Re- completing, Plugging Back or Reworking operations are commenced within ______ days from the date of abandonment of said well. "Abandonment" for such purposes shall mean either (i) a decision by all parties not to conduct any further operations on the well or (ii) the elapse of 180 days from the conduct of any operations on the well, whichever first occurs.~~

The termination of this agreement shall not relieve any party hereto from any expense, liability or other obligation or any remedy therefor which has accrued or attached prior to the date of such termination.

Upon termination of this agreement and the satisfaction of all obligations hereunder, in the event a memorandum of this Operating Agreement has been filed of record, Operator is authorized to file of record in all necessary recording offices a notice of termination, and each party hereto agrees to execute such a notice of termination as to Operator's interest, upon request of Operator, if Operator has satisfied all its financial obligations.

ARTICLE XIV.
COMPLIANCE WITH LAWS AND REGULATIONS

A. Laws, Regulations and Orders:

This agreement shall be subject to the applicable laws of the state in which the Contract Area is located, to the valid rules, regulations, and orders of any duly constituted regulatory body of said state; and to all other applicable federal, state, and local laws, ordinances, rules, regulations and orders.

B. Governing Law:

This agreement and all matters pertaining hereto, including but not limited to matters of performance, non- performance, breach, remedies, procedures, rights, duties, and interpretation or construction, shall be governed and determined by the law of the state in which the Contract Area is located. ~~If the Contract Area is in two or more states, the law of the state of ____________ shall govern.~~

C. Regulatory Agencies:

Nothing herein contained shall grant, or be construed to grant, Operator the right or authority to waive or release any rights, privileges, or obligations which Non- Operators may have under federal or state laws or under rules, regulations or orders promulgated under such laws in reference to oil, gas and mineral operations, including the location, operation, or production of wells, on tracts offsetting or adjacent to the Contract Area.

With respect to the operations hereunder, Non- Operators agree to release Operator from any and all losses, damages, injuries, claims and causes of action arising out of, incident to or resulting directly or indirectly from Operator's interpretation or application of rules, rulings, regulations or orders of the Department of Energy or Federal Energy Regulatory Commission or predecessor or successor agencies to the extent such interpretation or application was made in good faith and does not constitute gross negligence. Each Non- Operator further agrees to reimburse Operator for such Non- Operator's share of production or any refund, fine, levy or other governmental sanction that Operator may be required to pay as a result of such an incorrect interpretation or application, together with interest and penalties thereon owing by Operator as a result of such incorrect interpretation or application.

ARTICLE XV.
MISCELLANEOUS

A. Execution:

This agreement shall be binding upon each Non- Operator when this agreement or a counterpart thereof has been executed by such Non- Operator and Operator notwithstanding that this agreement is not then or thereafter executed by all of the parties to which it is tendered or which are listed on Exhibit "A" as owning an interest in the Contract Area or which own, in fact, an interest in the Contract Area.

B. Successors and Assigns:
This agreement shall be binding upon and shall inure to the benefit of the parties hereto and their respective heirs, devisees, legal representatives, successors and assigns, and the terms hereof shall be deemed to run with the Interests in the Carry and/or Head's Up Wells included within the Contract Area.
C. Counterparts:
This instrument may be executed in any number of counterparts, each of which shall be considered an original for all purposes.
D. Severability:
For the purposes of assuming or rejecting this agreement as an executory contract pursuant to federal bankruptcy laws, this agreement shall not be severable, but rather must be assumed or rejected in its entirety, and the failure of any party to this agreement to comply with all of its financial obligations provided herein shall be a material default.

ARTICLE XVI.
OTHER PROVISIONS

SEE PAGES 20- 22 FOR OTHER PROVISIONS.
IN WITNESS WHEREOF, this agreement shall be effective as of the 1st day of November, 2012.

ATTEST OR WITNESS:

ENCANA OIL & GAS (USA) INC.
OPERATOR

By ______________________________
Ricardo D. Gallegos
VP, Bus. Dev. Negotiations
& Lead Rockies & Intl. Land

Date ______________________________

ATTEST OR WITNESS:

NUCOR ENERGY HOLDINGS INC.
NON- OPERATOR

By ______________________________
Joseph Strateman
President

Date ______________________________

Acknowledgment in representative capacity:
State of Colorado)
) ss.

City and County of Denver)
This instrument was acknowledged before me on ____________, 2012 by Ricardo D. Gallegos, VP, Bus. Dev. Negotiations & Lead Rockies & Intl. Land of Encana Oil & Gas (USA) Inc.

(Seal, if any)

____
Notary Public
My commission expires: ______________________________

Acknowledgment in representative capacity:
State of __________________)
) ss.
County of ________________)
This instrument was acknowledged before me on ____________, 2012 by Joe Stratman, President of Nucor Energy Holdings Inc.

(Seal, if any)

____
Notary Public
My commission expires: ______________________________

EXHIBIT A

Attached to and made a part of that certain Operating Agreement executed October 31, 2012 but effective as of November 1, 2012 by and between Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

I. DESCRIPTION OF LANDS SUBJECT TO THIS AGREEMENT

The Lands subject to this Agreement are set out on the attached plat (Exhibit A- 1), pursuant to the BJU Carry and Earning Agreement dated effective November 1, 2012 between the Parties.

II. RESTRICTIONS AS TO DEPTHS, FORMATIONS, PREVIOUSLY EXISTING WELLS AND SUBSTANCES

Wellbore interest only in Carry Wells and/or Head's Up Wells designated and drilled pursuant to the BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012 between the Parties. All interests are limited in depth to the depth drilled in the applicable well, but not below the base of the Formation as defined in the BJU Carry and Earning Agreement, subject to Section 2.1 I of such agreement.

III. PARTIES TO THE AGREEMENT AND PERCENTAGE PARTICIPATION

A. Drilling costs, Completion costs, and Equipping costs for Carry Wells shall be borne as set forth in the BJU Carry and Earning Agreement executed October 31, 2012 but dated effective November 1, 2012 between the Parties as follows:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17th Street, Suite 1700 Denver, Colorado 80202	[***]%	50.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	[***]%	50.00%

Working Interest ownership in Carry Wells after Drilling, Completing and Equipping:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17th Street, Suite 1700 Denver, Colorado 80202	50.00%	50.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	50.00%	50.00%

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

B. Drilling Costs, Completion Costs and Equipping Costs for Head's Up Wells in which all Parties elect to participate shall be borne as set forth in the BJU Carry and Earning Agreement executed October 31, 2012 but dated effective November 1, 2012 between the Parties as follows:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	50.00%	50.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	50.00%	50.00%

Working Interest Ownership in Head's- Up Well in which all Parties elect to participate after Drilling, Completing and Equipping:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	50.00%	50.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	50.00%	50.00%

C. Drilling Costs, Completion Costs and Equipping Costs for Head's Up Wells in which Nucor elects not to participate shall be borne as set forth in the BJU Carry and Earning Agreement executed October 31, 2012 but dated effective November 1, 2012 between the Parties as follows:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	100.00%	100.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	0.00%	0.00%

Working Interest Ownership in Head's- Up Wells in which Nucor elects not to participate after Drilling, Completing and Equipping:

	Cost Share	WI Share
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	100.00%	100.00%
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	0.00%	0.00%

D. Drilling Costs, Completion Costs and Equipping Costs for Head's Up Wells in which Encana elects not to participate shall be borne as set forth in the BJU Carry and Earning Agreement executed October 31, 2012 but dated effective November 1, 2012 between the Parties as follows:

	Cost Share	WI Share
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	100.00%	97.5%
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	0.00%	2.5%

Working Interest Ownership in a Head's- Up Well in which Encana elects not to participate after Drilling, Completing and Equipping:

	Cost Share	WI Share
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	97.5%	97.5%
Encana Oil & Gas (USA) Inc. 370 17 th Street, Suite 1700 Denver, Colorado 80202	2.5%	2.5%

IV. LEASES, LANDS AND AGREEMENTS SUBJECT TO THIS AGREEMENT

See I. above

V. NOTICE ADDRESSES FOR THE PARTIES

Encana Oil & Gas (USA) Inc.
370 17 th Street, Suite 1700
Denver, Colorado 80202
Phone: 303- 623- 2300
Fax: 303- 623- 2400
Attention: Team Lead Land, South Rockies Business Unit
Nucor Energy Holdings Inc.
1915 Rexford Road
Charlotte, NC 28211
Phone: 704- 365- 1921
Fax: 704- 362- 4208
Attention: Chief Financial Officer

EXHIBIT B

(Lease Form)

Attached to and made a part of that certain Operating Agreement executed October 31, 2012 but effective as of November 1, 2012 by and between Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

There is no Exhibit B to this Agreement.

COPAS 2005 Accounting Procedure
Recommended by COPAS, Inc.

EXHIBIT C

ACCOUNTING PROCEDURE

JOINT OPERATIONS

Attached to and made part of that certain Operating Agreement executed October 31, 2012 but effective November 1, 2012 , by and between Encana Oil & Gas (USA) Inc and Nucor Energy Holdings Inc..

I. GENERAL PROVISIONS

IF THE PARTIES FAIL TO SELECT EITHER ONE OF COMPETING "ALTERNATIVE" PROVISIONS, OR SELECT ALL THE COMPETING "ALTERNATIVE" PROVISIONS, ALTERNATIVE 1 IN EACH SUCH INSTANCE SHALL BE DEEMED TO HAVE BEEN ADOPTED BY THE PARTIES AS A RESULT OF ANY SUCH OMISSION OR DUPLICATE NOTATION.

IN THE EVENT THAT ANY "OPTIONAL" PROVISION OF THIS ACCOUNTING PROCEDURE IS NOT ADOPTED BY THE PARTIES TO THE AGREEMENT BY A TYPED, PRINTED OR HANDWRITTEN INDICATION, SUCH PROVISION SHALL NOT FORM A PART OF THIS ACCOUNTING PROCEDURE, AND NO INFERENCE SHALL BE MADE CONCERNING THE INTENT OF THE PARTIES IN SUCH EVENT.

1. DEFINITIONS

All terms used in this Accounting Procedure shall have the following meaning, unless otherwise expressly defined in the Agreement:

"Affiliate" means for a person, another person that controls, is controlled by, or is under common control with that person. In this definition, (a) control means the ownership by one person, directly or indirectly, of more than fifty percent (50%) of the voting securities of a corporation or, for other persons, the equivalent ownership interest (such as partnership interests), and (b) "person" means an individual, corporation, partnership, trust, estate, unincorporated organization, association, or other legal entity.

"Agreement" means the operating agreement, farmout agreement, or other contract between the Parties to which this Accounting Procedure is attached.

"Controllable Material" means Material that, at the time of acquisition or disposition by the Joint Account, as applicable, is so classified in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Societies (COPAS).

"Equalized Freight" means the procedure of charging transportation cost to the Joint Account based upon the distance from the nearest Railway Receiving Point to the property.

"Excluded Amount" means a specified excluded trucking amount most recently recommended by COPAS.

"Field Office" means a structure, or portion of a structure, whether a temporary or permanent installation, the primary function of which is to directly serve daily operation and maintenance activities of the Joint Property and which serves as a staging area for directly chargeable field personnel.

"First Level Supervision" means those employees whose primary function in Joint Operations is the direct oversight of the Operator's field employees and/or contract labor directly employed On- site in a field operating capacity. First Level Supervision functions may include, but are not limited to:

Responsibility for field employees and contract labor engaged in activities that can include field operations, maintenance, construction, well remedial work, equipment movement and drilling

Responsibility for day- to- day direct oversight of rig operations

Responsibility for day- to- day direct oversight of construction operations

Coordination of job priorities and approval of work procedures

Responsibility for optimal resource utilization (equipment, Materials, personnel)

Responsibility for meeting production and field operating expense targets

Representation of the Parties in local matters involving community, vendors, regulatory agents and landowners, as an incidental part of the supervisor's operating responsibilities

Responsibility for all emergency responses with field staff

Responsibility for implementing safety and environmental practices

Responsibility for field adherence to company policy

Responsibility for employment decisions and performance appraisals for field personnel

Oversight of sub- groups for field functions such as electrical, safety, environmental, telecommunications, which may have group or team leaders.

"Joint Account" means the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties, but does not include proceeds attributable to hydrocarbons and by- products produced under the Agreement.

"Joint Operations" means all operations necessary or proper for the exploration, appraisal, development, production, protection, maintenance, repair, abandonment, and restoration of the Joint Property.

"Joint Property" means the real and personal property subject to the Agreement.
"Laws" means any laws, rules, regulations, decrees, and orders of the United States of America or any state thereof and all other governmental bodies, agencies, and other authorities having jurisdiction over or affecting the provisions contained in or the transactions contemplated by the Agreement or the Parties and their operations, whether such laws now exist or are hereafter amended, enacted, promulgated or issued.
"Material" means personal property, equipment, supplies, or consumables acquired or held for use by the Joint Property.
"Non- Operators" means the Parties to the Agreement other than the Operator.
"Offshore Facilities" means platforms, surface and subsea development and production systems, and other support systems such as oil and gas handling facilities, living quarters, offices, shops, cranes, electrical supply equipment and systems, fuel and water storage and piping, heliport, marine docking installations, communication facilities, navigation aids, and other similar facilities necessary in the conduct of offshore operations, all of which are located offshore.
"Off- site" means any location that is not considered On- site as defined in this Accounting Procedure.
"On- site" means on the Joint Property when in direct conduct of Joint Operations. The term "On- site" shall also include that portion of Offshore Facilities, Shore Base Facilities, fabrication yards, and staging areas from which Joint Operations are conducted, or other facilities that directly control equipment on the Joint Property, regardless of whether such facilities are owned by the Joint Account.
"Operator" means the Party designated pursuant to the Agreement to conduct the Joint Operations.
"Parties" means legal entities signatory to the Agreement or their successors and assigns. Parties shall be referred to individually as "Party."
"Participating Interest" means the percentage of the costs and risks of conducting an operation under the Agreement that a Party agrees, or is otherwise obligated, to pay and bear.
"Participating Party" means a Party that approves a proposed operation or otherwise agrees, or becomes liable, to pay and bear a share of the costs and risks of conducting an operation under the Agreement.
"Personal Expenses" means reimbursed costs for travel and temporary living expenses.
"Railway Receiving Point" means the railhead nearest the Joint Property for which freight rates are published, even though an actual railhead may not exist.
"Shore Base Facilities" means onshore support facilities that during Joint Operations provide such services to the Joint Property as a receiving and transshipment point for Materials; debarkation point for drilling and production personnel and services; communication, scheduling and dispatching center; and other associated functions serving the Joint Property.
"Supply Store" means a recognized source or common stock point for a given Material item.
"Technical Services" means services providing specific engineering, geoscience, or other professional skills, such as those performed by engineers, geologists, geophysicists, and technicians, required to handle specific operating conditions and problems for the benefit of Joint Operations; provided, however, Technical Services shall not include those functions specifically identified as overhead under the second paragraph of the introduction of Section III (*Overhead*). Technical Services may be provided by the Operator, Operator's Affiliate, Non- Operator, Non- Operator Affiliates, and/or third parties.

2. STATEMENTS AND BILLINGS

The Operator shall bill Non- Operators on or before the last day of the month for their proportionate share of the Joint Account for the preceding month. Such bills shall be accompanied by statements that identify the AFE (authority for expenditure), lease or facility, and all charges and credits summarized by appropriate categories of investment and expense. Controllable Material shall be separately identified and fully described in detail, or at the Operator's option, Controllable Material may be summarized by major Material classifications. Intangible drilling costs, audit adjustments, and unusual charges and credits shall be separately and clearly identified.

The Operator may make available to Non- Operators any statements and bills required under Section I.2 and/or Section I.3.A (*Advances and Payments by the Parties*) via email, electronic data interchange, internet websites or other equivalent electronic media in lieu of paper copies. The Operator shall provide the Non- Operators instructions and any necessary information to access and receive the statements and bills within the timeframes specified herein. A statement or billing shall be deemed as delivered twenty- four (24) hours (exclusive of weekends and holidays) after the Operator notifies the Non- Operator that the statement or billing is available on the website and/or sent via email or electronic data interchange transmission. Each Non- Operator individually shall elect to receive statements and billings electronically, if available from the Operator, or request paper copies. Such election may be changed upon thirty (30) days prior written notice to the Operator.

3. ADVANCES AND PAYMENTS BY THE PARTIES

A. Unless otherwise provided for in the Agreement, the Operator may require the Non- Operators to advance their share of the estimated cash outlay for the succeeding month's operations within fifteen (15) days after receipt of the advance request. The Operator shall adjust each monthly billing to reflect advances received from the Non- Operators for such month. If a refund is due, the Operator shall apply the amount to be refunded to the subsequent month's billing or advance, unless the Non- Operator sends the Operator a written request for a cash refund. The Operator shall remit the refund to the Non- Operator within fifteen (15) days of receipt of such written request.

B. Except as provided below, each Party shall pay its proportionate share of all bills in full within fifteen (15) days of receipt date. If payment is not made or a credit is not applied within such time, the unpaid balance shall bear interest compounded monthly at the prime rate published by the *Wall Street Journal* on the first day of each month the payment is delinquent, plus three percent (3%), per annum, or the maximum contract rate permitted by the applicable usury Laws governing the Joint Property, whichever is the lesser, plus attorney's fees, court costs, and other costs in connection with the collection of unpaid amounts. If the *Wall Street Journal* ceases to be published or discontinues publishing a prime rate, the unpaid balance shall bear interest compounded monthly at the prime rate published by the Federal Reserve plus three percent (3%), per annum. Interest shall begin accruing on the first day of the month in which the payment was due. Payment shall not be reduced or delayed as a result of inquiries or anticipated credits unless the Operator has agreed. Notwithstanding the foregoing, the Non-Operator may reduce payment, provided it furnishes documentation and explanation to the Operator at the time payment is made, to the extent such reduction is caused by:

(1) being billed at an incorrect working interest or Participating Interest that is higher than such Non- Operator's actual working interest or Participating Interest, as applicable; or

(2) being billed for a project or AFE requiring approval of the Parties under the Agreement that the Non- Operator has not approved or is not otherwise obligated to pay under the Agreement; or

(3) being billed for a property in which the Non- Operator no longer owns a working interest, provided the Non- Operator has furnished the Operator a copy of the recorded assignment or letter in- lieu. Notwithstanding the foregoing, the Non- Operator shall remain responsible for paying bills attributable to the interest it sold or transferred for any bills rendered during the thirty (30) day period following the Operator's receipt of such written notice; or

(4) charges outside the adjustment period, as provided in Section I.4 (*Adjustments*).

4. ADJUSTMENTS

A. Payment of any such bills shall not prejudice the right of any Party to protest or question the correctness thereof; however, all bills and statements, including payout statements, rendered during any calendar year shall conclusively be presumed to be true and correct, with respect only to expenditures, after twenty- four (24) months following the end of any such calendar year, unless within said period a Party takes specific detailed written exception thereto making a claim for adjustment. The Operator shall provide a response to all written exceptions, whether or not contained in an audit report, within the time periods prescribed in Section I.5 (*Expenditure Audits*).

B. All adjustments initiated by the Operator, except those described in items (1) through (4) of this Section I.4.B, are limited to the twenty-four (24) month period following the end of the calendar year in which the original charge appeared or should have appeared on the Operator's Joint Account statement or payout statement. Adjustments that may be made beyond the twenty- four (24) month period are limited to adjustments resulting from the following:

(1) a physical inventory of Controllable Material as provided for in Section V (*Inventories of Controllable Material*), or

(2) an offsetting entry (whether in whole or in part) that is the direct result of a specific joint interest audit exception granted by the Operator relating to another property, or

(3) a government/regulatory audit, or

(4) a working interest ownership or Participating Interest adjustment.

5. EXPENDITURE AUDITS

A. A Non- Operator, upon written notice to the Operator and all other Non- Operators, shall have the right to audit the Operator's accounts and records relating to the Joint Account or the Carry and Earning Agreement within the twenty- four (24) month period following the end of such calendar year in which such bill was rendered; however, conducting an audit shall not extend the time for the taking of written exception to and the adjustment of accounts as provided for in Section I.4 (*Adjustments*). Any Party that is subject to payout accounting under the Agreement shall have the right to audit the accounts and records of the Party responsible for preparing the payout statements, or of the Party furnishing information to the Party responsible for preparing payout statements. Audits of payout accounts may include the volumes of hydrocarbons produced and saved and proceeds received for such hydrocarbons as they pertain to payout accounting required under the Agreement. Unless otherwise provided in the Agreement, audits of a payout account shall be conducted within the twenty- four (24) month period following the end of the calendar year in which the payout statement was rendered.

Where there are two or more Non- Operators, the Non- Operators shall make every reasonable effort to conduct a joint audit in a manner that will result in a minimum of inconvenience to the Operator. The Operator shall bear no portion of the Non- Operators' audit cost incurred under this paragraph unless agreed to by the Operator. The audits shall not be conducted more than once each year without prior approval of the Operator, except upon the resignation or removal of the Operator, and shall be made at the expense of those Non- Operators approving such audit.

The Non- Operator leading the audit (hereinafter "lead audit company") shall issue the audit report within ninety (90) days after completion of the audit testing and analysis; however, the ninety (90) day time period shall not extend the twenty- four (24) month requirement for taking specific detailed written exception as required in Section I.4.A (*Adjustments*) above. All claims shall be supported with sufficient documentation.
A timely filed written exception or audit report containing written exceptions (hereinafter "written exceptions") shall, with respect to the claims made therein, preclude the Operator from asserting a statute of limitations defense against such claims, and the Operator hereby waives its right to assert any statute of limitations defense against such claims for so long as any Non- Operator continues to comply with the deadlines for resolving exceptions provided in this Accounting Procedure. If the Non- Operators fail to comply with the additional deadlines in Section I.5.B or I.5.C, the Operator's waiver of its rights to assert a statute of limitations defense against the claims brought by the Non- Operators shall lapse, and such claims shall then be subject to the applicable statute of limitations, provided that such waiver shall not lapse in the event that the Operator has failed to comply with the deadlines in Section I.5.B or I.5.C.

B. The Operator shall provide a written response to all exceptions in an audit report within one hundred eighty (180) days after Operator receives such report. Denied exceptions should be accompanied by a substantive response. If the Operator fails to provide substantive response to an exception within this one hundred eighty (180) day period, the Operator will owe interest on that exception or portion thereof, if ultimately granted, from the date it received the audit report. Interest shall be calculated using the rate set forth in Section I.3.B (*Advances and Payments by the Parties*).

C. The lead audit company shall reply to the Operator's response to an audit report within ninety (90) days of receipt, and the Operator shall reply to the lead audit company's follow- up response within ninety (90) days of receipt; provided, however, each Non- Operator shall have the right to represent itself if it disagrees with the lead audit company's position or believes the lead audit company is not adequately fulfilling its duties. Unless otherwise provided for in Section I.5.E, if the Operator fails to provide substantive response to an exception within this ninety (90) day period, the Operator will owe interest on that exception or portion thereof, if ultimately granted, from the date it received the audit report. Interest shall be calculated using the rate set forth in Section I.3.B (*Advances and Payments by the Parties*).

D. If any Party fails to meet the deadlines in Sections I.5.B or I.5.C or if any audit issues are outstanding fifteen (15) months after Operator receives the audit report, the Operator or any Non- Operator participating in the audit has the right to call a resolution meeting, as set forth in this Section I.5.D or it may invoke the dispute resolution procedures included in the Agreement, if applicable. The meeting will require one month's written notice to the Operator and all Non- Operators participating in the audit. The meeting shall be held at the Operator's office or mutually agreed location, and shall be attended by representatives of the Parties with authority to resolve such outstanding issues. Any Party who fails to attend the resolution meeting shall be bound by any resolution reached at the meeting. The lead audit company will make good faith efforts to coordinate the response and positions of the Non- Operator participants throughout the resolution process; however, each Non- Operator shall have the right to represent itself. Attendees will make good faith efforts to resolve outstanding issues, and each Party will be required to present substantive information supporting its position. A resolution meeting may be held as often as agreed to by the Parties. Issues unresolved at one meeting may be discussed at subsequent meetings until each such issue is resolved.
If the Agreement contains no dispute resolution procedures and the audit issues cannot be resolved by negotiation, the dispute shall be submitted to mediation. In such event, promptly following one Party's written request for mediation, the Parties to the dispute shall choose a mutually acceptable mediator and share the costs of mediation services equally. The Parties shall each have present at the mediation at least one individual who has the authority to settle the dispute. The Parties shall make reasonable efforts to ensure that the mediation commences within sixty (60) days of the date of the mediation request. Notwithstanding the above, any Party may file a lawsuit or complaint (1) if the Parties are unable after reasonable efforts, to commence mediation within sixty (60) days of the date of the mediation request, (2) for statute of limitations reasons, or (3) to seek a preliminary injunction or other provisional judicial relief, if in its sole judgment an injunction or other provisional relief is necessary to avoid irreparable damage or to preserve the status quo. Despite such action, the Parties shall continue to try to resolve the dispute by mediation.

~~***E.*** ❑ ***(Optional Provision- Forfeiture Penalties)***~~
~~*If the Non- Operators fail to meet the deadline in Section I.5.C, any unresolved exceptions that were not addressed by the Non- Operators within one (1) year following receipt of the last substantive response of the Operator shall be deemed to have been withdrawn by the Non- Operators. If the Operator fails to meet the deadlines in Section I.5.B or I.5.C, any unresolved exceptions that were not addressed by the Operator within one (1) year following receipt of the audit report or receipt of the last substantive response of the Non- Operators, whichever is later, shall be deemed to have been granted by the Operator and adjustments shall be made, without interest, to the Joint Account.*~~

6. APPROVAL BY PARTIES

A. GENERAL MATTERS
Where an approval or other agreement of the Parties or Non- Operators is expressly required under other Sections of this Accounting Procedure and if the Agreement to which this Accounting Procedure is attached contains no contrary provisions in regard thereto, the Operator shall notify all Non-Operators of the Operator's proposal and the agreement or approval of a majority in interest of the Non- Operators shall be controlling on all Non-Operators.

This Section I.6.A applies to specific situations of limited duration where a Party proposes to change the accounting for charges from that prescribed in this Accounting Procedure. This provision does not apply to amendments to this Accounting Procedure, which are covered by Section I.6.B.

B. AMENDMENTS

If the Agreement to which this Accounting Procedure is attached contains no contrary provisions in regard thereto, this Accounting Procedure can be amended by an affirmative vote of ALL (____) ~~or more~~ Parties, one of which is the Operator, having a combined working interest of at least 100 percent (100%), which approval shall be binding on all Parties, provided, however, approval of at least one (1) Non- Operator shall be required.

C. AFFILIATES

For the purpose of administering the voting procedures of Sections I.6.A and I.6.B, if Parties to this Agreement are Affiliates of each other, then such Affiliates shall be combined and treated as a single Party having the combined working interest or Participating Interest of such Affiliates.

For the purposes of administering the voting procedures in Section I.6.A, if a Non- Operator is an Affiliate of the Operator, votes under Section I.6.A shall require the majority in interest of the Non- Operator(s) after excluding the interest of the Operator's Affiliate.

II. DIRECT CHARGES

The Operator shall charge the Joint Account with the following items, to the extent that a reasonable and prudent operator would typically charge such items to the Joing Account:

1. RENTALS AND ROYALTIES

Lease rentals and royalties paid by the Operator, on behalf of all Parties, for the Joint Operations.

2. LABOR

A. Salaries and wages, including incentive compensation programs as set forth in COPAS MFI- 37 ("Chargeability of Incentive Compensation Programs"), for:

(1) Operator's field employees directly employed On- site in the conduct of Joint Operations,

(2) Operator's employees directly employed on Shore Base Facilities, Offshore Facilities, or other facilities serving the Joint Property if such costs are not charged under Section II.6 (*Equipment and Facilities Furnished by Operator*) or are not a function covered under Section III (*Overhead*),

(3) Operator's employees providing First Level Supervision,

(4) Operator's employees providing On- site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*),

(5) Operator's employees providing Off- site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*).

Charges for the Operator's employees identified in Section II.2.A may be made based on the employee's actual salaries and wages, or in lieu thereof, a day rate representing the Operator's average salaries and wages of the employee's specific job category.

Charges for personnel chargeable under this Section II.2.A who are foreign nationals shall not exceed comparable compensation paid to an equivalent U.S. employee pursuant to this Section II.2, unless otherwise approved by the Parties pursuant to Section I.6.A (*General Matters*).

B. Operator's cost of holiday, vacation, sickness, and disability benefits, and other customary allowances paid to employees whose salaries and wages are chargeable to the Joint Account under Section II.2.A, excluding severance payments or other termination allowances. Such costs under this Section II.2.B may be charged on a "when and as- paid basis" or by "percentage assessment" on the amount of salaries and wages chargeable to the Joint Account under Section II.2.A. If percentage assessment is used, the rate shall be based on the Operator's cost experience.

C. Expenditures or contributions made pursuant to assessments imposed by governmental authority that are applicable to costs chargeable to the Joint Account under Sections II.2.A and B.

D. Personal Expenses of personnel whose salaries and wages are chargeable to the Joint Account under Section II.2.A when the expenses are incurred in connection with directly chargeable activities.

E. Reasonable relocation costs incurred in transferring to the Joint Property personnel whose salaries and wages are chargeable to the Joint Account under Section II.2.A. Notwithstanding the foregoing, relocation costs that result from reorganization or merger of a Party, or that are for the primary benefit of the Operator, shall not be chargeable to the Joint Account. Extraordinary relocation costs, such as those incurred as a result of transfers from remote locations, such as Alaska or overseas, shall not be charged to the Joint Account unless approved by the Parties pursuant to Section I.6.A (*General Matters*).

F. Training costs as specified in COPAS MFI- 35 ("Charging of Training Costs to the Joint Account") for personnel whose salaries and wages are chargeable under Section II.2.A. This training charge shall include the wages, salaries, training course cost, and Personal Expenses incurred during the training session. The training cost shall be charged or allocated to the property or properties directly benefiting from the training. The cost of the training course shall not exceed prevailing commercial rates, where such rates are available.

G. Operator's current cost of established plans for employee benefits, as described in COPAS MFI- 27 ("Employee Benefits Chargeable to Joint Operations and Subject to Percentage Limitation"), applicable to the Operator's labor costs chargeable to the Joint Account under Sections II.2.A and B based on the Operator's actual cost not to exceed the employee benefits limitation percentage most recently recommended by COPAS.

H. Award payments to employees, in accordance with COPAS MFI- 49 ("Awards to Employees and Contractors") for personnel whose salaries and wages are chargeable under Section II.2.A.

3. MATERIAL

Material purchased or furnished by the Operator for use on the Joint Property in the conduct of Joint Operations as provided under Section IV (Material *Purchases, Transfers, and Dispositions*). Only such Material shall be purchased for or transferred to the Joint Property as may be required for immediate use or is reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

4. TRANSPORTATION

A. Transportation of the Operator's, Operator's Affiliate's, or contractor's personnel necessary for Joint Operations.

B. Transportation of Material between the Joint Property and another property, or from the Operator's warehouse or other storage point to the Joint Property, shall be charged to the receiving property using one of the methods listed below. Transportation of Material from the Joint Property to the Operator's warehouse or other storage point shall be paid for by the Joint Property using one of the methods listed below:

(1) If the actual trucking charge is less than or equal to the Excluded Amount the Operator may charge actual trucking cost or a theoretical charge from the Railway Receiving Point to the Joint Property. The basis for the theoretical charge is the per hundred weight charge plus fuel surcharges from the Railway Receiving Point to the Joint Property. The Operator shall consistently apply the selected alternative.

(2) If the actual trucking charge is greater than the Excluded Amount, the Operator shall charge Equalized Freight. Accessorial charges such as loading and unloading costs, split pick- up costs, detention, call out charges, and permit fees shall be charged directly to the Joint Property and shall not be included when calculating the Equalized Freight.

5. SERVICES

The cost of contract services, equipment, and utilities used in the conduct of Joint Operations, except for contract services, equipment, and utilities covered by Section III (*Overhead*), or Section II.7 (*Affiliates*), or excluded under Section II.9 (*Legal Expense*). Awards paid to contractors shall be chargeable pursuant to COPAS MFI- 49 ("Awards to Employees and Contractors").
The costs of third party Technical Services are chargeable to the extent excluded from the overhead rates under Section III (*Overhead*).

6. EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR

In the absence of a separately negotiated agreement, equipment and facilities furnished by the Operator will be charged as follows:

A. The Operator shall charge the Joint Account for use of Operator- owned equipment and facilities, including but not limited to production facilities, Shore Base Facilities, Offshore Facilities, and Field Offices, at rates commensurate with the costs of ownership and operation. The cost of Field Offices shall be chargeable to the extent the Field Offices provide direct service to personnel who are chargeable pursuant to Section II.2.A (*Labor*). Such rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, depreciation using straight line depreciation method, and interest on gross investment less accumulated depreciation not to exceed twelve percent (12%) per annum; provided, however, depreciation shall not be charged when the equipment and facilities investment have been fully depreciated. The rate may include an element of the estimated cost for abandonment, reclamation, and dismantlement. Such rates shall not exceed the average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in Section II.6.A above, the Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property, less twenty percent (20%). If equipment and facilities are charged under this Section II.6.B, the Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation. For automotive equipment, the Operator may elect to use rates published by the Petroleum Motor Transport Association (PMTA) or such other organization recognized by COPAS as the official source of rates.

7. AFFILIATES

Charges for services furnished by an Affiliate shall be charged in the same manner as Operator employees, pursuant to Section II.2. Charges for goods furnished by an Affiliate shall be charged in the same manner as charges for equipment and facilities furnished by Operator, pursuant to Section II.6.

~~A. Charges for an Affiliate's goods and/or services used in operations requiring an AFE or other authorization from the Non- Operators may be made without the approval of the Parties provided (i) the Affiliate is identified and the Affiliate goods and services are specifically detailed in the approved AFE or other authorization, and (ii) the total costs for such Affiliate's goods and services billed to such individual project do not exceed $ N/A If the total costs for an Affiliate's goods and services charged to such individual project are not specifically detailed in the approved AFE or authorization or exceed such amount, charges for such Affiliate shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*).~~

~~B. For an Affiliate's goods and/or services used in operations not requiring an AFE or other authorization from the Non- Operators, charges for such Affiliate's goods and services shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*), if the charges exceed $ N/A in a given calendar year.~~

~~C. The cost of the Affiliate's services shall not exceed average commercial rates prevailing in the area of the Joint Property, unless the Operator obtains the Non- Operators' approval of such rates. The Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation; provided, however, documentation of commercial rates shall not be required if the Operator obtains Non- Operator approval of its Affiliate's rates or charges prior to billing Non- Operators for such Affiliate's goods and services.~~ Notwithstanding the foregoing, direct charges for Affiliate- owned communication facilities or systems shall be made pursuant to Section II.12 (*Communications*).

~~If the Parties fail to designate an amount in Sections II.7.A or II.7.B, in each instance the amount deemed adopted by the Parties as a result of such omission shall be the amount established as the Operator's expenditure limitation in the Agreement. If the Agreement does not contain an Operator's expenditure limitation, the amount deemed adopted by the Parties as a result of such omission shall be zero dollars ($ 0.00).~~

8. DAMAGES AND LOSSES TO JOINT PROPERTY

All costs or expenses necessary for the repair or replacement of Joint Property resulting from damages or losses incurred, except to the extent such damages or losses result from a Party's or Parties' gross negligence or willful misconduct, in which case such Party or Parties shall be solely liable. The Operator shall furnish the Non- Operator written notice of damages or losses incurred as soon as practicable after a report has been received by the Operator.

9. LEGAL EXPENSE

Recording fees and costs of handling, settling, or otherwise discharging litigation, claims, and liens incurred in or resulting from operations under the Agreement, or necessary to protect or recover the Joint Property, to the extent permitted under the Agreement. Costs of the Operator's or Affiliate's legal staff or outside attorneys, including fees and expenses, are not chargeable unless approved by the Parties pursuant to Section I.6.A (*General Matters*) or otherwise provided for in the Agreement.

