ReoStar Energy CORP
Form 10KSB
July 15, 2008

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

FORM 10-KSB

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

For the fiscal year ended March 31, 2008

Commission file number 000-26139

REOSTAR ENERGY CORPORATION
(Name of small business issuer in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	20-8428738 (IRS Employer Identification Number)
3880 Hulen St., Ste 500, Fort Worth, TX (Address of principal executive offices))	76107 (Zip Code)

Issuer's telephone number: 817-989-7367

Securities registered under Section 12(b) of the Exchange Act:
None

Securities registered under Section 12(g) of the Exchange Act:

Common Stock, $.001 par value
(Title of class)

Check whether the issuer is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. o

Check whether the issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will 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-KSB o

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

Revenue for the fiscal year ended March 31, 2008 is $5,490,331 and the aggregate market value of the voting stock held by non-affiliates of the registrant based on the closing bid price of such stock as of March 31, 2008 amounted to $15,487,172.

The number of shares outstanding of the registrant's common stock as of March 31, 2008 was 80,181,310 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2008 annual meeting of shareholders to be filed with the SEC within 120 days after the end of the fiscal year ended March 31, 2008 are incorporated by reference in Part III of this Form 10-KSB.

Transitional Small Business Disclosure Format (check one): Yes o No x

REOSTAR ENERGY CORPORATION
FORM 10-KSB ANNUAL REPORT
FISCAL YEAR ENDED MARCH 31, 2008
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Disclosures Regarding Forward-Looking Statements

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission (the "SEC"), as well as information included in oral statements or other written statements made or to be made by us contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words "budget," "budgeted," "assumes," "should," "goal," "anticipates," "expects," "believes," "seeks," "plans," "estimates," "intends," "projects" or "targets" and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: the factors described in Item 1 of this report under the heading "Risk Factors," production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, we do not undertake, and specifically disclaim any obligation, to update or revise such statements to reflect new circumstances or unanticipated events as they occur, and we urge readers to review and consider disclosures we make in this and other reports that discuss factors germane to our business, including our reports on Forms 10-KSB, 10-QSB, and 8-K subsequently filed from time to time with the SEC.

PART I

ITEM 1. DESCRIPTION OF BUSINESS

General

We are engaged in the exploration, development and acquisition of oil and gas properties, primarily located in the state of Texas. We seek to increase oil and gas reserves and production through internally generated drilling projects, coupled with complementary acquisitions.

At year-end 2008, a certified engineering firm valued our proven reserves at $425,445,500, which reflects the present value of our future net cash flows from reserves before income taxes, discounted at 10 percent.

At year-end 2008, we owned approximately 20,000 gross (16,250 net) acres of leasehold, which includes 16,000 acres of exploratory and developmental prospects as well as 4,000 acres of enhanced oil recovery prospects. We have built a multi-year inventory of drilling projects and drilling locations and currently have enough acreage to sustain several years of drilling.

ReoStar was incorporated in Nevada on November 29, 2004 under the name Goldrange Resources, Inc. In February of 2007 we changed our name to ReoStar Energy Corporation.

Our corporate offices are located at 3880 Hulen Street, Suite 500, Fort Worth, Texas 76107. Our telephone number is (817) 989-7367.

Business Strategy

Our objective is to build shareholder value by establishing and consistently growing our production and reserves with a strong emphasis on cost control and risk mitigation. Our strategy is (1) to control operations of all our leases via our affiliated operating companies, (2) to acquire and develop leasehold in key regional resource development plays while utilizing existing infrastructure and engaging in long-term drilling and development programs, and (3) to acquire leasehold in mature fields and implement enhanced oil recovery programs.

Significant Accomplishments in Fiscal Year 2008

Leasehold Acquisition and Development:

Barnett Shale. Our main area of interest in the Barnett Shale play is located in the "oil window" of the Barnett in southwest Cooke County, Texas. We sold approximately 1,475 net acres outside our main area of interest and acquired bolt-on acreage of approximately 710 gross acres (approximately 533 net acres) contiguous to the acreage we hold in Cooke County.

We drilled, completed, and began production in twelve wells and drilled another seven wells that we anticipate will be completed in the first quarter of fiscal year 2009. Additionally, we repurchased working interests in 30 wells at a cost of approximately $1.8 million.

We identified zones up-hole in most of our existing wells that show significant hydro-carbon producing potential in addition to the proven reserves located in the Barnett Shale interval. In February, we successfully moved up-hole from the Barnett and re-completed one well into the Forestburg limestone formation. The re-completed well had an IP of 40 barrels of oil and 50 mcf gas per day at a cost of approximately $50,000.

Corsicana Enhanced Oil Recovery (EOR) Project. We began injecting surfactant polymer in our pilot project in mid-June 2007. The initial results have been positive. Average daily production in the pilot project increased by 50% for the fourth quarter when compared to pre-pilot production for the first quarter of the fiscal year. We have initiated the second phase of our polymer flood program and as of the date of this filing have drilled 12 new wells in an area immediately south to our injection facility adjacent to the pilot wells. To date, we have injected over 162,000 bbls of a polymer-surfactant solution into our pilot acreage and expanded the area to include an additional 100 acres. We have also drilled 1 of 4 planned and permitted deep exploration wells with our working interest partner and expect to drill the remaining three during the second quarter of fiscal year 2009.

Fayetteville Shale Mineral Interests. We have decided to sell our acreage in Fayetteville Shale as it lies outside of our geographic area of interest.

Tri-County Gas Gathering System. In June 2007, we sold our interest in the Tri-County Gas Gathering System for a gain of approximately $2.2 million. The 8-k filed on June 7, 2007 is incorporated herein by reference.

Concentrate in Core Operating Areas. We currently focus in one region: the Southern Mid-continent region of the United States (which includes the Barnett Shale of North Central Texas, and our Corsicana Enhanced Oil Recovery prospect in East Central Texas). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale. Operating developmental projects (such as our Barnett Shale prospects) and Enhanced Oil Recovery prospects in the same core area allows us to achieve reserve growth, balance our portfolio between oil and natural gas, and minimize some of the operational risks inherent in our industry, while leveraging the benefits of the existing infrastructure.

Manage Our Risk Exposure. We continue to sell a portion of the working interests in the development wells we drill. Currently, we sell our working interests on a turnkey basis, which helps us to save costs. Due to our focus on controlling costs, we are able to extend economic considerations to not only our third-party working interest investors, but to ourselves in the form of a higher retained interest.

Plans for fiscal year 2009

Barnett Shale

Our drilling budget for the Barnett acreage is $20.5 million for fiscal year 2009. The drilling budget will allow us to complete the seven wells that were in process at year-end and drill and complete 30 more wells in our main area of interest in Cooke County. We will retain up to 60% working interest in the new wells. We expect to fund the drilling with the proceeds of a debt facility, proceeds from the sale of up to 40% working interest in each well on a turnkey basis, and cash flow.

We expect to re-complete at least 20 wells in up-hole zones in fiscal year 2009 at an average cost for our working interest of approximately $50,000 per well. We expect to fund the entire re-completions out of cash flow.

Corsicana

We began drilling the second stage of the surfactant-polymer project in the first quarter. A total of 13 new wells are in the process of being drilled, of which four wells will be injectors and nine will be producers. The expansion will continue the drilling pattern established whereby each injector has approximately four producers surrounding it (inverted five-spot drilling pattern). To date, 12 of the second stage wells have been drilled and the Company is in the process of adding pumps to facilitate the increase in volume of surfactant -polymer being injected. The Company also intends to add an alkali to its injection solution, which will help stabilize clays existent in the formation and improve the sweep efficiency of the flood.

We expect to begin drilling Phase III of the surfactant-polymer project in October and continue with additional development during the third quarter of the fiscal year. We expect to drill as many as 36 additional wells by the end of the fiscal year.

We have acquired deeper rights on several leases and plan to drill up to 4 exploratory wells in the area. We plan to drill three wells in the Pecan Gap formation and one well in the Glen Rose formation. We have mitigated the exploration risk associated with drilling these deeper wells by selling a 50% working interests in each of these wells to our industry partner.

All of the planned tertiary project wells are shallow (800 ft.), and cost approximately $60,000 each to drill and complete. Total capital expenditure budget for fiscal 2009 for the Corsicana project is $3.5 million. The budget will be funded primarily with proceeds from a debt facility.

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production, and revenues.

Years Ending	March 31, 2008	December 31, 2006	2005
Production			
Oil (Bbl)	33,602	34,607	8,965
Gas (Mcf)	351,538	199,282	94,358
Total (BOE)	92,192	67,821	24,691
Revenues			
Crude Oil	$ 2,704,468	$ 1,772,649	$ 555,097
Gas	2,197,604	1,101,642	554,102
Total	4,902,072	2,874,291	1,109,199
Average Sale Price (per BOE)	$ 53.17	$ 42.38	$ 44.92

(a) Natural Gas was converted to BOE at the rate of 1 barrel equals 6 MCF.

Competition

We encounter substantial competition in developing and acquiring oil and gas properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independent oil companies, individual proprietors and others. Although our sizable acreage position and core-area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling.

Employees

Non-publicly traded affiliates operate our oil and gas properties. The affiliated operating companies are owned and managed by ReoStar shareholders that collectively own more than 50% of our stock. As of April 1, 2008, the aggregate number of employees and affiliated employees totaled 46.