Notwithstanding the foregoing paragraph, costs for procuring abstracts, fees paid to outside attorneys for title examinations (including preliminary, supplemental, shut- in royalty opinions, division order title opinions), and curative work shall be chargeable to the extent permitted as a direct charge in the Agreement.

10. TAXES AND PERMITS

All taxes and permitting fees of every kind and nature, assessed or levied upon or in connection with the Joint Property, or the production therefrom, and which have been paid by the Operator for the benefit of the Parties, including penalties and interest, except to the extent the penalties and interest result from the Operator's gross negligence or willful misconduct.

If ad valorem taxes paid by the Operator are based in whole or in part upon separate valuations of each Party's working interest, then notwithstanding any contrary provisions, the charges to the Parties will be made in accordance with the tax value generated by each Party's working interest.

Costs of tax consultants or advisors, the Operator's employees, or Operator's Affiliate employees in matters regarding ad valorem or other tax matters, are not permitted as direct charges unless approved by the Parties pursuant to Section I.6.A (*General Matters*).
Charges to the Joint Account resulting from sales/use tax audits, including extrapolated amounts and penalties and interest, are permitted, provided the Non- Operator shall be allowed to review the invoices and other underlying source documents which served as the basis for tax charges and to determine that the correct amount of taxes were charged to the Joint Account. If the Non- Operator is not permitted to review such documentation, the sales/use tax amount shall not be directly charged unless the Operator can conclusively document the amount owed by the Joint Account.

11. INSURANCE
Net premiums paid for insurance required to be carried for Joint Operations for the protection of the Parties. If Joint Operations are conducted at locations where the Operator acts as self- insurer in regard to its worker's compensation and employer's liability insurance obligation, the Operator shall charge the Joint Account manual rates for the risk assumed in its self- insurance program as regulated by the jurisdiction governing the Joint Property. In the case of offshore operations in federal waters, the manual rates of the adjacent state shall be used for personnel performing work On-site, and such rates shall be adjusted for offshore operations by the U.S. Longshoreman and Harbor Workers (USL&H) or Jones Act surcharge, as appropriate.

12. COMMUNICATIONS
Costs of acquiring, leasing, installing, operating, repairing, and maintaining communication facilities or systems, including satellite, radio and microwave facilities, between the Joint Property and the Operator's office(s) directly responsible for field operations in accordance with the provisions of COPAS MFI- 44 ("Field Computer and Communication Systems"). If the communications facilities or systems serving the Joint Property are Operator- owned, charges to the Joint Account shall be made as provided in Section II.6 (*Equipment and Facilities Furnished by Operator*). If the communication facilities or systems serving the Joint Property are owned by the Operator's Affiliate, charges to the Joint Account shall not exceed average commercial rates prevailing in the area of the Joint Property. The Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation.

13. ECOLOGICAL, ENVIRONMENTAL, AND SAFETY
Costs incurred for Technical Services and drafting to comply with ecological, environmental and safety Laws or standards recommended by Occupational Safety and Health Administration (OSHA) or other regulatory authorities. All other labor and functions incurred for ecological, environmental and safety matters, including management, administration, and permitting, shall be covered by Sections II.2 (*Labor*), II.5 (*Services*), or Section III (*Overhead*), as applicable.
Costs to provide or have available pollution containment and removal equipment plus actual costs of control and cleanup and resulting responsibilities of oil and other spills as well as discharges from permitted outfalls as required by applicable Laws, or other pollution containment and removal equipment deemed appropriate by the Operator for prudent operations, are directly chargeable.

14. ABANDONMENT AND RECLAMATION
Costs incurred for abandonment and reclamation of the Joint Property, including costs required by lease agreements or by Laws.

15. OTHER EXPENDITURES
Any other expenditure not covered or dealt with in the foregoing provisions of this Section II (*Direct Charges*), or in Section III (*Overhead*) and which is of direct benefit to the Joint Property and is incurred by the Operator in the necessary and proper conduct of the Joint Operations. Charges made under this Section II.15 shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*).

III. OVERHEAD

As compensation for costs not specifically identified as chargeable to the Joint Account pursuant to Section II (*Direct Charges*), the Operator shall charge the Joint Account in accordance with this Section III.
Functions included in the overhead rates regardless of whether performed by the Operator, Operator's Affiliates or third parties and regardless of location, shall include, but not be limited to, costs and expenses of:

- warehousing, other than for warehouses that are jointly owned under this Agreement
- design and drafting (except when allowed as a direct charge under Sections II.13, III.1.A(ii), and III.2, Option B)
- inventory costs not chargeable under Section V (*Inventories of Controllable Material*)
- procurement
- administration
- accounting and auditing

gas dispatching and gas chart integration

human resources

management

supervision not directly charged under Section II.2 (*Labor*)

legal services not directly chargeable under Section II.9 (*Legal Expense*)

taxation, other than those costs identified as directly chargeable under Section II.10 (*Taxes and Permits*)

preparation and monitoring of permits and certifications; preparing regulatory reports; appearances before or meetings with governmental agencies or other authorities having jurisdiction over the Joint Property, other than On- site inspections; reviewing, interpreting, or submitting comments on or lobbying with respect to Laws or proposed Laws.

Overhead charges shall include the salaries or wages plus applicable payroll burdens, benefits, and Personal Expenses of personnel performing overhead functions, as well as office and other related expenses of overhead functions.

1. OVERHEAD- DRILLING AND PRODUCING OPERATIONS

As compensation for costs incurred but not chargeable under Section II (*Direct Charges*) and not covered by other provisions of this Section III, the Operator shall charge on either:

✓ **(Alternative 1)** Fixed Rate Basis, Section III.1.B.

❑ **(Alternative 2)** Percentage Basis, Section III.1.C.

A. TECHNICAL SERVICES

(i) Except as otherwise provided in Section II.13 (*Ecological Environmental, and Safety*) and Section III.2 (*Overhead Major Construction and Catastrophe*), or by approval of the Parties pursuant to Section I.6.A (*General Matters*), the salaries, wages, related payroll burdens and benefits, and Personal Expenses for **On- site** Technical Services, including third party Technical Services:

✓ **(Alternative 1 Direct)** shall be charged **direct** to the Joint Account.

❑ **(Alternative 2 Overhead)** shall be covered by the **overhead** rates.

(ii) Except as otherwise provided in Section II.13 (*Ecological, Environmental, and Safety*) and Section III.2 (*Overhead Major Construction and Catastrophe*), or by approval of the Parties pursuant to Section I.6.A (*General Matters*), the salaries, wages, related payroll burdens and benefits, and Personal Expenses for **Off- site** Technical Services, including third party Technical Services:

✓ **(Alternative 1 All Overhead)** shall be covered by the **overhead** rates.

❑ **(Alternative 2 All Direct)** shall be charged **<u>direct</u>** to the Joint Account.

❑ **(Alternative 3 Drilling Direct)** shall be charged **<u>direct</u>** to the Joint Account, **<u>only</u>** to the extent such Technical Services are directly attributable to drilling, redrilling, deepening, or sidetracking operations, through completion, temporary abandonment, or abandonment if a dry hole. Off- site Technical Services for all other operations, including workover, recompletion, abandonment of producing wells, and the construction or expansion of fixed assets not covered by Section III.2 (*Overhead Major Construction and Catastrophe*) shall be covered by the overhead rates.

Notwithstanding anything to the contrary in this Section III, Technical Services provided by Operator's Affiliates are subject to limitations set forth in Section II.7 (*Affiliates*). Charges for Technical personnel performing non- technical work shall not be governed by this Section III.1.A, but instead governed by other provisions of this Accounting Procedure relating to the type of work being performed.

B. OVERHEAD- FIXED RATE BASIS

(1) The Operator shall charge the Joint Account at the following rates per well per month:
Drilling Well Rate per month $<u>6,000</u> (prorated for less than a full month)
Producing Well Rate per month $ <u>600</u>

(2) Application of Overhead- Drilling Well Rate shall be as follows:

(a) Charges for onshore drilling wells shall begin on the spud date and terminate on the date the drilling and/or completion equipment used on the well is released, whichever occurs later. Charges for offshore and inland waters drilling wells shall begin on the date the drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location, or is released, whichever occurs first. No charge shall be made during suspension of drilling and/or completion operations for fifteen (15) or more consecutive calendar days.

(b) Charges for any well undergoing any type of workover, recompletion, and/or abandonment for a period of five (5) or more consecutive workdays shall be made at the Drilling Well Rate. Such charges shall be applied for the period from date operations, with rig or other units used in operations, commence through date of rig or other unit release, except that no charges shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

(3) Application of Overhead- Producing Well Rate shall be as follows:

(a) An active well that is produced, injected into for recovery or disposal, or used to obtain water supply to support operations for any portion of the month shall be considered as a one- well charge for the entire month.

(b) Each active completion in a multi- completed well shall be considered as a one- well charge provided each completion is considered a separate well by the governing regulatory authority.

(c) A one- well charge shall be made for the month in which plugging and abandonment operations are completed on any well, unless the Drilling Well Rate applies, as provided in Sections III.1.B.(2)(a) or (b). This one- well charge shall be made whether or not the well has produced.

(d) An active gas well shut in because of overproduction or failure of a purchaser, processor, or transporter to take production shall be considered as a one- well charge provided the gas well is directly connected to a permanent sales outlet.

(e) Any well not meeting the criteria set forth in Sections III.1.B.(3) (a), (b), (c), or (d) shall not qualify for a producing overhead charge.

(4) The well rates shall be adjusted on the first day of April each year following the effective date of the Agreement; provided, however, if this Accounting Procedure is attached to or otherwise governing the payout accounting under a farmout agreement, the rates shall be adjusted on the first day of April each year following the effective date of such farmout agreement. The adjustment shall be computed by applying the adjustment factor most recently published by COPAS. The adjusted rates shall be the initial or amended rates agreed to by the Parties increased or decreased by the adjustment factor described herein, for each year from the effective date of such rates, in accordance with COPAS MFI-47 ("Adjustment of Overhead Rates").

~~C. OVERHEAD- PERCENTAGE BASIS~~

~~(1) Operator shall charge the Joint Account at the following rates:~~

~~(a) Development Rate ____ percent (____)% of the cost of development of the Joint Property, exclusive of costs provided under Section II.9 (*Legal Expense*) and all Material salvage credits.~~

~~(b) Operating Rate ____ percent (____%) of the cost of operating the Joint Property, exclusive of costs provided under Sections II.1 (*Rentals and Royalties*) and II.9 (*Legal Expense*); all Material salvage credits; the value of substances purchased for enhanced recovery; all property and ad valorem taxes, and any other taxes and assessments that are levied, assessed, and paid upon the mineral interest in and to the Joint Property.~~

~~(2) Application of Overhead- Percentage Basis shall be as follows:~~

~~(a) The Development Rate shall be applied to all costs in connection with:~~

~~[i] drilling, redrilling, sidetracking, or deepening of a well~~

~~[ii] a well undergoing plugback or workover operations for a period of five (5) or more consecutive workdays~~

~~[iii] preliminary expenditures necessary in preparation for drilling~~

~~[iv] expenditures incurred in abandoning when the well is not completed as a producer~~

~~[v] construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, other than Major Construction or Catastrophe as defined in Section III.2 (*Overhead- Major Construction and Catastrophe*).~~

~~(b) The Operating Rate shall be applied to all other costs in connection with Joint Operations, except those subject to Section III.2 (*Overhead- Major Construction and Catastrophe*).~~

2. OVERHEAD- MAJOR CONSTRUCTION AND CATASTROPHE

To compensate the Operator for overhead costs incurred in connection with a Major Construction project or Catastrophe, the Operator shall either negotiate a rate prior to the beginning of the project, or shall charge the Joint Account for overhead based on the following rates for any Major Construction project in excess of the Operator's expenditure limit under the Agreement, or for any Catastrophe regardless of the amount. If the Agreement to which this Accounting Procedure is attached does not contain an expenditure limit, Major Construction Overhead shall be assessed for any single Major Construction project costing in excess of $100,000 gross.

Major Construction shall mean the construction and installation of fixed assets, the expansion of fixed assets, and any other project clearly discernible as a fixed asset required for the development and operation of the Joint Property, or in the dismantlement, abandonment, removal, and restoration of platforms, production equipment, and other operating facilities.
Catastrophe is defined as a sudden calamitous event bringing damage, loss, or destruction to property or the environment, such as an oil spill, blowout, explosion, fire, storm, hurricane, or other disaster. The overhead rate shall be applied to those costs necessary to restore the Joint Property to the equivalent condition that existed prior to the event.

A. If the Operator absorbs the engineering, design and drafting costs related to the project:

(1) 6% of total costs if such costs are less than $100,000; plus

(2) 4% of total costs in excess of $100,000 but less than $1,000,000; plus

(3) 3% of total costs in excess of $1,000,000.

B. If the Operator charges engineering, design and drafting costs related to the project directly to the Joint Account:

(1) 5% of total costs if such costs are less than $100,000; plus

(2) 3% of total costs in excess of $100,000 but less than $1,000,000; plus

(3) 2% of total costs in excess of $1,000,000.

Total cost shall mean the gross cost of any one project. For the purpose of this paragraph, the component parts of a single Major Construction project shall not be treated separately, and the cost of drilling and workover wells and purchasing and installing pumping units and downhole artificial lift equipment shall be excluded. For Catastrophes, the rates shall be applied to all costs associated with each single occurrence or event.
On each project, the Operator shall advise the Non- Operator(s) in advance which of the above options shall apply.
For the purposes of calculating Catastrophe Overhead, the cost of drilling relief wells, substitute wells, or conducting other well operations directly resulting from the catastrophic event shall be included. Expenditures to which these rates apply shall not be reduced by salvage or insurance recoveries. Expenditures that qualify for Major Construction or Catastrophe Overhead shall not qualify for overhead under any other overhead provisions.
In the event of any conflict between the provisions of this Section III.2 and the provisions of Sections II.2 (*Labor*), II.5 (*Services*), or II.7 (*Affiliates*), the provisions of this Section III.2 shall govern.

3. AMENDMENT OF OVERHEAD RATES

The overhead rates provided for in this Section III may be amended from time to time if, in practice, the rates are found to be insufficient or excessive, in accordance with the provisions of Section I.6.B (*Amendments*).

IV. MATERIAL PURCHASES, TRANSFERS, AND DISPOSITIONS

The Operator is responsible for Joint Account Material and shall make proper and timely charges and credits for direct purchases, transfers, and dispositions. The Operator shall provide all Material for use in the conduct of Joint Operations; however, Material may be supplied by the Non-Operators, at the Operator's option. Material furnished by any Party shall be furnished without any express or implied warranties as to quality, fitness for use, or any other matter.

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. The Operator shall make good faith efforts to take discounts offered by suppliers, but shall not be liable for failure to take discounts except to the extent such failure was the result of the Operator's gross negligence or willful misconduct. A direct purchase shall be deemed to occur when an agreement is made between an Operator and a third party for the acquisition of Material for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the manufacturer, distributor, or agent until usage, is considered a direct purchase. If Material is found to be defective or is returned to the manufacturer, distributor, or agent for any other reason, credit shall be passed to the Joint Account within sixty (60) days after the Operator has received adjustment from the manufacturer, distributor, or agent.

2. TRANSFERS

A transfer is determined to occur when the Operator (i) furnishes Material from a storage facility or from another operated property, (ii) has assumed liability for the storage costs and changes in value, and (iii) has previously secured and held title to the transferred Material. Similarly, the removal of Material from the Joint Property to a storage facility or to another operated property is also considered a transfer; provided, however, Material that is moved from the Joint Property to a storage location for safe- keeping pending disposition may remain charged to the Joint Account and is not considered a transfer. Material shall be disposed of in accordance with Section IV.3 (*Disposition of Surplus*) and the Agreement to which this Accounting Procedure is attached.

A. PRICING

The value of Material transferred to/from the Joint Property should generally reflect the market value on the date of physical transfer. Regardless of the pricing method used, the Operator shall make available to the Non- Operators sufficient documentation to verify the Material valuation. When higher than specification grade or size tubulars are used in the conduct of Joint Operations, the Operator shall charge the Joint Account at the equivalent price for well design specification tubulars, unless such higher specification grade or sized tubulars are approved by the Parties pursuant to Section I.6.A (*General Matters*). Transfers of new Material will be priced using one of the following pricing methods; provided, however, the Operator shall use consistent pricing methods, and not alternate between methods for the purpose of choosing the method most favorable to the Operator for a specific transfer:

(1) Using published prices in effect on date of movement as adjusted by the appropriate COPAS Historical Price Multiplier (HPM) or prices provided by the COPAS Computerized Equipment Pricing System (CEPS).

(a) For oil country tubulars and line pipe, the published price shall be based upon eastern mill carload base prices (Houston, Texas, for special end) adjusted as of date of movement, plus transportation cost as defined in Section IV.2.B (*Freight*).

(b) For other Material, the published price shall be the published list price in effect at date of movement, as listed by a Supply Store nearest the Joint Property where like Material is normally available, or point of manufacture plus transportation costs as defined in Section IV.2.B (*Freight*).

(2) Based on a price quotation from a vendor that reflects a current realistic acquisition cost.

(3) Based on the amount paid by the Operator for like Material in the vicinity of the Joint Property within the previous twelve (12) months from the date of physical transfer.

(4) As agreed to by the Participating Parties for Material being transferred to the Joint Property, and by the Parties owning the Material for Material being transferred from the Joint Property.

B. FREIGHT

Transportation costs shall be added to the Material transfer price using the method prescribed by the COPAS Computerized Equipment Pricing System (CEPS). If not using CEPS, transportation costs shall be calculated as follows:

(1) Transportation costs for oil country tubulars and line pipe shall be calculated using the distance from eastern mill to the Railway Receiving Point based on the carload weight basis as recommended by the COPAS MFI- 38 ("Material Pricing Manual") and other COPAS MFIs in effect at the time of the transfer.

(2) Transportation costs for special mill items shall be calculated from that mill's shipping point to the Railway Receiving Point. For transportation costs from other than eastern mills, the 30,000- pound interstate truck rate shall be used. Transportation costs for macaroni tubing shall be calculated based on the interstate truck rate per weight of tubing transferred to the Railway Receiving Point.

(3) Transportation costs for special end tubular goods shall be calculated using the interstate truck rate from Houston, Texas, to the Railway Receiving Point.

(4) Transportation costs for Material other than that described in Sections IV.2.B.(1) through (3), shall be calculated from the Supply Store or point of manufacture, whichever is appropriate, to the Railway Receiving Point

Regardless of whether using CEPS or manually calculating transportation costs, transportation costs from the Railway Receiving Point to the Joint Property are in addition to the foregoing, and may be charged to the Joint Account based on actual costs incurred. All transportation costs are subject to Equalized Freight as provided in Section II.4 (*Transportation*) of this Accounting Procedure.

C. TAXES

Sales and use taxes shall be added to the Material transfer price using either the method contained in the COPAS Computerized Equipment Pricing System (CEPS) or the applicable tax rate in effect for the Joint Property at the time and place of transfer. In either case, the Joint Account shall be charged or credited at the rate that would have governed had the Material been a direct purchase.

D. CONDITION

(1) Condition "A" New and unused Material in sound and serviceable condition shall be charged at one hundred percent (100%) of the price as determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*). Material transferred from the Joint Property that was not placed in service shall be credited as charged without gain or loss; provided, however, any unused Material that was charged to the Joint Account through a direct purchase will be credited to the Joint Account at the original cost paid less restocking fees charged by the vendor. New and unused Material transferred from the Joint Property may be credited at a price other than the price originally charged to the Joint Account provided such price is approved by the Parties owning such Material, pursuant to Section I.6.A (*General Matters*). All refurbishing costs required or necessary to return the Material to original condition or to correct handling, transportation, or other damages will be borne by the divesting property. The Joint Account is responsible for Material preparation, handling, and transportation costs for new and unused Material charged to the Joint Property either through a direct purchase or transfer. Any preparation costs incurred, including any internal or external coating and wrapping, will be credited on new Material provided these services were not repeated for such Material for the receiving property.

(2) Condition "B" Used Material in sound and serviceable condition and suitable for reuse without reconditioning shall be priced by multiplying the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) by seventy- five percent (75%).

Except as provided in Section IV.2.D(3), all reconditioning costs required to return the Material to Condition "B" or to correct handling, transportation or other damages will be borne by the divesting property.

If the Material was originally charged to the Joint Account as used Material and placed in service for the Joint Property, the Material will be credited at the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) multiplied by sixty- five percent (65%).

Unless otherwise agreed to by the Parties that paid for such Material, used Material transferred from the Joint Property that was not placed in service on the property shall be credited as charged without gain or loss.

(3) Condition "C" Material that is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced by multiplying the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) by fifty percent (50%).

The cost of reconditioning may be charged to the receiving property to the extent Condition "C" value, plus cost of reconditioning, does not exceed Condition "B" value.

(4) Condition "D" Material that (i) is no longer suitable for its original purpose but useable for some other purpose, (ii) is obsolete, or (iii) does not meet original specifications but still has value and can be used in other applications as a substitute for items with different specifications, is considered Condition "D" Material. Casing, tubing, or drill pipe used as line pipe shall be priced as Grade A and B seamless line pipe of comparable size and weight. Used casing, tubing, or drill pipe utilized as line pipe shall be priced at used line pipe prices. Casing, tubing, or drill pipe used as higher pressure service lines than standard line pipe, e.g., power oil lines, shall be priced under normal pricing procedures for casing, tubing, or drill pipe. Upset tubular goods shall be priced on a non- upset basis. For other items, the price used should result in the Joint Account being charged or credited with the value of the service rendered or use of the Material, or as agreed to by the Parties pursuant to Section 1.6.A (*General Matters*).

(5) Condition "E" Junk shall be priced at prevailing scrap value prices.

E. OTHER PRICING PROVISIONS

(1) Preparation Costs

Subject to Section II (*Direct Charges*) and Section III (*Overhead*) of this Accounting Procedure, costs incurred by the Operator in making Material serviceable including inspection, third party surveillance services, and other similar services will be charged to the Joint Account at prices which reflect the Operator's actual costs of the services. Documentation must be provided to the Non- Operators upon request to support the cost of service. New coating and/or wrapping shall be considered a component of the Materials and priced in accordance with Sections IV.1 (*Direct Purchases*) or IV.2.A (*Pricing*), as applicable. No charges or credits shall be made for used coating or wrapping. Charges and credits for inspections shall be made in accordance with COPAS MFI- 38 ("Material Pricing Manual").

(2) Loading and Unloading Costs

Loading and unloading costs related to the movement of the Material to the Joint Property shall be charged in accordance with the methods specified in COPAS MFI- 38 ("Material Pricing Manual").

3. DISPOSITION OF SURPLUS

Surplus Material is that Material, whether new or used, that is no longer required for Joint Operations. The Operator may purchase, but shall be under no obligation to purchase, the interest of the Non- Operators in surplus Material.

Dispositions for the purpose of this procedure are considered to be the relinquishment of title of the Material from the Joint Property to either a third party, a Non- Operator, or to the Operator. To avoid the accumulation of surplus Material, the Operator should make good faith efforts to dispose of surplus within twelve (12) months through buy/sale agreements, trade, sale to a third party, division in kind, or other dispositions as agreed to by the Parties.

Disposal of surplus Materials shall be made in accordance with the terms of the Agreement to which this Accounting Procedure is attached. If the Agreement contains no provisions governing disposal of surplus Material, the following terms shall apply:

The Operator may, through a sale to an unrelated third party or entity, dispose of surplus Material having a gross sale value that is less than or equal to the Operator's expenditure limit as set forth in the Agreement to which this Accounting Procedure is attached without the prior approval of the Parties owning such Material.

If the gross sale value exceeds the Agreement expenditure limit, the disposal must be agreed to by the Parties owning such Material.

Operator may purchase surplus Condition "A" or "B" Material without approval of the Parties owning such Material, based on the pricing methods set forth in Section IV.2 (*Transfers*).

Operator may purchase Condition "C" Material without prior approval of the Parties owning such Material if the value of the Materials, based on the pricing methods set forth in Section IV.2 (*Transfers*), is less than or equal to the Operator's expenditure limitation set forth in the Agreement. The Operator shall provide documentation supporting the classification of the Material as Condition C.

Operator may dispose of Condition "D" or "E" Material under procedures normally utilized by Operator without prior approval of the Parties owning such Material.

4. SPECIAL PRICING PROVISIONS

A. PREMIUM PRICING

Whenever Material is available only at inflated prices due to national emergencies, strikes, government imposed foreign trade restrictions, or other unusual causes over which the Operator has no control, for direct purchase the Operator may charge the Joint Account for the required Material at the Operator's actual cost incurred in providing such Material, making it suitable for use, and moving it to the Joint Property. Material transferred or disposed of during premium pricing situations shall be valued in accordance with Section IV.2 (*Transfers*) or Section IV.3 (*Disposition of Surplus*), as applicable.

B. SHOP- MADE ITEMS

Items fabricated by the Operator's employees, or by contract laborers under the direction of the Operator, shall be priced using the value of the Material used to construct the item plus the cost of labor to fabricate the item. If the Material is from the Operator's scrap or junk account, the Material shall be priced at either twenty- five percent (25%) of the current price as determined in Section IV.2.A (*Pricing*) or scrap value, whichever is higher. In no event shall the amount charged exceed the value of the item commensurate with its use.

C. MILL REJECTS

Mill rejects purchased as "limited service" casing or tubing shall be priced at eighty percent (80%) of K- 55/J- 55 price as determined in Section IV.2 (*Transfers*). Line pipe converted to casing or tubing with casing or tubing couplings attached shall be priced as K- 55/J- 55 casing or tubing at the nearest size and weight.

V. INVENTORIES OF CONTROLLABLE MATERIAL

The Operator shall maintain records of Controllable Material charged to the Joint Account, with sufficient detail to perform physical inventories. Adjustments to the Joint Account by the Operator resulting from a physical inventory of Controllable Material shall be made within twelve (12) months following the taking of the inventory or receipt of Non- Operator inventory report. Charges and credits for overages or shortages will be valued for the Joint Account in accordance with Section IV.2 (*Transfers*) and shall be based on the Condition "B" prices in effect on the date of physical inventory unless the inventorying Parties can provide sufficient evidence another Material condition applies.

1. DIRECTED INVENTORIES

Physical inventories shall be performed by the Operator upon written request of a majority in working interests of the Non- Operators (hereinafter, "directed inventory"); provided, however, the Operator shall not be required to perform directed inventories more frequently than once every five (5) years. Directed inventories shall be commenced within one hundred eighty (180) days after the Operator receives written notice that a majority in interest of the Non- Operators has requested the inventory. All Parties shall be governed by the results of any directed inventory.

Expenses of directed inventories will be borne by the Joint Account; provided, however, costs associated with any post- report follow- up work in settling the inventory will be absorbed by the Party incurring such costs. The Operator is expected to exercise judgment in keeping expenses within reasonable limits. Any anticipated disproportionate or extraordinary costs should be discussed and agreed upon prior to commencement of the inventory. Expenses of directed inventories may include the following:

A. A per diem rate for each inventory person, representative of actual salaries, wages, and payroll burdens and benefits of the personnel performing the inventory or a rate agreed to by the Parties pursuant to Section I.6.A (*General Matters*). The per diem rate shall also be applied to a reasonable number of days for pre- inventory work and report preparation.

B. Actual transportation costs and Personal Expenses for the inventory team.

C. Reasonable charges for report preparation and distribution to the Non- Operators.

2. NON- DIRECTED INVENTORIES

A. OPERATOR INVENTORIES

Physical inventories that are not requested by the Non- Operators may be performed by the Operator, at the Operator's discretion. The expenses of conducting such Operator- initiated inventories shall not be charged to the Joint Account.

B. NON- OPERATOR INVENTORIES

Subject to the terms of the Agreement to which this Accounting Procedure is attached, the Non- Operators may conduct a physical inventory at reasonable times at their sole cost and risk after giving the Operator at least ninety (90) days prior written notice. The Non- Operator inventory report shall be furnished to the Operator in writing within ninety (90) days of completing the inventory fieldwork.

C. SPECIAL INVENTORIES

The expense of conducting inventories other than those described in Sections V.1 (*Directed Inventories*), V.2.A (*Operator Inventories*), or V.2.B (*Non- Operator Inventories*), shall be charged to the Party requesting such inventory; provided, however, inventories required due to a change of Operator shall be charged to the Joint Account in the same manner as described in Section V.1 (*Directed Inventories*).

EXHIBIT D

Attached to and made a part of the certain Operating Agreement executed October 31, 2012 but dated effective November 1, 2012, by and between, Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

INSURANCE

1. The Operator shall carry for the benefit of the joint account insurance unless otherwise agreed, to be comprised of the following coverage:

A. Commercial General Liability

$10,000,000. Each occurrence and in the aggregate

B. Operator's Extra Expense (Control of Well)

$10,000,000 for wells 10,000 feet or greater in depth
$5,000,000 for wells less than 10,000 feet in depth
Combined Single Limit and any one accident or occurrence for 100% interest.

2. The Operator shall carry for the benefit of the joint account the following minimum amounts of insurance:

A: Workmen's Compensation in accordance with Federal law and the laws of the State in which operations will be conducted and/or other applicable jurisdiction.

B. Employer's Liability

a.	Bodily Injury by Accident	$1,000,000 each accident
b.	Bodily Injury by Disease	$1,000,000 policy limit
c.	Bodily Injury by Disease	$1,000,000 each employee

C. Comprehensive Automobile Public Liability

a.	Bodily Injury	$2,000,000 per occurrence
b.	Property Damage	$2,000,000 per occurrence

3. No other insurance will be required other than that set forth above. Premiums associated with the insurance for the benefit of the Joint Account herein shall be charged to the Joint Account.

4. The insurance provided for herein for the benefit of the Joint Account provides for certain deductibles to be borne by the insured parties. In the event a claim is made by the Operator on behalf of the Joint Account, and the insurance proceeds are subject to reduction as a result of a deductible provision, said deductible amount shall be a direct charge to the Joint Account.

5. The insurance provided for herein shall be primary regardless of any insurance carried by Operator or Non- Operator for their own account.

6. Insurance, other than Worker's Compensation, will name Non- Operator as an additional insured and will provide a waiver of subrogation in favor of Non- Operator.

7. In the event a Non- Operator elects to carry its own insurance and waive the insurance coverage set forth above, then the Non- Operator shall notify Operator seven days prior to any operation proposed under this Agreement wherein the applicable premiums shall not be charged to the Joint Account. If Non- Operator elects to carry its own insurance, or anytime upon the request of Operator, Non- Operator shall provide a Certificate of Insurance confirming its insurance coverage.

ELECTION BALLOT

Well

Location

City State

Nucor Energy Holdings Inc. hereby Elects ______ Does Not Elect ______ to participate for a [%] WI in the drilling of the [well] under Encana's insurance program as follows:

Commercial General Liability:

USD 10,000,000 limit, scaled to interest, each occurrence and in the aggregate, subject to USD 1,000,000 deductible, scaled to interest, each occurrence.

Operator's Extra Expense:

USD 10,000,000 limit, scaled to interest, each occurrence subject to USD 1,000,000 deductible, scaled to interest, each occurrence

Coverage is extended to the above- named non- operator only in respect of operations of the above- noted well.

NUCOR ENERGY HOLDINGS INC.

By: __________

Print Name: _____

Title: __________

Date Signed: _____

In the event that you have elected to participate in this operation, please be advised that Commercial General Liability and Operator's Extra Expense insurance covering your interest is required.

Please indicate your well control insurance election below:

______Elect to be covered under the JOA with the Operator

______Elect to carry own insurance CERTIFICATE SHOWING PROOF OF INSURANCE (with Encana Oil & Gas (USA) Inc. named as certificate holder) MUST BE SUBMITTED TO ENCANA BEFORE THE START OF OPERATIONS.

EXHIBIT E
GAS BALANCING AGREEMENT ("AGREEMENT")

Attached to and made a part of the certain Operating Agreement, executed October 31, 2012 but dated effective November 1, 2012, by and between Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

1. DEFINITIONS

The following definitions shall apply to this Agreement:

1.01 "Arm's Length Agreement" shall mean any gas sales agreement with an unaffiliated purchaser or any gas sales agreement with an affiliated purchaser where the sales price and delivery conditions under such agreement are representative of prices and delivery conditions existing under other similar agreements in the area between unaffiliated parties at the same time for natural gas of comparable quality and quantity.

1.02 "Balancing Area" shall mean:

All of the acreage and depths subject to the Operating Agreement, subject to the following: (i) if a well is completed in two (2) or more producing intervals where the working interest and royalty ownership is not uniform, producing intervals having uniform working interest and royalty ownership shall be considered a separate Balancing Area, and (ii) if a well or group of wells have uniform working interest and royalty ownership, but any of such well or wells are considered to be in a different state and/or federal communitized area, state or federal unit, or pooled unit, each such well or group of wells shall be considered a separate Balancing Area.

1.03 "Full Share of Current Production" shall mean the Percentage Interest of each Party in the Gas actually produced from the Balancing Area during each month.

1.04 "Gas" shall mean all hydrocarbons produced or producible from the Balancing Area, whether from a well classified as an oil well or gas well by the regulatory agency having jurisdiction in such matters, which are or may be made available for sale or separate disposition by the Parties, excluding oil, condensate and other liquids recovered by field equipment operated for the joint account. "Gas" does not include gas used in joint operations, such as for fuel, recycling or reinjection, or which is vented or lost prior to its delivery from the Balancing Area.

1.05 "Makeup Gas" shall mean any Gas taken by an Underproduced Party from the Balancing Area in excess of its Full Share of Current Production, whether pursuant to Section 3.3 or Section 4.1 hereof.

1.06 "Mcf" shall mean one thousand cubic feet. A cubic foot of Gas shall mean the volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base.

1.07 "MMBtu" shall mean one million British Thermal Units. A British Thermal Unit shall mean the quantity of heat required to raise one pound avoirdupois of pure water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit at a constant pressure of 14.73 pounds per square inch absolute.

1.08 "Operator" shall mean the individual or entity designated under the terms of the Operating Agreement or, in the event this Agreement is not employed in connection with an operating agreement, the individual or entity designated as the operator of the well(s) located in the Balancing Area.

1.09 "Overproduced Party" shall mean any Party having taken a greater quantity of Gas from the Balancing Area than the Percentage Interest of such Party in the cumulative quantity of all Gas produced from the Balancing Area.

1.10 "Overproduction" shall mean the cumulative quantity of Gas taken by a Party in excess of its Percentage Interest in the cumulative quantity of all Gas produced from the Balancing Area.

1.11 "Party" shall mean those individuals or entities subject to this Agreement, and their respective heirs, successors, transferees and assigns.

1.12 "Percentage Interest" shall mean the percentage or decimal interest of each Party in the Gas produced from the Balancing Area pursuant to the Operating Agreement covering the Balancing Area.

1.13 "Published Reference Price" shall mean the Index price published for the applicable geographic area on the transporting pipeline in the first of the production month's edition of *Inside FERC Gas Market Report* ("*Inside FERC Index*"). In the event that the *Inside FERC Index* ceases to be published, the parties will attempt in good faith to agree on a replacement reference price reflective of the same market reflected by the *Inside FERC Index*.

1.14 "Royalty" shall mean payments on production of Gas from the Balancing Area to all owners of royalties, overriding royalties, production payments or similar interests.

1.15 "Underproduced Party" shall mean any Party having taken a lesser quantity of Gas from the Balancing Area than the Percentage Interest of such Party in the cumulative quantity of all Gas produced from the Balancing Area.

1.16 "Underproduction" shall mean the deficiency between the cumulative quantity of Gas taken by a Party and its Percentage Interest in the cumulative quantity of all Gas produced from the Balancing Area.

1.17 "Winter Period" shall mean the month(s) of November and December in one calendar year and the month(s) of January, February, and March in the succeeding calendar year.

2. BALANCING AREA

2.1 If this Agreement covers more than one Balancing Area, it shall be applied as if each Balancing Area were covered by separate but identical agreements. All balancing hereunder, other than cash settlements made pursuant to Section 7, shall be on the basis of Gas taken from the Balancing Area measured in Mcfs.

2.2 In the event that all or part of the Gas deliverable from a Balancing Area is or becomes subject to one or more maximum lawful prices, any Gas not subject to price controls shall be considered as produced from a single Balancing Area and Gas subject to each maximum lawful price category shall be considered produced from a separate Balancing Area.