All of ReoStar's full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field and on-site production operation services.

Available Information

We maintain an internet website under the name "www.reostarenergy.com." Information contained on or connected to our website is not incorporated by reference into this Form 10-KSB and should not be considered part of this report or any other filing that we make with the SEC. We make available, free of charge, on our website, the annual report on Form 10-KSB, quarterly reports on Form 10-QSB, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, our Code of Ethics is available on our website and in print to any stockholder who provides a written request to Investor Relations at 3880 Hulen Street, Suite 500, Fort Worth, Texas 76107.

We file annual reports on Form 10-KSB, quarterly reports on Form 10-QSB and current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including REOSTAR, that file electronically with the SEC. The public can obtain any document we file with the SEC at "www.sec.gov."

Effective February 1, 2007 three entities contributed certain assets to Goldrange Resources, Inc. ("Goldrange") in exchange for stock. The contributing entities were under common control prior to the transaction, and immediately after the transactions, the former shareholders of the contributing entities owned 80.4% of the issued and outstanding stock of Goldrange. The contribution was accounted for as a reverse merger, therefore, all assets are carried on the balance sheet at historical cost. The predecessor entities kept accounting records based on a calendar year end. However, Goldrange's year end was March 31. Therefore, for prior years, all data presented reflects data using a calendar year end.

Marketing and Customers

We market nearly all of our oil and gas production from the properties we operate for both our interest and that of the other working interest owners and royalty owners. All of our gas produced from the Barnett Shale is sold pursuant to a gas contract with Copano Field Services/North Texas LLC. The contract expires May 31, 2017 and provides for two stages of gathering fees. For all wells in production through December 31, 2010, a gathering fee of $0.55 per mcf is assessed against our revenue. Thereafter, for all wells in production as of December 31, 2010, no gathering fee will be assessed. Currently, none of our gas is sold under long-term fixed price contracts. Our Barnett oil is currently sold to Cimmarron Gathering, LP under a month to month contract until such time as either party cancels by providing thirty (30) days advance written notice to the other party of intent to cancel. The contract pays Platts plus minus $1.00 based on Plains - North Texas Sweet posted price.

Oil and gas purchasers are selected on the basis of price, credit quality and service. For a summary of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue, see Note 10 to our financial statements. Because alternative purchasers of oil and gas are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

In the third quarter we initiated a hedging program. We purchased oil put contracts of 1,000 barrels per month through September 2008. The hedging program was intended to protect downside price risk in the oil markets. Both oil and gas markets have recently experienced a significant increase in pricing. We expect to implement a more comprehensive hedging program during this fiscal year with unaffiliated third parties for portions of our production to achieve more predictable cash flows and to reduce our exposure to down-side price risk.

Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices for which our production can be sold. Market volatility due to international political developments, overall energy supply and demand, fluctuating weather conditions, economic growth rates and other factors in the United States and worldwide has had, and will continue to have, a significant effect on energy prices.

For additional information, see "Risk Factors".

Governmental Regulation

Federal, state and local laws and regulations substantially affect our operations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individuals wells.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, the EPAct 2005 amends the Natural Gas Act ("NGA"), to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as ReoStar, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC's enforcement authority. ReoStar does not anticipate it will be affected any differently than other producers of natural gas.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Congress, the states, the FERC, and the courts regularly consider additional proposals and proceedings that affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective.

Environmental Matters

Our operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency ("EPA") issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our operations and financial position, as well as the industry in general. We believe we are in substantial compliance with current applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters during fiscal year ended 2008, nor do we anticipate that such expenditures will be material in fiscal year ended 2009.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include owners or operators of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that such wastes may therefore give rise to liability under CERCLA. Beyond CERCLA, state laws regulate the disposal of oil and gas wastes, and periodically new state legislative initiatives are proposed that could have a significant impact on us. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment pursuant to environmental statutes, common law or both.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into waters of the United States. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and Federal National Pollutant Discharge Elimination System permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The cost to comply with zero discharges mandated under federal and state law has not had a material adverse impact on our financial condition and results of operations.

Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing and implementing storm water pollution prevention plans. The Resource Conservation and Recovery Act ("RCRA") as amended, generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as non-hazardous solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, can be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

The Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States" (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have sufficient financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time-to-time that would alter the RCRA exemption by reclassifying certain oil and gas exploration and production wastes as "hazardous wastes" and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on our capital expenditures, earnings or competitive position. Although we have not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes some, but not all, of the risks and uncertainties that may adversely affect our business, financial condition or results of operations.

Volatility of oil and natural gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically.

Oil and natural gas prices are volatile, and a decline in prices would adversely affect our profitability and financial condition. The oil and natural gas industry is typically cyclical, and prices for oil and natural gas have been highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. In recent years, higher oil and natural gas prices have contributed to increased earnings industry wide. However, long-term supply and demand for oil and natural gas is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of oil and gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Decreases in oil and natural gas prices from current levels could adversely affect our revenues, net income, cash flow and proved reserves. Significant price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production.

Hedging transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we may, from time to time, enter into hedging arrangements, utilizing commodity derivatives with respect to a significant portion of our future production. The goal of hedging is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions may limit potential gains if oil and natural gas prices rise above the price established by the hedge. In addition, hedging transactions may cause risk of financial loss in certain circumstances.

Information concerning our reserves and future net reserve estimates is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates, and these variances could be material.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment, assumptions used regarding quantities of oil and natural gas in place, recovery rates, and future commodity pricing.

Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and such variances may be material. Any variance in the assumptions could materially affect the estimated quantity and value of the reserves.

If oil and natural gas prices decrease or exploration efforts are unsuccessful, we may be required to take write-downs of our oil and natural gas properties.

This could occur when oil and natural gas prices are low, if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our exploration results, unsatisfactory results in our enhanced oil recovery projects, or mechanical problems with wells where the cost to re-drill or repair does not justify the expenditures required.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. "Impairment" is recognized when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, as well as a continuing evaluation of drilling results, production data, economics and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Our business is subject to operating hazards and environmental regulations that could result in substantial losses or liabilities.

Oil and natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic natural gas and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; or
- suspension of operations

As we drill to deeper horizons and in more geologically complex areas, we could experience a greater increase in operating and financial risks due to inherent higher reservoir pressures and unknown downhole risk exposures. As we continue to drill deeper, the number of rigs capable of drilling to such depths will be fewer and we may experience greater competition from other operators.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities from cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

In accordance with our operating agreements, the operator maintains insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. We do not maintain business interruption insurance.

In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities and place us at a competitive disadvantage.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties.

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing oil and natural gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do.

The demand for field services and their ability to meet that demand may limit our ability to drill and produce our oil and natural gas properties.

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This will result in escalating prices, the possibility of poor services coupled with potential damage to down-hole reservoirs and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel.

The oil and natural gas industry is subject to extensive regulation.

The oil and natural gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and natural gas industry. Compliance with such rules and regulations often increases our cost of doing business and, in turn, decreases our profitability.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business.

We could be subject to significant liabilities related to acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are not able to obtain financing on terms acceptable to regulatory approvals or us.

Acquisitions often pose integration risks and difficulties. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our success is highly dependent on our management personnel. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

Our future success depends on our ability to replace reserves that we produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are not able to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our business depends on oil and natural gas transportation facilities, most of which are owned by others.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements.

Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Indebtedness could limit our ability to successfully operate our business.

If we decide to pursue additional acquisitions, our capital expenditures will increase both to complete such acquisitions and to explore and develop any newly acquired properties. Our existing operations will also require ongoing capital expenditures. We may choose to increase debt in order to finance any of these potential capital expenditure requirements. The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- the terms of our credit arrangements could contain numerous financial and other restrictive covenants;
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations.

If our cash flow and capital resources are insufficient to fund our current or future debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We exist in a litigious environment.

Any constituent could bring suit or allege a violation of an existing contract. This action could delay when operations can actually commence or could cause a halt to production until the courts resolve such alleged violations. Not only could we incur significant legal and support expenses in defending our rights, planned operations could be delayed which would impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Common stockholders will be diluted if additional shares are issued.

We may incur debt that provides for a conversion to equity. Additionally, we may issue stock as consideration for additional property acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations.

Our ability to pay dividends may be limited by covenants imposed under future debt arrangements.

Our financial statements are complex.

Due to accounting rules, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, and deferred taxes. We expect such complexity to continue and possibly increase.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid.

The price of our common stock fluctuates significantly, which may result in losses for investors. To date our stock has been lightly traded, with the average daily volume being quite low. The low trading volume may prevent you from liquidating your position in our stock quickly. Additionally, the low trading volume may contribute significantly to price volatility. We expect our stock to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, re-completions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result.

ITEM 2. DESCRIPTION OF PROPERTIES

The information below summarizes certain data for our core operating areas for the year ended March 31, 2008. Segment reporting is not applicable to us as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

We conduct drilling, production and field operations in the Barnett Shale of North Central Texas, the Corsicana field of East Central Texas, and the Fayetteville Shale of Central Arkansas.

Barnett Shale

We have drilled and own interests in 59 completed wells, all of which are operated by Rife Energy Operating, Inc., a non-publicly traded affiliate. Our average working interest is 40%, and our average net revenue interest is 30 percent. We have approximately 6,500 gross (5,800 net) acres under lease, the majority of which is not classified as proven.

Proved developed producing reserves were 739 MBOE, and proved developed non-producing reserves were 698 MBOE. The majority of the proved developed non-producing reserves represented the reserves associated with the 7 wells that were drilled, but were not yet completed. Total proved developed reserves at March 31, 2008 were 1,437 MBOE. Total proven, undeveloped reserves were 2,642 MBOE.

At March 31, 2008, we had a Barnett Shale development inventory of more than 250 drilling locations and 17 proven re-completions. Development projects include re-completions and infill drilling (current field rules provide for 20 acre spacing).

Corsicana Field

We own interests in 67 producing well bores and 199 inactive wells. All of our properties in Corsicana are operated by Texas MOR, Inc, a non-publicly traded affiliate. Our average working interest is 95%, and our average net revenue interest is 76%. Currently, the active wells produce an average of 37 barrels of oil per day. We commenced flooding on our polymer pilot in June of 2007. Production in the polymer pilot wells during the fourth quarter increased by 50% when compared to production on those well before the polymer flood began.

The oil reserves in the field are fairly shallow with depths of less than 1,000 feet. While this field has been producing for more than one hundred years, several engineering studies have estimated that more than 80% of the original reserves still remain in place or approximately 100 MMBO. We believe the Polymer flood will allow us to achieve a marked increase in production volumes and give us the ability to prove larger reserves estimates.

There are many alternative reservoirs between 1000 and 7000 feet, which are being evaluated for optimal exploitation. The company feels that there are tremendous opportunities in the multiple zones within this range and it plans on attempting to produce from each one. Currently, the Company has scheduled four exploration wells into two of these zones, the Pecan Gap and the Glen Rose formations. The Company has secured co-financing for these wells from an industry partner who has purchased a 50% working interest in each of these deep wells.

In addition to the Polymer flood, we are evaluating optional EOR techniques including the use of steam and fire floods. Working in conjunction with New Mexico State University and funded from a federal grant program, we will jointly study the reservoir dynamics of the field to determine which enhanced oil recovery technique will optimize the recoverable reserves.

As of March 31, 2008, total proved developed reserves were 430 MBOE and proved undeveloped reserves totaled 10,393 MBOE.

East Texas Properties

We own interest in 4 leases in eastern Texas and western Louisiana. Our average working interest is 50% and our average net revenue interest is 40%.

As of March 31, 2008, total proved developed reserves were 9 MBOE and proved undeveloped reserves totaled 9 MBOE.

Fayetteville Shale

We own 6,450 net acres in the Fayetteville Shale located in Arkansas. The leasehold interests are not contiguous and we expect to sell the acreage during fiscal year 2009. No wells have been drilled on this acreage and no reserve values have been assigned to the leasehold interests.

Proven Reserves

At year-end 2008, the independent petroleum-consulting firm of Forrest Garb and Associates reviewed our reserves. These engineers were selected for their geographic expertise and their history in engineering enhanced oil recovery prospects similar to our Corsicana properties. At March 31, 2008, these consultants reviewed 100% of our proved reserves.

All estimates of oil and gas reserves are subject to uncertainty. The following table sets forth the estimated proven reserves in barrel of oil equivalents, estimated future net revenues from proved reserves, the present value of those net revenues and the expected benchmark prices used in projecting them (in thousands except prices):

Reserves	*Barnett Shale*	*Corsicana Field*	*E. Texas Field*	*Total*
Proved Developed (MBOE)	1,437	430	9	1,876
Proved Undeveloped (MBOE)	2,642	10,393	9	13,044
Total Proven Reserves at March 31, 2008	4,079	10,823	18	14,920
Estimated Future Net Revenues (M$)	175,177	754,202	669	930,048
Present Value of Future Net Revenues (M$)	89,447	335,509	489	425,445
Benchmark Pricing				
Natural Gas per mcf	$9.86			
Crude Oil per barrel	$101.54			

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations, prepared in accordance with Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities," are based on costs and prices in effect at March 31, 2008. There can be no assurance that the proved reserves will be produced within the periods indicated and prices and costs will not remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of our reserves have been filed with or included in reports to another federal authority or agency since year-end.

Wells are classified as crude oil or natural gas according to their predominant production stream.

The day-to-day operations of oil and gas properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated. Our operators are affiliated with ReoStar and are owned by shareholders who own more than 15% of our issued and outstanding common stock.

Undeveloped Acreage Expirations

A significant amount of our Barnett Shale acreage is not yet held by production. However, due to our planned drilling schedules and lease renewal provisions, we due not anticipate significant leasehold expirations during the next two years.

Our Corsicana properties and east Texas properties are held by production. Our Fayetteville acreage has an initial five-year term with an option for an additional five years. We have not drilled any wells in the Fayetteville Shale.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

customary royalty interests;
liens incident to operating agreements and for current taxes;
obligations or duties under applicable laws;
development obligations under oil and gas leases; or
burdens such as net profit interests.

Our headquarters are located at 3880 Hulen St, Suite 500, Fort Worth, Texas. We lease approximately one-half of the 12,000 square feet of office space under a sublease with the remaining half occupied by our affiliated operating entities, each of which contribute to the costs of leasing and maintenance of the leasehold, pro-rata to their respective usage. The term of the sub-lease is three years, and we pay rent at a rate of $1 per square foot, per month. Our administrative and office facilities are suitable for their respective uses.

ITEM 3. LEGAL PROCEEDINGS

We do not know of any material, active or pending legal proceedings against us, nor are we involved as a plaintiff in any material proceedings or pending litigation.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of our security holders during the fourth quarter of 2008.

PART II

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

Market Information

Our common stock is currently quoted for trading on Over-the-Counter Bulletin Board (OTCBB) maintained by the Financial Industry Regulatory Authority (FINRA) under the symbol "REOS". There was no active market or any trading volume with respect to the shares of our common stock in the periods prior to the quarter ended December 31, 2006.

The following table sets forth the high and low closing sale price of our common stock, as reported by the National Association of Securities Dealers Composite for each quarter during the past two fiscal years.

Fiscal 2008	High	Low
June 30, 2007	$1.28	$1.05
September 30, 2007	$1.30	$1.02
December 31, 2007	$1.42	$0.80
March 31, 2008	$1.04	$0.62

Fiscal 2007	High	Low
June 30, 2006	$Nil	$Nil
September 30, 2006	$Nil	$Nil
December 31, 2006	$1.26	$0.05
March 31, 2007	$1.33	$0.95

Holders of Record

On March 31, 2008, there were approximately 80 holders of record of our common stock.

Dividends

We have not paid any cash dividends on our Common Stock, and do not anticipate paying cash dividends on our Common Stock in the next year. We anticipate that any income generated in the foreseeable future will be retained for the development and expansion of our business. Future dividend policy is subject to the discretion of the Board of Directors and will depend upon a number of factors, including future earnings, debt service, capital requirements, business conditions, the financial condition of the Company and other factors that the Board of Directors may deem relevant.

Recent Sales of Unregistered Securities

In April 2007, we issued 350,000 shares of restricted common stock pursuant to employment agreements with certain of the Company's officers. The shares were issued pursuant to Section 4(2) of the Securities Act.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OR PLAN OF OPERATION

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with Item 6, "Selected Financial Data", the financial statements and the accompanying notes included elsewhere in this Form 10-KSB.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See "Disclosures Regarding Forward-Looking Statements" at the beginning of this Annual Report and "Risk Factors" in Item 1 for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil company engaged in the acquisition, development, and exploration of oil and gas properties, primarily in Texas. Our objective is to build a balanced portfolio consisting of oil and gas producing properties and reserves in both resource (developmental) and enhanced oil recovery (redevelopment) plays. We will expand reserves through internally generated drilling projects coupled with complementary acquisitions.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Our profitability depends upon our ability to control operations of our oil and gas assets.

We have a single company-wide management team that administers all properties as a whole rather than by independent operating segments. We track only basic operational data by area and we do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Successful Efforts Method of Accounting

We account for our exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. As a mature region, while new discoveries of oil and gas occur in the United States, the size and frequency of these discoveries is declining, while finding and development costs are increasing.

We believe that there remain certain areas in the southern Mid-continent region which are under-explored or have not been fully explored and developed with the benefit of newly available exploration, production and reserve enhancement technology. Examples of such technology include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, and enhanced oil recovery practices.

Another characteristic of a mature region is the historical exit of larger independent producers and major oil companies from such regions. These companies, searching larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided acquisition opportunities for companies like ours that are capable of quickly analyzing opportunities, well positioned financially to quickly close an acquisition, and have the technical expertise to generate additional value from these assets.

In other situations, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures and farm-in arrangements.

We believe the acquisition market for natural gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities. Acquisition values have reached historic highs and we expect these values to remain high in the near future. We expect drilling and service costs pressures to increase, resulting in higher finding and development costs. In addition, we expect lease-operating expenses to continue to rise as producers are forced to make operational enhancements to maintain production in aging fields.

Crude oil and natural gas are commodities. The price that we receive for the crude oil and natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically over the last ten years. Demand is impacted by general economic conditions, estimates of gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms. Demand for crude oil has also increased over the last ten years while the increase in supply has not increased proportionately resulting in a tight market. Market conditions involving over or under supply of crude oil and natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. A substantial or extended decline in oil and gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and our ability to access capital markets.