3. RIGHT OF PARTIES TO TAKE GAS

3.1 Each Party desiring to take Gas will notify the Operator, or cause the Operator to be notified, of the volumes nominated, the name of the transporting pipeline and the pipeline contract number (if available) and the meter station relating to such delivery, sufficiently in advance for the Operator, acting with reasonable diligence, to meet all nomination and other requirements. Operator is authorized to deliver the volumes so nominated and confirmed (if confirmation is required) to the transporting pipeline in accordance with the terms of this Agreement.
3.2 Each Party to take its Full Share of Current Production each month, to the extent that such production is required to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production.
3.3 When a Party fails for any reason to take its Full Share of Current Production (as such Share may be reduced by the right of the other Parties to make up for Underproduction as provided herein), the other Parties shall be entitled to take any Gas which such Party fails to take. To the extent practicable, such Gas shall be made available initially to each Underproduced Party in the proportion that its Percentage Interest in the Balancing Area bears to the total Percentage Interests of all Underproduced Parties desiring to take such Gas and then be made available to the other Parties in the proportion that their respective Percentage Interests in the Balancing Area bear to the total Percentage Interests of such Parties.
3.4 All Gas taken by a Party in accordance with the of this Agreement, regardless of whether such Party is underproduced or overproduced, shall be regarded as Gas taken for its own account with title thereto being in such taking Party.
3.5 Notwithstanding the provisions of Section 3.3 hereof, no Overproduced Party shall be entitled in any month to take any Gas in excess of three hundred percent (300%) of its Percentage Interest of the Balancing Area's then- current Maximum Monthly Availability; provided, however, that this limitation shall not apply to the extent that it would preclude production that is required to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production. "Maximum Monthly Availability" shall mean the maximum average monthly rate of production at which Gas can be delivered from the Balancing Area, as determined by the Operator, considering the maximum efficient well rate for each well within the Balancing Area, the maximum allowable(s) set by the appropriate regulatory agency, mode of operation, production facility capabilities and pipeline pressures.
3.6 In the event the Operator determines that a Party has failed to make arrangements to take its Full Share of Current Production required to be produced to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production, the Operator shall notify such Party that it has failed to take such Full Share of Current Production. If the notified Party does not begin taking its Full Share of Current Production effective the second business day following notification from the Operator, the Operator shall, to the extent practicable, make available to the Underproduced Party(ies) any part of such Party's Full Share of Current Production that such Party fails to take or the Operator may sell any part of such Party's Full Share of Current Production that such Party fails to take for the account of such Party and render to such Party, on a current basis, the full proceeds of the sale, less any reasonable marketing, compression, treating, gathering or transportation costs incurred directly in connection with the sale of such Full Share of Current Production. In making the sale contemplated herein, the Operator shall be obligated only to obtain such price and conditions for the sale as are reasonable under the circumstances and shall not be obligated to share any of its markets. Any such sale by Operator under the terms hereof shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one year. Notwithstanding the provisions of Section 3.4 hereof, Gas sold by Operator for a Party under the provisions hereof shall be deemed to be Gas taken for the account of such Party.

4. IN- KIND BALANCING

Effective the first day of any calendar month following at least thirty (30) days' prior written notice to the Operator, any Underproduced Party may begin taking, in addition to its Full Share of Current Production and any Makeup Gas taken pursuant to Section 3.3 of this Agreement, a share of current production determined by multiplying twenty five percent (25%) of the Full Shares of Current Production of all Overproduced Parties by a fraction, the numerator of which is the Percentage Interest of such Underproduced Party and the denominator of which is the total of the Percentage Interests of all Underproduced Parties desiring to take Makeup Gas. In no event will an Overproduced Party be required to provide more than twenty five percent (25%) of its Full Share of Current Production for Makeup Gas.

5. STATEMENT OF GAS BALANCES

5.1 The Operator will maintain appropriate accounting on a monthly and cumulative basis of the volumes of Gas that each Party is entitled to receive and the volumes of Gas actually taken or sold for each Party's account. Within sixty (60) days after the month of production, the Operator will furnish a statement for such month showing (1) each Party's Full Share of Current Production, (2) the total volume of Gas actually taken or sold for each Party's account, (3) the difference between the volume taken by each Party and that Party's Full Share of Current Production, (4) the Overproduction or Underproduction of each Party, and (5) other data as recommended by the provisions of the Council of Petroleum Accounting Societies Bulletin No.24, as amended or supplemented hereafter. Each Party taking Gas will promptly provide to the Operator any data required by the Operator for preparation of the statements required hereunder. If the Operator is notified that a Party elects to have another Party market or otherwise dispose of its Gas, the Operator will allocate to each such Party, in proportion to their respective Percentage Interests, the difference between the total volume of Gas actually taken by such Parties and their combined Full Share of Current Production.

5.2 If any Party fails to provide the data required herein for four (4) consecutive production months, the Operator, or where the Operator has failed to provide data, another Party, may audit the production and Gas sales and transportation volumes of the non- reporting Party to provide the required data. Such audit shall be conducted only after reasonable notice and during normal business hours in the office of the Party whose records are being audited. All costs associated with such audit will be charged to the account of the Party failing to provide the required data.

6. PAYMENTS ON PRODUCTION

6.1 Each Party taking Gas shall pay or cause to be paid all production and severance taxes due on all volumes of Gas actually taken by such Party.
6.2 Each Party shall pay or cause to be paid Royalty due with respect to Royalty owners to whom it is accountable based on the volume of Gas actually taken for its account.
6.3 In the event that any governmental authority requires that Royalty payments be made on any other basis than that provided for in this Section 6, each Party agrees to make such Royalty payments accordingly, commencing on the effective date required by such governmental authority, and the method provided for herein shall be thereby superseded.

7. CASH SETTLEMENTS

7.1 Each Party will work cooperatively pursuant to Section 4.0 to reduce any cumulative Gas production imbalance to as close to zero (0) as practicable. Upon the earlier of (i) the plugging and abandonment of the last producing interval in the Balancing Area, (ii) the termination of the Operating Agreement or any pooling or unit agreement covering the Balancing Area, (iii) any time no Gas is taken from the Balancing Area for a period of twelve (12) consecutive months, (iv) all leases in the Balancing Area have expired, or (v) the end of any calendar year, any Party may give written notice calling for cash settlement of the Gas production imbalances among the Parties. Such notice shall be given to all Parties in the Balancing Area.
7.2 Within sixty (60) days after the notice calling for cash settlement under Section 7.1, the Operator will distribute to each Party a Final Gas Settlement Statement detailing the quantity of Overproduction owed by each Overproduced Party to each Underproduced Party and identifying the month to which such Overproduction is attributed, pursuant to the methodology set out in Section 7.3.
7.3 The amount of the cash settlement will be based on the proceeds received by the Overproduced Party under an Arm's Length Agreement for the Gas taken from time to time by the Overproduced Party in excess of the Overproduced Party's Full Share of Current Production. Any Makeup Gas taken by the Underproduced Party prior to monetary settlement hereunder will be applied to offset Overproduction chronologically in the order of accrual.
7.4 The values used for calculating the cash settlement under Section 7.3 will include all proceeds received for the sale of the Gas by the Overproduced Party calculated at the Balancing Area, after deducting any production or severance taxes paid and any Royalty actually paid by the Overproduced Party to an Underproduced Party's Royalty owner(s), to the extent said payments amounted to a discharge of said Underproduced Party's Royalty obligation, as well as any reasonable marketing, compression, treating, gathering or transportation costs incurred directly in connection with the sale of the Overproduction.
7.5 To the extent the Overproduced Party did not sell all Overproduction under an Arm's Length Agreement, the cash settlement will be based on the weighted average price received by the Overproduced Party for any gas sold from the Balancing Area under Arm's Length Agreements during the months to which such Overproduction is attributed. In the event that no sales under Arm's Length Agreements were made during any such month the cash settlement for such month will be based on the spot sales prices published for the applicable geographic area during such month in a mutually acceptable pricing bulletin.
7.6 Interest compounded at the prime rate published by the *Wall Street Journal* plus one percent (1%) per annum or the maximum lawful rate of interest applicable to the Balancing Area, whichever is less, will accrue for all amounts due under Section 7.1, beginning the first day following the date payment is due pursuant to Section 7.3. Such interest shall be borne by the Operator or any Overproduced Party in the proportion that their respective delays beyond the deadlines set out in Sections 7.2 contributed to the accrual of the interest.
7.7 In lieu of the cash settlement required by Section 7.3, an Overproduced Party may deliver to the Underproduced Party an offer to settle its Overproduction in- kind and at such rates, quantities, times and sources as may be agreed upon by the Underproduced Party. If the Parties are unable to agree upon the manner in which such in- kind settlement gas will be furnished within sixty (60) days after the Overproduced Party's offer to settle in kind, which period may be extended by agreement of said Parties, the Overproduced Party shall make a cash settlement as provided in Section 7.3. The making of an in- kind settlement offer under this Section 7.7 will not delay the accrual of interest on the cash settlement should the Parties fail to reach agreement on an in- kind settlement.

8. OPERATING COSTS

Nothing in this Agreement shall change or affect any Party's obligation to pay its proportionate share of all costs and liabilities incurred in operations on or in connection with the Balancing Area, as its share thereof is set forth in the Operating Agreement, irrespective of whether any Party is at any time selling and using Gas or whether such sales or use are in proportion to its Percentage Interest in the Balancing Area.

9. LIQUIDS

The Parties shall share proportionately in and own all liquid hydrocarbons recovered with Gas by field equipment operated for the joint account in accordance with their Percentage Interests in the Balancing Area.

10. AUDIT RIGHTS

Notwithstanding any provision in this Agreement or any other agreement between the Parties hereto, and further notwithstanding any termination or cancellation of this Agreement, for a period of two (2) years from the end of the calendar year in which any information to be furnished under Section 5 and 7 hereof is supplied, any Party shall have the right to audit the records of any other Party regarding quantity, including but not limited to information regarding Btu- content. Any Underproduced Party shall have the right for a period of two (2) years from the end of the calendar year in which any cash settlement is received pursuant to Section 7 to audit the records of any Overproduced Party as to all matters concerning values, including but not limited to information regarding prices and disposition of Gas from the Balancing Area. Any such audit shall be conducted at the expense of the Party or Parties desiring such audit, and shall be conducted, after reasonable notice, during normal business hours in the office of the Party whose records are being audited. Each Party hereto agrees to maintain records as to the volumes and prices of Gas sold each month and the volumes of Gas used in its own operations, along with the Royalty paid on any such Gas used by a Party in its own operations. The audit rights provided for in this Section 10 shall be in addition to those provided for in Section 5.2 of this Agreement.

11. MISCELLANEOUS

11.1 As between the Parties, in the event of any conflict between the provisions of this Agreement and the provisions of any gas sales contract, or in the event of any conflict between the provisions of this Agreement and the provisions of the Operating Agreement, the provisions of this Agreement shall govern.

11.2 Each Party agrees to defend, indemnify and hold harmless all other Parties from and against any and all liability for any claims, which may be asserted by any third party which now or hereafter stands in a contractual relationship with such indemnifying Party and which arise out of the operation of this Agreement or any activities of such indemnifying Party under the provisions of this Agreement, and does further agree to save the other Parties harmless from all judgments or damages sustained and costs incurred in connection therewith.

11.3 Except as otherwise provided in this Agreement, Operator is authorized to administer the provisions of this Agreement, but shall have no liability to the other Parties for losses sustained or liability incurred which arise out of or in connection with the performance of Operator's duties hereunder, except such as may result from Operator's gross negligence or willful misconduct. Operator shall not be liable to any Underproduced Party for the failure of any Overproduced Party (other than Operator) to pay any amounts owed pursuant to the terms hereof.

11.4 This Agreement shall remain in full force and effect for as long as the Operating Agreement shall remain in force and effect as to the Balancing Area, and thereafter until the Gas accounts between the Parties are settled in full, and shall inure to the benefit of and be binding upon the Parties hereto, and their respective heirs, successors, legal representatives and assigns, if any. The Parties hereto agree to give notice of the existence of this Agreement to any successor in interest of any such Party and to provide that any such successor shall be bound by this Agreement, and shall further make any transfer of any interest subject to the Operating Agreement, or any part thereof, also subject to the terms of this Agreement.

11.5 Unless the context clearly indicates otherwise, words used in the singular include the plural, the plural includes the singular, and the neuter gender includes the masculine and the feminine.

11.6 In the event that any "Optional" provision of this Agreement is not adopted by the Parties to this Agreement by a typed, printed or handwritten indication, such provision shall not form a part of this Agreement, and no inference shall be made concerning the intent of the Parties in such event. In the event that any "Alternative" provision of this Agreement is not so adopted by the Parties, Alternative 1 in each such instance shall be deemed to have been adopted by the Parties as a result of any such omission. In those cases where it is indicated that an Optional provision may be used only if a specific Alternative is selected: (i) an election to include said Optional provision shall not be effective unless the Alternative in question is selected; and (ii) the election to include said Optional provision must be expressly indicated hereon, it being understood that the selection of an Alternative either expressly or by default as provided herein shall not, in and of itself, constitute an election to include an associated Optional Provision.

11.7 This Agreement shall bind the Parties in accordance with the provisions hereof, and nothing herein shall be construed or interpreted as creating any rights in any person or entity not a signatory hereto, or as being a stipulation in favor of any such person or entity.

11.8 In the event Internal Revenue Service regulations require a uniform method of computing taxable income by all Parties, each Party agrees to compute and report income to the Internal Revenue Service based on the quantity of Gas taken for its account (the cumulative method) in accordance with such regulations, insofar as same relate to sales method tax computations.

12. ASSIGNMENT AND RIGHTS UPON ASSIGNMENT

12.1 Subject to the provisions of Sections 12, and notwithstanding anything in this Agreement or in the Operating Agreement to the contrary, if any Party assigns (including any sale, exchange or other transfer) any of its working interest in the Balancing Area when such Party is an Underproduced or Overproduced Party, the assignment or other act of transfer shall, insofar as the Parties hereto are concerned, include all interest of the assigning or transferring Party in the Gas, all rights to receive or obligations to provide or take Makeup Gas and all rights to receive or obligations to make any monetary payment which may ultimately be due hereunder, as applicable. Operator and each of the other Parties hereto shall thereafter treat the assignment accordingly, and the assigning or transferring Party shall look solely to its assignee or other transferee for any interest in the Gas or monetary payment that such Party may have or to which it may be entitled, and shall cause its assignee or other transferee to assume its obligations hereunder.

12.2 The provisions of this Section 12 shall not be applicable in the event any Party mortgages its interest or disposes of its interest by merger, reorganization, consolidation or sale of substantially all of its assets to a subsidiary or parent company, or to any company in which any parent or subsidiary of such Party owns a majority of the stock of such company.

13. DISPUTE RESOLUTION

The Parties agree to resolve all disputes concerning or relating to this Agreement pursuant to the provisions of this Section. The Parties agree to submit all disputes to binding arbitration in Denver, Colorado. The arbitration will be conducted according to the procedure that follows. The arbitration proceedings shall be governed by Colorado law and shall be conducted in accordance with the rules for Non- Administered Arbitration of Business Disputes published by The Center for Public Resources, Inc., with discovery to be conducted in accordance with the Federal Rules of Civil Procedure, and with any disputes over the scope of discovery to be determined by the Arbitrators (as defined below). The arbitration shall be before a single Arbitrator chosen by the mutual agreement of the Parties, or if no agreement as to the identity of the Arbitrator can be reached within ten days, a three- person panel of neutral Arbitrators, consisting of one person chosen by each Party, and the two Arbitrators so selected choosing the third. The panel so chosen or the single person are referred to herein as the "Arbitrators." The Arbitrators shall conduct a hearing no later than 60 days after submission of the matter to arbitration, and the Arbitrators shall render a written decision within 30 days of the hearing. At the hearing, the Parties shall present such evidence and witnesses as they may choose, with or without counsel. Adherence to formal rules of evidence shall not be required, but the Arbitrators shall consider any evidence and testimony that they determine to be relevant, in accordance with procedures that they determine to be appropriate. Any award entered in the arbitration shall be made by a written opinion stating the reasons and basis for the award made and any payment due pursuant to the arbitration shall be made within 15 days of the decision by the Arbitrators. The decision of the Arbitrators shall be binding on the Parties, final and non- appealable, and may be filed in a court of competent jurisdiction and may be enforced by either Party as a final judgment of such court. Each Party shall bear its own costs and expenses of the arbitration, provided, however, that the costs of employing the Arbitrators shall by shared equally by the Parties.

EXHIBIT F

Attached to and made a part of the certain Operating Agreement executed October 31, 2012 but dated effective November 1, 2012, by and between, Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

NON- DISCRIMINATION AND CERTIFICATION OF
NON- SEGREGATED FACILITIES

In the performance of work under this Agreement, Operator agrees to comply with all the provisions of Section 202 (1) to (7), inclusive, of Executive Order 11246 (30 F.R 12319), as amended by Executive Order 11758 Employment of the Handicapped, Equal Employment Opportunity 11701 Employment of Veterans, and Equal Employment Opportunity 11625 Minority Business Enterprise.

The foregoing obligations of Operator shall be modified as necessary to comply with current executive orders, regulations and statutes, federal or state, relating to non- discrimination in employment.

Exhibit G to

Operating Agreement executed October 31, 2012 but dated effective November 1, 2012 by and between Nucor Energy Holdings Inc. and Encana Oil & Gas (USA) Inc.

TAX PARTNERSHIP PROVISIONS
OF THE ENCANA- NUCOR 2012 TAX PARTNERSHIP
EIN: [TBD]

Table of Contents

1. General Provisions

1.1. Designation of Documents.

This exhibit is referred to in, and is part of, the agreements identified above and, if so provided, a part of any agreement to which the agreements are an exhibit. Such agreements (including all exhibits thereto, other than this exhibit) shall be hereinafter referred to as the "Agreement;" and this exhibit is hereinafter referred to as the "Exhibit" or the "Tax Partnership Provisions" (the "TPPs"). Except as may be otherwise provided in this Exhibit, terms defined and used in the Agreement shall have the same meaning when used herein.

1.2. Relationship of the Parties.

The parties to the Agreement shall be hereinafter referred to as "Party" or "Parties." The Parties understand and agree that the arrangement and undertakings evidenced by the Agreement result in a partnership for purposes of Federal income taxation and certain State income tax laws which incorporate or follow Federal income tax principles as to tax partnerships. Such partnership for tax purposes is hereinafter referred to as the "Tax Partnership". For every other purpose of the Agreement, the Parties understand and agree that their legal relationship to each other under applicable State law with respect to all property subject to the Agreement is one of tenants in common, or undivided interest owners and not members in or partners of a partnership; that the liabilities of the Parties shall be several and not joint or collective; and that each Party shall be responsible solely for its own obligations.

1.3. Priority of Provisions of this Exhibit.

If there is a conflict or inconsistency, whether direct or indirect, actual or apparent, between the terms and conditions of this Exhibit and the terms and conditions of the Agreement, or any other exhibit or any part thereof, the terms and conditions of this Exhibit shall govern and control.

1.4. Survivorship.

1.4.1. Any termination of the Agreement shall not affect the continuing application of the TPPs for the termination and liquidation of the Tax Partnership.
1.4.2. Any termination of the Agreement shall not affect the continuing application of the TPPs for the resolution of all matters regarding Federal and State income reporting.

1.4.3. These TPPs shall inure to the benefit of, and be binding upon, the Parties hereto and their successors and assigns.
1.4.4. The effective date of the Agreement shall be the effective date of these TPPs. The Tax Partnership shall continue in full force and effect from, and after such date, until termination and liquidation pursuant to Sec. 7.1.

2. Tax Reporting Partner

Encana Oil & Gas (USA) Inc. as the Tax Reporting Partner ("TRP") is responsible for compliance with all tax reporting obligations of the Tax Partnership, see Sec. 3.1, below. In the event of any change in the TRP, the Party serving as TRP at the beginning of a given taxable year shall continue as TRP with respect to all matters concerning such year.

3. Income Tax Compliance and Capital Accounts

3.1. Tax Returns.

The TRP shall prepare and file all required Federal and State partnership income tax returns. Not less than thirty (30) days prior to the return due date (including extensions), the TRP shall submit to each Party for review a copy of the return as proposed.

3.2. Fair Market Value Capital Accounts.

The TRP shall establish and maintain for each Party a fair market value ("FMV") capital account and a tax basis capital account. Upon request, the TRP shall submit to each Party along with a copy of any proposed partnership income tax return an accounting of such Party's FMV capital account as of the end of the return period.

3.3. Information Requests.

In addition to any obligation under Sec. 2, each Party agrees to furnish to the TRP not later than sixty (90) days before the return due date (including extensions) such information relating to the operations conducted under the Agreement as may be required for the proper preparation of such returns. Similarly, each Party agrees to furnish timely to the TRP, as requested, any information and data necessary for the preparation and/or filing of other required reports and notifications, and for the computation of the capital accounts. As provided in Code §6050K(c), a Party transferring its interest must notify the TRP to allow compliance with Code §6050K(a) (see also Sec. 8.1).

3.4. Best Efforts Without Liability.

The TRP and the other Party shall use their best efforts to comply with responsibilities outlined in this Section, and with respect to the service as TRP as outlined Sec. 2, and in doing so shall incur no liability to any other Party.

3.5. Tax Matters Partner

The provisions of this Section 3.5 shall be applicable only if the Tax Partnership does not qualify for the "small partnership exception" from Subchapter C of Chapter 63 of Subtitle A (the "TEFRA rules") of the Internal Revenue Code of 1986, as amended (the "Code") or otherwise elects in Section 9.1 to be subject to the TEFRA Rules.
3.5.1 The TRP shall also be the Tax Matters Partner as defined in Code §6231(a) (the "TMP") and references to the TRP shall then include references to the TMP.
3.5.2 The TMP shall not be required to incur any expenses for the preparation for, or pursuance of, administrative or judicial proceedings, unless the Parties agree on a method for sharing such expenses.

3.5.3 The Parties shall furnish the TMP, within two weeks from the receipt of the request, the information the TMP may reasonably request to comply with the requirements on furnishing information to the Internal Revenue Service.
3.5.4 The TMP shall not agree to any extension of the statute of limitations for making assessments on behalf of the Tax Partnership without first obtaining the written consent of all Parties. The TMP shall not bind any other Party to a settlement agreement in tax audits without obtaining the written concurrence of any such Party.
3.5.5 Any Party who enters in a settlement agreement with the Secretary of the Treasury with respect to any "partnership items," as defined in Code §6231(a)(3), shall notify the other Parties of the terms within ninety (90) days from the date of such settlement.
3.5.6 If any Party intends to file a notice of inconsistent treatment under Code §6222(b), such Party shall, prior to the filing of such notice, notify the TMP of the (actual or potential) inconsistency of the Party's intended treatment of a partnership item with the treatment of that item by the Tax Partnership. Within one week of receipt the TMP shall remit copies of such notification to the other Parties. If an inconsistency notice is filed solely because a Party has not received a Schedule K- 1 in time for filing of its income tax return, the TMP need not be notified.
3.5.7 No Party shall file pursuant to Code §6227 a request for an administrative adjustment of partnership items (a "RFAA") without first notifying all other Parties. If all other Parties agree with the requested adjustment, the TMP shall file the RFAA on behalf of the Tax Partnership. If unanimous consent is not obtained within thirty (30) days from such notice, or within the period required to timely file the RFAA, if shorter, any Party, including the TMP, may file a RFAA on its own behalf.
3.5.8 Any Party intending to file with respect to any partnership item, or any other tax matter involving the Tax Partnership, a petition under Code § §6226, 6228, or any other provision, shall notify the other Parties prior to such filing of the nature of the contemplated proceeding. If the TMP is the Party intending to file such petition, such notice shall be given within a reasonable time to allow the other Parties to participate in the choice of the forum for such petition. If the Parties do not agree on the appropriate forum, then the forum shall be chosen by majority vote. Each Party shall have a vote in accordance with its percentage interest in the Tax Partnership for the year under audit. If a majority cannot agree, the TMP shall choose the forum. If a Party intends to seek review of any court decision rendered as a result of such proceeding, the Party shall notify the other Parties prior to seeking such review.

4. Tax and FMV Capital Account Elections

4.1. General Elections.

For both income tax return and capital account purposes, the Tax Partnership shall elect:
4.1.1. to deduct when incurred intangible drilling and development costs ("IDC");
4.1.2. to use the maximum allowable accelerated tax method and the shortest permissible tax life for depreciation;
4.1.3. the accrual method of accounting;
and the Tax Partnership shall also make any elections as specially noted in Sec. 9.1, below.

4.2. Depletion.

Solely for FMV capital account purposes, depletion shall be calculated by using simulated cost depletion within the meaning of Treas. Reg.§1.704-1(b)(2)(iv)(k)(2), unless the use of simulated percentage depletion is elected in Sec. 9.1, below. The simulated cost depletion allowance shall be determined under the principles of Code §612 and be based on the FMV capital account basis of each property. Solely for purposes of this calculation, remaining reserves shall be determined consistently by the TRP.

4.3. Election Out Under Code §761(a).

4.3.1. The Parties agree not to elect to be excluded from the application of Subchapter K of Chapter 1 of the Code. The TRP shall notify all Parties of an intended election to be excluded from the application of Subchapter K of Chapter 1 of the Code not later than sixty (60) days prior to the filing date or the due date (including extensions) for the Federal partnership income tax return, whichever comes earlier. Even after an effective election-out, the TRP's rights and obligations, other than the relief from tax return filing obligations of the Tax Partnership, shall continue.

4.3.2. After an election- out, to avoid an unintended impairment of the election- out: The Parties will avoid, without prior coordination, any operational changes which would terminate the qualification for the election- out status; all Parties will monitor the continuing qualification of the Tax Partnership for the election- out status and will notify the other Parties if, in their opinion, a change in operations will jeopardize the election-out; and, all Parties will use, unless agreed to by them otherwise, the cumulative gas balancing method as described in Treas. Reg. §1.761- 2(d)(3).

4.4. Consent Requirements For Subsequent Tax or FMV Capital Account Elections.

Future elections, in addition to or in amendment of those in this Exhibit, must be approved by the affirmative consent of the Parties.

5. CAPITAL CONTRIBUTIONS AND FMV CAPITAL ACCOUNTS

The provisions of this Sec. 5 and any other provisions of the TPPs relating to the maintenance of the capital accounts are intended to comply with Treas. Reg. §1.704- 1(b) and shall be interpreted and applied in a manner consistent with such regulations.

5.1. Capital Contributions.

The respective capital contributions of each Party to the Tax Partnership shall be (a) each Party's interest in the oil and gas lease(s), including all associated lease and well equipment, committed to the Tax Partnership, and (b) all amounts of money paid by each Party in connection with the acquisition, exploration, development, and operation of the lease(s), and all other costs characterized as contributions or expenses borne by such Party under the Agreement. The contribution of the leases and any other properties committed to the Tax Partnership shall be made by each Party's agreement to hold legal title to its interest in such leases or other property as nominee of the Tax Partnership.

5.2. FMV Capital Accounts.

The FMV capital accounts shall be increased and decreased as follows:

5.2.1. The FMV capital account of a Party shall be increased by:

(i) the amount of money and the FMV (as of the date of contribution) of any property contributed by such Party to the Tax Partnership (net of liabilities assumed by the Tax Partnership or to which the contributed property is subject);

(ii) that Party's share of Tax Partnership items of income or gain, allocated in accordance with Sec. 6.1; and
(iii) that Party's share of any Code §705(a)(1)(B) item.
5.2.2. The FMV capital account of a Party shall be decreased by:
(i) the amount of money and the FMV of property distributed to a Party (net of liabilities assumed by such Party or to which the property is subject);
(ii) that Party's Sec. 6.1 allocated share of Tax Partnership loss and deductions, or items thereof; and,
(iii) that Party's share of any Code §705(a)(2)(B) item.
5.2.3. "FMV" when it applies to property contributed by a Party to the Tax Partnership shall be assumed, for purposes of 5.2.1, to equal the adjusted tax basis, as defined in Code §1011, of that property unless the Parties agree otherwise as indicated in Sec. 9.1.
5.2.4. As provided in Treas. Reg. §1.704- 1(b)(2)(iv)(e*),* upon distribution of Tax Partnership property to a Party the capital accounts will be adjusted to reflect the manner in which the unrealized income, gain, loss and deduction inherent in distributed property (not previously reflected in the FMV capital accounts) would be allocated among the Parties if there were a taxable disposition of such property at its FMV as of the time of distribution. Furthermore, if so agreed to in Sec. 9.1, pursuant to the rules of Treas. Reg. § 1.704- 1(b)(2)(iv)(f*),* the FMV capital accounts shall be revalued at certain times to reflect value changes of the Tax Partnership property.

6. Partnership Allocations

6.1. FMV Capital Account Allocations.

Each item of income, gain, loss, or deduction shall be allocated to each Party as follows:
6.1.1. Actual or deemed income from the sale, exchange, distribution or other disposition of production shall be allocated to the Party entitled to such production or the proceeds from the sale of such production. The amount received from the sale of production and the amount of the FMV of production taken in kind by the Parties are deemed to be identical; accordingly, such items may be omitted from the adjustments made to the Parties' FMV capital accounts.
6.1.2. Exploration cost, IDC, operating and maintenance cost shall be allocated to each Party in accordance with its respective contribution, or obligation to contribute, to such cost.
6.1.3. Depreciation shall be allocated to each Party in accordance with its contribution, or obligation to contribute, to the cost of the underlying asset.
6.1.4. Simulated depletion shall be allocated to each Party in accordance with its FMV capital account adjusted basis in each oil and gas property of the Tax Partnership.

6.1.5. Loss (or simulated loss) upon the sale, exchange, distribution, abandonment or other disposition of depreciable or depletable property shall be allocated to the Parties in the ratio of their respective FMV capital account adjusted bases in the depreciable or depletable property.
6.1.6. Gain (or simulated gain) upon the sale, exchange, distribution, or other disposition of depreciable or depletable property shall be allocated to the Parties so that the FMV capital account balances of the Parties will most closely reflect their respective percentage or fractional interests in such property under the Agreement.
6.1.7. Costs or expenses of any other kind shall be allocated to each Party in accordance with its respective contribution, or obligation to contribute, to such costs or expense.
6.1.8. Any other income item shall be allocated to the Parties in accordance with the manner in which such income is realized by each Party.

6.2. Tax Return and Tax Basis Capital Account Allocations.

6.2.1. Unless otherwise expressly provided in this Sec. 6.2, the allocations of the Tax Partnership's items of income, gain, loss, or deduction for tax return and tax basis capital account purposes shall follow the principles of the allocations under Sec. 6.1. However, the Tax Partnership's gain or loss on the taxable disposition of a Tax Partnership property in excess of the gain or loss under Sec. 6.1, if any, is allocated to the contributing Party to the extent of such Party's pre- contribution gain or loss.
6.2.2. The Parties recognize that under Code §613A(c)(7)(D) the depletion allowance is to be computed separately by each Party. For this purpose, each Party's share of the adjusted tax basis in each oil and gas property shall be equal to its contribution to the adjusted tax basis of such property.
6.2.3. Under Code §613A(c)(7)(D) gain or loss on the disposition of an oil and gas property is to be computed separately by each Party. Pursuant to Treas. Reg. §1.704- 1(b)(4)(v), the amount realized shall be allocated as follows: (i) an amount that represents recovery of adjusted simulated depletion basis is allocated (without being credited to the FMV capital accounts) to the Parties in the same proportion as the aggregate simulated depletion basis was allocated to such Parties under Sec. 5.2; and (ii) any remaining realization is allocated in accordance with Sec. 6.1.6.
6.2.4. Depreciation shall be allocated to each Party in accordance with its contribution to the adjusted tax basis of the depreciable asset.
6.2.5. In accordance with Treas. Reg. §1.1245- 1(e), depreciation recapture shall be allocated, to the extent possible, among the Parties to reflect their prior sharing of the depreciation deductions.
6.2.6. In accordance with the principles of Treas. Reg. §1.1254- 5, any recapture of IDC shall be determined and reported by each Party separately. Similarly, any recapture of depletion shall be computed separately by each Party, in accordance with its depletion allowance computed pursuant to Sec. 6.2.2.
6.2.7. For Tax Partnership properties with FMV capital account values different from their adjusted tax bases the Parties intend that the allocations described in this Section 6.2 constitute a "reasonable method" of allocating gain or loss under Treas. Reg. §1.704- 3(a)(1).

6.2.8. Take- in- kind.
If checked "Yes" in Sec. 9.1, below, each Party has the right to determine the market for its proportionate share of production. All items of income, deductions, and credits arising from such marketing of production shall be recognized by the Tax Partnership and shall be allocated to the Party whose production is so marketed.

7. Termination and Liquidating Distribution

7.1. Termination of the Tax Partnership.

The Tax Partnership shall terminate upon the first to occur of (a) a deemed termination of the Tax Partnership pursuant to Section 708(b)(1)(A) of the Code, (b) the effectiveness of an election by the Parties to be excluded from the application of Subchapter K of Chapter 1 of the Code (if and when all the Parties affirmatively agree to make such an election) or (c) the occurrence of any other event which causes the Tax Partnership to terminate as a matter of law.
7.1.1. Upon termination, as provided in Code §708(b)(1)(A), the business shall be wound- up and concluded, and the assets shall be distributed to the Parties as described below by the end of such calendar year (or, if later, within ninety (90) days after the date of such termination). The assets shall be valued and distributed to the Parties in the order provided in Secs. 7.1.2, 7.5, and 7.7
7.1.2. First, all cash representing unexpended contributions by any Party and any property in which no interest has been earned by any other Party under the Agreement shall be returned to the contributor.

7.2. Balancing of FMV Capital Accounts.

Second, the FMV capital accounts of the Parties shall be determined as described hereafter. The TRP shall take the actions specified under Secs. 7.2 through 7.5 in order to cause the Parties' FMV capital accounts to reflect, to the maximum extent possible, their interests under the Agreement. These actions are hereafter referred to as the "balancing of the FMV capital accounts" and, when each Party's FMV capital account balance is equal to the fair market value of its interest under the Agreement, the FMV capital accounts of the Parties shall be referred to as "balanced."

7.3. Deemed Sale Gain/Loss Charge Back.

The FMV of all Tax Partnership properties shall be determined and the gain or loss for each property, which would have resulted if sold at such FMV, shall be allocated in accordance with Secs. 6.1.5 and 6.1.6. If each Party's FMV capital account balance following such allocation does not correspond to the fair market value of its respective interests under the Agreement, then income, gain, loss, and deduction for the taxable year in which the liquidation occurs shall be reallocated among the Parties to cause, to the maximum extent possible, the ratio of their positive FMV capital account balances to equal the fair market value of their respective interests under the Agreement.

7.4. Deficit Make- Up Obligation and Balancing Cash Contributions.

If hereafter a Party has a negative FMV capital account balance, that is a balance of less than zero, in accordance with Treas. Reg. §1.704-1(b)(2)(ii)(b)(3), such Party is obligated to contribute by the end of the taxable year or, if later, within 90 days from the Tax Partnership's liquidation, an amount of money to the Tax Partnership sufficient to achieve a zero balance FMV capital account (the "Deficit Make- Up Obligation"). Moreover, any Party may contribute an amount of cash to the Tax Partnership to facilitate the balancing of the FMV capital accounts. If after these adjustments the FMV capital accounts are not balanced, Sec. 7.5 shall apply.

7.5. Distribution to Balance Capital Accounts.

7.5.1. If the FMV capital accounts of the Parties are not balanced after the application of Sec. 7.3, (i) a Party may contribute cash in the amount required to cause its FMV capital account to be balanced, and/or (ii) if all Parties agree, any cash or an undivided interest in certain selected properties shall be distributed to any Party whose FMV capital account balance exceeds its interest in the fair market value of the Tax Partnership properties under the Agreement as necessary to cause, following such distribution, all FMV capital accounts to be balanced with respect to the remaining Tax Partnership properties.

7.5.2. Unless Sec.7.5.1 applies, an undivided interest in each and every property shall be distributed to one or more Parties in accordance with their FMV capital accounts.