We derive our revenues from the sale of crude oil and natural gas that is produced from our properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of oil and natural gas is the primary factor affecting our revenues.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include work-over repairs to our oil and gas properties not covered by insurance. To minimize and help control our costs, we acquired a work-over drilling rig and a swab rig in June of 2007.

Production and Ad Valorem Taxes. These costs are primarily paid based on a percentage of market prices or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. The costs include geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful wells or dry holes. While our current asset mix requires a minimum of geological and geophysical costs and seismic costs, it is possible this component of our cost structure could sharply increase depending upon future property acquisitions.

Plugging Costs. The Corsicana field is over one hundred years old and has hundreds of abandoned well bores scattered throughout the properties. In order to properly execute our enhanced oil recovery projects, we need to plug these abandoned, worn out well bores. Since the wells are fairly shallow, we are able to cement in the entire well bore at a cost of less than $1,500 per well.

General and Administrative Expenses. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of finding our working interest partners, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R), amortization of restricted stock grants as part of employee compensation.

Interest. We carry minimum levels of debt, but in the future, we may finance a portion of our working capital requirements and acquisitions with borrowings under a credit facility or with longer-term public traded debt securities. As a result, interest expense could become a much more prevalent component of our cost structure.

Depreciation, Depletion and Amortization. As a successful efforts company, we capitalize all costs associated with our acquisition and all successful development and exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly depreciation of our oilfield equipment assets.

Income Taxes. We are subject to state and federal income taxes but are currently not in a minimal tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). We are also subject to some state income taxes. Currently, virtually all of our Federal taxes are deferred; however, at some point, we will utilize all of our net operating loss carry-forwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

Results and Analysis of Financial Condition, Cash Flows and Liquidity

During the fiscal year ended March 31, 2008, we drilled and completed 12 wells in our Barnett Shale project. At year-end, there were seven wells drilled and awaiting completion. ReoStar retained an average working interest in these wells of 44.5% at a total net investment of $7.1 million. The following chart summarizes pertinent reserve information for our Barnett Shale properties at March 31, 2008 and March 31, 2007:

	Discounted Cash Flows @ 10%			Net Reserves (MBOE)		
	2008	2007	% Change	2008	2007	% Change
Proved Developed	$ 37,209,260	$ 7,781,890	478.2%	1,437	426	337.0%
Proved Undeveloped	52,238,110	2,323,380	2248.4%	2,642	409	646.4%
	$ 89,447,370	$ 10,105,270	885.2%	4,079	835	488.4%

We began injecting surfactant polymer in the pilot project in June 2007. Production responded positively with monthly production for the fourth quarter on the pilot increasing by 50% when compared to the pre-injection production. We began the permitting process for the second stage of the pilot and expect to complete the pilot expansion and to begin injection during the second quarter of the next fiscal year. The following chart summarizes pertinent reserve information for our Corsicana properties at March 31, 2008 and March 31, 2007.

	Discounted Cash Flows @ 10%			Net Reserves (MBOE)		
	2008	2007	% Change	2008	2007	% Change
Proved Developed	$ 14,799,080	$ 1,104,080	1340.4%	430	106	406.4%
Proved Undeveloped	320,710,090	169,758,910	188.9%	10,394	11,302	-8.0%
	$ 335,509,170	$ 170,862,990	196.4%	10,823	11,408	-5.1%

The average price per barrel of oil during the fiscal year was $80.48 compared with $52.10 for the twelve months ended December 31, 2006. The average price realized per thousand cubic feet (MCF) of gas produced during the fiscal year was $6.25 compared with $6.19 for the twelve months ended December 31, 2006.

Oil and gas production for the year increased 36% to a total of 92,193 BOE compared with 67,821 for the twelve months ended December 31, 2006. Oil and gas revenue for the year increased 70% to a total of $4.9 million compared to $2.9 million for the twelve months ended December 31, 2006. Net income for the fiscal year was $796,000 compared to $193,000 for the twelve months ended December 31, 2006.

During fiscal year ended March 31, 2008, our cash provided from operations was $300 thousand, and we invested $11 million on capital expenditures. Financing activities provided net cash of $4.7 million. The offering closed on April 30, 2007. The Company raised a total of $10.3 million in net proceeds from the private placement, of which $6.9 million was raised during the fiscal year ended March 31, 2008.

On March 31, 2008, we had $592,000 in cash and total assets of $21.3 million. Debt consisted of payables to non-related parties of $2.7 million, of which $1.65 million were long-term note payables. We also had accounts and notes payables to related parties of $5.7 million.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves, which is typical in the oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We are in the process of securing a credit facility, and we believe that the proceeds from such a credit facility and the net cash generated from operating activities will be adequate to satisfy financial obligations and liquidity needs over the next 12-18 months.

However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to efficiently develop our properties and offset inherent declines in production and proved reserves.

Cash Flow

Our principal sources of cash are net cash generated by oil and gas operations, the sale of a portion of the working interest in our Barnett Shale drilling projects, and the issuance of equity or debt securities. Our operating cash flow is highly dependent on oil and gas prices.

Based on current projections and oil and gas futures prices, the 2009 capital program is expected to be funded with internal cash flow and a planned credit facility.

Capital Requirements

Our primary needs for cash are for exploration and development of our Barnett Shale properties, establishing the enhanced oil recovery projects in our Corsicana properties, and the acquisition of additional oil and gas properties, both in unconventional gas plays and re-development of mature fields. During the year ended December 31, 2006, a predecessor company, REO Energy, Ltd. expended approximately $24 million on Barnett drilling projects. During the three months ended March 31, 2007, $4.5 million of capital was expended on Barnett Shale drilling projects, and during the fiscal year ended March 31, 2008, $18.2 million of capital was expended on Barnett Shale drilling projects. For fiscal year 2008, $12.2 million of the capital program was funded via the sale of working interests on a turnkey basis. The balance of the Barnett Shale capital program was funded by cash flow from operations and the proceeds of the private placement.

We repurchased working interests in several of our Barnett properties during fiscal year 2008 for a total cost of $1.4 million. The resulting increase in undiscounted cash flow on our March 31, 2008 reserve report was approximately $4.8 million.

Our capital expenditure budget for fiscal year 2009 is $25 million. Of this, $20.5 million is budgeted for drilling in the Barnett Shale, $1 million is budget for up-hole re-completions in our Barnett wells, and $3.5 million is budgeted for the Corsicana surfactant polymer project expansion. Our capital expenditure budget will be funded by a planned credit facility and cash flow from the properties.

Cautionary Statement: There can be no assurance that we will be successful in raising capital through a credit facility or otherwise. Even if we are successful in raising capital through the sources specified, there can be no assurances that any such financing would be available in a timely manner or on terms acceptable to our current shareholders and us. Additional equity financing could be dilutive to our then existing shareholders, and any debt financing could involve restrictive covenants with respect to future capital raising activities and other financial and operational matters.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of March 31, 2008, we do not have any capital leases nor have we entered into any material long-term contracts for equipment, nor do we have any off-balance sheet debt or other such unrecorded obligations.

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at March 31, 2008. In addition to the contractual obligations listed on the table below, our balance sheet at March 31, 2008 reflects accrued interest payable on our debt of $109,000 which is payable throughout the rest of 2008.

	Fiscal Year Ending March 31		
	2009	2010	2011
Office Lease -	150,000	160,000	131,525
Mineral Lease loans	72,000	-	-
Related Party Notes	325,000	3,195,000	-
Construction Loan	15,000	16,000	16,000

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource position, or for any other purpose.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated during 2007 and 2008, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These costs trends have put pressure not only on our operating costs but also on our capital costs.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our 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 amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Oil and Gas Properties

To ensure the reliability of our reserve estimates, we engage independent petroleum consultants to prepare an estimate of proved reserves. Proved the SEC defines reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict whether impairment charges may be required in the future. We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to the consolidated financial statements for information on these acquisitions.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take, years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carry forwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized. In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned.

At year-end 2008, deferred tax liabilities exceeded deferred tax assets by $2.2 million. We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of costs can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingencies and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

ITEM 7. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS

Killman, Murrell & Company, P.C.
Certified Public Accountants

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
ReoStar Energy Corporation
(Formerly Goldrange Resources, Inc.)
Fort Worth, Texas 76107

We have audited the accompanying balance sheet of ReoStar Energy Corporation (formerly Goldrange Resources, Inc.) as of March 31, 2007 and the related statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the two-year period ended December 31, 2006, and the three month period ended March 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of ReoStar Energy Corporation as of March 31, 2007, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2006, and the three month period ended March 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

/s/ Killman. Murrell & Company. P. C.
Killman, Murrell & Company, P.C.
Odessa, Texas
July 14,2007

ReoStar Energy Corporation
(formerly Goldrange Resources, Inc.)
Consolidated Balance Sheets

	March 31, 2008	March 31, 2007
ASSETS		
Current Assets:		
Cash	$ 592,665	$ 212,254
Accounts Receivable:		
Oil & Gas - Related Party	868,406	495,200
Other	-	63,389
Inventory	4,748	-
Hedging Account	13,062	-
Discontinued Operations - Assets Net of Liabilities	-	4,005,567
Total Current Assets	1,478,881	4,776,410
Note Receivable	1,355,228	1,614,218
Oil and Gas Properties - successful efforts method	17,832,931	11,712,673
Less Accumulated Depletion and Depreciation	(4,139,337)	(2,740,044)
Oil & Gas Properties (net)	13,693,594	8,972,629
Other Depreciable Assets:	1,641,806	-
Less Accumulated Depreciation	(121,113)	-
Other Depreciable Assets (net)	1,520,693	-
Other Related Party Receivable	80,395	70,395
Leasehold Held for Sale	1,680,813	-
Investment in Equity Method Investment	142,395	-
Total Assets	$ 19,951,999	$ 15,433,652
LIABILITIES		
Current Liabilities:		
Accounts Payable	$ 103,479	$ 509,540
Notes Payable to Related Parties	324,330	324,330
Payable to Related Parties	1,547,136	3,379,069
Royalties Payable	57,485	-
Accrued Expenses	857,887	889,857
Accrued Expenses - Related Parties	171,788	23,646
Current Portion of Long-Term Debt	14,960	5,093,864
Total Current Liabilities	3,077,065	10,220,306
Notes Payable	1,647,769	3,605,937
Notes Payable - Related Parties	3,194,594	3,294,594
Other Related Party Payables	490,840	880,261
Less Current Portion of Notes Payable	(14,960)	(5,093,864)
Total Long-Term Debt	5,318,243	2,686,928

Deferred Tax Liability		2,163,183		1,734,563
Total Liabilities		10,558,491		14,641,797
Commitments & Contingencies:				
Contingent Stock Based Compensation		214,976		-
Stockholders' Equity				
Common Stock, $.001 par,200,000,000 shares authorized and 80,181,310 and 71,954,262 shares outstanding on March 31, 2008 and 2007, respectively		80,181		71,954
Additional Paid-In-Capital		9,553,346		1,970,795
Retained Deficit		(454,995)		(1,250,894)
Total Stockholders' Equity		9,178,532		791,855
Total Liabilities & Stockholders' Equity	$	19,951,999	$	15,433,652

See Accompanying Notes to Consolidated Financial Statements

ReoStar Energy Corporation
(formerly Goldrange Resources, Inc.)
Consolidated Statements of Operations

	Three Months Ended March 31, 2008 (unaudited)	Three Months Ended March 31, 2007	Fiscal Year Ended Mar. 31, 2008	Twelve Months Ended Dec. 31, 2006
Revenues				
Oil & Gas Sales	$ 1,471,908	$ 814,400	$ 4,902,072	$ 2,874,291
Sale of Leases	-	19,431	307,028	400,378
Other Income	113,919	95,388	281,231	45,771
	1,585,827	929,219	5,490,331	3,320,440
Costs and Expenses				
Oil & Gas Lease Operating Expenses	655,208	168,346	2,125,261	1,131,502
Workover Expenses	317,349	-	356,342	-
Severance & Ad Valorem Taxes	116,524	40,962	318,785	163,523
Geologic & Geophysical	-	-	8,993	-
Delay Rentals	-	-	52,186	-
Plugging Costs & Expired Leases	290,959	-	290,959	-
Depletion & Depreciation	647,309	468,540	1,520,406	1,940,354
General & Administrative:	-	135,947	-	281,727
Salaries & Benefits	308,052	-	1,104,785	-
Legal & Professional	86,196	-	584,765	-
Other General & Administrative	101,489	-	332,009	-
Interest, net of capitalized interest of $120,208 and $113,706 for the three months ended March 31, 2008, and March 31, 2007, respectively and $488,299 and $420,230 for the years ended March 31, 2008 and December 31, 2006, respectively	-	63,321	-	13,660
	2,523,086	877,116	6,694,491	3,530,766
Interest Income	54,959	55,811	210,938	-
Hedging Loss	(10,047)	-	(16,938)	-
Loss on Equity Method Investments	(32,605)	-	(32,605)	-
Income (Loss) from continuing operations before income taxes and discontinued operations	(924,952)	107,914	(1,042,765)	(210,326)
Income Tax Provision	323,695	(1,363,244)	364,930	-
Income from discontinued operations, net of income taxes:				
Pipeline Income	-	107,536	22,930	403,082
Gain on Sale of Pipeline	-	-	1,450,805	-
Income from discontinued operations	-	107,536	1,473,735	403,082
Net Income (Loss)	$ (601,257)	$ (1,147,794)	$ 795,900	$ 192,756
Basic & Diluted Loss per Common Share	$ (0.01)	$ (0.02)	$ 0.01	
Weighted Average Common Shares Outstanding	79,831,310	69,616,786	78,800,618	

Pro-Forma Earnings Per Share		
Net Income	$	192,756
Proforma Income Tax Expense at Statutory Rate (35%)		(67,465)
Proforma Net Income	$	125,291
Proforma Weighted Average Shares Outstanding		68,129,310
Proforma Basic & Diluted Earnings Per Share	$	0.00

See Accompanying Notes to Consolidated Financial Statements

ReoStar Energy Corporation
(Formerly Goldrange Resources, Inc.)
Consolidated Statements of Stockholders' Equity (Deficit)

	Common Stock				
	Number of Shares	Amount	Paid-In Capital	Retained Deficit	Total
Combined Equities of Merged Companies December 31, 2005	68,129,310	$ 68,129	$ (921,301)	$ (829,935)	$ (1,683,107)
Net Income 2006	-	-	-	192,756	192,756
Balance, December 31, 2006	68,129,310	68,129	(921,301)	(637,179)	(1,490,351)
Sale of Common Stock	3,824,952	3,825	3,426,175	-	3,430,000
Change in Tax Status of Two Merged Companies	-	-	(534,079)	534,079	-
Net Loss 2007	-	-	-	(1,147,794)	(1,147,794)
Balance, March 31, 2007	71,954,262	71,954	1,970,795	(1,250,894)	791,855
Sale of Common Stock	7,637,048	7,637	6,877,717	-	6,885,354
Common Stock Issued for Wilson Energy Acquisition	240,000	240	298,560	-	298,800
Common Stock Issued for Employee Compensation	350,000	350	406,274	-	406,624
Net Income 2008	-	-	-	795,900	795,900
Balance, March 31, 2008	80,181,310	$ 80,181	$ 9,553,346	$ (454,994)	$ 9,178,533

See Accompanying Notes to Consolidated Financial Statements

ReoStar Energy Corporation
(formerly Goldrange Resources, Inc.)
Consolidated Statements of Cash Flows

	Three Months Ended		Fiscal Year Ended	Year Ended
Operating Activities:	**Mar. 31, 2008 (unaudited)**	**Mar. 31, 2007**	**Mar. 31, 2008**	**Dec 31, 2006**
Net Income	$ (601,257)	$ (1,147,794)	$ 795,900	$ 192,756
Adjustments to reconcile net income to cash from operating activities:				
Deferred Income Tax Expense	(323,695			

	Shares	Amount	Paid-in Capital	Undenominated Capital	Comprehensive Income
	(dollars in thousands, except share data)				
Balance at December 31, 2016	54,530,843	$4,692	$438,126	$809	$ (86,300)
Comprehensive income:					
Net income	-	-	-	-	-
Currency translation adjustment	-	-	-	-	27,274
Currency impact of long term funding	-	-	-	-	12,925
Tax on currency impact of long term funding	-	-	-	-	335
Unrealized capital gain – investments	-	-	-	-	18
Amortization of interest rate hedge	-	-	-	-	(696)
Total comprehensive income	-	-	-	-	39,856
Exercise of share options	321,685	21	7,761	-	-
Issue of restricted share units	667,808	43	-	-	-
Share issuance costs	-	-	(13)	-	-
Non-cash stock compensation expense	-	-	25,847	-	-
Share repurchase program	(1,368,136)	(87)	-	87	-
Share repurchase costs	-	-	-	-	-
Cumulative effect adjustment from adoption of ASU 2016-09	-	-	-	-	-
Balance at September 30, 2017	54,152,200	$4,669	$471,721	$896	$ (46,444)

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

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NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)
September 30, 2017

1. Basis of Presentation

These condensed consolidated financial statements which have been prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP") have not been audited. The condensed consolidated financial statements reflect all adjustments, which are, in the opinion of management, necessary to present a fair statement of the operating results and financial position for the periods presented. The preparation of the condensed consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect reported amounts and disclosures in the condensed consolidated financial statements. Actual results could differ from those estimates.

The condensed consolidated financial statements should be read in conjunction with the accounting policies and notes to the consolidated financial statements included in ICON's Form 20-F for the year ended December 31, 2016. Operating results for the three and nine months ended September 30, 2017, are not necessarily indicative of the results that may be expected for the fiscal period ending December 31, 2017.

2. Goodwill

	Nine months ended September 30, 2017	Year ended December 31, 2016
	(in thousands)	
Opening balance	$616,088	$588,434
Current period acquisitions (Note 3)	129,072	34,576
Prior period acquisitions (Note 3)	1,393	7,689
Foreign exchange movement	17,824	(14,611)
Closing balance	$764,377	$616,088

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3. Business Combinations

Acquisitions – Mapi Group.