7.6. FMV Determination.

If a property is to be valued for purposes of balancing the capital accounts and making a distribution under this Sec. 7, the Parties shall first attempt to agree on the FMV of the property; failing such an agreement, the TRP shall cause a nationally recognized independent engineering firm to prepare an appraisal of the FMV of such property.

7.7. Final Distribution.

After the FMV capital accounts of the Parties have been adjusted pursuant to Secs. 7.2 to 7.5, all remaining property and interests then held by the Tax Partnership shall be distributed to the Parties in accordance with their positive FMV capital account balances.

8. Transfers, Indemnification, and Correspondence

8.1. Transfer of Tax Partnership Interests.

Transfers of Tax Partnership interests shall be governed by the Agreement. A Party transferring its interest, or any part thereof, shall notify the TRP in writing within two (2) weeks after such transfer.

8.2. Farmouts, Distributions and Contributions to Other Partnerships.

If any Party wishes to sell, farm out or exchange a portion of any property with a third party or contribute its interest in a property to a partnership or tax partnership with a third party to the extent allowed under the Agreement, the other Parties shall not unreasonably withhold consent to distribute the property from the Tax Partnership to each Party in proportion to its interest in such property, and shall execute within 30 days such documents as are necessary to effect the distribution; provided that the Party participating in such sale, farm out, exchange or contribution shall fully compensate the other Party or Parties for any accelerated recognition of gain to such Party or Parties resulting from the distribution, including any gain recognized under Code §704(c)(1)(B) and Code §737.

8.3 Correspondence.

All correspondence relating to the preparation and filing of the Tax Partnership's income tax returns and capital accounts shall be sent to:

(Attach separate list, if necessary)

TRP Encana Oil & Gas (USA) Inc. 370 17th Street, Suite 1700 Denver, CO 80202	"Att to:" reference Tax Department
Nucor Energy Holdings Inc. 1915 Rexford Road Charlotte, NC 28211	Tax Department

9. Elections and Changes to above Provisions

9.1. Special Tax Elections.

With respect to Sec. 4.1, the Parties agree (if not agreed, insert "No"):

a) that the Tax Partnership shall elect to account for dispositions of depreciable assets under the general asset method to the extent permitted by Code §168(i)(4);	No
b) that the Tax Partnership shall elect under Code §754 to adjust the basis of Tax Partnership property, with the adjustments provided in Code §734 for a distribution of property and in Code §743 for a transfer of a partnership interest. In case of distribution of property the TRP shall adjust all tax basis capital accounts. In the case of a transfer of a partnership interest the acquiring party(ies) shall establish and maintain its (their) tax basis capital account(s);	Yes
c) that the Tax Partnership shall elect under Code §6231 to be subject to the TEFRA rules;	No
d) that the Tax Partnership shall elect under Code §709 to amortize over the shortest permissible period all deferred organizational expenses;	Yes
e) that the Tax Partnership shall elect under Code §195 to amortize over the shortest permissible period all deferred business start- up expenses;	Yes
f) with respect to Sec. 4.2, Depletion, the Parties agree that the Tax Partnership shall use simulated percentage depletion instead of simulated cost depletion;	No
g) with respect to Sec.5.2.4, under the rules of Treas. Reg. § 1.704- 1(b)(2)(iv)(f) the Parties agree that the FMV capital accounts shall be revalued to reflect value changes of the Tax Partnership property upon the occurrence of the events specified in (5)(i) through (iii) of said - 1(b)(2)(iv)(f) regulations;	Yes
h) with respect to Sec. 6.2.8, the income attributable to take- in- kind production will be reflected on the tax return.	No

With respect to Sec. 5.2.3, the FMV for the listed properties are determined on Schedule 5.2.3, which shall describe each property that becomes subject to the Agreement and the agreed fair market value of such property at the time it becomes subject to the Agreement.

Exhibit H

Attached to and made a part of the Operating Agreement executed October 31, 2012 but dated effective November 1, 2012, by and between, Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.

A. WELL INFORMATION AND NOTIFICATION REQUIREMENTS

Encana Oil & Gas (USA) Inc.

In the drilling of the above well(s), please furnish Nucor Energy Holdings Inc. with the following notices, reports and information:
Copies by mail or email:

1. Daily drilling reports by email
2. Location plat and drilling prognosis
3. Regulatory forms
4. DST reports, core analysis, etc.
5. Mud logs
6. Wireline log prints
7. Cased hole logs
8. Directional surveys
9. Daily completion reports by email
10. Production reports by email

Notify:

Mail: Nucor Energy Holdings Inc.
1915 Rexford Road
Charlotte, North Carolina 28211
Attention: Chief Financial Officer

Telephone: 704- 365- 1321

EXHIBIT I
MODEL FORM RECORDING SUPPLEMENT TO
OPERATING AGREEMENT AND FINANCING STATEMENT

THIS AGREEMENT, entered into by and between **Encana Oil & Gas (USA) Inc.** hereinafter referred to as "Operator," and the signatory party or parties other than Operator, hereinafter referred to individually as "Non- Operator," and collectively as "Non- Operators."

WHEREAS, the parties to this agreement executed that certain BJU Carry and Earning Agreement on **October 31, 2012 but dated** effective November 1, 2012 to jointly drill Carry and/or Head's Up Wells on lands identified on Exhibit "A" (said lands being hereinafter called the "Contract Area").

WHEREAS, the parties hereto executed an Operating Agreement on October 31, 2012 that is dated effective **November 1, 2012** (herein the "Operating Agreement"), covering the Contract Area for the purpose of exploring and developing such lands, Leases and Interests for Oil and Gas; and

WHEREAS, the parties hereto have executed this agreement for the purpose of imparting notice to all persons of the rights and obligations of the parties under the Operating Agreement and for the further purpose of perfecting those rights capable of perfection.

NOW, THEREFORE, in consideration of the mutual rights and obligations of the parties hereto, it is agreed as follows:

1. This agreement supplements the Operating Agreement, which Agreement in its entirety is incorporated herein by reference, and all terms used herein shall have the meaning ascribed to them in the Operating Agreement.

2. The parties do hereby agree that:

A. The Interests of the parties comprising the Contract Area shall be subject to and burdened with the terms and provisions of this agreement and the Operating Agreement, and the parties do hereby commit such Interests to the performance thereof.

B. The exploration and development of the Contract Area for Oil and Gas shall be governed by the terms and provisions of the Operating Agreement, as supplemented by this agreement.

C. All costs and liabilities incurred in operations under this agreement and the Operating Agreement shall be borne and paid, and all equipment and materials acquired in operations on the Contract Area shall be owned, by the parties hereto, as provided in the Operating Agreement.

D. Regardless of the record title ownership to the Interests identified on Exhibit "A," all production of Oil and Gas from the Contract Area shall be owned by the parties as provided in the Operating Agreement; provided nothing contained in this agreement shall be deemed an assignment or cross-assignment of interests covered hereby.

E. Each party shall pay or deliver, or cause to be paid or delivered, all burdens on its share of the production from the Contract Area as provided in the Operating Agreement.

F. An overriding royalty, production payment, net profits interest or other burden payable out of production hereafter created, assignments of production given as security for the payment of money and those overriding royalties, production payments and other burdens payable out of production heretofore created and defined as Subsequently Created Interests in the Operating Agreement shall be (i) borne solely by the party whose interest is burdened therewith, (ii) subject to suspension if a party is required to assign or relinquish to another party an interest which is subject to such burden, and (iii) subject to the lien and security interest hereinafter provided if the party subject to such burden fails to pay its share of expenses chargeable hereunder and under the Operating Agreement, all upon the terms and provisions and in the times and manner provided by the Operating Agreement.

G. The Interests which are subject hereto may not be assigned or transferred except in accordance with those terms, provisions and restrictions in the Operating Agreement regulating such transfers. This agreement and the Operating Agreement shall be binding upon and shall inure to the benefit of the parties hereto, and their respective heirs, devisees, legal representatives, and assigns, and the terms hereof shall be deemed to run with the or interests included within the Contract Area.

H. The parties shall have the right to acquire an interest in wells proposed to be abandoned, and interests to be relinquished as a result of non-participation in subsequent operations, all in accordance with the terms and provisions of the Operating Agreement.

I. The rights and obligations of the parties and the adjustment of interests among them in the event of a failure or loss of title, each party's right to propose operations, obligations with respect to participation in operations on the Contract Area and the consequences of a failure to participate in operations, the rights and obligations of the parties regarding the marketing of production, and the rights and remedies of the parties for failure to comply with financial obligations shall be as provided in the Operating Agreement.

J. Each party's interest under this agreement and under the Operating Agreement shall be subject to relinquishment for its failure to participate in subsequent operations and each party's share of production and costs shall be reallocated on the basis of such relinquishment, all upon the terms and provisions provided in the Operating Agreement.

K. All other matters with respect to exploration and development of the Contract Area and the ownership and transfer of the Interest therein shall be governed by the terms and provisions of the Operating Agreement.

3. The parties hereby grant reciprocal liens and security interests as follows:

A. Each party grants to the other parties hereto a lien upon any interest it now owns or hereafter acquires in Carry and/or Head's Up Wells in the Contract Area, and a security interest and/or purchase money security interest in any interest it now owns or hereafter acquires in the personal property and fixtures on or used or obtained for use in connection therewith, to secure performance of all of its obligations under this agreement, the Operating Agreement and the Carry and Earning Agreement, including but not limited to payment of expense, interest and fees, the proper Disbursement of all monies paid under this agreement, the BJU Carry and Earning Agreement and the Operating Agreement, the assignment or relinquishment of interest in Carry and/or Head's Up Wells as required under this agreement, the BJU Carry and Earning Agreement and the Operating Agreement, and the proper performance of operations under this agreement and the Operating Agreement. Such lien and security interest granted by each party hereto shall include such party's working interests in the Carry and/or Head's Up Wells now owned or hereafter acquired and in lands pooled or unitized therewith or otherwise becoming subject to this agreement, the BJU Carry and Earning Agreement and the Operating Agreement, the Oil and Gas when extracted therefrom and equipment situated thereon or used or obtained for use in connection therewith (including, without limitation, all wells, tools, and tubular goods), and accounts (including, without limitation, accounts arising from the sale of production at the wellhead), contract rights, inventory and general intangibles relating thereto or arising therefrom, and all proceeds and products of the foregoing.

B. Each party represents and warrants to the other parties hereto that the lien and security interest granted by such party to the other parties shall be a first and prior lien, and each party hereby agrees to maintain the priority of said lien and security interest against all persons acquiring an interest in Interests covered by this agreement, the BJU Carry and Earning Agreement and the Operating Agreement by, through or under such party. All parties acquiring an interest in Interests covered by this agreement, the BJU Carry and Earning Agreement and the Operating Agreement, whether by assignment, merger, mortgage, operation of law, or otherwise, shall be deemed to have taken subject to the lien and security interest granted by the Operating Agreement and this instrument as to all obligations attributable to such interest under this agreement, the BJU Carry and Earning Agreement and the Operating Agreement whether or not such obligations arise before or after such interest is acquired.

C. To the extent that the parties have a security interest under the Uniform Commercial Code of the state in which the Contract Area is situated, they shall be entitled to exercise the rights and remedies of a secured party under the Code to the extent provided by the BJU Carry and Earning Agreement and the Operating Agreement. . All purchasers of production may rely on a notification of default from the non- defaulting party or parties stating the amount due as a result of the default, and all parties waive any recourse available against purchasers for releasing production proceeds as provided in this paragraph.
Paragraphs D through G are intentionally omitted.
H. The above described security will be financed at the wellhead of the well or wells located on the Contract Area and this Recording Supplement may be filed in the land records in the County in which the Contract Area is located, and as a financing statement in all recording offices required under the Uniform Commercial Code or other applicable state statutes to perfect the above- described security interest, and any party hereto may file a continuation statement as necessary under the Uniform Commercial Code, or other state laws.
4. This agreement shall be effective as of the date of the Operating Agreement as above recited. Upon termination of this agreement and the Operating Agreement and the satisfaction of all obligations thereunder, Operator is authorized to file of record in all necessary recording offices a notice of termination, and each party hereto agrees to execute such a notice of termination as to Operator's interest, upon the request of Operator, if Operator has complied with all of its financial obligations.
5. This agreement, the BJU Carry and Earning Agreement and the Operating Agreement shall be binding upon and shall inure to the benefit of the parties hereto and their respective heirs, devisees, legal representatives, successors and assigns. No sale, encumbrance, transfer or other disposition shall be made by any party of any interest in the Interests subject hereto except as expressly permitted under the BJU Carry and Earning and the Operating Agreement and, if permitted, shall be made expressly subject to this agreement, the BJU Carry and Earning Agreement and the Operating Agreement and without prejudice to the rights of the other parties. If the transfer is permitted, the assignee of an ownership interest in any Interest shall be deemed a party to this agreement, the BJU Carry and Earning Agreement and the Operating Agreement as to the interest assigned from and after the effective date of the transfer of ownership; provided, however, that the other parties shall not be required to recognize any such sale, encumbrance, transfer or other disposition for any purpose hereunder until thirty (30) days after they have received a copy of the instrument of transfer or other satisfactory evidence thereof in writing from the transferor or transferee. No assignment or other disposition of interest by a party shall relieve such party of obligations previously incurred by such party under this agreement, the BJU Carry and Earning Agreement or the Operating Agreement with respect to the interest transferred, including without limitation the obligation of a party to pay all costs attributable to an operation conducted under this agreement, the BJU Carry and Earning Agreement and the Operating Agreement in which such party has agreed to participate prior to making such assignment, and the lien and security interest granted by Article VII.B. of the Operating Agreement and hereby, shall continue to burden the interest transferred to secure payment of any such obligation.
6. In the event of a conflict between the terms and provisions of this agreement and the terms and provisions of the Operating Agreement, then, as between the parties, the terms and provisions of the Operating Agreement shall control.
7. This agreement shall be binding upon each Non- Operator when this agreement or a counterpart thereof has been executed by such Non- Operator and Operator notwithstanding that this agreement is not then or thereafter executed by all of the parties to which it is tendered or which are listed on Exhibit "A" as owning an interest in the Contract Area or which own, in fact, an interest in the Contract Area. In the event that any provision herein is illegal or unenforceable, the remaining provisions shall not be affected, and shall be enforced as if the illegal or unenforceable provision did not appear herein.
8. Other provisions.
- NONE-
IN WITNESS WHEREOF, this agreement shall be effective as of the 1st day of November, 2012.

ATTEST OR WITNESS:

ENCANA OIL & GAS (USA) INC.
OPERATOR

_______________________ By _______________________

Ricardo D. Gallegos
VP, Bus. Dev. Negotiations
& Lead Rockies & Intl. Land

____

Date _______________________

ATTEST OR WITNESS:

NUCOR ENERGY HOLDINGS INC.
NON- OPERATOR

_______________________ By _______________________

____

Date _______________________

ACKNOWLEDGEMENTS

STATE OF COLORADO §
§
CITY AND COUNTY OF DENVER §

BEFORE ME, the undersigned authority, on this day personally appeared Ricardo D. Gallegos, VP, Bus. Dev. Negotiations & Lead Rockies & Intl. Land for ENCANA OIL & GAS (USA) INC., known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledged to me that he executed the same for the purposes and consideration therein expressed and in the capacity therein stated.

GIVEN UNDER MY HAND AND OFFICIAL SEAL OF OFFICE on this 1st day of November, 2012.

MY COMMISSION EXPIRES:

______________________________ ______________________________

Notary Public in and for the State of Colorado

STATE OF __________ §
§
COUNTY OF __________ §

BEFORE ME, the undersigned authority, on this day personally appeared ____________ for Nucor Energy Holdings Inc., known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledged to me that he executed the same for the purposes and consideration therein expressed and in the capacity therein stated.

GIVEN UNDER MY HAND AND OFFICIAL SEAL OF OFFICE on this 1st day of November, 2012

MY COMMISSION EXPIRES:

______________________________ ______________________________

Notary Public

EXHIBIT A

Attached to and made a part of that certain Model Form Recording Supplement to Operating Agreement and Financing Statement executed October 31, 2012 but dated effective November 1, 2012, by and between EnCana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.

I. DESCRIPTION OF CARRY WELLS AND HEAD'S UP WELLS SUBJECT TO THIS AGREEMENT

Carry Wells and Head's Up Wells drilled pursuant to the BJU Carry and Earning Agreement dated effective November 1, 2012 and Operating Agreement dated effective November 1, 2012 between the Parties in the following described sections:

Garfield County, Colorado

[***]

Rio Blanco County, Colorado

[***]

II. RESTRICTIONS AS TO DEPTHS, FORMATIONS, PREVIOUSLY EXISTING WELLS AND SUBSTANCES

Wellbore interest only in Carry Wells and/or Head's Up Wells designated and drilled pursuant to the BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012 between the Parties. All interests are limited in depth to the depth drilled in the applicable well, but not below the base of the Formation as defined in the BJU Carry and Earning Agreement, subject to Section 2.1 I of such agreement.

Article XVI. Other Provisions

Attached to and made a part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective as of November 1, 2012 by and between Encana Oil &Gas (USA) Inc. and Nucor Energy Holdings Inc.

A. **Other Provisions**. This Article XVI Other Provisions is attached to and made a part of that certain Operating Agreement (this "Agreement") executed October 31, 2012 but effective November 1, 2012, by and between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc. In the event of a conflict between the terms and conditions of this Article XVI and the terms and conditions of this Agreement, the terms and conditions of this Article XVI shall control and govern the point in conflict.

B. **BJU Carry and Earning Agreement**. This Agreement is subject to and burdened by the terms and conditions of that certain BJU Carry and Earning Agreement executed October 31, 2012 but effective November 1, 2012, between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc. (the "BJU Carry and Earning Agreement"). Except as otherwise defined herein, all capitalized terms shall have the meaning assigned to them in the BJU Carry and Earning Agreement. In the event of a conflict between the terms and conditions hereof and the terms and conditions of the BJU Carry and Earning Agreement: (i) during the term of the BJU Carry and Earning Agreement only, the terms and conditions of the BJU Carry and Earning Agreement shall control and govern the point in conflict; and (ii) after the expiration of the term of the BJU Carry and Earning Agreement, the terms and conditions of this Agreement shall control and govern the point in conflict.

C. **Conflicts**. If any of the Carry Wells or Head's Up Wells are subject to an existing operating agreement with a third party, such existing operating agreement shall control as to such third party. However, as between Nucor and Encana, this Agreement and the BJU Carry and Earning Agreement shall control. In the event of any conflict or inconsistency between the terms of this Agreement and the BJU Carry and Earning Agreement, the BJU Carry and Earning Agreement shall prevail to the extent of such conflict. If Nucor and/or Encana acquire the entire interest covered by an existing third party operating agreement, then such third party agreement shall be superseded and replaced in its entirety by this Agreement. Carry Wells and Head's Up Wells shall be designated under the BJU Carry and Earning Agreement. The Parties intend that this Agreement shall govern a Party's election to participate in subsequent operations on the Carry Wells. Head's Up Wells shall be proposed under the provisions of this Agreement, as modified by the provisions of Section 2.4 of the BJU Carry and Earning Agreement. Carry Wells and Head's Up Wells are defined in the BJU Carry and Earning Agreement.

D. **Burdens.** Notwithstanding anything in Article III.B and C of this Agreement to the contrary, with respect to the Carry Wells and Head's Up Wells, the burdens on the production shall be equal to and shall not exceed those in existence on the effective date of the BJU Carry and Earning Agreement; provided, however, that Nucor's interest in Carry Wells and Head's Up Wells shall be subject to no overriding royalties or other burdens on production owned by Encana or its Affiliates other than those shown on Schedule 5.2 to the BJU Carry and Earning Agreement and other than the royalty provided for in Section 2.1 H.(iv) of the BJU Carry and

Earning Agreement. If any Party receives acreage support for such Carry and/or Head's Up Well from a third party, the burdens shall include any burdens reserved by such third party, but the Party receiving such acreage support shall not reserve any additional burdens to itself burdening such acreage support.

After the Effective Date, if Encana or Nucor creates any additional burdens on the Property, the Party creating such additional burden shall be solely responsible for and shall pay such additional burden; provided however, that any mineral interest owned by Encana that is not subject to a lease will be subject to a royalty payable to Encana of 16.67%. Subject to the foregoing sentence, Encana shall make payment of all burdens affecting the Carry Wells and Head's Up Wells, and Nucor shall reimburse Encana for all burdens on the interest of Nucor.

E. **Operations.** Notwithstanding anything in Article V.B of this Agreement to the contrary, if the Operator of the Carry and/or Head's Up Wells sells, assigns or otherwise transfers its interest in the Carry and/or Head's Up Wells, such Operator's successor- in- interest to the Carry Wells and Head's Up Wells shall have the right to vote for itself and elect itself as successor Operator of the Carry Wells and Head's Up Wells.

F. **Definitions.** "Reworked" or "reworking", as used in this Agreement, shall include perforating, cleaning out, acidizing, fracturing, testing, completing (in the same horizon or in a deeper or shallower horizon), plugging back or any other operation for the purpose of restoring or increasing production which does not involve the drilling of an additional hole. In each instance in Articles VI.B. and VI.C. in which the term "deepen", "deeper drilling" or "deepening" are used, the same shall also mean "deepen, sidetrack", "deepened, sidetracked", or "deeper drilling, sidetracking" and "deepening, sidetracking".

G. **Well Requirements and Information** Operator agrees to furnish information to participating Non- Operator on a current basis, including but not limited to daily drilling reports, test reports, logs and all other related reports and data. Non- Operator has furnished Operator a list of geological requirements and information that Non- Operator requires, and such requirements and information are attached hereto as Exhibit H.

H. **Royalties, Overriding Royalties And Other Payments.** Operator shall use its reasonable best effort to pay or cause to be paid all royalties, shut-in royalties, minimum royalties, overriding royalties, payments out of production, or other amounts or charges which may be or become payable out of production and shall charge all such payments to the account of the Party or Parties responsible therefor. However, Operator shall never be liable for a standard of performance in making such payment or payments in excess of a reasonable good faith effort to pay same prior to the due date; and no liability is to be incurred for the failure to make payment within the time, in the manner and for the amounts due through error or omission of the employees or representatives of Operator.

I. **Shut- in Production.** Operator shall not shut- in Non- Operator's share of production from any Carry Well or a Head's Up Well for a period of more than 90 days or due solely to market conditions without Non- Operator's consent.

J. **Revision to Article V.D.: Rights and Duties of Operator.** Competitive Rates and Use of Affiliates: All wells drilled on the Contract Area shall be drilled on a competitive basis at the prevailing market rate for such operations as would be charged by a Third Party contractor in a bona fide arm's length transaction. If it so desires, Operator has the right to provide materials, equipment and services, either directly or indirectly or through Operator, or an affiliate of Operator, or a third party whose equipment was funded by the Operator or an Affiliate so long as the rates charged by Operator or any such Affiliate do not exceed the prevailing market rates in the area for comparable services and/or equipment as would be charged by a Third Party contractor in a bona fide arm's length transaction. Such work shall be performed by Operator under the same terms and conditions as are customary and usual in the area.

K. **Mutuality.** The Parties hereto acknowledge and declare that this Agreement is the result of extensive negotiations between themselves. Accordingly, in the event of any ambiguity in this Agreement, there shall be no presumption that this instrument was prepared solely by either Party hereto.

L. **Headings.** The heading of the several articles and sections of this Agreement are for convenience only, and shall not control or affect the meaning or construction of the terms and provisions hereof.

M. **Notice Of Recording Supplement.** The Parties hereto agree to execute a Recording Supplement in substantially the form attached hereto as Exhibit I to give notice of this Agreement to third parties, and to further create, secure, and perfect the liens and security interests provided by Article VII B. Such Notice may be filed of record at any time by any Party hereto. The Parties may execute additional Recording Supplements in order to accurately reflect the current properties covered by the Operating Agreement and the current working interests of the Parties.

N. **Dispute Resolution.** The Parties agree to resolve all disputes concerning or relating to this Agreement pursuant to the provisions of this Section XVI N. The Parties agree to submit all disputes to binding arbitration in Denver, Colorado. The arbitration will be conducted according to the procedure that follows. The arbitration proceedings shall be governed by Colorado law and shall be conducted in accordance with the rules for Non-Administered Arbitration of Business Disputes published by The Center for Public Resources, Inc., with discovery to be conducted in accordance with the Federal Rules of Civil Procedure, and with any disputes over the scope of discovery to be determined by the Arbitrators (as defined below). The arbitration shall be before a single Arbitrator chosen by the mutual agreement of the Parties, or if no agreement as to the identity of the Arbitrator can be reached within ten days, a three person panel of neutral Arbitrators, consisting of one person chosen by each Party, and the two Arbitrators so selected choosing the third. The panel so chosen or the single person are referred to herein as the "Arbitrators." The Arbitrators shall conduct a hearing no later than sixty (60) days after submission of the matter to arbitration, and the Arbitrators shall render a written decision within thirty (30) days of the hearing. At the hearing, the Parties shall present such evidence and witnesses as they may choose, with or without counsel. Adherence to formal rules of evidence shall not be required, but the Arbitrators shall consider any evidence and testimony that they determine to be relevant, in accordance with procedures that they determine to be appropriate. Any award entered in the arbitration shall be made by a written opinion stating the reasons and basis for the award made and any payment due pursuant to the arbitration shall be made within fifteen (15) days of the decision by the Arbitrators. The decision of the Arbitrators shall be binding on the Parties, final and non- appealable, and may be filed in a court of competent jurisdiction and may be enforced by either Party as a final judgment of such court. Each Party shall bear its own costs and expenses of the arbitration, provided, however, that the costs of employing the Arbitrators shall by shared equally by the Parties.

O. **TLQ Expenses.** Non- operator shall bear none of the capital costs for Operator's Temporary Living Quarters ("TLQ") located adjacent to the Big Jimmy Unit, but Non- operator shall bear its pro rata share of TLQ operating expenses, including, without limitation, electricity, gas, water, maintenance, food, staff and insurance.

P. **Water Disposal.** If disposal of Nucor's share of water used for Completion Operations or produced from the Contract Area ("Nucor Water") is required, Nucor shall pay its share of the costs of such disposal, including, but not limited to, transportation costs. If there is excess Nucor Water that is released from any dedication made by Nucor for disposal services, and Operator has sufficient capacity on the water facilities owned or leased by Operator (including, but not limited to, Operator's water facility at the Middle Fork Station and disposal wells owned or leased by Operator), then Operator shall dispose of Nucor Water in such facilities; provided, however, that Operator shall have no obligation to dispose of Nucor Water pro rata with any other water disposed of by Operator. If Operator disposes of Nucor Water by injection into a disposal well owned or leased by Operator, Nucor shall pay actual operating costs to transport and dispose of such Nucor Water, including, but not limited to, disposal fees, surface owner injection fees, and water treatment costs, plus $0.15 per bbl. In lieu of disposal of Nucor Water, Operator may, but shall not have any obligation to, use Nucor Water for completion operations for wells in which Nucor does not have an interest, and in such case, Nucor shall not be required to pay any operating costs to transport or dispose of such water nor the $0.15 per bbl injection fee. Beginning on January 1, 2014, and every year thereafter on such date, the $0.15 per bbl injection fee shall be adjusted by the percentage increase or decrease, if any, in the Consumer Price Index for All Urban Consumers ("CPI- U") between the immediately preceding December and the previous December; provided, however the injection fee shall never be less than $0.15. The percentage adjustment shall be calculated based upon the difference between the most recent calendar year and the previous calendar year, as published in the U.S. Department of Labor, Bureau of Labor Statistics. If the CPI- U ceases to be published, the parties shall use commercially reasonable efforts to negotiate a replacement index. The provisions of this paragraph are not intended to modify the provisions of the BJU Carry and Earning Agreement with respect to Nucor's obligation to pay the Nucor Cost Share.

END OF ARTICLE XVI

Schedule 2.2 A

[***]

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

Schedule 5.2

Attached to and made a part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective as of November 1, 2012
by and between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.

Agreement Number	Agreement Name	Effective Date	Legal Description	Encana's ORRI	Encana's RI
12987.000	USA COC 64805	6/1/2001	[***]	0.00000000	0.00000000
12988.000	USA COC 64806	6/1/2001	[***]	0.00000000	0.00000000
12989.000	USA COC 64815	6/1/2001	[***]	0.00000000	0.00000000
12989.000	USA COC 64815	6/1/2001	[***]	0.00000000	0.00000000
12989.000	USA COC 64815	6/1/2001	[***]	0.00000000	0.00000000
12990.000	USA COC 64804	6/1/2001	[***]	0.00000000	0.00000000
12992.000	USA COC 64836	6/1/2001	[***]	0.00000000	0.00000000
12992.000	USA COC 64836	6/1/2001	[***]	0.00000000	0.00000000
12995.000	USA COC 64835	6/1/2001	[***]	0.00000000	0.00000000
12996.000	USA COC 64807	6/1/2001	[***]	0.00000000	0.00000000
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000

[***] This confidential information has been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.

Schedule 5.2
Attached to and made a part of the BJU Carry and Earning Agreement executed October 31, 2012 but effective as of November 1, 2012
by and between Encana Oil & Gas (USA) Inc. and Nucor Energy Holdings Inc.

Agreement Number	Agreement Name	Effective Date	Legal Description	Encana's ORRI	Encana's RI
12997.000	USA COC 64814	6/1/2001	[***]	0.00000000	0.00000000
12998.000	USA COC 64834	6/1/2001	[***]	0.00000000	0.00000000
12998.000	USA COC 64834	6/1/2001	[***]	0.00000000	0.00000000
12999.000	USA COC 64820	6/1/2001	[***]	0.00000000	0.00000000
13000.000	USA COC 64821	6/1/2001	[***]	0.00000000	0.00000000
13410.000	USA COC 65563	12/1/2001	[***]	0.00000000	0.00000000
13410.000	USA COC 65563	12/1/2001	[***]	0.00000000	0.00000000
13411.000	USA COC 65557	12/1/2001	[***]	0.00000000	0.00000000
13411.000	USA COC 65557	12/1/2001	[***]	0.00000000	0.00000000
13412.000	USA COC 65556	12/1/2001	[***]	0.00000000	0.00000000
13412.000	USA COC 65556	12/1/2001	[***]	0.00000000	0.00000000
13413.000	USA COC 65555	12/1/2001	[***]	0.00000000	0.00000000
13413.000	USA COC 65555	12/1/2001	[***]	0.00000000	0.00000000
13413.000	USA COC 65555	12/1/2001	[***]	0.00000000	0.00000000
13413.000	USA COC 65555	12/1/2001	[***]	0.00000000	0.00000000
13414.000	USA COC 65574	12/1/2001	[***]	0.00000000	0.00000000
13415.000	USA COC 65573	12/1/2001	[***]	0.00000000	0.00000000

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13416.000	USA COC 65571	12/1/2001	[***]	0.00000000	0.00000000
13417.000	USA COC 65570	12/1/2001	[***]	0.00000000	0.00000000
13418.000	USA COC 65569	12/1/2001	[***]	0.00000000	0.00000000
13419.000	USA COC 65568	12/1/2001	[***]	0.00000000	0.00000000
13422.000	USA COC 65565	12/1/2001	[***]	0.00000000	0.00000000
13423.000	USA COC 65564	12/1/2001	[***]	0.00000000	0.00000000
13424.000	USA COC 65562	12/1/2001	[***]	0.00000000	0.00000000
13425.000	USA COC 65561	12/1/2001	[***]	0.00000000	0.00000000
13426.000	USA COC 65559	12/1/2001	[***]	0.00000000	0.00000000
13426.000	USA COC 65559	12/1/2001	[***]	0.00000000	0.00000000
13432.000	USA COC 65771	4/1/2002	[***]	0.00000000	0.00000000
13432.000	USA COC 65771	4/1/2002	[***]	0.00000000	0.00000000

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14802.000	USA COC 56835	9/1/1994	[***]	0.00000000	0.00000000
14802.000	USA COC 56835	9/1/1994	[***]	0.00000000	0.00000000
14802.000	USA COC 56835	9/1/1994	[***]	0.00000000	0.00000000
14806.000	USA COC 56834	11/1/1994	[***]	0.00000000	0.00000000
15002.000	USA COC 64833	6/1/2001	[***]	0.00000000	0.00000000
15002.000	USA COC 64833	6/1/2001	[***]	0.00000000	0.00000000
15084.000	USA COC 60751	10/1/1997	[***]	0.00000000	0.00000000
15085.000	USA COC 60752	10/1/1997	[***]	0.00000000	0.00000000
15085.000	USA COC 60752	10/1/1997	[***]	0.00000000	0.00000000
15085.000	USA COC 60752	10/1/1997	[***]	0.00000000	0.00000000
15283.000	USA COC 58684	9/1/1997	[***]	0.00000000	0.00000000
15283.000	USA COC 58684	9/1/1997	[***]	0.00000000	0.00000000
15283.000	USA COC 58684	9/1/1997	[***]	0.00000000	0.00000000
15619.000	EXXON MOBIL CORPORATION	11/1/2002	[***]	0.00000000	0.00000000
15619.000	EXXON MOBIL CORPORATION	11/1/2002	[***]	0.00000000	0.00000000
15619.000	EXXON MOBIL CORPORATION	11/1/2002	[***]	0.00000000	0.00000000
23513.000	USA COC 64832	6/1/2001	[***]	0.00000000	0.00000000

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23521.000	USA COC 66587	3/1/2003	[***]	0.00000000	0.00000000
23549.000	USA COC 66809	6/1/2001	[***]	0.00000000	0.00000000
23552.000	USA COC 57683	3/1/1995	[***]	0.00000000	0.00000000
23553.000	USA COC 57685	3/1/1995	[***]	0.00000000	0.00000000
23553.000	USA COC 57685	3/1/1995	[***]	0.00000000	0.00000000
23554.000	USA COC 50268	11/1/1989	[***]	0.00250000	0.00000000
23554.000	USA COC 50268	11/1/1989	[***]	0.00250000	0.00000000
23554.000	USA COC 50268	11/1/1989	[***]	0.00250000	0.00000000
23554.000	USA COC 50268	11/1/1989	[***]	0.00250000	0.00000000
23554.000	USA COC 50268	11/1/1989	[***]	0.00250000	0.00000000
23555.000	USA COC 56828	11/1/1994	[***]	0.02750001	0.00000000
23559.000	USA COC 65560	12/1/2001	[***]	0.02750001	0.00000000
23608.000	USA COC 50950	2/1/1990	[***]	0.02750001	0.00000000
23608.000	USA COC 50950	2/1/1990	[***]	0.02750001	0.00000000
23609.000	USA COC 57687	3/1/1995	[***]	0.02750001	0.00000000

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23609.000	USA COC 57687	3/1/1995	[***]	0.02750001	0.00000000
23610.000	USA COC 61717	6/1/1998	[***]	0.01096563	0.00000000
23610.000	USA COC 61717	6/1/1998	[***]	0.01096563	0.00000000
23610.000	USA COC 61717	6/1/1998	[***]	0.02750001	0.00000000
23611.000	USA COC 57965	6/1/1995	[***]	0.01083302	0.00000000
23612.000	USA COC 57966	6/1/1995	[***]	0.02750001	0.00000000
23612.000	USA COC 57966	6/1/1995	[***]	0.02750001	0.00000000
23613.000	USA COC 57967	6/1/1995	[***]	0.01083302	0.00000000
23614.000	USA COC 57969	6/1/1995	[***]	0.01083302	0.00000000
23614.000	USA COC 57969	6/1/1995	[***]	0.01083302	0.00000000
23615.000	USA COC 57970	6/1/1995	[***]	0.01083302	0.00000000
23615.000	USA COC 57970	6/1/1995	[***]	0.01083302	0.00000000
23616.000	USA COC 57972	6/1/1995	[***]	0.01083302	0.00000000
23617.000	USA COC 57973	6/1/1995	[***]	0.01083302	0.00000000
23618.000	USA COC 57975	6/1/1995	[***]	0.01083302	0.00000000
23619.000	USA COC 57976	6/1/1995	[***]	0.01083302	0.00000000
23620.000	USA COC 59138	6/1/1996	[***]	0.01083302	0.00000000
23621.000	USA COC 50267	9/1/1989	[***]	0.01375000	0.00000000
23621.000	USA COC 50267	9/1/1989	[***]	0.00250000	0.00000000
23621.000	USA COC 50267	9/1/1989	[***]	0.00250000	0.00000000