On July 27, 2017, a subsidiary of the Company, ICON Clinical Research Limited, acquired Mapi Development SAS ('Mapi'). Mapi is a leading patient-centered health outcomes research and commercialization company. Cash outflows on acquisition were $144.1 million.

The acquisition of Mapi has been accounted for as a business combination in accordance with FASB ASC 805 Business Combinations. The Company has made a provisional assessment of the fair value of assets acquired and liabilities assumed as at that date. The table following summarizes the Company's provisional estimates of the fair values of the assets acquired and liabilities assumed:

	July 27, 2017 (in thousands)
Cash	$ 18,634
Property, plant and equipment	3,196
Goodwill*	129,072
Intangible assets**	30,637
Accounts receivable	14,167
Unbilled revenue	11,818
Prepayments and other current assets	4,458
Other receivables	2,379
Income taxes receivable	2,799
Accounts payable	(3,184)
Payments on account	(28,851)
Other liabilities	(28,814)
Non-current other liabilities	(1,061)
Non-current deferred tax liability	(1,966)
Net assets acquired	$ 153,284
Cash outflows	$ 144,131
Assessment of valuation of contingent consideration at acquisition	$ 9,153
Total consideration	$ 153,284

*Goodwill represents the acquisition of an established workforce with experience in late phase commercialization, analytics, real world evidence generation and strategic regulatory services in clinical trial services for biologics, drugs and devices.

**The Company has made an initial estimate of separate intangible assets acquired of $30.6 million, being customer relationships and order book assets. This assessment is under review and will be finalized within 12 months of the date of acquisition.

Acquisitions – Clinical Research Management, Inc.

On September 15, 2016, a subsidiary of the Company, ICON US Holdings Inc. acquired ClinicalRM resulting in an initial net cash outflow of $52.4 million inclusive of certain payments made on behalf of ClinicalRM totaling $9.2 million.

ClinicalRM is a full-service CRO specializing in preclinical through Phase IV support of clinical research and clinical trial services for biologics, drugs and devices. The organization helps customers progress their products to market faster with a wide array of research, regulatory and sponsor services within the U.S. and around the globe. ClinicalRM provide full service and functional research solutions to a broad range of US government agencies. Their extensive expertise extends across basic and applied research, infectious diseases, vaccines development and testing and the response to bio-threats. They have worked in collaboration with government and commercial customers to respond to the threat of global viral epidemics. Further consideration of up to $12.0 million is payable if certain performance milestones are achieved in respect of periods up to December 31, 2017. The fair value of the contingent consideration on acquisition and at March 31, 2017, was estimated at $6 million. The evaluation of the performance and forecast performance of ClinicalRM against performance milestones was updated as required at June 30, 2017. Arising from that evaluation, the fair value of the contingent consideration liability was determined as $Nil, resulting in a net credit of $6 million being recorded within selling, general & administrative expenses in the Statement of operations.

The acquisition of ClinicalRM has been accounted for as a business combination in accordance with FASB ASC 805 Business Combinations. The table following summarizes the fair values of the assets acquired and liabilities assumed:

	September 15, 2016 (in thousands)
Cash	$ 3,168
Property, plant and equipment	939
Goodwill*	35,969
Customer lists	4,012
Order backlog	1,668
Brand	1,409
Accounts receivable	11,431
Unbilled revenue	3,868
Prepayments and other current assets	1,673
Accounts payable	(165)
Other liabilities	(5,569)
Non-current other liabilities	(7)
Net assets acquired	$ 58,396
Cash outflows (including other liabilities assumed of $9.2 million)	$ 52,396
Assessment of valuation of contingent consideration at acquisition	6,000
Total consideration	$ 58,396

*Goodwill represents the acquisition of an established workforce with experience in preclinical through Phase IV support of clinical research and clinical trial services for biologics, drugs and devices. Goodwill related to the US portion of the business acquired is tax deductible.

Acquisitions - PMG

On December 4, 2015, a subsidiary of the Company, ICON Clinical Research LLC. acquired PMG for total cash outflows of $65.4 million, including certain payments made on behalf of PMG totaling $10.1 million. PMG is an integrated network of 52 clinical research sites in North Carolina, South Carolina, Tennessee, Illinois and Iowa. The site network includes wholly owned facilities and dedicated clinical research sites. PMG conducts clinical trials in all major therapeutic areas and has particular expertise in vaccine, gastroenterology, cardiovascular, neurology and endocrinology studies. It has a proprietary database of clinical trial participants. It also has access to in excess of 2 million active patients via electronic medical records through its partnerships with healthcare institutions and community physical practices.

The acquisition of PMG has been accounted for as a business combination in accordance with FASB ASC 805 Business Combinations. The table following summarizes the fair values of the assets acquired and liabilities assumed:

	December 4, 2015 (in thousands)
Cash	$ 194
Property, plant and equipment	712
Goodwill*	48,728
Customer lists	6,938
Order backlog	2,948
Accounts receivable	11,597
Prepayments and other current assets	1,329
Accounts payable	(530)
Other liabilities	(3,456)
Non-current deferred tax liability	(3,106)
Net assets acquired	65,354
Cash consideration	53,681
Other liabilities assumed	10,060
Working capital adjustment	1,613
Total cash outflows	65,354

*Goodwill represents the acquisition of an established workforce with experience in clinical trial consulting and regulatory support for the development of drugs, medical devices and diagnostics, with a specific focus on strategy to increase efficiency and productivity in product development. In finalizing the goodwill on acquisition of PMG in the twelve month period from acquisition, fair value adjustments of $7.7 million were made to deferred tax liabilities ($3.1 million), accounts receivable acquired ($1.4 million), other liabilities ($1.2 million) and the value of the customer list and order backlog assets acquired ($0.4 million). Additional consideration of $1.6 million was provided on completion of the contractual working capital process.

Acquisitions - MediMedia Pharma Solutions

On February 27, 2015, a subsidary of the Company, ICON Holdings Unlimited Company (formerly ICON Holdings), acquired MediMedia Pharma Solutions for cash consideration of $104.8 million (net of working capital adjustments of $3.9 million). In addition to the cash consideration, certain payments were made on behalf of MediMedia Pharma Solutions on completion totaling $11.3 million. Headquartered in Yardley, Pennsylvania, MediMedia Pharma Solutions includes MediMedia Managed Markets and Complete Healthcare Communications. MediMedia Managed Markets is a leading provider of strategic payer-validated market access solutions. Complete Healthcare Communications is one of the leading medical and scientific communication agencies working with medical affairs, commercial and brand development teams within life science companies. The acquisition agreement also provided for certain working capital targets to be achieved by MediMedia Pharma Solutions.

The acquisition of MediMedia Pharma Solutions has been accounted for as a business combination in accordance with FASB ASC 805 Business Combinations. The table following summarizes the fair values of the assets acquired and liabilities assumed on acquisition:

	February 27, 2015 (in thousands)
Property, plant and equipment	$ 1,049
Goodwill*	92,084
Customer lists	22,752
Order backlog	2,521
Accounts receivable	5,240
Unbilled Revenue	4,324
Prepayments and other current assets	621
Accounts payable	(749)
Payments on account	(4,186)
Deferred tax liability	(2,171)
Other liabilities	(5,483)
Net assets acquired	$ 116,002
Cash consideration	$ 108,717
Other liabilities assumed**	11,283
Gross cash outflows	120,000
Working capital adjustment	(3,998)
Net cash outflows	$ 116,002

*Goodwill represents the acquisition of an established workforce with experience in the provision of strategic payer-validated market access solutions while the acquisition of Complete Healthcare Communications comprises an established workforce with significant communication experience working with medical affairs, commercial and brand development teams within the life science industry. Goodwill related to the US portion of the business is tax deductible.
** Payments made at acquisition date of $11.3 million were in respect of certain one-time liabilities which have subsequently been discharged.

4. Restructuring

Restructuring charges

A restructuring charge of $7.8 million was recognized during the nine months ended September 30, 2017, under a restructuring plan adopted following a review of operations. The restructuring plan reflected resource rationalization across the business to improve resource utilization.

Details of the restructuring charge recognized in the three and nine months ended September 30, 2017, are as follows;

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(in thousands)		(in thousands)	
Restructuring charges	-	$ 4,065	$7,753	$ 8,159
Total	-	$ 4,065	$7,753	$ 8,159

Details of the movement in the restructuring charge recognized in the three and nine months ended September, 30 2017 are as follows;

	Workforce reductions (in thousands)
Initial restructuring charge recorded	$ 7,753
Cash payments	$ (2,536)
Foreign exchange movement	-
Provision at September 30, 2017	$ 5,217

Prior Periods Restructuring charges

A restructuring charge of $8.2 million was recognized during the year ended December 31, 2016, under a restructuring plan adopted following a review by the Company of its operations. The restructuring plan includes resource rationalizations in certain areas of the business to improve resource utilization, resulting in a charge of $6.2 million and office consolidation resulting in the recognition of an onerous lease obligation of $2.0 million during the twelve months ended December 31, 2016. No additional charge was recorded during the nine months ended September 30, 2017.

	Workforce Reductions	Onerous Lease (in thousands)	Total
Total provision recognized	$ 6,190	$ 1,969	$8,159
Utilized	(5,734)	(571)	(6,305)
Foreign exchange	(63)	-	(63)

Provision at December 31, 2016	$ 393	$ 1,398	$1,791
Utilized	(393)	(757)	(1,150)
Provision at September 30, 2017	-	$ 641	$641

At September 30, 2017, $5.6 million is included within other liabilities and $0.5 million within non-current other liabilities.
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5. Income Taxes

Income taxes recognized during the three and nine months ended September 30, 2017, comprise:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(in thousands)		(in thousands)	
Provision for income taxes before restructuring and other items	$8,239	$ 10,979	$31,414	$ 31,669
Tax impact of restructuring and other items	-	(509)	(969)	(1,020)
Provision for income taxes after restructuring and other items	$8,239	$ 10,470	$30,445	$ 30,649

As at September 30, 2017, the Company maintains a $27.7 million liability (December 31, 2016: $29.9 million) for unrecognized tax benefit, which is comprised of $24.1 million (December 31, 2016: $26.6 million) related to items generating unrecognized tax benefits and $3.6 million (December 31, 2016: $3.3 million) for interest and related penalties to such items. The Company recognizes interest accrued on unrecognized tax benefits as an additional income tax expense.

The Company has analyzed the filing positions in all of the significant federal, state and foreign jurisdictions where it is required to file income tax returns, as well as open tax years in these jurisdictions. The only periods subject to examination by the major tax jurisdictions where the Company does business are 2012 through 2016 tax years. The Company does not believe that the outcome of any examination will have a material impact on its financial statements.

6. Net income per ordinary share

Basic net income per ordinary share has been computed by dividing net income available to ordinary shareholders by the weighted average number of ordinary shares outstanding during the period. Diluted net income per ordinary share is computed by adjusting the weighted average number of ordinary shares outstanding during the period for all potentially dilutive ordinary shares outstanding during the period and adjusting net income for any changes in income or loss that would result from the conversion of such potential ordinary shares. There is no difference in net income used for basic and diluted net income per ordinary share.

The reconciliation of the number of shares used in the computation of basic and diluted net income per ordinary share is as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
Weighted average number of ordinary shares outstanding for basic net income per ordinary share	54,109,566	55,734,773	54,110,022	55,355,020
Effect of dilutive share options outstanding	646,618	910,466	730,090	1,120,299
Weighted average number of ordinary shares outstanding for diluted net income per ordinary share	54,756,184	56,645,239	54,840,112	56,475,319

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7. Share-based Awards

Share Options

On July 21, 2008, the Company adopted the Employee Share Option Plan 2008 (the "2008 Employee Plan") pursuant to which the Compensation and Organization Committee of the Company's Board of Directors may grant options to any employee, or any Director holding a salaried office or employment with the Company or a Subsidiary for the purchase of ordinary shares. On the same date, the Company also adopted the Consultants Share Option Plan 2008 (the "2008 Consultants Plan"), pursuant to which the Compensation and Organization Committee of the Company's Board of Directors may grant options to any consultant, adviser or non-executive Director retained by the Company or any Subsidiary for the purchase of ordinary shares.

On February 14, 2017, both the 2008 Employee Plan and the 2008 Consultants Plan (together the "2008 Option Plans") were amended and restated in order to increase the number of options that can be issued under the 2008 Consultants Plan from 400,000 to 1 million and to extend the date for options to be granted under the 2008 Option Plans.

Each option granted under the 2008 Option Plans will be an employee stock option, or Non-qualifying Stock Options ('NSO'), as described in Section 422 or 423 of the Internal Revenue Code. Each grant of an option under the 2008 Options Plans will be evidenced by a Stock Option Agreement between the optionee and the Company. The exercise price will be specified in each Stock Option Agreement, however option prices will not be less than 100% of the fair market value of an ordinary share on the date the option is granted.

An aggregate of 6 million ordinary shares have been reserved under the 2008 Employee Plan, as reduced by any shares issued or to be issued pursuant to options granted under the 2008 Consultants Plan, under which a limit of 1 million shares applies. Further, the maximum number of ordinary shares with respect to which options may be granted under the 2008 Employee Option Plan, during any calendar year to any employee shall be 400,000 ordinary shares. There is no individual limit under the 2008 Consultants Plan. No options may be granted under the 2008 Option Plans after February 14, 2027.

On January 17, 2003, the Company adopted the Share Option Plan 2003 (the "2003 Share Option Plan") pursuant to which the Compensation and Organization Committee of the Board could grant options to officers and other employees of the Company or its subsidiaries for the purchase of ordinary shares. An aggregate of 6 million ordinary shares were reserved under the 2003 Share Option Plan; and, in no event could the number of ordinary shares issued pursuant to options awarded under this plan exceed 10% of the outstanding shares, as defined in the 2003 Share Option Plan, at the time of the grant, unless the Board expressly determined otherwise. Further, the maximum number of ordinary shares with respect to which options could be granted under the 2003 Share Option Plan during any calendar year to any employee was 400,000 ordinary shares. The 2003 Share Option Plan expired on January 17, 2013. No new options may be granted under this plan.

Share option awards are granted with an exercise price equal to the market price of the Company's shares at date of grant. Share options typically vest over a period of five years from date of grant and expire eight years from date of grant. The maximum contractual term of options outstanding at September 30, 2017 is eight years.

The following table summarizes option activity for the nine months ended September 30, 2017:

	Options Outstanding Number of Shares	Weighted Average Exercise Price	Weighted Average Fair Value	Weighted Average Remaining Contractual Life
Outstanding at December 31, 2016	1,466,444	$ 43.45	$ 13.94	

Granted	219,113	$ 85.98	$ 25.06	
Exercised	(321,685)	$ 24.19	$ 9.19	
Forfeited	(49,579)	$ 53.65	$ 16.58	
Outstanding at September 30, 2017	1,314,293	$ 54.87	$ 16.86	4.97
Exercisable at September 30, 2017	612,869	$ 39.86	$ 13.25	3.71

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The Company has outstanding options with fair values ranging from $8.53 to $25.99 per option or a weighted average fair value of $11.56 per option. The Company issues ordinary shares for all options exercised. The total amount of fully vested share options which remained outstanding at September 30, 2017, was 612,869. Fully vested share options at September 30, 2017, have an average remaining contractual term of 3.71 years, an average exercise price of $39.86 and a total intrinsic value of $45.4 million. The total intrinsic value of options exercised during the nine months ended September 30, 2017 was $21.8 million (September 30, 2016: $12.5 million).

The following table summarizes the movement in non-vested share options for the nine months ended September 30, 2017:

	Options Outstanding Number of Shares	Weighted Average Exercise Price	Weighted Average Fair Value
Non-vested outstanding at December 31, 2016	814,870	$ 54.37	$ 16.55
Granted	219,113	$ 85.98	$ 25.06
Vested	(290,600)	$ 44.61	$ 14.40
Forfeited	(41,959)	$ 59.31	$ 17.87
Non-vested outstanding at September 30, 2017	701,424	$ 67.99	$ 20.02

Fair value of Stock Options Assumptions

The weighted average fair value of options granted during the nine months ended September 30, 2017, and September 30, 2016, was calculated using the Black-Scholes option pricing model. The weighted average fair values and assumptions used were as follows:

	Nine Months Ended	
	September 30, 2017	September 30, 2016
Weighted average fair value	$25.06	$ 20.10
Assumptions:		
Expected volatility	29%	30%
Dividend yield	0%	0%
Risk-free interest rate	1.93%	1.39%
Expected life	5 years	5 years

Expected volatility is based on the historical volatility of our common stock over a period equal to the expected term of the options; the expected life represents the weighted average period of time that options granted are expected to be outstanding given consideration to vesting schedules and our historical experience of past vesting and termination patterns. The risk-free rate is based on the U.S. government zero-coupon bonds yield curve in effect at time of the grant for periods corresponding with the expected life of the option.

Restricted Share Units and Performance Share Units

On July 21, 2008, the Company adopted the 2008 Employees Restricted Share Unit Plan (the “2008 RSU Plan”) pursuant to which the Compensation and Organization Committee of the Company’s Board of Directors may select any employee, or any Director holding a salaried office or employment with the Company, or a Subsidiary to receive an award under the plan. An aggregate of 1.0 million ordinary shares have been reserved for issuance under the 2008 RSU Plan.

On April 23, 2013, the Company adopted the 2013 Employees Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") Plan (the "2013 RSU Plan") pursuant to which the Compensation and Organization Committee of the Company's Board of Directors may select any employee, or any Director holding a salaried office or employment with the Company, or a Subsidiary to receive an award under the plan. On May 11, 2015, the 2013 RSU Plan was amended and restated in order to increase the number of shares that can be issued under the RSU Plan by 2.5 million shares. Accordingly, an aggregate of 4.1 million ordinary shares have been reserved for issuance under the 2013 RSU Plan. The shares are awarded at par value and vest over a service period. Awards under the 2013 RSU Plan may be settled in cash or shares at the option of the Company.