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23621.000	USA COC 50267	9/1/1989	[***]	0.00250000	0.00000000
23622.000	USA COC 56829	9/1/1994	[***]	0.02750001	0.00000000
23623.000	USA COC 60729	10/1/1997	[***]	0.01096563	0.00000000
23623.000	USA COC 60729	10/1/1997	[***]	0.01096563	0.00000000
23623.000	USA COC 60729	10/1/1997	[***]	0.02750001	0.00000000
23624.000	SHELL FRONTIER OIL & GAS	6/1/1998	[***]	0.00666668	0.16666667
23624.000	SHELL FRONTIER OIL & GAS	6/1/1998	[***]	0.01083302	0.16666667
23624.000	SHELL FRONTIER OIL & GAS	6/1/1998	[***]	0.01083302	0.16666667
23624.000	SHELL FRONTIER OIL & GAS	6/1/1998	[***]	0.01083302	0.16666667
23624.000	SHELL FRONTIER OIL & GAS	6/1/1998	[***]	0.01083302	0.16666667
28301.000	USA COC 67779	2/1/2005	[***]	0.00000000	0.00000000
28302.000	USA COC 67781	2/1/2005	[***]	0.00000000	0.00000000
28303.000	USA COC 67780	2/1/2005	[***]	0.00000000	0.00000000
28352.000	USA COC 61138	1/1/1998	[***]	0.00000000	0.00000000
28352.000	USA COC 61138	1/1/1998	[***]	0.00000000	0.00000000
28352.000	USA COC 61138	1/1/1998	[***]	0.00000000	0.00000000

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28353.000	USA COC 61137	1/1/1998	[***]	0.00000000	0.00000000
28353.000	USA COC 61137	1/1/1998	[***]	0.00000000	0.00000000
28354.000	USA COC 61136	1/1/1998	[***]	0.00000000	0.00000000
28355.000	USA COC 61129	1/1/1998	[***]	0.00000000	0.00000000
28356.000	USA COC 69620	1/1/1998	[***]	0.00000000	0.00000000
28357.000	USA COC 61461	4/1/1998	[***]	0.00000000	0.00000000
28358.000	USA COC 62562	4/1/1999	[***]	0.00000000	0.00000000
28360.000	USA COC 68711	12/1/2001	[***]	0.00000000	0.00000000
28369.000	USA COC 61460	4/1/1998	[***]	0.00000000	0.00000000
28370.000	USA COC 61459	4/1/1998	[***]	0.00000000	0.00000000
28373.000	USA COC 69557	12/1/2001	[***]	0.00000000	0.00000000
28373.000	USA COC 69557	12/1/2001	[***]	0.00000000	0.00000000
28374.000	USA COC 67295	4/1/1978	[***]	0.07500000	0.00000000
28375.000	USA COC 60728	10/1/1997	[***]	0.00000000	0.00000000
28376.000	USA COC 64819	6/1/2001	[***]	0.00000000	0.00000000
28377.000	USA COC 62808	6/1/1999	[***]	0.00000000	0.00000000
28378.000	USA COC 62803	6/1/1999	[***]	0.00000000	0.00000000

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28379.000	USA COC 60749	10/1/1997	[***]	0.00000000	0.00000000
28380.000	USA COC 60727	10/1/1997	[***]	0.00000000	0.00000000
28381.000	USA COC 63811	6/1/1995	[***]	0.00000000	0.00000000
28386.000	EXXON MOBIL CORPORATION	9/1/2005	[***]	0.00000000	0.00000000
28386.000	EXXON MOBIL CORPORATION	9/1/2005	[***]	0.00000000	0.00000000
28388.000	USA COC 69590	6/1/2001	[***]	0.00000000	0.00000000
28388.000	USA COC 69590	6/1/2001	[***]	0.00000000	0.00000000
28432.000	USA COC 70653	6/1/2001	[***]	0.00000000	0.00000000
28432.000	USA COC 70653	6/1/2001	[***]	0.00000000	0.00000000
36115.000	USA COC 69593	6/1/2001	[***]	0.00000000	0.00000000
36117.000	USA COC 70626	1/1/1953	[***]	0.00000000	0.00000000
36230.000	EXXON MOBIL CORPORATION	9/1/2009	[***]	0.00000000	0.00000000

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Exhibit 12
Nucor Corporation
2012 Form 10- K

Computation of Ratio of Earnings to Fixed Charges

	Year- ended December 31,				
	2008	2009	2010	2011	2012
	(In thousands, except ratios)				
Earnings					
Earnings/(loss) before income taxes and noncontrolling interests	$ 3,104,391	$ (413,978)	$ 267,115	$ 1,251,812	$ 852,940
Plus: losses from equity investments	36,920	82,341	32,082	10,043	13,323
Plus: fixed charges (includes interest expense and amortization of bond issuance costs and settled swaps and estimated interest on rent expense)	146,360	168,317	163,626	183,541	179,169
Plus: amortization of capitalized interest	300	962	2,332	2,724	2,550
Plus: distributed income of equity investees	20,117	7,373	4,923	3,883	9,946
Less: interest capitalized	(10,020)	(16,390)	(940)	(3,509)	(4,715)
Less: pre- tax earnings in noncontrolling interests in subsidiaries that have not incurred fixed charges	(314,277)	(57,865)	(73,110)	(83,591)	(88,507)
Total earnings/(loss) before fixed charges	$ 2,983,791	$ (229,240)	$ 396,028	$ 1,364,903	$ 964,706
Fixed charges					
Interest cost and amortization of bond issuance and settled swaps	$ 144,845	$ 166,313	$ 162,213	$ 182,321	$ 178,218
Estimated interest on rent expense	1,515	2,004	1,413	1,220	951
Total fixed charges	$ 146,360	$ 168,317	$ 163,626	$ 183,541	$ 179,169
Ratio of earnings to fixed charges	20.39	*	2.42	7.44	5.38

* Earnings for the year ended December 31, 2009 were inadequate to cover fixed charges. The coverage deficiency was $397,557.

FINANCIAL HIGHLIGHTS

(dollar and share amounts in thousands, except per share data)

	2012	2011	% CHANGE
FOR THE YEAR			
Net sales	$19,429,273	$20,023,564	- 3%
Earnings:			
Earnings before income taxes and noncontrolling interests	852,940	1,251,812	- 32%
Provision for income taxes	259,814	390,828	- 34%
Net earnings	593,126	860,984	- 31%
Earnings attributable to noncontrolling interests	88,507	82,796	7%
Net earnings attributable to Nucor stockholders	504,619	778,188	- 35%
Per share:			
Basic	1.58	2.45	- 36%
Diluted	1.58	2.45	- 36%
Dividends declared per share	1.4625	1.4525	1%
Percentage of net earnings to net sales	2.6% 6.7%	3.9% 10.7%	

Return on average stockholders' equity			
Capital expenditures	1,019,334	450,627	126%
Depreciation	534,010	522,571	2%
Acquisitions (net of cash acquired)	760,833	3,959	*not meaningful*
Sales per employee	906	974	- 7%
AT YEAR END			
Working capital	$ 3,631,796	$ 4,312,022	- 16%
Property, plant and equipment, net	4,283,056	3,755,604	14%
Long- term debt (including current maturities)	3,630,200	4,280,200	- 15%
Total Nucor stockholders' equity	7,641,571	7,474,885	2%
Per share	24.06	23.60	2%
Shares outstanding	317,663	316,749	-
Employees	22,200	20,800	7%

FORWARD- LOOKING STATEMENTS Certain statements made in this annual report are forward- looking statements that involve risks and uncertainties. The words "believe," "expect," "project," "will," "should" and similar expressions are intended to identify those forward- looking statements. These forward- looking statements reflect the Company's best judgment based on current information, and although we base these statements on circumstances that we believe to be reasonable when made, there can be no assurance that future events will not affect the accuracy of such forward-looking information. As such, the forward- looking statements are not guarantees of future performance, and actual results may vary materially from the projected results and expectations discussed in this report. Factors that might cause the Company's actual results to differ materially from those anticipated in forward- looking statements include, but are not limited to: (1) the sensitivity of the results of our operations to prevailing steel prices and changes in the supply and cost of raw materials, including pig iron, iron ore and scrap steel; (2) availability and cost of electricity and natural gas; (3) market demand for steel products, which, in the case of many of our products, is driven by the level of nonresidential construction activity in the U.S.; (4) competitive pressure on sales and pricing, including pressure from imports and substitute materials; (5) impairment in the recorded value of goodwill, equity investments, inventory, fixed assets or other long- lived assets; (6) uncertainties surrounding the global economy, including the severe economic downturn in construction markets and excess world capacity for steel production; (7) fluctuations in currency conversion rates; (8) U.S. and foreign trade policies affecting steel imports or exports; (9) significant changes in laws or government regulations affecting environmental compliance, including legislation and regulations that result in greater regulation of greenhouse gas emissions, which could increase our energy costs and our capital expenditures and operating costs; (10) the cyclical nature of the steel industry; (11) capital investments and their impact on our performance; and (12) our safety performance.

02 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

MACROECONOMIC CONDITIONS

After four years of recession, the worst the United States has experienced in decades, we still do not see any real and sustained signs of a full recovery. The pace and degree of the economic recovery can be characterized as anemic at best. Our nation's unemployment rate remains high due to the loss of millions of jobs during the recession, the slow pace of the recovery and the uncertainty surrounding domestic fiscal policies. In some sectors of the economy, particularly housing and nonresidential construction, the recovery has been modest at best. Employment is not expected to regain the peak reached during the most recent economic cycle for several more years. Until a stronger job recovery takes hold, consumer confidence and spending will be inconsistent, indirectly negatively affecting demand for our products. Macro- level uncertainties in world markets will almost certainly continue to weigh on global and domestic growth in 2013. We believe our net sales and financial results will be stronger in 2013 than in 2012, but they will continue to be adversely affected by these general economic factors as well as by the conditions specific to the steel industry that are described below.

CONDITIONS IN THE STEEL INDUSTRY

The steel industry has always been cyclical in nature, but North American producers of steel and steel products have been facing and are continuing to face some of the most challenging market conditions they have experienced in decades. The average capacity utilization rate of U.S. steel mills was at a historically unprecedented low of 52% in 2009. Since then, the average capacity utilization rate increased to approximately 75% in both 2012 and 2011. These rates, though improved, still compare unfavorably to capacity utilization rates of 81% and 87% in 2008 and 2007, respectively. As domestic demand for steel and steel products is expected to improve only slightly in 2013, it is unlikely that average capacity utilization rates will increase significantly. The average utilization rates of all operating facilities in our steel mills, steel products and raw materials segments were approximately 74%, 60% and 63%, respectively, in 2012, compared with 74%, 57% and 70% respectively, in 2011.

The steel industry has also historically been characterized by overcapacity and intense competition for sales among producers. This aspect of the industry remains true today despite the bankruptcies of numerous domestic steel companies and ongoing global steel industry consolidation. The recent addition of new production capacity in the United States, as well as the very rapid and extraordinary increase in China's total production of steel in the last decade, have exacerbated this overcapacity issue domestically as well as globally.

Imports of steel increased approximately 17% in 2012 and continued to significantly affect our domestic markets. Imported steel and steel products continue to present unique challenges for us because foreign producers often benefit from government subsidies, either directly through government- owned enterprises or indirectly through government- owned or controlled financial institutions. Foreign imports accounted for approximately 24% of the U.S. steel market in 2012. In particular, competition from China, the world's largest producer and exporter of steel, which produces more than 45% of the steel produced globally, is a major challenge. Chinese producers, many of which are government- owned in whole or in part, continue to benefit from their government's manipulation of foreign currency exchange rates and from the receipt of government subsidies, which allows them to sell steel into our markets at artificially low prices. China is not only selling steel at artificially low prices into our domestic market but also across the globe. When they do so, steel products which would otherwise have been consumed by the local steel customers in other countries are displaced into global markets, which compounds the issue. In a more indirect manner, but still significant, is the import of fabricated steel products, such as oil country tubular goods, wind towers and other construction components that were produced in China.

OUR CHALLENGES AND RISKS

Sales of many of our products are dependent upon capital spending in the nonresidential construction markets in the United States, including in the industrial and commercial sectors, as well as capital spending on infrastructure that is publicly funded such as bridges, schools, prisons and hospitals. Unlike recoveries from past recessions, the recovery from the recession of 2008- 2009 has not included a strong recovery in the severely depressed nonresidential construction market. In fact, capital spending on nonresidential construction projects continues to show little, if any, strength, posing a significant challenge to our business. We do not expect to see strong growth in our net sales until we see a sustained increase in capital spending on these types of construction projects.

Artificially cheap exports by some of our major foreign competitors to the United States and elsewhere reduce our net sales and adversely impact our financial results. Direct steel imports in 2012 accounted for a 24% share of the U.S. market despite significant unused domestic steelmaking capacity. Aggressive enforcement of trade rules by the World Trade Organization

(WTO) to limit unfairly traded imports remains uncertain, although it is critical to our ability to remain competitive. We have been encouraged by recent actions the United States government has taken before the WTO to challenge some of China's trade practices as violating world trade rules, and we continue to believe that assertive enforcement of world trade rules must be one of the highest priorities of the United States government.

A major uncertainty we continue to face in our business is the price of our principal raw material, ferrous scrap, which is volatile and often increases rapidly in response to changes in domestic demand, unanticipated events that decrease the flow of scrap into scrap yards and increased foreign demand for scrap. Increasing our prices for the products we sell quickly enough to offset increases in the prices we pay for ferrous scrap is challenging but critical to maintaining our profitability. We attempt to manage this risk via a raw material surcharge mechanism, which our customers understand is a necessary response by us to the market forces of supply and demand for our raw materials. The surcharge mechanism functions to offset changes in prices of our raw materials and is based upon widely available market indices for prices of scrap and other raw materials. We monitor changes in those indices closely and make adjustments as needed, generally on a monthly basis, to our surcharges and sometimes directly to the selling prices for our products. The surcharges are determined from a base scrap price and can differ by product. To help mitigate the scrap price risk, we also aim to manage scrap inventory levels at the steel mills to match the anticipated demand over the next several weeks for various steel products. Certain scrap substitutes, including pig iron, have longer lead times for delivery than scrap. Our raw material surcharge mechanism works best when demand for the affected products ranges from stable to strong. Then, we are generally able to pass through relatively quickly the increased costs of ferrous scrap and scrap substitutes and protect our gross margins from significant erosion. The surcharge mechanism can be less effective when the demand for our products is weak.

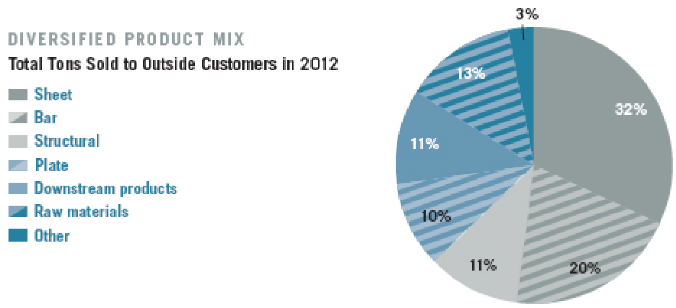
Although the majority of our steel sales are to spot market customers who place their orders each month based on their business needs and our pricing competitiveness compared to both domestic and global producers and trading companies, we also sell contract tons, primarily in our sheet operations. Slightly more than 55% of our sheet sales were to contract customers in 2012 (50% and 40% in 2011 and 2010, respectively), with the balance in the spot market at the prevailing prices at the time of sale. Steel contract sales outside of our sheet operations are not significant. The amount of tons sold to contract customers depends on the overall market conditions at the time, how the end- use customers see the market moving forward and the strategy that Nucor management believes is appropriate to the upcoming period. Nucor management considerations include maintaining an appropriate balance of spot and contract tons based on market projections and appropriately supporting our diversified customer base. The percentage of tons that is placed under contract also depends on the overall market dynamics and customer negotiations. In years of strengthening demand, we typically see an increase in the percentage of sheet sales sold under contract as our customers have an expectation that transaction prices will rapidly rise and available capacity will quickly be sold out. To mitigate this risk, customers prefer to enter into contracts in order to obtain committed volumes of supply from the mills. Our contracts include a method of adjusting prices on a periodic basis to reflect changes in the market pricing for steel and/or scrap. Market indices for steel generally trend with scrap pricing changes. Since the selling price adjustments are not immediate, there will always be a timing difference between changes in the prices we pay for raw materials and the adjustments we make to our contract selling prices. Generally, in periods of increasing scrap prices, we experience a short- term margin contraction on contract tons. Conversely, in periods of decreasing scrap prices, we typically experience a short- term margin expansion. Contract sales typically have terms ranging from six to twelve months.

Another significant uncertainty we face is the cost of energy. The availability and prices of electricity and natural gas are influenced today by many factors including changes in supply and demand, advances in drilling technology and, increasingly, by changes in public policy relating to energy production and use. Proposed regulation of greenhouse gas emissions from new and refurbished power plants could increase our cost of electricity in future years, particularly if they are adopted in a form that requires deep reductions in greenhouse gas emissions. Adopting these regulations in an onerous form could lead to foreign producers that are not affected by them gaining a competitive advantage over us. We are monitoring these regulatory developments closely and will seek to educate public policy makers during the adoption process about their potential impact on our business.

Finally, due to our natural gas working interest drilling programs with Encana, a substantial or extended decline in natural gas prices could have a material adverse effect on these programs and, by extension, us. A substantial or extended decline in the price of natural gas could result in a delay or cancellation of existing or future drilling programs or curtailment in production at some properties, all of which could have an adverse effect on our revenues, profitability and cash flows. In addition, natural gas drilling and production are subject to intense federal and state regulation as well as to public interest in environmental protection. Such regulation and interest, when coupled, could result in these drilling programs being forced to comply with certain unknown regulations in the future, resulting in unknown impacts on the programs' ability to achieve the cost and hedge benefits we expect from the programs.

OUR STRENGTHS AND OPPORTUNITIES

We are North America's most diversified steel producer. As a result, our short- term performance is not tied to any one market. The pie chart below shows the diversity of our product mix by total tons sold to outside customers in 2012.



Our highly variable cost structure, combined with our financial strength and liquidity, has allowed us to succeed in cyclical severely depressed steel industry market conditions in the past. In such times, our incentive- based pay system reduces our payroll costs, both hourly and salary, which helps to offset lower selling prices. Our pay- for- performance system that is closely tied to our levels of production also allows us to keep our work force intact and to continue operating our facilities when some of our competitors with greater fixed costs are forced to shut down some of their facilities. Because we use electric arc furnaces to produce our steel, we can easily vary our production levels to match short- term changes in demand, unlike our integrated competitors. We believe these strengths have given us opportunities to gain market share during such times.

EVALUATING OUR OPERATING PERFORMANCE

We report our results of operations in three segments: steel mills, steel products and raw materials. Most of the steel we produce in our mills is sold to outside customers, but a significant percentage is used internally by some of the facilities in our steel products segment. We begin measuring our performance by comparing our net sales, both in total and by individual segment, during a reporting period with our net sales in the corresponding period in the prior year. In doing so, we focus on changes in and the reasons for such changes in the two key variables that have the greatest influence on our net sales, average sales price per ton during the period and total tons shipped to outside customers.

We also focus on both dollar and percentage changes in gross margins, which are key drivers of our profitability, and the reasons for such changes. There are many factors from period to period that can affect our gross margins. One consistent area of focus for us is changes in "metal margins," which is the difference between the selling price of steel and the cost of scrap and scrap substitutes. Increases in the cost of scrap and scrap substitutes that are not offset by increases in the selling price of steel can quickly compress our margins and reduce our profitability.

Another factor affecting our gross margins in any given period is the application of the last- in, first- out (LIFO) method of accounting to a substantial portion of our inventory (45% of total inventories as of December 31, 2012). LIFO charges or credits for interim periods are based on management's interim period- end estimates, after considering current and anticipated market conditions, of both inventory costs and quantities at fiscal year end. The actual year end amounts may differ significantly from these estimated interim amounts. Annual LIFO charges or credits are largely based on the relative changes in cost and quantities year over year, primarily with raw material inventory in the steel mills segment.

Because we are such a large user of energy, material changes in energy costs per ton can significantly affect our gross margins as well. Lower energy costs per ton increase our gross margins. Generally, our energy costs per ton are lower when the average utilization rates of all operating facilities in our steel mills segment are higher.

Changes in marketing, administrative and other expenses, particularly profit sharing costs, can have a material effect on our results of operations for a reporting period as well. Profit sharing costs vary significantly from period to period as they are based upon changes in our pre- tax earnings and are a reflection of our pay- for- performance system that is closely tied to our levels of production.

EVALUATING OUR FINANCIAL CONDITION

We evaluate our financial condition each reporting period by focusing primarily on the amounts of and reasons for changes in cash provided by operating activities, our current ratio, the turnover rate of our accounts receivable and inventories, the amount and reasons for changes in cash used in investing activities, the amount and reasons for changes in cash provided by financing activities and our cash and cash equivalents and short- term investments position at period end. Our conservative financial practices have served us well in the past and are serving us well today. As a result, our financial position remains strong despite the negative effects on our business of the continued weakness in the domestic and global economies.

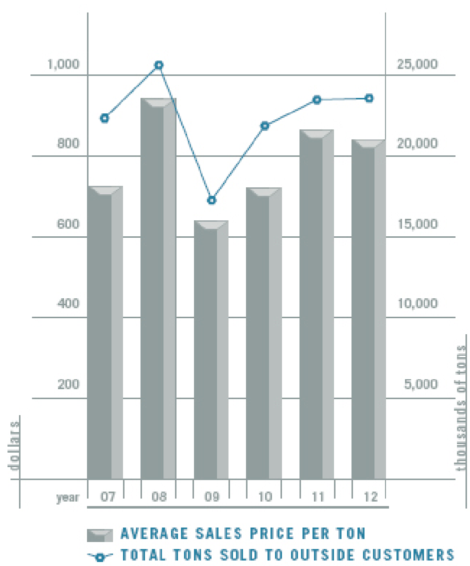
COMPARISON OF 2012 TO 2011
RESULTS OF OPERATIONS
NET SALES

Net sales to external customers by segment for 2012 and 2011 were as follows:

(in thousands)

Year Ended December 31,	2012	2011	% Change
Steel mills	$ 13,317,980	$ 13,960,245	- 5%
Steel products	3,738,381	3,431,490	9%
Raw materials	1,909,095	2,128,391	- 10%
All other	463,817	503,438	- 8%
Total net sales to external customers	$ 19,429,273	$ 20,023,564	- 3%

Net sales for 2012 decreased 3% from the prior year. The average sales price per ton decreased 3% from $869 in 2011 to $841 in 2012, while total tons shipped to outside customers only slightly increased.



In the steel mills segment, production and sales tons were as follows:

(in thousands)

Year Ended December 31,	2012	2011	% Change
Steel production	19,865	19,561	2%
Outside steel shipments	16,825	16,796	-
Inside steel shipments	3,417	3,329	3%
Total steel shipments	20,242	20,125	1%

Net sales to external customers in the steel mills segment decreased 5% due to a 5% decrease in the average sales price per ton from $832 in 2011 to $792 in 2012, partially offset by a slight increase in tons sold to outside customers. Total production levels at the steel mills increased 2% due to a slight increase in outside shipments as well as an increase of approximately 88,000 tons supplied to other Nucor businesses.

The average sales price per ton in the steel mills segment declined each quarter during 2012. The average sales price per ton in the fourth quarter of 2012 was $751, a decrease of 9% from $824 in the first quarter of 2012. The most significant decreases in average selling prices were for our sheet, bar and plate products, which were impacted by an import surge across most products that began in late 2011 and continued through 2012. In addition, new domestic capacity that began ramping up production in 2011 also added downward pressure on pricing in 2012. Average selling prices for our structural products group would have been relatively flat year over year, but the addition of Skyline's distribution business caused an increase in average selling prices for structural products. Acquired on June 20, 2012, Skyline has higher average sales prices for its products because of the value- added functions it provides to its customers. Manufactured goods, including automotive, energy and heavy equipment, were the strongest end markets in 2012, much like they were in 2011. Construction markets did show some modest improvement, but remain at historically anemic levels.

Tonnage data for the steel products segment is as follows:

(in thousands)

Year Ended December 31,	2012	2011	% Change
Joist production	291	288	1%
Deck sales	308	312	- 1%
Cold finished sales	492	494	-
Fabricated concrete reinforcing steel sales	1,180	1,074	10%

Net sales to external customers in the steel products segment increased 9% over 2011 due to a 4% increase in tons sold to outside customers and a 5% increase in the average sales price per ton from $1,355 to $1,417. Pricing of joists, deck, metal buildings and components and rebar fabricated products improved over the prior year as nonresidential construction activity has shown modest improvement; however, sales in the steel products segment remain depressed as demand in the nonresidential construction market remains weak. Pricing and volumes of cold finished bar products decreased slightly from the prior year. Net sales to external customers in this segment decreased 11% in the fourth quarter of 2012 from the third quarter because of typical seasonality in the nonresidential construction market.

Sales of rebar fabricated products contributed most significantly to the year- over- year increases in volumes and prices in the steel products segment due to the modest improvement in nonresidential construction activity.

Sales for the raw materials segment decreased 10% from 2011 primarily due to decreased pricing and decreased volumes in DJJ's brokerage operations. Approximately 85% of outside sales in the raw materials segment in 2012 were from brokerage operations of DJJ and approximately 13% of the outside sales were from the scrap processing facilities (86% and 13%, respectively, in 2011).

The "All other" category includes Nucor's steel trading businesses. The year- over- year decrease in sales is due to decreases in both volume and price.

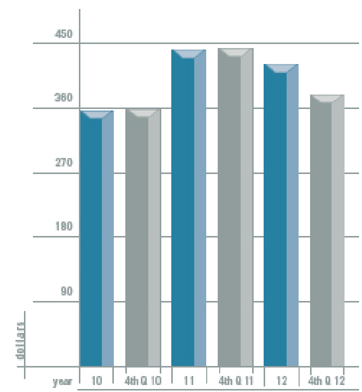
GROSS MARGIN

In 2012, Nucor recorded gross margins of $1.51 billion (8%) compared to $1.88 billion (9%) in 2011. The year- over- year dollar and gross margin decreases were primarily the result of the 3% decrease in the average sales price per ton. Additionally, gross margins were impacted by the following factors:

In the steel mills segment, the average scrap and scrap substitute cost per ton used decreased 7% from $439 in 2011 to $407 in 2012; however, metal margins also decreased from 2011.

The average scrap and scrap substitute cost per ton used decreased each quarter during 2012. However, the average sales price per ton also decreased each quarter of 2012 for all of the products within our steel mills segment except for structural. The decrease in sales prices and the resulting decrease in metal margins is primarily the result of new domestic suppliers and very high import levels in 2012 that increased from 2011 levels.

Scrap prices are driven by global supply and demand. We experienced more quarterly volatility in scrap costs during 2012 than in 2011, with an overall downward trend in scrap prices. We anticipate that scrap costs will be less volatile going forward until we see stronger market demand either domestically or globally.



AVERAGE SCRAP AND SCRAP SUBSTITUTE COST PER TON USED

Nucor's gross margins are significantly impacted by the application of the LIFO method of accounting. LIFO charges or credits are largely based on the relative changes in cost and quantities year over year, primarily within raw material inventory in the steel mills segment. The average scrap and scrap substitute cost per ton in ending inventory within our steel mills segment at December 31, 2012 decreased 13% as compared to December 31, 2011, which was partially offset by increased quantities included in ending inventory. As a result of these factors, Nucor recorded a LIFO credit of $155.9 million (a LIFO charge of $142.8 million in 2011). The decrease in cost per ton was driven by decreases in the demand for steel and the related raw materials.

Nucor's 2012 gross margins were negatively impacted by $48.8 million in inventory related purchase accounting adjustments associated with our acquisition of Skyline.

Total energy costs decreased $2 per ton from 2011 to 2012 due primarily to lower natural gas unit costs. Due to the efficiency of Nucor's steel mills, energy costs remained less than 6% of the sales dollar in 2012 and 2011. Total energy costs per ton in the fourth quarter of 2012 were higher than in the first and second quarters of 2012, but decreased $2 per ton from the third quarter of 2012. The decrease from the third quarter to the fourth quarter was due to lower electricity unit costs.

Gross margins related to DJJ's scrap processing operations were significantly lower in 2012 compared to 2011. The decrease was due to conditions in the scrap processing industry, in which excess shredding capacity increased competition for raw materials. As scrap selling prices decreased throughout the year, DJJ experienced severe downward pressure on margins in 2012.

Gross margins were impacted in the fourth quarter of 2011 by a non- cash gain of $29.0 million as a result of the correction of an actuarial calculation related to the medical plan covering certain eligible early retirees.

Gross margins in 2012 were positively affected by the improved performance of our steel products segment, which experienced gross margin improvement between the third and fourth quarters.

MARKETING, ADMINISTRATIVE AND OTHER EXPENSES

The largest component of marketing, administrative and other expenses is profit sharing costs. Profit sharing costs, which are based upon and fluctuate with pre- tax earnings, decreased from 2011 to 2012. In 2012, profit sharing costs consisted of $77.7 million of contributions, including the Company's matching contribution, made to the Company's Profit Sharing and Retirement Savings Plan for qualified employees ($117.7 million in 2011). Other bonus costs also fluctuate based on Nucor's achievement of certain financial performance goals, including comparisons of Nucor's financial performance to peers in the steel industry and other companies. Stock-based compensation included in marketing, administrative and other expenses increased by 1% to $25.0 million in 2012 compared with $24.7 million in 2011 and includes costs associated with vesting of stock awards granted in prior years.

In 2012, marketing, administrative and other expenses included a charge of $17.6 million for the loss on the sale of the assets of Nucor Wire Products Pennsylvania, Inc. Also contributing to the increase in marketing, administrative and other expenses in 2012 was the inclusion of Skyline's results since the acquisition date and a general increase in expenses in the steel products segment related to increased shipments to outside customers.

EQUITY IN LOSSES OF UNCONSOLIDATED AFFILIATES

Nucor incurred equity method investment losses of $13.3 million and $10.0 million in 2012 and 2011, respectively. Included in equity method losses is amortization expense associated with the purchase of equity method investments. The increase in the equity method investment losses from 2012 to 2011 is primarily due to an increase in losses generated by Duferdofin Nucor S.r.l. The markets served by Duferdofin Nucor continue to be negatively affected by global economic weakness and lower- priced imports from foreign steel producers receiving government subsidies. Equity in losses of unconsolidated affiliates was $4.2 million in the fourth quarter of 2012 compared to earnings of $4.1 million in the fourth quarter of 2011 and losses of $2.3 million in the third quarter of 2012. The change in equity method losses from the fourth quarter of 2011 is mainly due to the reversal of a deferred tax asset valuation allowance of $7.1 million related to the Duferdofin Nucor joint venture's Italian net operating loss carryforward. This valuation allowance was reversed in the fourth quarter of 2011 as a result of changes in Italian tax regulations in December 2011.

IMPAIRMENT OF NON- CURRENT ASSETS

In 2012, Nucor recorded $30.0 million in charges for impairment of non- current assets compared with $13.9 million in 2011. In the second quarter of 2012, Nucor concluded that a triggering event had occurred requiring assessment for impairment of its equity investment in Duferdofin Nucor due to the continued declines in the global demand for steel, the escalated economic and political turmoil in Europe and continued operating performance well below budgeted levels through the first half of 2012. Duferdofin Nucor's updated unfavorable forecast of future operating performance was also a contributing factor. After completing its assessment, Nucor determined that the carrying amount exceeded its estimated fair value on an other- than- temporary basis and recorded a $30.0 million impairment charge against the Company's investment in Duferdofin Nucor. The entire impairment charge recorded in 2011 relates to the impairment of Nucor's investment in a dust recycling joint venture that has since been terminated.

INTEREST EXPENSE (INCOME)

Net interest expense is detailed below:

(in thousands)

Year Ended December 31,		2012		2011
Interest expense	$	173,503	$	178,812
Interest income		(11,128)		(12,718)
Interest expense, net	$	162,375	$	166,094

The 3% decrease in gross interest expense from 2011 is primarily attributable to a 3% decrease in average debt outstanding and a slight decrease in the average interest rate. Gross interest income decreased 13% due primarily to a 14% decrease in average investments.

EARNINGS BEFORE INCOME TAXES AND NONCONTROLLING INTERESTS

Earnings before income taxes and noncontrolling interests by segment for 2012 and 2011 are as follows:

(in thousands)

Year Ended December 31,		2012		2011
Steel mills	$	1,161,449	$	1,808,859
Steel products		(17,140)		(60,282)
Raw materials		55,264		156,180
All other		821		4,296
Corporate/eliminations		(347,454)		(657,241)
Earnings before income taxes and noncontrolling interests	$	852,940	$	1,251,812

Earnings before income taxes and noncontrolling interests in the steel mills segment for 2012 decreased 36% from 2011. A major factor behind the decrease is that metal margin dollars decreased from 2011 resulting from the factors described above. Other factors impacting the profitability of the steel mills segment in 2012 were the $30.0 million impairment charge related to Duferdofin

Nucor and the $48.8 million of inventory related purchase accounting adjustments related to Skyline. Earnings before income taxes and noncontrolling interests in the steel mills segment decreased during the first three quarters of 2012, but were flat between the third and fourth quarters. The market conditions that have impacted the steel mills segment include an import surge across most products that began late in 2011 and continued through 2012. Preliminary U.S. Census Bureau data for December of 2012 indicate full year 2012 imports were 26.7 million tons, which is an increase of 17% from 2011 imports of 22.8 million tons. In addition, U.S. sheet steel markets have been negatively impacted by new domestic supply that began ramping up production in 2011. The strongest end markets continue to be manufactured goods including automotive, energy and heavy equipment.

Losses before income taxes and noncontrolling interests in the steel products segment in 2012 decreased from 2011. The 2012 loss was impacted by the $17.6 million loss on the sale of assets of Nucor Wire Products Pennsylvania, Inc. The steel products segment results improved significantly throughout the year, with fourth quarter of 2012 earnings before income taxes and noncontrolling interests of $17.0 million compared with the first quarter loss before income taxes and noncontrolling interests of $33.0 million. At our rebar fabrication businesses, 2012 shipments to outside customers increased 10% over 2011, which led to improved profitability within the segment. Although the segment has experienced market share gains, improved pricing and effective management of costs, the profitability of this segment remains weak due to the continued challenging conditions in the nonresidential construction market.

The profitability of our raw materials segment, particularly DJJ, decreased significantly from 2011 primarily due to continued margin compression at the scrap processing operations resulting from falling scrap selling prices and excess shredding capacity.

The improvements in results in Corporate/eliminations in 2012 were primarily due to the change in LIFO from a charge to a credit and lower profit sharing and incentive compensation costs.

NONCONTROLLING INTERESTS

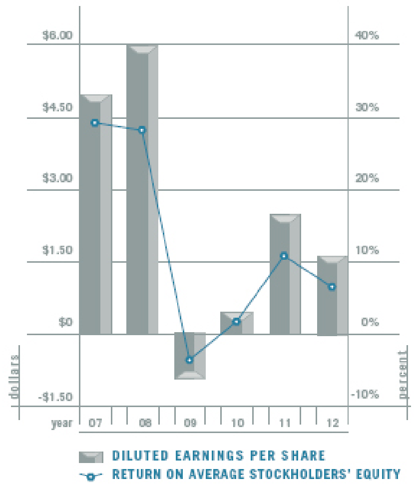
Noncontrolling interests represent the income attributable to the minority interest partners of Nucor's joint ventures, primarily Nucor-Yamato Steel Company (NYS) of which Nucor owns 51%. The 7% increase in noncontrolling interests was primarily attributable to the increased earnings of NYS, which were primarily due to increases in volumes and changes in product mix. Under the NYS limited partnership agreement, the minimum amount of cash to be distributed each year to the partners is the amount needed by each partner to pay applicable U.S. federal and state income taxes.

PROVISION FOR INCOME TAXES

The effective tax rate in 2012 was 30.5% compared with 31.2% in 2011. The change in the rate between 2011 and 2012 was primarily due to the change in relative proportions of net earnings attributable to noncontrolling interests to total pre- tax earnings, a greater benefit in 2012 from the domestic manufacturing deduction and the recognition of a deferred tax asset related to state tax credit carryforwards and the adjustment of tax expense to previously filed returns. Nucor has concluded U.S. federal income tax matters for years through 2006. The 2008 through 2012 tax years are open to examination by the Internal Revenue Service. The years 2004 and 2007 are open to the extent net operating losses were carried back. The Canada Revenue Agency has completed an audit examination for the periods 2006 to 2008 for Harris Steel Group Inc. and subsidiaries with immaterial adjustments to the income tax returns. The tax years 2008 through 2012 remain open to examination by other major taxing jurisdictions to which Nucor is subject (primarily Canada and other state and local jurisdictions).

NET EARNINGS AND RETURN ON EQUITY

Nucor reported net earnings of $504.6 million, or $1.58 per diluted share, in 2012 compared to net earnings of $778.2 million, or $2.45 per diluted share, in 2011. Net earnings attributable to Nucor stockholders as a percentage of net sales were 3% in 2012 and 4% in 2011. Return on average stockholders' equity was 7% and 11% in 2012 and 2011, respectively.



COMPARISON OF 2011 TO 2010
RESULTS OF OPERATIONS
NET SALES

Net sales to external customers by segment for 2011 and 2010 were as follows:

(in thousands)

Year Ended December 31,	2011	2010	% Change
Steel mills	$ 13,960,245	$ 10,860,760	29%
Steel products	3,431,490	2,831,209	21%
Raw materials	2,128,391	1,814,329	17%
All other	503,438	338,329	49%
Total net sales to external customers	$ 20,023,564	$ 15,844,627	26%

Net sales for 2011 increased 26% from the prior year. The average sales price per ton increased 21% from $720 in 2010 to $869 in 2011, while total tons shipped to outside customers increased 5%.

In the steel mills segment, production and sales tons were as follows:

(in thousands)

Year Ended December 31,	2011	2010	% Change
Steel production	19,561	18,258	7%
Outside steel shipments	16,796	15,821	6%
Inside steel shipments	3,329	2,752	21%
Total steel shipments	20,125	18,573	8%

Net sales to external customers in the steel mills segment increased 29% due to a 6% increase in tons sold to outside customers and a 21% increase in the average sales price per ton from $689 in 2010 to $832 in 2011. Total production levels at the steel mills increased 7% due to an increase in outside shipments as well as an increase of more than 500,000 tons supplied to other Nucor divisions.
Tonnage data for the steel products segment was as follows:

(in thousands)

Year Ended December 31,	2011	2010	% Change
Joist production	288	276	4%
Deck sales	312	306	2%
Cold finished sales	494	462	7%
Fabricated concrete reinforcing steel sales	1,074	981	9%

Net sales to external customers in the steel products segment increased 21% over 2010 due to a 7% increase in tons sold to outside customers and a 13% increase in the average sales price per ton from $1,194 to $1,355. Sales of cold finished bar products contributed most significantly to the year- over- year increases in volumes and prices due to improved demand in heavy equipment and transportation markets. While 2011 pricing of joists, deck, cold finished bar products and rebar fabricated products improved over 2010, sales in the steel products segment were weak due to the depressed levels of demand in the nonresidential construction market.
Sales for the raw materials segment increased 17% over 2010 primarily due to increased prices. Approximately 86% of outside sales in the raw materials segment in 2011 were from brokerage operations of DJJ and approximately 13% of the outside sales were from the scrap processing facilities (88% and 12%, respectively, in 2010).
The "All other" category includes Nucor's steel trading businesses. The year- over- year increases in sales are due to increases in both volume and price.

GROSS MARGIN

In 2011, Nucor recorded gross margins of $1.88 billion (9%) compared to $783.7 million (5%) in 2010. The year- over- year dollar and gross margin increases were primarily the result of the 21% increase in the average sales price per ton and the 5% increase in tons shipped to outside customers. Additionally, gross margins were impacted by the following factors:

In the steel mills segment, the average scrap and scrap substitute cost per ton used increased 25% from $351 in 2010 to $439 in 2011; however, metal margins also increased. Metal margins for the full year 2011 were at their highest level since 2008. This metal margin expansion demonstrated our historical experience of rising scrap prices leading, after a short lag, to higher metal margins.

The average scrap and scrap substitute cost per ton in ending inventory within our steel mills segment at December 31, 2011 increased 12% as compared with December 31, 2010, while quantities included in ending inventory also increased. As a result of these factors, Nucor incurred a LIFO charge of $142.8 million in 2011 (a LIFO charge of $164.0 million in 2010).

Total energy costs increased $1 per ton from 2010 to 2011 due primarily to higher electricity unit costs. Due to the efficiency of Nucor's steel mills, energy costs remained less than 6% of the sales dollar in 2011 and 2010.

Gross margins were impacted in the fourth quarter of 2011 by a non- cash gain of $29.0 million as a result of the correction of an actuarial calculation related to the medical plan covering certain eligible early retirees.

MARKETING, ADMINISTRATIVE AND OTHER EXPENSES

Profit sharing costs increased more than fivefold from 2010 to 2011 due to the Company's increased profitability in 2011. In 2011, profit sharing costs consisted of $117.7 million of contributions, including the Company's matching contribution, made to the Company's Profit Sharing and Retirement Savings Plan for qualified employees ($22.1 million in 2010). Stock- based compensation included in marketing, administrative and other expenses increased 56% to $24.7 million in 2011 compared with $15.8 million in 2010 and includes costs associated with vesting of stock awards granted in prior years.

EQUITY IN LOSSES OF UNCONSOLIDATED AFFILIATES

Nucor incurred equity method investment losses of $10.0 million and $32.1 million in 2011 and 2010, respectively. The decrease in the equity method investment losses is primarily attributable to decreased losses incurred at the HIsmelt joint venture that was closed in late 2010 and to increased earnings generated by NuMit LLC, of which Nucor acquired a 50% interest in the second quarter of 2010.

IMPAIRMENT OF NON- CURRENT ASSETS

In 2011, Nucor recorded $13.9 million in charges for impairment of non- current assets (none in 2010). The 2011 impairment charge relates to the impairment of Nucor's investment in a dust recycling joint venture.

INTEREST EXPENSE (INCOME)

Net interest expense is detailed below:

(in thousands)

Year Ended December 31,	2011	2010
Interest expense	$178,812	$161,140
Interest income	(12,718)	(8,047)
Interest expense, net	$166,094	$153,093

The 11% increase in gross interest expense over 2010 is attributable to a 29% increase in average debt outstanding, partially offset by a 14% decrease in the average interest rate. Gross interest income increased 58% due to a 76% increase in average investments, partially offset by a 16% decrease in average interest rate earned on investments.

EARNINGS BEFORE INCOME TAXES AND NONCONTROLLING INTERESTS

Earnings before income taxes and noncontrolling interests by segment for 2011 and 2010 are as follows:

(in thousands)

Year Ended December 31,	2011	2010
Steel mills	$1,808,859	$872,566
Steel products	(60,282)	(173,433)
Raw materials	156,180	122,393
All other	4,296	4,344
Corporate/eliminations	(657,241)	(558,755)
Earnings before income taxes and noncontrolling interests	$1,251,812	$267,115

Earnings before income taxes and noncontrolling interests in the steel mills segment for 2011 more than doubled over 2010 because of increased utilization rates, increased sales prices and metal margins, decreased pre- operating and start- up costs and decreased losses from unconsolidated affiliates. Nucor benefited from our diversified product mix in 2011, in which our sheet, bar, plate and beam mills all improved their profitability compared to 2010. Our plate and bar mills had the largest increases in profitability, while our sheet and beam mills also contributed solid profitability growth.

Losses before income taxes and noncontrolling interests in the steel products segment in 2011 decreased from 2010. The strongest performer in the steel products segment was the cold finished business due to improved demand in the heavy equipment and transportation markets.

The profitability of our raw materials segment, particularly DJJ, increased over 2010 as higher selling prices in the scrap market allowed for margin enhancement.

NONCONTROLLING INTERESTS

The 15% increase in noncontrolling interests in 2011 over 2010 was primarily attributable to the increased earnings of NYS, which were due to improvements in the structural steel market.

PROVISION FOR INCOME TAXES

The effective tax rate in 2011 was 31.2% compared with 22.8% in 2010. The change in the rate between 2010 and 2011 was primarily due to the changes in relative proportions of net earnings attributable to noncontrolling interests, state income tax benefit and foreign tax benefit to total pre- tax earnings.

NET EARNINGS AND RETURN ON EQUITY

Nucor reported net earnings of $778.2 million, or $2.45 per diluted share, in 2011 compared to net earnings of $134.1 million, or $0.42 per diluted share, in 2010. Net earnings attributable to Nucor stockholders as a percentage of net sales were 4% in 2011 and 1% in 2010. Return on average stockholders' equity was 11% and 2% in 2011 and 2010, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Cash flows provided by operating activities provide us with a significant source of liquidity. When needed, we also have external short- term financing sources available including the issuance of commercial paper and borrowings under our bank credit facilities. We also issue long- term debt from time to time.

In 2011, Nucor increased its revolving credit facility to $1.5 billion and extended its maturity date to December 2016. The revolving credit facility was undrawn and Nucor had no commercial paper outstanding at December 31, 2012. We believe our financial strength is a key strategic advantage among domestic steel producers, particularly during recessionary business cycles. We currently carry the highest credit ratings of any metals and mining company in North America with an A rating from Standard & Poor's and an A3 rating from Moody's. Based upon these ratings, we expect to continue to have adequate access to the capital markets at a reasonable cost of funds for liquidity purposes when needed. Our credit ratings are dependent, however, upon a number of factors, both qualitative and quantitative, and are subject to change at any time. If the credit agencies were to downgrade our credit ratings in the future, we could experience greater difficulty in obtaining new financing or higher interest rates paid on those borrowed funds. The disclosure of our credit ratings is made in order to enhance investors' understanding of our sources of liquidity and the impact of our credit ratings on our cost of funds.

Nucor's cash and cash equivalents and short- term investments position remains robust at $1.16 billion as of December 31, 2012, and an additional $275.2 million of restricted cash and investments is available for use in the construction of the DRI facility in Louisiana. Approximately $186.2 million and $181.3 million of the cash and cash equivalents position at December 31, 2012 and December 31, 2011, respectively, was held by our majority- owned joint ventures.

Selected Measures of Liquidity and Capital Resources:

(dollars in thousands)

December 31,	2012	2011
Cash and cash equivalents	$ 1,052,862	$ 1,200,645
Short- term investments	$ 104,167	$ 1,362,641
Restricted cash and investments	$ 275,163	$ 585,833
Working capital	$ 3,631,796	$ 4,312,022
Current ratio	2.8	2.8

The current ratio was 2.8 at year end 2012 and 2011. The current ratio was negatively impacted by a 55% decrease from 2011 in cash and short- term investments, which were sold primarily to provide funding for the Skyline acquisition, for our capital expenditures and for our scheduled debt repayments. This decrease was partially offset by the 17% increase in inventories primarily attributable to the acquisition of Skyline. The impact of the increase in inventory tons on hand at year end was partially offset by a 13% decrease in scrap cost per ton in ending inventory. The ratio was also impacted by a 57% decrease from 2011 in long- term debt due within one year and short- term debt, due primarily to the repayment of $650 million in debt partially offset by the reclassification to a current liability of $250 million of long- term debt that matures in 2013.

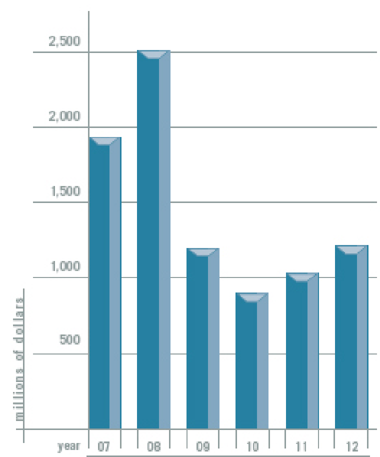
Due primarily to the 8% decrease in net sales in the fourth quarter of 2012 compared with the prior year fourth quarter, accounts receivable decreased slightly from 2011. The slight decrease in accounts receivable is the result of lower sales prices and lower sales volumes in the fourth quarter of 2012 as compared with sales volumes in the fourth quarter of 2011. These decreases were offset by increases related to the acquisition of Skyline. In 2012, total accounts receivable turned approximately monthly and inventories turned approximately every six weeks. These turnover rates are comparable to Nucor's historical performance.

Funds provided by operations, cash and cash equivalents, short- term investments and new borrowings under existing credit facilities are expected to be adequate to meet future capital expenditure and working capital requirements for existing operations for at least the next 24 months.

We have a simple capital structure with no off- balance sheet arrangements or relationships with unconsolidated special purpose entities that we believe could have a material impact on our financial condition or liquidity.

OPERATING ACTIVITIES

Cash provided by operating activities was $1.20 billion in 2012 compared with $1.03 billion in 2011, an increase of 16%. The changes in operating assets and liabilities of ($86.1) million in 2012 compared with ($551.4) million in 2011 were partially offset by the decrease in net earnings from the prior year. The funding of working capital decreased from the prior year due to slightly lower levels of operations in 2012 and decreases in the costs of raw materials and selling prices.



CASH PROVIDED BY OPERATIONS

INVESTING ACTIVITIES

Our business is capital intensive; therefore, cash used in investing activities represents capital expenditures for new facilities, the expansion and upgrading of existing facilities and the acquisition of other companies. Nucor invested $947.6 million in new facilities (exclusive of acquisitions) and expansion or upgrading of existing facilities in 2012 compared with $438.9 million in 2011, an increase of 116%. Nucor invested $760.8 million in the acquisition of other companies (primarily Skyline) in 2012 compared with just $4.0 million in 2011. Nucor's capital investment and maintenance practices give us the flexibility to reduce our current spending on our facilities to low levels during severely depressed market conditions such as we experienced in recent years.

Despite the increases in capital expenditures and acquisitions, cash used in investing activities decreased from 2011. The decrease in cash used in investing activities was impacted by the net increase of $1.76 billion in proceeds from the sale of investments and restricted investments (net of purchases), which were mainly sold in order to fund acquisitions, capital expenditures and the payment of $650.0 million to retire maturing long- term debt.

FINANCING ACTIVITIES

Cash used in financing activities was $1.15 billion in 2012 compared with $495.0 million in 2011. In the fourth quarter of 2012, Nucor paid $650.0 million to retire maturing long- term debt, which accounts for the majority of the increase.

In 2012, Nucor increased its quarterly base dividend resulting in dividends paid of $466.4 million ($461.5 million in 2011).

Although there were no repurchases in 2012 or 2011, approximately 27.2 million shares remain authorized for repurchase under the Company's stock repurchase program.

Our credit facility includes only one financial covenant, which is a limit of 60% on the ratio of funded debt to total capitalization. In addition, the credit facility contains customary non- financial covenants, including a limit on Nucor's ability to pledge the Company's assets and a limit on consolidations, mergers and sales of assets. Our funded debt to total capital ratio was 32% and 36% at year- end 2012 and 2011, respectively, and we were in compliance with all other covenants under our credit facility.

MARKET RISK

Nucor's largest exposure to market risk is in our steel mills and steel products segments. Our utilization rates for the steel mills and steel products facilities for the fourth quarter of 2012 were 71% and 56%, respectively. A significant portion of our steel and steel products segments sales are into the commercial, industrial and municipal construction markets, which continue to be depressed. Our largest single customer in 2012 represented approximately 5% of sales and consistently pays within terms. In the raw materials segment, we are exposed to price fluctuations related to the purchase of scrap steel and iron ore. Our exposure to market risk is mitigated by the fact that our steel mills use a significant portion of the products of this segment.

The majority of Nucor's tax- exempt industrial revenue bonds (IDRBs), including the Gulf Opportunity Zone bonds, have variable interest rates that are adjusted weekly, with the rate of one IDRB adjusted annually. These IDRBs represent 28% of Nucor's long- term debt outstanding at December 31, 2012. The remaining 72% of Nucor's long- term debt is at fixed rates. Future changes in interest rates are not expected to significantly impact earnings. From time to time, Nucor makes use of interest rate swaps to manage interest rate risk. As of December 31, 2012, there were no such contracts outstanding. Nucor's investment practice is to invest in securities that are highly liquid with short maturities. As a result, we do not expect changes in interest rates to have a significant impact on the value of our investment securities recorded as short- term investments.

Nucor also uses derivative financial instruments from time to time to partially manage its exposure to price risk related to natural gas purchases used in the production process as well as scrap, copper and aluminum purchased for resale to its customers. In addition, Nucor uses forward foreign exchange contracts from time to time to hedge cash flows associated with certain assets and liabilities, firm commitments and anticipated transactions. Nucor generally does not enter into derivative instruments for any purpose other than hedging the cash flows associated with specific volumes of commodities that will be purchased and processed in future periods and hedging the exposures related to changes in the fair value of outstanding fixed rate debt instruments and foreign currency transactions. Nucor recognizes all derivative instruments in the consolidated balance sheets at fair value.

The Company is exposed to foreign currency risk through its operations in Canada, Europe, Trinidad and Colombia. We periodically use derivative contracts to mitigate the risk of currency fluctuations.

CONTRACTUAL OBLIGATIONS AND OTHER COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations and other commercial commitments as of December 31, 2012 for the periods presented:

(in thousands)

	Payments Due By Period				
Contractual Obligations	Total	2013	2014 - 2015	2016 - 2017	2018 and thereafter
Long- term debt	$ 3,630,200	$ 250,000	$ 19,600	$ 600,000	$2,760,600
Estimated interest on long- term debt(1)	1,705,330	139,347	268,175	265,163	1,032,645
Operating leases	105,253	26,588	37,336	19,308	22,021
Raw material purchase commitments(2)	5,489,808	1,236,004	2,292,049	1,513,241	448,514
Utility purchase commitments(2)	915,879	197,012	168,464	106,314	444,089
Natural gas drilling commitments(3)	4,327,966	279,486	717,700	635,000	2,695,780
Other unconditional purchase obligations(4)	485,160	455,666	14,272	3,416	11,806
Other long- term obligations(5)	324,071	156,825	43,535	20,388	103,323
Total contractual obligations	$16,983,667	$2,740,928	$3,561,131	$3,162,830	$7,518,778

(1) Interest is estimated using applicable rates at December 31, 2012 for Nucor's outstanding fixed and variable rate debt.

(2) Nucor enters into contracts for the purchase of scrap and scrap substitutes, iron ore, electricity, natural gas and other raw materials and related services. These contracts include multi- year commitments and minimum annual purchase requirements and are valued at prices in effect on December 31, 2012, or according to the contract language. These contracts are part of normal operations and are reflected in historical operating cash flow trends. We do not believe such commitments will adversely affect our liquidity position.

(3) Represents contractual obligations under natural gas working interest drilling programs.

(4) Purchase obligations include commitments for capital expenditures on operating machinery and equipment.

(5) Other long- term obligations include amounts associated with Nucor's early- retiree medical benefits, management compensation and guarantees.

Note: In addition to the amounts shown in the table above, $80.9 million of unrecognized tax benefits have been recorded as liabilities, and we are uncertain as to if or when such amounts may be settled. Related to these unrecognized tax benefits, we have also recorded a liability for potential penalties and interest of $36.4 million at December 31, 2012.

DIVIDENDS

Nucor has increased its base cash dividend every year since it began paying dividends in 1973. Nucor paid dividends of $1.46 per share in 2012 compared with $1.45 per share in 2011. In December 2012, the board of directors increased the base quarterly dividend to $0.3675 per share. The base quarterly dividend has more than tripled since the end of 2007. In February 2013, the board of directors declared Nucor's 160th consecutive quarterly cash dividend of $0.3675 per share payable on May 10, 2013 to stockholders of record on March 28, 2013.

OUTLOOK

In 2013, we will continue to take advantage of our position of strength to grow Nucor's long- term earnings power and shareholder value despite a U.S. economy burdened by a challenging regulatory and overall business environment. Although macro- level uncertainties in world markets will almost certainly affect both global and domestic growth, we anticipate sales and profitability to strengthen. Utilization rates, which were flat when compared to 2011, have continued at a similar pace in early 2013 and we expect this trend to continue as we progress through the first quarter. We expect a more positive trend in earnings as we enter into the second quarter and then into the second half of the year. We are therefore cautiously optimistic regarding full year volume, pricing and profitability. We believe several end- use markets such as automotive, heavy equipment, energy and general manufacturing will experience some real demand improvement that will gain momentum throughout 2013. However, the effect this improvement in demand will have on our operating rates will be challenged by increases in domestic sheet steel capacity as well as continued increases in imported steel. We also expect that we will continue to experience fluctuations in raw material costs in 2013, although we expect the fluctuations to be less volatile than in 2012. The most challenging markets for our products continue to be those associated with residential and nonresidential construction. We have continued to use our very strong balance sheet to support investments in our facilities that will prepare us for increased profitability as we enter into more favorable market conditions. In 2013, we will continue to allocate capital to investments that build our long- term earnings power. Capital expenditures are currently projected to be approximately $1.1 billion in 2013, which is somewhat higher than in 2012 but more than double the levels of 2009- 2011. Included in this total are expenditures for our Louisiana DRI facility, our natural gas related investments, capacity expansion in SBQ steel as well as other investments in our core operations to expand our product offerings and keep them state- of- the- art and globally competitive.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year end, and the reported amount of revenues and expenses during the year. On an ongoing basis, we evaluate our estimates, including those related to the valuation allowances for receivables, the carrying value of non- current assets, reserves for environmental obligations and income taxes. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Accordingly, actual costs could differ materially from these estimates under different assumptions or conditions.

We believe the following critical accounting policies affect our significant judgments and estimates used in the preparation of our consolidated financial statements.

ALLOWANCES FOR DOUBTFUL ACCOUNTS

We maintain allowances for doubtful accounts for estimated losses resulting from the inability of our customers to make required payments. If the financial condition of our customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required.

INVENTORIES

Inventories are stated at the lower of cost or market. All inventories held by the parent company and Nucor- Yamato Steel Company are valued using the LIFO method of accounting except for supplies that are consumed indirectly in the production process, which are valued using the first- in, first- out (FIFO) method of accounting. All inventories held by the parent company's other subsidiaries are valued using the FIFO method of accounting. The Company records any amount required to reduce the carrying value of inventory to net realizable value as a charge to cost of products sold.

If steel selling prices were to decline in future quarters, write- downs of inventory could result. Specifically, the valuation of raw material inventories purchased during periods of peak market pricing held by subsidiaries valued using the FIFO method of accounting would most likely be impacted. Low utilization rates at our steel mills could hinder our ability to work through high- priced scrap and scrap substitutes (particularly pig iron), leading to period- end exposure when comparing carrying value to net realizable value.

LONG- LIVED ASSET IMPAIRMENTS

We evaluate our property, plant and equipment and finite- lived intangible assets for potential impairment on an individual asset basis or at the lowest level asset grouping for which cash flows can be separately identified. Asset impairments are assessed whenever changes in circumstances indicate that the carrying amounts of those productive assets could exceed their projected undiscounted cash flows. In developing estimated values for assets that we currently use in our operations, we utilize judgments and assumptions of future undiscounted cash flows that the assets will produce. When it is determined that an impairment exists, the related assets are written down to estimated fair market value.

Certain long- lived asset groupings were tested for impairment during the fourth quarter of 2012. Undiscounted cash flows for each asset grouping were estimated using management's long- range estimates of market conditions associated with each asset grouping over the estimated useful life of the principal asset within the group. Our undiscounted cash flow analysis indicated that those long- lived asset groupings were recoverable as of December 31, 2012; however, if our projected cash flows are not realized, either because of an extended recessionary period or other unforeseen events, impairment charges may be required in future periods. A 5% decrease in the projected cash flows of each of our asset groupings would not result in an impairment.

GOODWILL

Goodwill is tested annually for impairment and whenever events or circumstances change that would make it more likely than not that an impairment may have occurred. We perform our annual impairment analysis as of the first day of the fourth quarter each year. The evaluation of impairment involves comparing the current estimated fair value of each reporting unit to the recorded value, including goodwill.

When appropriate, Nucor performs a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. For certain reporting units it is necessary to perform a quantitative analysis. In these instances, a discounted cash flow model is used to determine the current estimated fair value of these reporting units. Key assumptions used to determine the fair value of each reporting unit as part of our annual testing (and any required interim testing) include:

(a) expected cash flow for the five- year period following the testing date (including market share, sales volumes and prices, costs to produce and estimated capital needs); (b) an estimated terminal value using a terminal year growth rate determined based on the growth prospects of the reporting unit; (c) a discount rate based on management's best estimate of the after- tax weighted average cost of capital; and (d) a probability- weighted scenario approach by which varying cash flows are assigned to certain scenarios based on the likelihood of occurrence. Management considers historical and anticipated future results, general economic and market conditions, the impact of planned business and operational strategies and all available information at the time the fair values of its reporting units are estimated.

Our fourth quarter 2012 annual goodwill impairment analysis did not result in an impairment charge. The excess of fair value over carrying value for the majority of our reporting units improved from 2011 levels. Accordingly, management does not currently believe that future impairment of these reporting units is probable. However, the performance of certain businesses that comprise our reporting units requires continued improvement. A 50 basis point increase in the discount rate, a critical assumption in which a minor change can have a significant impact on the estimated fair value, would not result in an impairment charge.

Nucor will continue to monitor operating results within all reporting units throughout the upcoming year in an effort to determine if events and circumstances warrant further interim impairment testing. Otherwise, all reporting units will again be subject to the required annual impairment test during our fourth quarter of 2013. Changes in the judgments and estimates underlying our analysis of goodwill for possible impairment, including expected future operating cash flows and discount rate, could decrease the estimated fair value of our reporting units in the future and could result in an impairment of goodwill.

EQUITY METHOD INVESTMENTS

Investments in joint ventures in which Nucor shares control over the financial and operating decisions but in which Nucor is not the primary beneficiary are accounted for under the equity method. Each of the Company's equity method investments is subject to a review for impairment if, and when, circumstances indicate that an other- than- temporary decline in value below its carrying amount may have occurred. Examples of such circumstances include, but are not limited to, a significant deterioration in the earnings performance or business prospects of the investee; a significant adverse change in the regulatory, economic, or technological environment of the investee; a significant adverse change in the general market condition of either the geographic area or the industry in which the investee operates; and recurring negative cash flows from operations. If management considers the decline to be other than temporary, the Company would write down the investment to its estimated fair market value. An other- than- temporary decline in carrying value is determined to have occurred when, in management's judgment, a decline in fair value below carrying value is of such length of time and/or severity that it is considered permanent.

In the second quarter of 2012, Nucor concluded that a triggering event had occurred requiring assessment for impairment of its equity investment in Duferdofin Nucor due to the continued declines in the global demand for steel, the escalated economic and political turmoil in Europe and continued operating performance well below budgeted levels through the first half of 2012. Duferdofin Nucor's updated unfavorable forecast of future operating performance was also a contributing factor. After completing its assessment, Nucor determined that the carrying amount exceeded its estimated fair value and recorded a $30.0 million impairment charge against the Company's investment in Duferdofin Nucor in the second quarter of 2012. This charge is included in impairment of non- current assets in the consolidated statements of earnings. In the fourth quarter of 2012, Nucor reassessed its equity investment in Duferdofin Nucor for impairment. After completing its assessment, the Company determined that the estimated fair value exceeded its carrying amount and that there was no need for further impairment. The assumptions that most significantly affect the fair value determination include projected revenues and the discount rate. Steel market conditions in Europe have continued to be challenging through the fourth quarter of 2012, and, therefore, it is reasonably possible that based on actual performance in the near term the estimates used in our fourth quarter valuation could change and result in further impairment of our investment. Changes in management estimates to the unobservable inputs would change the valuation of the investment. The estimates for the projected revenue and discount rate are the assumptions that most significantly affect the fair value determination.

ENVIRONMENTAL REMEDIATION

We are subject to environmental laws and regulations established by federal, state and local authorities, and we make provisions for the estimated costs related to compliance. Undiscounted remediation liabilities are accrued based on estimates of known environmental exposures. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as we believe are necessary. Our measurement of environmental liabilities is based on currently available facts, present laws and regulations and current technology.

INCOME TAXES

We utilize the liability method of accounting for income taxes. Under the liability method, deferred taxes are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities using tax rates expected to be in effect during the years in which the basis differences reverse. A valuation allowance is recorded when it is more likely than not that some of the deferred tax assets will not be realized. We recognize the effect of income tax positions only if those positions are more likely than not of being sustained. Potential accrued interest and penalties related to unrecognized tax benefits within operations are recognized as a component of earnings before taxes and noncontrolling interests.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 2 to our consolidated financial statements for a discussion of new accounting pronouncements adopted by Nucor during 2012 and the expected financial impact of accounting pronouncements recently issued or proposed but not yet required to be adopted.

RECLASSIFICATIONS

In 2012, we began classifying internal fleet and some common carrier costs in cost of products sold in the consolidated statements of earnings. We made this change so that all freight costs will be recorded within the same financial statement line item to allow users of our financial statements to better understand our expense structure. This change resulted in the reclassification of $67.2 million of these costs from marketing, administrative and other expenses to cost of products sold for the year ended December 31, 2011 ($59.9 million in 2010) in order to conform to the current year presentation. Additionally, certain other prior period amounts have been reclassified to conform to current period presentation. These reclassifications did not have an impact on net earnings for the current or any prior periods.

(dollar and share amounts in thousands, except per share data)

	2012	2011	2010	2009	2008
FOR THE YEAR					
Net sales	$ 19,429,273	$ 20,023,564	$ 15,844,627	$ 11,190,296	$ 23,663,324
Costs, expenses and other:					
Cost of products sold	17,915,735	18,142,144	15,060,882	11,090,230	19,711,437
Marketing, administrative and other expenses	454,900	439,528	331,455	296,951	614,910
Equity in losses of unconsolidated affiliates	13,323	10,043	32,082	82,341	36,920
Impairment of non-current assets	30,000	13,943	-	-	105,183
Interest expense, net	162,375	166,094	153,093	134,752	90,483
	18,576,333	18,771,752	15,577,512	11,604,274	20,558,933
Earnings (loss) before income taxes and noncontrolling interests	852,940	1,251,812	267,115	(413,978)	3,104,391
Provision for (benefit from) income taxes	259,814	390,828	60,792	(176,800)	959,480
Net earnings (loss)	593,126	860,984	206,323	(237,178)	2,144,911
Earnings attributable to noncontrolling interests	88,507	82,796	72,231	56,435	313,921

Net earnings (loss) attributable to Nucor stockholders	504,619	778,188	134,092	(293,613)	1,830,990
Net earnings (loss) per share:					
Basic	1.58	2.45	0.42	(0.94)	5.99
Diluted	1.58	2.45	0.42	(0.94)	5.98
Dividends declared per share	1.4625	1.4525	1.4425	1.41	1.91
Percentage of net earnings (loss) to net sales	2.6%	3.9%	0.8%	- 2.6%	7.7%
Return on average stockholders' equity	6.7%	10.7%	1.8%	- 3.8%	28.1%
Capital expenditures	1,019,334	450,627	345,294	390,500	1,018,980
Acquisitions (net of cash acquired)	760,833	3,959	64,788	32,720	1,826,030
Depreciation	534,010	522,571	512,147	494,035	479,484
Sales per employee	906	974	777	539	1,155
AT YEAR END					
Current assets	$ 5,661,364	$ 6,708,081	$ 5,861,175	$ 5,182,248	$ 6,397,486
Current liabilities	2,029,568	2,396,059	1,504,438	1,227,057	1,854,192
Working capital	3,631,796	4,312,022	4,356,737	3,955,191	4,543,294
Cash provided by operating activities	1,200,385	1,031,053	866,794	1,173,194	2,502,063
Current ratio	2.8	2.8	3.9	4.2	3.5
Property, plant and equipment, net	4,283,056	3,755,604	3,852,118	4,013,836	4,131,861

Total assets	14,152,059	14,570,350	13,921,910	12,571,904	13,874,443
Long- term debt (including current maturities)	3,630,200	4,280,200	4,280,200	3,086,200	3,266,600
Percentage of debt to capital(1)	31.5%	35.7%	36.9%	28.9%	28.3%
Total Nucor stockholders' equity	7,641,571	7,474,885	7,120,070	7,390,526	7,929,204
Per share	24.06	23.60	22.55	23.47	25.25
Shares outstanding	317,663	316,749	315,791	314,856	313,977
Employees	22,200	20,800	20,500	20,400	21,700

(1) Long- term debt divided by total equity plus long- term debt.

MANAGEMENT'S REPORT on internal control over financial reporting

Nucor's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a- 15(f) and 15d- 15(f) under the Securities Exchange Act of 1934, as amended.

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.

Management assessed the effectiveness of Nucor's internal control over financial reporting as of December 31, 2012. In making this assessment, management used criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.*

Our evaluation did not include the internal controls over financial reporting of Skyline Steel LLC, which was acquired on June 20, 2012. Total assets and total sales for the acquisition represent 3.2% and 2.4%, respectively, of the related consolidated financial statement amounts as of and for the fiscal year ended December 31, 2012.

Based on its assessment, management concluded that Nucor's internal control over financial reporting was effective as of December 31, 2012. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of Nucor's internal control over financial reporting as of December 31, 2012 as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Nucor Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of earnings, comprehensive income, stockholders' equity and cash flows present fairly, in all material respects, the financial position of Nucor Corporation and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these 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 opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (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 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 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.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Skyline Steel LLC from its assessment of internal control over financial reporting as of December 31, 2012 because it was acquired by the Company in a purchase business combination during 2012. We have also excluded Skyline Steel LLC from our audit of internal control over financial reporting. Skyline Steel LLC is a wholly owned subsidiary whose total assets and total sales represent 3.2% and 2.4%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Charlotte, NC
February 28, 2013

CONSOLIDATED BALANCE SHEETS

(in thousands)

December 31,	2012		2011	
ASSETS				
CURRENT ASSETS:				
Cash and cash equivalents (Note 15)	$	1,052,862	$	1,200,645
Short- term investments (Notes 4 and 15)		104,167		1,362,641
Accounts receivable, net (Note 5)		1,707,317		1,710,773
Inventories, net (Note 6)		2,323,641		1,987,257
Other current assets (Notes 10, 14, 15 and 20)		473,377		446,765
Total current assets		5,661,364		6,708,081
PROPERTY, PLANT AND EQUIPMENT, NET (Note 7)		4,283,056		3,755,604
RESTRICTED CASH AND INVESTMENTS (Notes 8 and 15)		275,163		585,833
GOODWILL (Note 9)		2,004,538		1,830,661
OTHER INTANGIBLE ASSETS, NET (Note 9)		959,240		784,640
OTHER ASSETS (Note 10)		968,698		905,531
TOTAL ASSETS	$	14,152,059	$	14,570,350
LIABILITIES AND EQUITY				

CURRENT LIABILITIES:		
Short- term debt (Notes 12 and 15)	$ 29,912	$ 1,826
Long- term debt due within one year (Notes 12 and 15)	250,000	650,000
Accounts payable (Note 11)	1,046,713	958,645
Salaries, wages and related accruals (Notes 17 and 18)	279,898	333,341
Accrued expenses and other current liabilities (Notes 11, 14, 15 and 16)	423,045	452,247
Total current liabilities	2,029,568	2,396,059
LONG- TERM DEBT DUE AFTER ONE YEAR (Notes 12 and 15)	3,380,200	3,630,200
DEFERRED CREDITS AND OTHER LIABILITIES (Notes 16, 17, 18 and 20)	856,917	837,511
TOTAL LIABILITIES	6,266,685	6,863,770
COMMITMENTS AND CONTINGENCIES (Notes 6, 14 and 16)		
EQUITY		
NUCOR STOCKHOLDERS' EQUITY (Notes 13 and 17):		
Common stock (800,000 shares authorized; 377,013 and 376,239 shares issued, respectively)	150,805	150,496
Additional paid- in capital	1,811,459	1,756,534
Retained earnings	7,124,523	7,111,566
Accumulated other comprehensive income (loss), net of income taxes (Notes 2 and 14)	56,761	(38,177)
	(1,501,977)	(1,505,534)

Treasury stock (59,350 and 59,490 shares, respectively)				
Total Nucor stockholders' equity		7,641,571		7,474,885
NONCONTROLLING INTERESTS		243,803		231,695
TOTAL EQUITY		7,885,374		7,706,580
TOTAL LIABILITIES AND EQUITY	$	14,152,059	$	14,570,350

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF EARNINGS

(in thousands, except per share data)

Year Ended December 31,	2012	2011	2010
NET SALES	$ 19,429,273	$ 20,023,564	$ 15,844,627
COSTS, EXPENSES AND OTHER:			
Cost of products sold (Notes 1, 6, 14 and 18)	17,915,735	18,142,144	15,060,882
Marketing, administrative and other expenses (Notes 1, 3 and 10)	454,900	439,528	331,455
Equity in losses of unconsolidated affiliates (Note 10)	13,323	10,043	32,082
Impairment of non- current assets (Note 10)	30,000	13,943	-
Interest expense, net (Note 19)	162,375	166,094	153,093
	18,576,333	18,771,752	15,577,512
EARNINGS BEFORE INCOME TAXES AND NONCONTROLLING INTERESTS	852,940	1,251,812	267,115
PROVISION FOR INCOME TAXES (Note 20)	259,814	390,828	60,792
NET EARNINGS	593,126	860,984	206,323
EARNINGS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	88,507	82,796	72,231
NET EARNINGS ATTRIBUTABLE TO NUCOR STOCKHOLDERS	$ 504,619	$ 778,188	$ 134,092
NET EARNINGS PER SHARE (Note 21):			
Basic	$1.58	$2.45	$0.42
Diluted	$1.58	$2.45	$0.42

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

Year Ended December 31,	2012	2011	2010
NET EARNINGS	$ 593,126	$ 860,984	$ 206,323
OTHER COMPREHENSIVE INCOME (LOSS):			
Net unrealized loss on hedging derivatives, net of income taxes of ($1,100), ($4,700) and ($17,200) for 2012, 2011 and 2010, respectively	(2,264)	(8,454)	(29,957)
Reclassification adjustment for loss on settlement of hedging derivatives included in net earnings, net of income taxes of $25,000, $21,800 and $20,700 for 2012, 2011 and 2010, respectively	42,515	37,093	35,141
Foreign currency translation gain (loss), net of income taxes of $0, $100 and ($1,300) for 2012, 2011 and 2010, respectively	58,626	(40,210)	8,182
Adjustment to early retiree medical plan, net of income taxes of ($1,528), $952 and $64 for 2012, 2011 and 2010, respectively	(3,646)	1,165	(76)
	95,231	(10,406)	13,290
COMPREHENSIVE INCOME	688,357	850,578	219,613
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(88,512)	(82,791)	(72,241)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NUCOR STOCKHOLDERS	$ 599,845	$ 767,787	$ 147,372

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands, except per share data)

		COMMON STOCK				ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TREASURY STOCK (AT COST)			
	TOTAL	SHARES	AMOUNT	ADDITIONAL PAID- IN CAPITAL	RETAINED EARNINGS		SHARES	AMOUNT	TOTAL NUCOR STOCKHOLDERS EQUITY	NON-CONTROLLING INTERESTS
BALANCES, December 31, 2009	$7,584,289	374,692	$149,877	$1,675,777	$7,120,218	$(41,056)	59,836	$(1,514,290)	$7,390,526	$193,763
Net earnings in 2010	206,323				134,092				134,092	72,231
Other comprehensive income	13,290					13,280			13,280	10
Stock options exercised	4,662	319	128	4,534					4,662	
Stock option expense	729			729					729	
Issuance of stock under award plans, net of forfeitures	32,777	440	176	28,152			(176)	4,449	32,777	
Amortization of unearned compensation	2,326			2,326					2,326	
Cash dividends ($1.4425 per share)	(458,322)				(458,322)				(458,322)	
Distributions to noncontrolling interests	(55,380)									(55,380)
BALANCES, December 31, 2010	7,330,694	375,451	150,181	1,711,518	6,795,988	(27,776)	59,660	(1,509,841)	7,120,070	210,624

Net earnings in 2011	860,984				778,188				778,188	82,796
Other comprehensive income	(10,406)					(10,401)			(10,401)	(5)
Stock options exercised	8,097	387	155	7,942					8,097	
Stock option expense	9,850			9,850					9,850	
Issuance of stock under award plans, net of forfeitures	30,091	401	160	25,624			(170)	4,307	30,091	
Amortization of unearned compensation	1,600			1,600					1,600	
Cash dividends ($1.4525 per share)	(462,610)				(462,610)				(462,610)	
Distributions to noncontrolling interests	(61,720)									(61,720)
BALANCES, December 31, 2011	7,706,580	376,239	150,496	1,756,534	7,111,566	(38,177)	59,490	(1,505,534)	7,474,885	231,695
Net earnings in 2012	593,126				504,619				504,619	88,507
Other comprehensive income	95,231					95,226			95,226	5
Stock options	10,515	354	142	10,373					10,515	

exercised										
Stock option expense	9,850			9,850					9,850	
Issuance of stock under award plans, net of forfeitures	36,119	420	167	32,395			(140)	3,557	36,119	
Amortization of unearned compensation	800			800					800	
Cash dividends ($1.4625 per share)	(467,662)				(467,662)				(467,662)	
Distributions to noncontrolling interests	(74,848)									(74,848)
Other	(24,337)			1,507	(24,000)	(288)			(22,781)	(1,556)
BALANCES, December 31, 2012	$7,885,374	377,013	$150,805	$1,811,459	$7,124,523	$56,761	59,350	$(1,501,977)	$7,641,571	$243,803

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

Year Ended December 31,	2012	2011	2010
OPERATING ACTIVITIES:			
Net earnings	$ 593,126	$ 860,984	$ 206,323
Adjustments:			
Depreciation	534,010	522,571	512,147
Amortization	73,011	67,829	70,455
Stock- based compensation	50,733	49,003	43,041
Deferred income taxes	(25,274)	58,051	138,262
Equity in losses of unconsolidated affiliates	13,323	10,043	32,082
Impairment of non- current assets	30,000	13,943	-
Loss on sale of assets	17,563	-	-
Changes in assets and liabilities (exclusive of acquisitions):			
Accounts receivable	148,113	(274,920)	(310,188)
Inventories	(65,655)	(433,696)	(231,913)
Accounts payable	(111,496)	62,012	179,807
Federal income taxes	(28,022)	930	180,821
Salaries, wages and related accruals	(60,363)	129,340	56,641
Other	31,316	(35,037)	(10,684)

Cash provided by operating activities	1,200,385	1,031,053	866,794
INVESTING ACTIVITIES:			
Capital expenditures	(947,608)	(438,943)	(338,684)
Investment in and advances to affiliates	(180,472)	(95,950)	(434,006)
Repayment of advances to affiliates	65,446	50,000	83,885
Disposition of plant and equipment	51,063	25,333	24,944
Acquisitions (net of cash acquired)	(760,833)	(3,959)	(64,788)
Purchases of investments	(409,403)	(1,494,782)	(1,323,264)
Proceeds from the sale of investments	1,667,142	1,285,763	394,640
Purchases of restricted investments	-	(564,994)	-
Proceeds from the sale of restricted investments	359,295	47,479	-
Changes in restricted cash	(48,625)	530,165	(598,482)
Cash used in investing activities	(203,995)	(659,888)	(2,255,755)
FINANCING ACTIVITIES:			
Net change in short- term debt	27,945	(11,450)	11,561
Repayment of long- term debt	(650,000)	-	(6,000)
Proceeds from issuance of long- term debt, net of discount	-	-	1,198,992
Debt issuance costs	-	-	(4,050)
Issuance of common stock	10,515	8,097	4,687
	4,700	1,000	(700)

Excess tax benefits from stock-based compensation						
Distributions to noncontrolling interests		(74,848)		(61,720)		(55,380)
Cash dividends		(466,361)		(461,518)		(457,282)
Other financing activities		1,172		30,569		-
Cash provided by (used in) financing activities		(1,146,877)		(495,022)		691,828
Effect of exchange rate changes on cash		2,704		(904)		5,558
DECREASE IN CASH AND CASH EQUIVALENTS		(147,783)		(124,761)		(691,575)
CASH AND CASH EQUIVALENTS - BEGINNING OF YEAR		1,200,645		1,325,406		2,016,981
CASH AND CASH EQUIVALENTS - END OF YEAR	$	1,052,862	$	1,200,645	$	1,325,406
NON- CASH INVESTING ACTIVITY:						
Change in accrued plant and equipment purchases	$	71,726	$	1,559	$	6,610

See notes to consolidated financial statements.

YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Nature of Operations Nucor is principally a manufacturer of steel and steel products, as well as a scrap broker and processor, with operating facilities and customers primarily located in North America.

Principles of Consolidation The consolidated financial statements include Nucor and its controlled subsidiaries, including Nucor-Yamato Steel Company, a limited partnership of which Nucor owns 51%. All significant intercompany transactions are eliminated. Distributions are made to noncontrolling interest partners in Nucor- Yamato Steel Company in accordance with the limited partnership agreement by mutual agreement of the general partners. At a minimum, sufficient cash is distributed so that each partner may pay their U.S. federal and state income taxes.

Use of Estimates The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from these estimates.

Reclassifications In 2012, we began classifying internal fleet and some common carrier costs in cost of products sold in the consolidated statements of earnings. We made this change so that all freight costs will be recorded within the same financial statement line item to allow users of our financial statements to better understand our expense structure. This change resulted in the reclassification of $67.2 million of these costs from marketing, administrative and other expenses to cost of products sold for the year ended December 31, 2011 ($59.9 million in 2010) in order to conform to the current year presentation. Additionally, certain other prior period amounts have been reclassified to conform to current period presentation. These reclassifications did not have an impact on net earnings for the current or any prior periods.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents Cash equivalents are recorded at cost plus accrued interest, which approximates market, and have original maturities of three months or less at the date of purchase. Cash and cash equivalents are maintained primarily with a few high-credit quality financial institutions.

Short- term Investments Short- term investments are recorded at cost plus accrued interest, which approximates market. Unrealized gains and losses on investments classified as available- for- sale are recorded as a component of accumulated other comprehensive income (loss). Management determines the appropriate classification of its investments at the time of purchase and re- evaluates such determination at each balance sheet date.

Inventories Valuation Inventories are stated at the lower of cost or market. Inventories valued using the last- in, first- out (LIFO) method of accounting represent approximately 45% of total inventories as of December 31, 2012 (47% as of December 31, 2011). All inventories held by the parent company and Nucor- Yamato Steel Company are valued using the LIFO method of accounting except for supplies that are consumed indirectly in the production process, which are valued using the first- in, first- out (FIFO) method of accounting. All inventories held by other subsidiaries of the parent company are valued using the FIFO method of accounting. The Company records any amount required to reduce the carrying value of inventory to net realizable value as a charge to cost of products sold.

Property, Plant and Equipment Property, plant and equipment are stated at cost, except for property, plant and equipment acquired through acquisitions which were recorded at fair value. Depreciation is provided on a straight- line basis over the estimated useful lives of the assets. The costs of planned major maintenance activities are capitalized and amortized over the period until the next scheduled major maintenance activity. All other repairs and maintenance activities are expensed when incurred.

Goodwill and Other Intangibles Goodwill is the excess of cost over the fair value of net assets of businesses acquired. Goodwill is not amortized but is tested annually for impairment and whenever events or circumstances change that would make it more likely than not that an impairment may have occurred. We perform our annual impairment analysis as of the first day of the fourth quarter each year. The evaluation of impairment involves comparing the current estimated fair value of each reporting unit, which is a level below the reportable segment, to the recorded value, including goodwill. When appropriate, Nucor performs a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. For certain reporting units it is necessary to perform a quantitative analysis. In these instances, a discounted cash flow model is used to determine the current estimated fair value of these reporting units. A number of significant assumptions and estimates are involved in the application of the discounted cash flow model to forecast operating cash flows, including market growth and market share, sales volumes and prices, costs to produce, discount rate and estimated capital needs. Management considers historical experience and all available information at the time the fair values of its reporting units are estimated. Assumptions in estimating future cash flows are subject to a high degree of judgment and complexity. Changes in assumptions and estimates may affect the fair value of goodwill and could result in additional impairment charges in future periods.

Finite- lived intangible assets are amortized over their estimated useful lives.

Long- Lived Asset Impairments We evaluate our property, plant and equipment and finite- lived intangible assets for potential impairment on an individual asset basis or at the lowest level asset grouping for which cash flows can be separately identified. Asset impairments are assessed whenever changes in circumstances indicate that the carrying amounts of those productive assets could exceed their projected undiscounted cash flows. When it is determined that an impairment exists, the related assets are written down to estimated fair market value.

Equity Method Investments Investments in joint ventures in which Nucor shares control over the financial and operating decisions but in which Nucor is not the primary beneficiary are accounted for under the equity method. Each of the Company's equity method investments is subject to a review for impairment if, and when, circumstances indicate that a decline in value below its carrying amount may have occurred. Examples of such circumstances include, but are not limited to, a significant deterioration in the earnings performance or business prospects of the investee; a significant adverse change in the regulatory, economic or technological environment of the investee; a significant adverse change in the general market condition of either the geographic area or the industry in which the investee operates; and recurring negative cash flows from operations. If management considers the decline to be other than temporary, the Company would write down the investment to its estimated fair market value.

Derivative Financial Instruments Nucor uses derivative financial instruments from time to time primarily to partially manage its exposure to price risk related to natural gas purchases used in the production process as well as scrap, copper and aluminum purchased for resale to its customers. In addition, Nucor uses derivatives from time to time to partially manage its exposure to changes in interest rates on outstanding debt instruments and uses forward foreign exchange contracts to hedge cash flows associated with certain assets and liabilities, firm commitments and anticipated transactions.

Nucor recognizes all derivative instruments in the consolidated balance sheets at fair value. Amounts included in accumulated other comprehensive income (loss) related to cash flow hedges are reclassified into earnings when the underlying transaction is recognized in net earnings. Changes in fair value hedges are reported currently in earnings along with changes in the fair value of the hedged items. When cash flow and fair value hedges affect net earnings, they are included on the same financial statement line as the underlying transaction (cost of products sold or interest expense). If these instruments do not meet hedge accounting criteria or contain ineffectiveness, the change in fair value (or a portion thereof) is recognized immediately in earnings in the same financial statement line as the underlying transaction.

Revenue Recognition Nucor recognizes revenue when the customer takes title, assumes risk of loss and when collection is reasonably assured.

Income Taxes Nucor utilizes the liability method of accounting for income taxes. Under the liability method, deferred taxes are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities using tax rates expected to be in effect during the years in which the basis differences reverse. A valuation allowance is recorded when it is more likely than not that some of the deferred tax assets will not be realized.

Nucor recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Potential accrued interest and penalties related to unrecognized tax benefits are recognized as a component of earnings before taxes and noncontrolling interests.

Nucor's intention is to permanently reinvest the earnings of certain foreign investments. Accordingly, no provisions have been made for taxes that may be payable upon remittance of such earnings.

Stock- Based Compensation The Company recognizes the cost of stock- based compensation as an expense using fair value measurement methods. The assumptions used to calculate the fair value of stock- based compensation granted are evaluated and revised, as necessary, to reflect market conditions and experience.

Comprehensive Income (Loss) Accumulated other comprehensive income (loss) is comprised of the following:

(in thousands)

December 31,		2012		2011
Foreign currency translation, net of income taxes when applicable	$	46,181	$	(12,311)
Early- retiree medical plan adjustments, net of income taxes		10,580		14,384
Fair market value of derivatives, net of income taxes		-		(40,250)
	$	56,761	$	(38,177)

Foreign Currency Translation For Nucor's operations where the functional currency is other than the U.S. dollar, assets and liabilities have been translated at year- end exchange rates, and income and expenses translated using average exchange rates for the respective periods. Adjustments resulting from the process of translating an entity's financial statements into the U.S. dollar have been recorded in accumulated other comprehensive income (loss) and are included in net earnings only upon sale or liquidation of the underlying investments. Foreign currency transaction gains and losses are included in net earnings in the period they occur.

Recent Accounting Pronouncements In January 2012, Nucor adopted accounting guidance regarding changes to the presentation of comprehensive income in the financial statements. The new accounting guidance requires entities to report components of comprehensive income in either (1) a single continuous statement of comprehensive income or (2) two separate but consecutive statements of net income and comprehensive income. We have elected to report the components of comprehensive income in two separate but consecutive statements. The adoption of this guidance impacts the presentation of comprehensive income, but does not impact Nucor's consolidated financial position, results of operations or cash flows.

Also in January 2012, Nucor adopted accounting guidance that amends the existing requirements for fair value measurement and disclosure. The guidance expands the disclosure requirements around transfers between Level 1 and Level 2 of the fair value hierarchy and around the sensitivity to changes in inputs of fair value measurements categorized in Level 3 of the hierarchy. It also requires disclosure of the level in the fair value hierarchy of items that are not measured at fair value in the statement of financial position but whose fair value must be disclosed. The guidance also clarifies and expands upon existing requirements for measurement of the fair value of financial assets and liabilities as well as instruments classified in stockholders' equity. The adoption of this guidance did not have an impact on the consolidated financial statements.

In the first quarter of 2013, Nucor will adopt new accounting guidance requiring additional disclosures on reclassifications from accumulated other comprehensive income into net income. The new accounting guidance requires entities to report either parenthetically on the face of the financial statements or in the notes to the financial statements these reclassifications for each financial statement line item. This new guidance only impacts disclosures and will have no impact on Nucor's consolidated financial position, results of operations or cash flows.

3. ACQUISITIONS AND DISPOSITIONS

2012 On June 20, 2012, Nucor completed the acquisition of the entire equity interest in Skyline Steel LLC (Skyline) and its subsidiaries for the cash purchase price of approximately $675.4 million. No cash was received nor was any debt assumed as a result of the acquisition. Skyline's financial results are included as part of the steel mills segment (see Note 22).

Skyline is a steel foundation manufacturer and distributor serving the U.S., Canada, Mexico and the Caribbean. Skyline's steel products are used in marine construction, bridge and highway construction, heavy civil construction, storm protection, underground commercial parking and environmental containment projects in the infrastructure and construction industries. Skyline is a significant consumer of H-piling and sheet piling from Nucor- Yamato Steel Company, and it will become a larger downstream consumer of Nucor's coiled plate and sheet products.

We have allocated the purchase price for Skyline to its individual assets acquired and liabilities assumed.
The following table summarizes the estimated fair values of the assets acquired and liabilities assumed of Skyline as of the date of acquisition:

		(in thousands)
Accounts receivable	$	128,004
Inventory		260,473
Other current assets		4,410
Property, plant and equipment		70,100
Goodwill		138,579
Other intangible assets		215,600
Total assets acquired		817,166
Current liabilities		137,654
Deferred credits and other liabilities		4,078
Total liabilities assumed		141,732
Net assets acquired	$	675,434

The purchase price allocation to the identifiable intangible assets is as follows:

As of the date of acquisition		(in thousands, except years)	Weighted-Average Life
Customer relationships	$	184,500	17 years
Trademarks and trade names		28,500	20 years
Other		2,600	3 years
	$	215,600	

The goodwill of $138.6 million is primarily attributed to the synergies expected to arise after the acquisition and has been allocated to the steel mills segment (see Note 9). Approximately $128.2 million of the goodwill recognized is expected to be deductible for tax purposes.
In August 2012, Nucor sold the assets of Nucor Wire Products Pennsylvania, Inc., resulting in a loss of $17.6 million. This charge is included in marketing, administrative and other expenses in the consolidated statement of earnings.
In November 2012, Nucor acquired a 50% economic and voting interest in Hunter Ridge Energy Services LLC (Hunter Ridge). Hunter Ridge provides services for the gathering, separation and compression of energy products including natural gas produced by Nucor's working interest drilling program. Nucor accounts for the investment (on a one- month lag basis) under the equity method (see Note 10). As of December 31, 2012, our investment in Hunter Ridge was $95.4 million.
2010 In April 2010, Nucor acquired a 50% economic and voting interest in NuMit LLC (NuMit) for a purchase price of approximately $221.3 million. NuMit owns 100% of the equity interest in Steel Technologies LLC, an operator of 25 sheet processing facilities throughout the U.S., Canada and Mexico. Nucor accounts for the investment using the equity method (see Note 10).
All Years Other minor acquisitions, exclusive of purchase price adjustments of acquisitions made in prior years, totaled $85.4 million in 2012 ($4.0 million in 2011 and $64.8 million in 2010).

4. SHORT- TERM INVESTMENTS

Nucor's short- term investments held as of December 31, 2012 consisted of certificates of deposit (CDs) and are classified as available- for- sale. The interest rates on the certificates of deposit are fixed at inception.

At December 31, 2011, Nucor's short- term investments consisted of CDs, corporate debt, Federal Home Loan Bank (FHLB) obligations and variable rate demand notes (VRDNs), all of which were classified as available- for- sale. The investments in corporate debt were debt securities issued by a financial institution that management believes have low credit risk. FHLB consolidated obligations carry high credit ratings from both Moody's and Standard & Poor's. VRDNs are variable rate bonds tied to short- term interest rates with stated original maturities in excess of 90 days. All of the VRDNs in which Nucor invested were secured by a direct- pay letter of credit issued by financial institutions that management believes have low credit risk. Nucor could receive the principal invested and interest accrued thereon no later than seven days after notifying the financial institution that Nucor elected to tender the VRDNs. The interest rates on the CDs and the coupon rates on the corporate debt and FHLBs were fixed at inception, and the VRDNs traded at par value.

No realized or unrealized gains or losses were incurred in 2012, 2011 or 2010.

The following is a summary of the short- term investments held at December 31, 2012 and 2011:

(in thousands)

December 31,	2012		2011	
Certificates of deposit	$	104,167	$	775,000
Corporate debt		-		103,506
Federal Home Loan Bank obligations		-		185,500
Variable rate demand notes		-		298,635
	$	104,167	$	1,362,641

The contractual maturities of all of the CDs outstanding at December 31, 2012 are in 2013.

5. ACCOUNTS RECEIVABLE

An allowance for doubtful accounts is maintained for estimated losses resulting from the inability of our customers to make required payments. Accounts receivable are stated net of the allowance for doubtful accounts of $57.4 million at December 31, 2012 ($54.3 million at December 31, 2011 and $61.2 million at December 31, 2010).

6. INVENTORIES

Inventories consist of approximately 37% raw materials and supplies and 63% finished and semi- finished products at December 31, 2012 (40% and 60%, respectively, at December 31, 2011). Nucor's manufacturing process consists of a continuous, vertically integrated process from which products are sold to customers at various stages throughout the process. Since most steel products can be classified as either finished or semi- finished products, these two categories of inventory are combined.

If the FIFO method of accounting had been used, inventories would have been $607.2 million higher at December 31, 2012 ($763.2 million higher at December 31, 2011). During 2010, inventory quantities at locations that value inventory using LIFO were reduced, resulting in a liquidation of LIFO inventory layers carried at lower costs that prevailed in prior years. The effect of the liquidation was to decrease cost of products sold by $30.4 million in 2010 (there was no liquidation of LIFO inventory layers in 2012 or 2011). Use of the lower of cost or market method reduced inventories by $3.5 million at December 31, 2012 ($6.8 million at December 31, 2011).

Nucor has entered into supply agreements for certain raw materials, utilities and other items in the ordinary course of business. These agreements extend into 2029 and total approximately $6.41 billion at December 31, 2012.

7. PROPERTY, PLANT AND EQUIPMENT

(in thousands)

December 31,	2012	2011
Land and improvements	$ 546,234	$ 515,674
Buildings and improvements	899,944	841,179
Machinery and equipment	8,160,140	7,727,630
Construction in process and equipment deposits	832,255	396,614
	10,438,573	9,481,097
Less accumulated depreciation	(6,155,517)	(5,725,493)
	$ 4,283,056	$ 3,755,604

The estimated useful lives range from 5 to 20 years for land improvements, 9 to 31.5 years for buildings and improvements, and 2 to 15 years for machinery and equipment.

8. RESTRICTED CASH AND INVESTMENTS

As of December 31, 2012, restricted cash and investments consisted of net proceeds from $600.0 million 30- year variable rate Gulf Opportunity Zone bonds issued in November 2010. The restricted cash and investments are held in a trust account and are to be used to partially fund the capital costs associated with the construction of Nucor's direct reduced ironmaking facility in St. James Parish, Louisiana. Funds are disbursed as qualified expenditures for the construction of the facility are made ($311.8 million in 2012 and $43.2 million in 2011). Restricted investments totaled $149.8 million at December 31, 2012 ($514.3 million at December 31, 2011), and are held in similar short- term investment instruments as described in Note 4. Interest earned on these investments is subject to the same usage requirements as the bond proceeds. Since the restricted cash, investments and interest on investments must be used for the construction of the facility, the entire balance has been classified as a non- current asset.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

The change in the net carrying amount of goodwill for the years ended December 31, 2012 and 2011 by segment is as follows:

(in thousands)

	Steel Mills	Steel Products	Raw Materials	All Other	Total
Balance, December 31, 2010	$ 268,466	$ 799,060	$ 679,916	$ 88,852	$ 1,836,294
Acquisitions	-	-	2,986	-	2,986
Translation	-	(8,619)	-	-	(8,619)
Balance, December 31, 2011	268,466	790,441	682,902	88,852	1,830,661
Acquisitions and dispositions	138,579	(3,489)	20,323	-	155,413
Translation	-	18,464	-	-	18,464
Balance, December 31, 2012	$ 407,045	$ 805,416	$ 703,225	$ 88,852	$ 2,004,538

The majority of goodwill is not tax deductible.

Intangible assets with estimated lives of 3 to 22 years are amortized on a straight- line or accelerated basis and are comprised of the following:

(in thousands)

December 31,	2012		2011	
	Gross Amount	Accumulated Amortization	Gross Amount	Accumulated Amortization
Customer relationships	$ 1,156,979	$ 325,819	$ 941,787	$ 262,841
Trademarks and trade names	152,869	32,653	123,192	25,628
Other	28,610	20,746	25,868	17,738
	$ 1,338,458	$ 379,218	$ 1,090,847	$ 306,207

Intangible asset amortization expense was $73.0 million in 2012 ($67.8 million in 2011 and $70.5 million in 2010). Annual amortization expense is estimated to be $72.1 million in 2013; $70.1 million in 2014; $68.2 million in 2015; $66.6 million in 2016; and $64.8 million in 2017.

The Company completed its annual goodwill impairment testing as of the first days of the fourth quarters of 2012, 2011 and 2010 and concluded that as of such dates there was no impairment of goodwill for any of its reporting units. We do not believe there are currently any reporting units at risk of goodwill impairment in the near term. However, assumptions in estimating reporting unit fair values are subject to a high degree of judgment and complexity. Changes in assumptions and estimates may affect the estimated reporting unit fair values and could result in additional impairment charges in future periods.

10. EQUITY INVESTMENTS

The carrying value of our equity investments in domestic and foreign companies was $855.9 million at December 31, 2012 ($775.7 million at December 31, 2011) and is recorded in other assets in the consolidated balance sheets.

DUFERDOFIN NUCOR Nucor owns a 50% economic and voting interest in Duferdofin Nucor S.r.l. (Duferdofin Nucor), an Italian steel manufacturer, and accounts for the investment (on a one- month lag basis) under the equity method, as control and risk of loss are shared equally between the members.

Nucor's investment in Duferdofin Nucor at December 31, 2012 was $454.1 million ($493.9 million at December 31, 2011). Nucor's 50% share of the total net assets of Duferdofin Nucor was $53.0 million at December 31, 2012, resulting in a basis difference of $401.1 million due to the step- up to fair value of certain assets and liabilities attributable to Duferdofin Nucor as well as the identification of goodwill ($319.1 million) and finite- lived intangible assets. This basis difference, excluding the portion attributable to goodwill, is being amortized based on the remaining estimated useful lives of the various underlying net assets, as appropriate. Amortization expense and other purchase accounting adjustments associated with the fair value step- up were $11.1 million in 2012 ($11.5 million in 2011 and in 2010).

As of December 31, 2012, Nucor had outstanding notes receivable of 35 million ($46.3 million) from Duferdofin Nucor (30 million as of December 31, 2011). The notes receivable bear interest at 1.69% and will reset annually on September 30 to the twelve- month Euro Interbank Offered Rate (Euribor) plus 1% per year. The principal amounts are due on January 31, 2016. Accordingly, the notes receivable were classified in other assets in the consolidated balance sheets as of December 31, 2012.

Nucor has issued a guarantee for its ownership percentage (50%) of Duferdofin Nucor's borrowings under Facility A of a Structured Trade Finance Facilities Agreement that matures on October 26, 2013. The maximum amount that Duferdofin Nucor can borrow under Facility A is 112.5 million, and as of December 31, 2012, Duferdofin Nucor had 102.0 million ($134.8 million) outstanding under that facility. If Duferdofin Nucor fails to pay when due any amounts for which it is obligated under Facility A, Nucor could be required to pay 50% of such amounts pursuant to and in accordance with the terms of its guarantee. Any indebtedness of Duferdofin Nucor to Nucor is effectively subordinated to the indebtedness of Duferdofin Nucor under the Structured Trade Finance Facilities Agreement. Nucor has not recorded any liability associated with the guarantee.

NUMIT Nucor has a 50% economic and voting interest in NuMit LLC. NuMit owns 100% of the equity interest in Steel Technologies LLC, an operator of 25 sheet processing facilities located throughout the U.S., Canada and Mexico. Nucor accounts for the investment in NuMit (on a one- month lag basis) under the equity method as control and risk of loss are shared equally between the members. The acquisition did not result in a significant amount of goodwill or intangible assets.

Nucor's investment in NuMit at December 31, 2012 was $288.4 million ($259.3 million as of December 31, 2011), which is comprised of the purchase price of approximately $221.3 million plus subsequent additional capital contributions and equity method earnings less distributions since acquisition. Nucor also has recorded a $40.0 million note receivable from Steel Technologies LLC that bears interest at 1.26% and resets quarterly to the three- month London Interbank Offered Rate (LIBOR) plus 90 basis points. The principal amount is due on October 21, 2014. In addition, Nucor has extended a $130.0 million line of credit (of which $47.0 million was outstanding at December 31, 2012) to Steel Technologies. As of December 31, 2012, the amounts outstanding on the line of credit bear interest at 1.83% and mature on April 1, 2013. The note receivable was classified in other assets and the amount outstanding on the line of credit was classified in other current assets in the consolidated balance sheets.

HUNTER RIDGE In November 2012, Nucor acquired a 50% economic and voting interest in Hunter Ridge. Hunter Ridge provides services for the gathering, separation and compression of energy products including natural gas produced by Nucor's working interest drilling program. Nucor accounts for the investment (on a one- month lag basis) under the equity method, as control and risk of loss are shared equally between the members. Nucor's investment in Hunter Ridge at December 31, 2012 was $95.4 million (none at December 31, 2011). The acquisition did not result in a significant amount of goodwill or intangible assets.

ALL EQUITY INVESTMENTS Nucor reviews its equity investments for impairment if and when circumstances indicate that a decline in value below their carrying amounts may have occurred. In the second quarter of 2012, Nucor concluded that a triggering event had occurred requiring assessment for impairment of its equity investment in Duferdofin Nucor due to the continued declines in the global demand for steel, the escalated economic and political turmoil in Europe and continued operating performance well below budgeted levels through the first half of 2012. Duferdofin Nucor's updated unfavorable forecast of future operating performance was also a contributing factor. After completing its assessment, Nucor determined that the carrying amount exceeded its estimated fair value and recorded a $30.0 million impairment charge against the Company's investment in Duferdofin Nucor in the second quarter of 2012. This charge is included in impairment of non- current assets in the consolidated statements of earnings. In the fourth quarter of 2012, Nucor reassessed its equity investment in Duferdofin Nucor for impairment. After completing its assessment, the Company determined that the estimated fair value exceeded its carrying amount and that there was no need for further impairment. The assumptions that most significantly affect the fair value determination include projected revenues and the discount rate. Steel market conditions in Europe have continued to be challenging through the fourth quarter of 2012, and, therefore, it is reasonably possible that based on actual performance in the near term the estimates used in our fourth quarter valuation could change and result in further impairment of our investment.

In the third quarter of 2011, the Company concluded that an equity investment in a dust recycling project had been impaired, resulting in an impairment charge of $13.9 million. This charge is included in impairment of non- current assets in the consolidated statements of earnings.

In December 2010, Nucor and its joint venture partners agreed to permanently close the HIsmelt plant in Kwinana, Western Australia. Nucor has a 25% interest in the joint venture that will be terminated. Nucor recorded a pre- tax charge of $10.0 million in the fourth quarter of 2010 (none in 2012 and 2011) in marketing, administrative and other expenses for its portion of the estimated closure costs.

11. CURRENT LIABILITIES

Book overdrafts, included in accounts payable in the consolidated balance sheets, were $53.8 million at December 31, 2012 ($53.6 million at December 31, 2011). Dividends payable, included in accrued expenses and other current liabilities in the consolidated balance sheets, were $117.6 million at December 31, 2012 ($116.3 million at December 31, 2011).

12. DEBT AND OTHER FINANCING ARRANGEMENTS

				(in thousands)
December 31,		2012		2011
Industrial revenue bonds: 0.30% to 1.5%, variable, due from 2014 to 2040	$	1,030,200	$	1,030,200
Notes, 4.875%, due 2012		-		350,000
Notes, 5.0%, due 2012		-		300,000
Notes, 5.0%, due 2013		250,000		250,000
Notes, 5.75%, due 2017		600,000		600,000
Notes, 5.85%, due 2018		500,000		500,000
Notes, 4.125%, due 2022		600,000		600,000
Notes, 6.40%, due 2037		650,000		650,000
		3,630,200		4,280,200
Less current maturities		(250,000)		(650,000)
	$	3,380,200	$	3,630,200

Annual aggregate long- term debt maturities are: $250.0 million in 2013; $3.3 million in 2014; $16.3 million in 2015; none in 2016; $600.0 million in 2017; and $2.761 billion thereafter.

In December 2011, Nucor received increased commitments under the unsecured revolving credit facility to provide for up to $1.50 billion in revolving loans. The amended multi- year revolving credit agreement matures in December 2016 and allows up to $500.0 million in additional commitments at Nucor's election in accordance with the terms set forth in the credit agreement. Up to the equivalent of $850.0 million of the credit facility is available for foreign currency loans, up to $500.0 million is available for the issuance of letters of credit, and up to $500.0 million is available for the issuance of revolving loans for Nucor subsidiaries in accordance with terms set forth in the credit agreement. The credit facility provides for a pricing grid based upon the credit rating of Nucor's senior unsecured long- term debt and, alternatively, interest rates quoted by lenders in connection with competitive bidding. The credit facility includes customary financial and other covenants, including a limit on the ratio of funded debt to capital of 60%, a limit on Nucor's ability to pledge the Company's assets and a limit on consolidations, mergers and sales of assets. As of December 31, 2012, Nucor's funded debt to total capital ratio was 32%, and Nucor was in compliance with all covenants under the credit facility. No borrowings were outstanding under the credit facility as of December 31, 2012 and 2011.

Harris Steel has credit facilities totaling approximately $35.5 million, with $2.8 million of borrowings outstanding at December 31, 2012. In addition, the business of Nucor Trading S.A. is financed by uncommitted trade credit arrangements with a number of European banking institutions. As of December 31, 2012, Nucor Trading S.A. had outstanding borrowings of $27.1 million and outstanding guarantees of $0.1 million. In addition, $21.5 million of the amount outstanding at December 31, 2012 (none at December 31, 2011) was guaranteed by Nucor. If Nucor Trading S.A. fails to pay when due any amounts for which it is obligated, Nucor could be required to pay such amounts pursuant to and in accordance with the terms of the guarantee.

Letters of credit totaling $27.2 million were outstanding as of December 31, 2012 related to certain obligations, including workers' compensation, utilities deposits and credit arrangements by Nucor Trading S.A. for commitments to purchase inventories.

Nucor capitalized $4.7 million of interest expense in 2012 ($3.5 million in 2011 and $0.9 million in 2010) related to the borrowing costs associated with various construction projects.

13. CAPITAL STOCK

The par value of Nucor's common stock is $0.40 per share and there are 800 million shares authorized. In addition, 250,000 shares of preferred stock, par value of $4.00 per share, are authorized, with preferences, rights and restrictions as may be fixed by Nucor's board of directors. There are no shares of preferred stock issued or outstanding.

In 2001, the board of directors adopted a Stockholder Rights Plan in which one right was distributed as a dividend for each Nucor common share outstanding. The rights had no voting power and expired on March 8, 2011.

14. DERIVATIVE FINANCIAL INSTRUMENTS

The following tables summarize information regarding Nucor's derivative instruments:

(in thousands)

December 31,	Consolidated Balance Sheet Location	Fair Value	
		2012	2011
Asset derivatives not designated as hedging instruments:			
Commodity contracts	Other current assets	$ -	$ 5,071
Liability derivatives designated as hedging instruments:			
Commodity contracts	Accrued expenses and other current liabilities	$ -	$(21,100)
Liability derivatives not designated as hedging instruments:			
Commodity contracts	Accrued expenses and other current liabilities	(303)	-
Foreign exchange contracts	Accrued expenses and other current liabilities	(15)	(334)
Total liability derivatives not designated as hedging instruments		(318)	(334)
Total liability derivatives		$ (318)	$(21,434)

truments on the Consolidated Statements of Earnings

Derivatives Designated as Hedging Instruments *(in thousands)*

Derivatives in Cash Flow Hedging Relationships	Statement of Earnings Location	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)			Amount of Gain or (Loss) Reclassified from Accumulated OCI into Earnings (Effective Portion)			Amount of Gain or (Loss) Recognized in Earnings on Derivative (Ineffective Portion)		
		2012	2011	2010	2012	2011	2010	2012	2011	2010
Commodity contracts	Cost of products sold	$ (2,264)	$ (8,454)	$ (29,957)	$ (42,515)	$ (37,093)	$ (35,141)	$ 500	$ 600	$ 600

Derivatives Not Designated as Hedging Instruments *(in thousands)*

Derivatives Not Designated as Hedging Instruments	Statement of Earnings Location	Amount of Gain or (Loss) Recognized in Earnings on Derivative		
		2012	2011	2010
Commodity contracts	Cost of products sold	$1,321	$11,757	$(1,417)
	Cost of products sold	198	(665)	907

Foreign exchange contracts					
Total			$1,519	$11,092	$ (510)

During the first quarter of 2012, Nucor settled all of its open natural gas forward purchase contracts that were previously in place. These settlements affected earnings over the periods specified in the original agreements.

Nucor has also entered into various natural gas purchase contracts, which effectively commit Nucor to the following purchases of natural gas to be used for production: $88.4 million in 2013; $30.2 million in 2014; $29.1 million in 2015; $28.8 million in 2016; $29.1 million in 2017; and $347.4 million between 2018 and 2028. These natural gas purchase contracts will primarily supply our direct reduced iron facility in Trinidad.

15. FAIR VALUE MEASUREMENTS

The following table summarizes information regarding Nucor's financial assets and financial liabilities that are measured at fair value as of December 31, 2012. Nucor does not currently have any non- financial assets or liabilities that are measured at fair value on a recurring basis.

(in thousands)

		Fair Value Measurements at Reporting Date Using		
December 31,	Carrying Amount in Consolidated Balance Sheets	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2012				
Assets:				
Cash equivalents	$ 830,011	$ 830,011		
Short- term investments	104,167	104,167		
Restricted cash and investments	275,163	275,163		
Total assets	$1,209,341	$1,209,341	-	-
Liabilities:				
Foreign exchange and commodity contracts	$ (318)	-	$ (318)	-
2011				
Assets:				
Cash equivalents	$1,012,122	$1,012,122	$ -	
Short- term investments	1,362,641	1,362,641	-	
Commodity contracts	5,071	-	5,071	
Restricted cash and investments	585,833	585,833	-	
Total assets	$2,965,667	$2,960,596	$ 5,071	-
Liabilities:				
Foreign exchange and commodity contracts	$ (21,434)	-	$(21,434)	-

Fair value measurements for Nucor's cash equivalents, short- term investments and restricted cash and investments are classified under Level 1 because such measurements are based on quoted market prices in active markets for identical assets. Fair value measurements for Nucor's derivatives are classified under Level 2 because such measurements are based on published market prices for similar assets or are estimated based on observable inputs such as interest rates, yield curves, credit risks, spot and future commodity prices and spot and future exchange rates.

The fair value of short- term and long- term debt, including current maturities, was approximately $4.24 billion at December 31, 2012 ($4.76 billion at December 31, 2011). The fair value estimates are classified under Level 2 because such estimates are based on readily available market prices of our debt at December 31, 2012 and 2011, or similar debt with the same maturities, rating and interest rates.

16. CONTINGENCIES

Nucor is subject to environmental laws and regulations established by federal, state and local authorities, and, accordingly, makes provision for the estimated costs of compliance. Of the undiscounted total of $26.5 million of accrued environmental costs at December 31, 2012 ($31.4 million at December 31, 2011), $9.5 million was classified in accrued expenses and other current liabilities ($14.4 million at December 31, 2011) and $17.0 million was classified in deferred credits and other liabilities ($17.0 million at December 31, 2011). Inherent uncertainties exist in these estimates primarily due to unknown conditions, evolving remediation technology, and changing governmental regulations and legal standards.

Nucor has been named, along with other major steel producers, as a co- defendant in several related antitrust class- action complaints filed by Standard Iron Works and other steel purchasers in the United States District Court for the Northern District of Illinois. The majority of these complaints were filed in September and October of 2008, with two additional complaints being filed in July and December of 2010. Two of these complaints have been voluntarily dismissed and are no longer pending. The plaintiffs allege that from April 1, 2005 through December 31, 2007, eight steel manufacturers, including Nucor, engaged in anticompetitive activities with respect to the production and sale of steel. The plaintiffs seek monetary and other relief. Although we believe the plaintiffs' claims are without merit and will vigorously defend against them, we cannot at this time predict the outcome of this litigation or estimate the range of Nucor's potential exposure.

Nucor is involved in various other judicial and administrative proceedings as both plaintiff and defendant, arising in the ordinary course of business. Nucor maintains liability insurance for certain risks that arise that are also subject to certain self- insurance limits. Although the outcome of the claims and proceedings against us cannot be predicted with certainty, we believe that there are no existing claims or proceedings that are likely to have a material adverse effect on the consolidated financial statements.

17. STOCK- BASED COMPENSATION

Stock Options Stock options may be granted to Nucor's key employees, officers and non- employee directors with exercise prices at 100% of the market value on the date of the grant. The stock options granted in 2010, 2011 and 2012 are exercisable at the end of three years and have a term of 10 years. There are no options exercisable as of December 31, 2012. All stock options granted prior to 2010 were fully exercised at December 31, 2012. New shares are issued upon exercise of stock options.

A summary of activity under Nucor's stock option plans is as follows:

(shares in thousands)

Year Ended December 31,	2012		2011		2010	
	Shares	Weighted- Average Exercise Price	Shares	Weighted- Average Exercise Price	Shares	Weighted- Average Exercise Price
Number of shares under option:						
Outstanding at beginning of year	1,156	$38.26	983	$29.14	1,060	$21.95
Granted	754	$35.76	560	$42.34	242	$41.43
Exercised	(354)	$29.67	(387)	$20.96	(319)	$14.60
Canceled	-	-	-	-	-	-
Outstanding at end of year	1,556	$39.01	1,156	$38.26	983	$29.14
Options exercisable at end of year	-	-	354	$29.67	741	$25.12

The shares reserved for future grants as of December 31, 2012, 2011 and 2010 are reflected in the restricted stock units table below.

The total intrinsic value of options (the amount by which the stock price exceeded the exercise price of the option on the date of exercise) that were exercised during 2012 was $4.3 million ($7.6 million in 2011 and $8.5 million in 2010).

The following table summarizes information about stock options outstanding at December 31, 2012 (none are exercisable):

(shares in thousands)

	Options Outstanding	
Exercise Price	Number Outstanding	Weighted- Average Remaining Contractual Life
$35.76	754	9.4 years
$41.43	242	7.4 years
$42.34	560	8.4 years
$35.76 $ 42.34	1,556	8.7 years

As of December 31, 2012, the total aggregate intrinsic value of outstanding options was $6.5 million.
The grant date fair value of options granted was $11.40 in 2012 ($15.37 in 2011 and $15.50 in 2010). The fair value was estimated using the Black- Scholes option- pricing model with the following assumptions:

	2012	2011	2010
Exercise price	$35.76	$42.34	$41.43
Expected dividend yield	4.08%	3.42%	3.48%
Expected stock price volatility	48.99%	49.40%	50.58%
Risk- free interest rate	1.06%	2.39%	2.75%
Expected life (in years)	6.5	6.5	6.5

Compensation expense for stock options was $9.9 million in 2012 ($9.9 million in 2011 and $0.7 million in 2010). As of December 31, 2012, unrecognized compensation expense related to options was $0.5 million, which is expected to be recognized over 0.4 years.
Restricted Stock Units Nucor annually grants restricted stock units (RSUs) to key employees, officers and non- employee directors. The RSUs typically vest and are converted to common stock in three equal installments on each of the first three anniversaries of the grant date. A portion of the RSUs awarded to senior officers vest upon the officer's retirement. Retirement, for purposes of vesting in these units only, means termination of employment with approval of the Compensation and Executive Development Committee of the Board of Directors after satisfying age and years of service requirements. RSUs granted to non- employee directors are fully vested on the grant date and are payable to the non- employee director in the form of common stock after the termination of the director's service on the board of directors.
RSUs granted to employees who are eligible for retirement on the date of grant are expensed immediately, and RSUs granted to employees who will become retirement- eligible prior to the end of the vesting term are expensed over the period through which the employee will become retirement- eligible since these awards vest upon retirement from the Company. Compensation expense for RSUs granted to employees who are not retirement- eligible is recognized on a straight- line basis over the vesting period.
Cash dividend equivalents are paid to participants each quarter. Dividend equivalents paid on units expected to vest are recognized as a reduction in retained earnings.
The fair value of the RSUs is determined based on the closing stock price of Nucor's common stock on the day before the grant.
A summary of Nucor's restricted stock unit activity is as follows:

(shares in thousands)

Year Ended December 31,	2012		2011		2010	
	Shares	Grant Date Fair Value	Shares	Grant Date Fair Value	Shares	Grant Date Fair Value
Restricted stock units:						
Unvested at beginning of year	962	$46.09	1,203	$49.96	1,464	$54.69
Granted	1,101	$35.76	490	$42.34	462	$43.05
Vested	(915)	$40.36	(713)	$50.04	(709)	$55.24
Canceled	(42)	$39.41	(18)	$46.06	(14)	$49.52
Unvested at end of year	1,106	$40.80	962	$46.09	1,203	$49.96
Shares reserved for future grants (stock options and RSUs)	11,839		13,695		14,777	

Compensation expense for RSUs was $34.2 million in 2012 ($31.6 million in 2011 and $37.0 million in 2010). The total fair value of shares vested during 2012 was $33.1 million ($29.3 million in 2011 and $30.4 million in 2010). As of December 31, 2012, unrecognized compensation expense related to unvested RSUs was $27.4 million, which is expected to be recognized over a weighted- average period of 1.9 years.

Restricted Stock Awards Nucor's Senior Officers Long- Term Incentive Plan (the LTIP) and Annual Incentive Plan (the AIP) authorize the award of shares of common stock to officers subject to certain conditions and restrictions.

The LTIP provides for the award of shares of restricted common stock at the end of each LTIP performance measurement period at no cost to officers if certain financial performance goals are met during the period. One- third of the LTIP restricted stock award vests upon each of the first three anniversaries of the award date or, if earlier, upon the officer's attainment of age fifty- five while employed by Nucor. Although participants are entitled to cash dividends and may vote such awarded shares, the sale or transfer of such shares is limited during the restricted period.

The AIP provides for the payment of annual cash incentive awards. An AIP participant may elect, however, to defer payment of up to one- half of an annual incentive award. In such event, the deferred AIP award is converted into common stock units and credited with a deferral incentive, in the form of additional common stock units, equal to 25% of the number of common stock units attributable to the deferred AIP award. Common stock units attributable to deferred AIP awards are fully vested. Common stock units credited as a deferral incentive vest upon the AIP participant's attainment of age fifty- five while employed by Nucor. Vested common stock units are paid to AIP participants in the form of shares of common stock following their termination of employment with Nucor.

A summary of Nucor's restricted stock activity under the AIP and LTIP is as follows:

(shares in thousands)

Year Ended December 31,	2012		2011		2010	
	Shares	Grant Date Fair Value	Shares	Grant Date Fair Value	Shares	Grant Date Fair Value
Restricted stock awards and units:						
Unvested at beginning of year	94	$42.46	141	$44.62	240	$50.75
Granted	122	$42.20	118	$46.41	131	$44.82
Vested	(144)	$41.62	(165)	$47.13	(230)	$51.13
Canceled	-	-	-	-	-	-
Unvested at end of year	72	$43.72	94	$42.46	141	$44.62
Shares reserved for future grants	1,360		1,482		1,600	

Compensation expense for common stock and common stock units awarded under the AIP and LTIP is recorded over the performance measurement and vesting periods based on the anticipated number and market value of shares of common stock and common stock units to be awarded. Compensation expense for anticipated awards based upon Nucor's financial performance, exclusive of amounts payable in cash, was $6.6 million in 2012 ($7.4 million in 2011 and $5.2 million in 2010). The total fair value of shares vested during 2012 was $6.0 million ($7.3 million in 2011 and $10.2 million in 2010). As of December 31, 2012, unrecognized compensation expense related to unvested restricted stock awards was $0.6 million, which is expected to be recognized over a weighted- average period of 1.6 years.

18. EMPLOYEE BENEFIT PLANS

Nucor makes contributions to a Profit Sharing and Retirement Savings Plan for qualified employees based on the profitability of the Company. Nucor's expense for these benefits totaled $77.7 million in 2012 ($117.7 million in 2011 and $22.1 million in 2010). The related liability for these benefits is included in salaries, wages and related accruals.

Nucor also has a medical plan covering certain eligible early retirees. The unfunded obligation, included in deferred credits and other liabilities in the consolidated balance sheets, totaled $13.5 million at December 31, 2012 ($13.3 million at December 31, 2011). The benefit associated with this early retiree medical plan totaled $1.9 million in 2012 (expense of $3.5 million in 2011 and expense of $2.7 million in 2010). We also recorded a non- cash gain of $29.0 million in cost of products sold in the fourth quarter of 2011 as a result of a correction of an error in the actuarial calculation for the plan. The error also resulted in a $7.6 million reduction of other comprehensive income. This error did not have a material impact on that period or any previously reported periods.

The discount rate used was 3.7% in 2012 (4.5% in 2011 and 5.5% in 2010). The health care cost increase trend rate used was 6.6% in 2012 (6.7% in 2011 and 6.8% in 2010). The health care cost increase in the trend rate is projected to decline gradually to 4.5% by 2027.

19. INTEREST EXPENSE (INCOME)

The components of net interest expense are as follows:

(in thousands)

Year Ended December 31,		2012		2011		2010
Interest expense	$	173,503	$	178,812	$	161,140
Interest income		(11,128)		(12,718)		(8,047)
Interest expense, net	$	162,375	$	166,094	$	153,093

Interest paid was $178.0 million in 2012 ($177.6 million in 2011 and $151.8 million in 2010).

20. INCOME TAXES

Components of earnings from continuing operations before income taxes and noncontrolling interests are as follows:

(in thousands)

Year Ended December 31,		2012		2011		2010
United States	$	854,705	$	1,241,465	$	260,794
Foreign		(1,765)		10,347		6,321
	$	852,940	$	1,251,812	$	267,115

The provision for income taxes consists of the following:

(in thousands)

Year Ended December 31,		2012		2011		2010
Current:						
Federal	$	261,552	$	329,076	$	(66,462)
State		20,337		1,685		(19,297)
Foreign		3,199		2,016		8,289
Total current		285,088		332,777		(77,470)
Deferred:						
Federal		(23,052)		55,124		138,662
State		(10,440)		10,400		12,223
Foreign		8,218		(7,473)		(12,623)
Total deferred		(25,274)		58,051		138,262
Total provision for income taxes	$	259,814	$	390,828	$	60,792

A reconciliation of the federal statutory tax rate (35%) to the total provision is as follows:

Year Ended December 31,	2012	2011	2010
Taxes computed at statutory rate	35.00%	35.00%	35.00%
State income taxes, net of federal income tax benefit	0.75	0.63	(1.72)
Federal research credit	-	(0.28)	(1.19)
Domestic manufacturing deduction	(3.25)	(2.21)	-
Equity in losses of foreign joint venture	1.43	0.64	3.09
Foreign rate differential	0.60	(0.92)	(3.83)
Noncontrolling interests	(3.64)	(2.32)	(9.47)
Other, net	(0.43)	0.68	0.88
Provision for income taxes	30.46%	31.22%	22.76%

Deferred tax assets and liabilities resulted from the following:

(in thousands)

December 31,	2012	2011
Deferred tax assets:		
Accrued liabilities and reserves	$ 108,287	$ 115,752
Allowance for doubtful accounts	14,212	14,088
Inventory	174,499	142,236
Post- retirement benefits	11,119	8,260
Natural gas hedges	221	22,433
Net operating loss carryforward	15,033	25,739
Cumulative translation adjustments	-	2,254
Tax credit carryforwards	28,600	39,700
Total deferred tax assets	351,971	370,462
Deferred tax liabilities:		
Holdbacks and amounts not due under contracts	(17,523)	(9,406)
Cumulative translation adjustments	(1,600)	-
Intangibles	(233,413)	(236,627)
Property, plant and equipment	(475,176)	(461,915)
Total deferred tax liabilities	(727,712)	(707,948)
	$ (375,741)	$ (337,486)

Total net deferred tax liabilities		

Current deferred tax assets included in other current assets were $190.4 million at December 31, 2012 ($195.9 million at December 31, 2011). Non- current deferred tax liabilities included in deferred credits and other liabilities were $566.1 million at December 31, 2012 ($533.4 million at December 31, 2011). Nucor paid $313.5 million in net federal, state and foreign income taxes in 2012 (paid $322.4 million in net federal, state and foreign income taxes in 2011, and received $245.0 million in refunds in 2010).

Cumulative undistributed foreign earnings for which U.S. taxes have not been provided are included in consolidated retained earnings in the amount of $176.5 million at December 31, 2012 ($168.0 million at December 31, 2011). These earnings are considered to be indefinitely reinvested and, accordingly, no provisions for U.S. federal and state income taxes are required. It is not practicable to determine the amount of unrecognized deferred tax liability related to the unremitted earnings.

State net operating loss carryforwards were $418.8 million at December 31, 2012 ($490.8 million at December 31, 2011). If unused, they will expire between 2014 and 2032. Foreign net operating loss carryforwards were $59.2 million at December 31, 2012 ($66.2 million at December 31, 2011). If unused, they will expire between 2027 and 2029.

At December 31, 2012, Nucor had approximately $80.9 million of unrecognized tax benefits, of which $76.4 million would affect Nucor's effective tax rate, if recognized. At December 31, 2011, Nucor had approximately $80.9 million of unrecognized tax benefits, of which $78.5 million would affect Nucor's effective tax rate, if recognized.

A reconciliation of the beginning and ending amounts of unrecognized tax benefits recorded in deferred credits and other liabilities is as follows:

(in thousands)

Year Ended December 31,	2012	2011	2010
Balance at beginning of year	$80,897	$92,752	$108,587
Additions based on tax positions related to current year	9,456	6,733	1,983
Reductions based on tax positions related to current year	(132)	(3,160)	(1,358)
Additions based on tax positions related to prior years	5,821	937	5,705
Reductions based on tax positions related to prior years	(3,296)	(2,169)	(4,046)
Additions due to settlements with taxing authorities	-	-	2,363
Reductions due to settlements with taxing authorities	(764)	(958)	(3,246)
Reductions due to statute of limitations lapse	(11,120)	(13,238)	(17,236)
Balance at end of year	$80,862	$80,897	$ 92,752

We estimate that in the next twelve months, our gross uncertain tax positions, exclusive of interest, could decrease by as much as $19.3 million, as a result of the expiration of the statute of limitations.

During 2012, Nucor recognized $2.1 million of expense in interest and penalties ($3.6 million of expense in 2011 and $5.3 million of benefit in 2010). As of December 31, 2012, Nucor had approximately $36.4 million of accrued interest and penalties related to uncertain tax positions ($34.3 million at December 31, 2011).

Nucor has concluded U.S. federal income tax matters for years through 2006. The years 2004 and 2007 are open to the extent net operating losses were carried back. The 2008 to 2012 tax years are open to examination by the Internal Revenue Service. In 2011 the Canada Revenue Agency completed an audit examination for the periods 2006 to 2008 for Harris Steel Group Inc. and subsidiaries with immaterial adjustments to the income tax returns. The tax years 2008 through 2012 remain open to examination by other major taxing jurisdictions to which Nucor is subject (primarily Canada and other state and local jurisdictions).

21. EARNINGS PER SHARE

The computations of basic and diluted net earnings per share are as follows:

(in thousands, except per share data)

Year Ended December 31,		2012		2011		2010
Basic net earnings per share:						
Basic net earnings	$	504,619	$	778,188	$	134,092
Earnings allocated to participating securities		(1,713)		(2,653)		(1,823)
Net earnings available to common stockholders	$	502,906	$	775,535	$	132,269
Average shares outstanding		318,172		316,997		315,962
Basic net earnings per share	$	1.58	$	2.45	$	0.42
Diluted net earnings per share:						
Diluted net earnings	$	504,619	$	778,188	$	134,092
Earnings allocated to participating securities		(1,714)		(2,654)		(1,823)
Net earnings available to common stockholders	$	502,905	$	775,534	$	132,269
Diluted average shares outstanding:						
Basic shares outstanding		318,172		316,997		315,962
Dilutive effect of stock options and other		68		164		548
		318,240		317,161		316,510
Diluted net earnings per share	$	1.58	$	2.45	$	0.42

The following stock options were excluded from the computation of diluted net earnings per share because their effect would have been anti- dilutive:

(shares in thousands)

Year Ended December 31,	2012	2011	2010

Anti- dilutive stock options:			
Weighted average shares	801	801	242
Weighted average exercise price	$ 42.07	$ 42.07	$ 41.43

22. SEGMENTS

Nucor reports its results in the following segments: steel mills, steel products and raw materials. The steel mills segment includes carbon and alloy steel in sheet, bars, structural and plate, and Nucor's equity method investments in Duferdofin Nucor and NuMit. The steel products segment includes steel joists and joist girders, steel deck, fabricated concrete reinforcing steel, cold finished steel, steel fasteners, metal building systems, steel grating and expanded metal, and wire and wire mesh. The raw materials segment includes DJJ, a scrap broker and processor; Nu- Iron Unlimited, a facility that produces DRI used by the steel mills; a DRI facility under construction in Louisiana; our natural gas working interests; and certain equity method investments. The "All other" category primarily includes Nucor's steel trading businesses. The segments are consistent with the way Nucor manages its business, which is primarily based upon the similarity of the types of products produced and sold by each segment.

Net interest expense, other income, profit sharing expense, stock- based compensation and changes in the LIFO reserve are shown under Corporate/eliminations. Corporate assets primarily include cash and cash equivalents, short- term investments, restricted cash and investments, allowances to eliminate intercompany profit in inventory, deferred income tax assets, federal income taxes receivable, the LIFO reserve and investments in and advances to affiliates. Certain amounts for prior years have been reclassified to conform to the 2012 presentation.

Nucor's results by segment are as follows:

Year Ended December 31,	2012	2011	2010
			(in thousands)
Net sales to external customers:			
Steel mills	$ 13,317,980	$ 13,960,245	$ 10,860,760
Steel products	3,738,381	3,431,490	2,831,209
Raw materials	1,909,095	2,128,391	1,814,329
All other	463,817	503,438	338,329
	$ 19,429,273	$ 20,023,564	$ 15,844,627
Intercompany sales:			
Steel mills	$ 2,595,767	$ 2,405,590	$ 1,719,937
Steel products	71,277	55,646	43,565
Raw materials	9,514,163	10,436,379	8,052,986
All other	13,644	24,869	8,616
Corporate/eliminations	(12,194,851)	(12,922,484)	(9,825,104)
	$ -	$ -	$ -
Depreciation expense:			
Steel mills	$ 366,117	$ 371,984	$ 370,458
Steel products	47,948	53,272	58,429
Raw materials	112,939	92,250	78,308
All other	65	56	90
Corporate	6,941	5,009	4,862
	$ 534,010	$ 522,571	$ 512,147
Amortization expense:			
Steel mills	$ 7,879	$ -	$ 262
Steel products	35,152	38,743	40,745
Raw materials	29,109	28,215	28,577
All other	871	871	871
Corporate	-	-	-
	$ 73,011	$ 67,829	$ 70,455
Earnings (loss) before income taxes and noncontrolling interests:			
Steel mills	$ 1,161,449	$ 1,808,859	$ 872,566
Steel products	(17,140)	(60,282)	(173,433)
Raw materials	55,264	156,180	112,306
All other	821	4,296	4,344
Corporate/eliminations	(347,454)	(657,241)	(548,668)
	$ 852,940	$ 1,251,812	$ 267,115
Segment assets:			
Steel mills	$ 7,669,917	$ 6,440,868	$ 6,061,823
Steel products	2,870,810	2,903,281	2,835,812
Raw materials	3,379,742	2,925,651	2,713,819
All other	200,775	152,107	170,174
Corporate/eliminations	30,815	2,148,443	2,140,282
	$ 14,152,059	$ 14,570,350	$ 13,921,910

Capital expenditures:			
Steel mills	$ 369,314	$ 181,178	$ 186,236
Steel products	31,698	20,918	21,321
Raw materials	604,312	245,337	125,536
All other	149	15	24
Corporate	13,861	3,179	12,177
	$ 1,019,334	$ 450,627	$ 345,294

Net sales by product are as follows. Further product group breakdown is impracticable.

(in thousands)

Year Ended December 31,	2012	2011	2010
Net sales to external customers:			
Sheet	$ 5,540,868	$ 5,967,756	$ 4,952,236
Bar	3,536,094	3,733,716	2,668,706
Structural	2,301,778	2,049,907	1,633,203
Plate	1,939,240	2,208,866	1,606,615
Steel products	3,738,381	3,431,490	2,831,209
Raw materials	1,909,095	2,128,391	1,814,329
All other	463,817	503,438	338,329
	$ 19,429,273	$ 20,023,564	$ 15,844,627

23. QUARTERLY INFORMATION (UNAUDITED)

(in thousands, except per share data)

Year Ended December 31,	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2012				
Net sales	$5,072,594	$5,104,199	$4,801,206	$4,451,274
Gross margin[(1)]	380,527	399,930	348,733	384,348
Net earnings[(2)]	163,412	139,567	129,892	160,255
Net earnings attributable to Nucor stockholders[(2)]	145,104	112,299	110,308	136,908
Net earnings per share:				
Basic	0.46	0.35	0.35	0.43
Diluted	0.46	0.35	0.35	0.43
2011				
Net sales	$4,833,934	$5,107,809	$5,252,144	$4,829,677
Gross margin[(3)]	423,735	649,450	458,130	350,105
Net earnings[(4)]	181,122	321,578	200,111	158,173
Net earnings attributable to Nucor stockholders[(4)]	159,841	299,773	181,518	137,056
Net earnings per share:				

Basic	0.50	0.94	0.57	0.43
Diluted	0.50	0.94	0.57	0.43

(1) Nucor incurred a LIFO charge of $14.5 million in the first quarter and recorded LIFO credits of $14.5 million, $84.0 million and $71.9 million in the second, third and fourth quarters, respectively. Inventory related purchase accounting adjustments, associated with the acquisition of Skyline, of $8.6 million, $28.2 million, and $12.0 million were recorded in the second, third and fourth quarters, respectively.

(2) The second quarter includes a pre- tax charge of $30.0 million for impairment of Nucor's equity investment in Duferdofin Nucor S.r.l. The third quarter includes a pre- tax charge of $17.6 million related to the loss on the sale of the assets of Nucor Wire Products Pennsylvania, Inc.

(3) Nucor incurred LIFO charges of $31.0 million, $32.0 million, $28.0 million and $51.8 million in the first, second, third and fourth quarters, respectively. In the fourth quarter, Nucor recognized a gain of $29.0 million related to the correction of an error in the actuarial calculation associated with the medical plan covering certain eligible early retirees.

(4) The third quarter includes a pre- tax charge of $13.9 million for impairment of Nucor's equity investment in a dust recycling project.

CORPORATE AND STOCK DATA

CORPORATE OFFICE

1915 Rexford Road
Charlotte, North Carolina 28211
Phone 704/366- 7000
Fax 704/362- 4208

STOCK TRANSFERS
DIVIDEND DISBURSING
DIVIDEND REINVESTMENT

American Stock Transfer & Trust Company, LLC
6201 15th Avenue
Brooklyn, New York 11219
Phone 877/715- 0504
Fax 718/236- 2641

ANNUAL MEETING

The annual meeting of stockholders will be held at 10:00 a.m. on Thursday, May 9, 2013, at the Charlotte Marriott SouthPark, 2200 Rexford Road, Charlotte, NC.

STOCK LISTING

Nucor's common stock is traded on the New York Stock Exchange under the symbol NUE. As of January 31, 2013, there were approximately 19,000 stockholders of record.

FORM 10- K

A copy of Nucor's 2012 annual report filed with the Securities and Exchange Commission (SEC) on Form 10- K is available to stockholders upon request.

INTERNET ACCESS

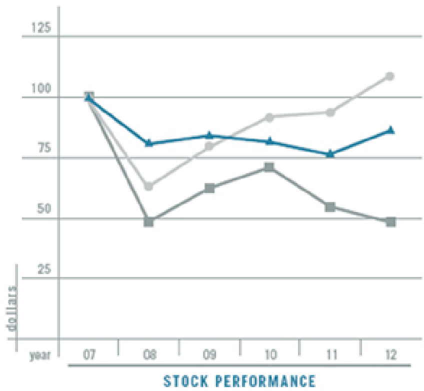
Nucor's annual report on Form 10- K, quarterly reports on Form 10- Q, current reports on Form 8- K, and all amendments to these reports are available without charge through Nucor's website, www.nucor.com, as soon as reasonably practicable after Nucor files these reports electronically with or furnishes them to the SEC. Additional information available on our website includes our Corporate Governance Principles, Board of Directors Committee Charters, Standards of Business Conduct and Ethics, and Code of Ethics for Senior Financial Professionals as well as various other financial and statistical data.

STOCK PRICE AND DIVIDENDS PAID

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2012				
Stock price:				
High	$45.75	$43.99	$40.97	$44.00
Low	40.08	34.23	36.61	37.70
Dividends paid	0.365	0.365	0.365	0.365
2011				
Stock price:				
High	$49.24	$48.00	$41.70	$41.57
Low	42.81	38.90	30.72	29.82
Dividends paid	0.3625	0.3625	0.3625	0.3625

STOCK PERFORMANCE

This graphic comparison assumes the investment of $100 in Nucor Corporation common stock, $100 in the S&P 500 Index and $100 in the S&P Steel Group Index, all at year- end 2007. The resulting cumulative total return assumes that cash dividends were reinvested. Nucor common stock comprised 53% of the S&P Steel Group Index at year end 2012 (42% at year- end 2007).



▲ **Nucor Corporation**

● **S&P 500 Index**

■ **S&P 500 Steel Index**

THIS ANNUAL REPORT HAS BEEN PRINTED ON RECYCLED PAPER.

Exhibit 21
Nucor Corporation
2012 Form 10- K

Subsidiaries

Subsidiary	State/Jurisdiction of Incorporation
Nucor Steel Auburn, Inc.	Delaware
Nucor Steel Birmingham, Inc.	Delaware
Nucor Steel Decatur, LLC.	Delaware
Nucor Steel Jackson, Inc.	Delaware
Nucor Steel Kankakee, Inc.	Delaware
Nucor Steel Kingman, LLC	Delaware
Nucor Steel Marion, Inc.	Delaware
Nucor Steel Memphis, Inc.	Delaware
Nucor Steel Seattle, Inc.	Delaware
Nucor Steel Tuscaloosa, Inc	Delaware
Nucor Steel Connecticut Inc.	Delaware
Nucor- Yamato Steel Company	Delaware
Nu- Iron Unlimited	Trinidad
Nucor Castrip Arkansas LLC	Delaware
Harris Steel Inc.	Delaware
Harris U.S. Holdings Inc	Delaware
Harris Steel ULC	Canada
Magnatrax Corporation	Delaware
The David J. Joseph Company	Delaware
Ambassador Steel Corporation	Indiana
Nucor Energy Holdings Inc	Delaware
Skyline Steel LLC	Delaware
Nucor Steel Louisiana LLC	Delaware

Exhibit 23
Nucor Corporation
2012 Form 10- K

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S- 8 (Numbers 333- 108749, 333- 108751 and 333- 167070) and on Form S- 3ASR (Number 333- 176786) of Nucor Corporation of our report dated February 28, 2013 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10- K. We also consent to the incorporation by reference of our report dated February 28, 2013 relating to the financial statement schedule, which appears in this Form 10- K.

/s/ PricewaterhouseCoopers LLP
Charlotte, North Carolina
February 28, 2013

Exhibit 31
Nucor Corporation
2012 Form 10- K

NUCOR CORPORATION
Section 302 Certifications

I, John J. Ferriola, certify that:

1. **I have reviewed this annual report on Form 10- K of Nucor Corporation;**

2. **Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;**

3. **Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;**

4. **The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a- 15(e) and 15d- 15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d- 15(f)) for the registrant and have:**

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. **The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):**

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2013

/s/ John J. Ferriola
John J. Ferriola
Chief Executive Officer
and President

Exhibit 31(i)
Nucor Corporation
2012 Form 10- K

NUCOR CORPORATION
Section 302 Certifications

I, James D. Frias, certify that:

1. **I have reviewed this annual report on Form 10- K of Nucor Corporation;**

2. **Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;**

3. **Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;**

4. **The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a- 15(e) and 15d- 15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a- 15(f) and 15d- 15(f)) for the registrant and have:**

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. **The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):**

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2013

/s/ James D. Frias
James D. Frias
Chief Financial Officer, Treasurer
and Executive Vice President

Exhibit 32
Nucor Corporation
2012 Form 10- K

Certification of Principal Executive Officer
Pursuant to Section 906 of the Sarbanes- Oxley Act of 2002
(18 U.S.C. 1350)

In connection with the Annual Report of Nucor Corporation (the "Registrant"), on Form 10- K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission (the "Report"), I, John J. Ferriola, Chief Executive Officer and President (principal executive officer) of the Registrant, certify, pursuant to § 906 of the Sarbanes- Oxley Act of 2002 (18 U.S.C. § 1350), that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ John J. Ferriola

Name:	**John J. Ferriola**
Date:	**February 28, 2013**

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Form 10- K and shall not be considered filed as part of the Form 10- K.

Exhibit 32(i)
Nucor Corporation
2012 Form 10- K

Certification of Principal Financial Officer
Pursuant to 18 U.S.C. 1350
(Section 906 of the Sarbanes- Oxley Act of 2002)

In connection with the Annual Report of Nucor Corporation (the "Registrant"), on Form 10- K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission (the "Report"), I, James D. Frias, Chief Financial Officer, Treasurer and Executive Vice President (principal financial officer) of the Registrant, certify, pursuant to § 906 of the Sarbanes- Oxley Act of 2002 (18 U.S.C. § 1350), that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ James D. Frias

Name:	**James D. Frias**
Date:	**February 28, 2013**

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Form 10- K and shall not be considered filed as part of the Form 10- K.