The Company has awarded RSUs and PSUs to certain key individuals of the Group. The following table summarizes RSU and PSU activity for the nine months ended September 30, 2017:

	PSU Outstanding Number of Shares	PSU Weighted Average Fair Value	PSU Weighted Average Remaining Contractual Life	RSU Outstanding Number of Shares	RSU Weighted Average Fair Value	RSU Weighted Average Remaining Contractual Life
Outstanding at December 31, 2016	830,523	$ 60.73	1.11	1,025,484	$ 58.64	1.40
Granted	87,794	$ 84.10		183,301	$ 88.63	
Shares vested	(320,640)	$ 46.63		(353,243)	$ 44.89	
Forfeited	(60,056)	$ 66.67		(110,354)	$ 62.91	
Outstanding at September 30, 2017	537,621	$ 72.05	1.18	745,188	$ 71.90	1.50

The fair value of RSUs vested for the nine months ended September 30, 2017, totaled $15.9 million (full year 2016: $10.8 million).

The fair value of PSUs vested for the nine months ended September 30, 2017, totaled $15.0 million (the fair value of PSUs vested for the full year 2016 was $10.3 million).

The PSUs vest based on service and specified EPS targets over the period 2014 – 2017, 2015 – 2018, 2016 – 2019 and 2017 – 2020. Since 2013, 274,628 PSUs (net of forfeitures) have been granted. Up to an additional 262,993 PSUs may also be granted, based on the actual EPS from 2014 to 2020.

Non-cash stock compensation expense

Non-cash stock compensation expense for the three and nine months ended September 30, 2017 has been allocated as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(In thousands)		(In thousands)	
Direct costs	$4,551	$ 5,755	$14,855	$ 16,830
Selling, general and administrative	3,709	4,690	12,106	14,305

$8,260	$ 10,445	$26,961	$ 31,135

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Total non-cash stock compensation expense not yet recognized at September 30, 2017, amounted to $60.6 million. The weighted average period over which this is expected to be recognized is 2.2 years.

The amendments required by Accounting Standards Update (‘ASU’) 2016-09 ‘Improvements to Employee Share-Based Payment Accounting’ require the Company to record all tax effects related to share-based payments through the income statement rather than additional paid in capital. The Company has applied the updated standard prospectively in the first nine months of the year ended December 31, 2017.

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8. Share Capital

On October 3, 2016, the Company commenced a previously announced share buyback program of up to $400 million. The Company can acquire up to 10% of its outstanding ordinary shares (by way of redemption), in accordance with Irish law, the United States securities laws, and the Company's constitutional documents through open market share acquisitions.

The buyback program gives a broker authority to acquire the Company's ordinary shares from time to time on the open market in accordance with agreed terms and limitations. The acquisition of shares pursuant to the buyback program was effected by way of redemption and cancellation of the shares, in accordance with the Constitution of the Company.

During the nine months ended September 30, 2017, 1,368,136 ordinary shares were redeemed by the Company under this buyback program for a total consideration of $108.1 million. At September 30, 2017 a total of 2,797,323 ordinary shares were redeemed by the Company under this buyback program for a total consideration of $218.1 million. All ordinary shares that were redeemed under the buyback program were canceled in accordance with the Constitution of the Company and the nominal value of these shares transferred to an other undenominated capital reserve as required under Irish Company Law.

9. Business Segment Information

The Company determines and presents operating segments based on the information that is internally provided to the chief operating decision maker, together the ('CODM') in accordance with FASB ASC 280-10 Disclosures about Segments of an Enterprises and Related Information. The Chief Executive Officer, Chief Financial Officer and Chief Operating Officer, were together considered the Company's CODM in the period up to and including March 1, 2017. On March 1, 2017, Mr. Ciaran Murray transitioned from his role as Chief Executive Officer to the role of Executive Chairman of the Board of Directors and Dr. Steve Cutler was appointed as Chief Executive Officer. As of March 1, 2017, the Company determined that the CODM is comprised of the Chief Executive Officer and the Chief Financial Officer.

The Company determines and presents operating segments based on the information that is provided to the CODM. The Company has determined that we operate in one single business segment which is the provision of outsourced development services on a global basis to the pharmaceutical, biotechnology and medical devices industries. There have been no changes to the basis of segmentation or the measurement basis for the segment results in the period.

The Company is a contract research organization ("CRO"), providing outsourced development services on a global basis to the pharmaceutical, biotechnology and medical device industries. It specializes in the strategic development, management and analysis of programs that support all stages of the clinical development process - from compound selection to Phase I-IV clinical studies. The Company has the expertise and capability to conduct clinical trials in most major therapeutic areas on a global basis and has the operational flexibility to provide development services on a stand-alone basis or as part of an integrated "full service" solution. The Company has expanded predominately through internal growth together with a number of strategic acquisitions to enhance its expertise and capabilities in certain areas of the clinical development process.

The Company is generally awarded projects based upon responses to requests for proposals received from companies in the pharmaceutical, biotechnology and medical device industries or work orders executed under our strategic partnership arrangements. Contracts with customers are generally entered into centrally, in most cases with ICON Clinical Research Limited ("ICON Ireland"), the Company's principal operating subsidiary in Ireland. Revenues, which consist primarily of fees earned under these contracts, are allocated to individual entities within the Group, based on where the work is performed in accordance with the Company's global transfer pricing model.

ICON Ireland acts as the group entrepreneur under the Company's global transfer pricing model given its role in the development and management of the group, it's ownership of key intellectual property and customer relationships, its key role in the mitigation of risks faced by the group and its responsibility for maintaining the Company's global network. ICON Ireland enters into the majority of the Company's customer contracts.

ICON Ireland remunerates other operating entities in the ICON Group on the basis of a guaranteed cost plus mark up for the services they perform in each of their local territories. The cost plus mark up for each ICON entity is established to ensure that each of ICON Ireland and the ICON entities that are involved in the conduct of services for customers, earn an appropriate arms-length return having regard to the assets owned, risks borne, and functions performed by each entity from these intercompany transactions. The cost plus mark-up policy is reviewed annually to ensure that it is market appropriate.

The geographic split of revenue disclosed for each region outside Ireland is the cost plus revenue attributable to these entities. The residual revenues of the Group, once each ICON entity has been paid its respective intercompany service fee, generally fall to be retained by ICON Ireland. As such revenues and income from operations in Ireland are a function of this global transfer pricing model and comprise net revenues of the Group after deducting the cost plus revenues attributable to the activities performed outside Ireland.

The Company's areas of operation outside of Ireland include the United States, United Kingdom, Belgium, France, Germany, Italy, Spain, The Netherlands, Sweden, Turkey, Poland, Czech Republic, Latvia, Russia, Ukraine, Hungary, Israel, Romania, Switzerland, Canada, Mexico, Brazil, Colombia, Argentina, Chile, Peru, India, China, South Korea, Japan, Thailand, Taiwan, Singapore, The Philippines, Australia, New Zealand, and South Africa.

The geographical distribution of the Company’s segment measures as at September 30, 2017, and December 31, 2016, and for the three and nine months ended September 30, 2017, and September 30, 2016, is as follows:

a) The distribution of net revenue by geographical area was as follows:

	Three Months ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(in thousands)		(in thousands)	
Ireland	$107,820	$97,299	$312,916	$293,787
Rest of Europe	89,536	76,427	239,447	231,505
U.S.	192,947	204,265	600,640	581,732
Rest of World	50,020	42,210	150,297	124,329
Total	$440,323	$420,201	$1,303,300	$1,231,353

* All sales shown for Ireland are export sales.

b) The distribution of income from operations, including restructuring, by geographical area was as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(in thousands)		(in thousands)	
Ireland	$62,152	$ 63,933	$164,760	$ 178,081
Rest of Europe	2,526	837	15,124	9,144
U.S.	16,150	11,471	52,897	34,081
Rest of World	4,110	873	15,813	5,745
Total	$84,938	$ 77,114	$248,594	$ 227,051

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c) The distribution of income from operations, excluding restructuring, by geographical area was as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(in thousands)		(in thousands)	
Ireland	$62,152	$ 64,821	$172,513	$ 182,698
Rest of Europe	2,526	1,364	15,124	9,979
U.S.	16,150	13,813	52,897	36,423
Rest of World	4,110	1,181	15,813	6,110
Total	$84,938	$ 81,179	$256,347	$ 235,210

d) The distribution of property, plant and equipment, net, by geographical area was as follows:

	September 30, 2017	December 31, 2016
	(in thousands)	
Ireland	$101,941	$105,684
Rest of Europe	8,827	6,231
U.S.	26,073	29,428
Rest of World	15,464	7,624
Total	$152,305	$148,967

e) The distribution of depreciation and amortization by geographical area was as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
	(in thousands)		(in thousands)	
Ireland	$6,985	$ 6,588	$19,465	$ 19,146
Rest of Europe	3,469	1,730	6,498	5,265
U.S.	4,819	5,368	16,348	17,154
Rest of World	1,007	857	2,812	2,555
Total	$16,280	$ 14,543	$45,123	$ 44,120

f) The distribution of total assets by geographical area was as follows:

	September 30, 2017	December 31, 2016
	(in thousands)	
Ireland	$797,019	$766,120
Rest of Europe	512,827	337,062
U.S.	633,065	651,160
Rest of World	110,438	71,501

Total	$2,053,349	$1,825,843

10. New accounting pronouncements –Revenue from Contacts with Customers

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"), which provides that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The updated standard will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective and permits the use of either the retrospective or cumulative effect transition method. To achieve the core principle of the new standard, an entity should apply the following steps: (1) identify the contract(s) with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. Early adoption is permitted for annual periods beginning after December 16, 2016. Subsequent to issuing ASU 2014-09, the FASB issued the following amendments concerning clarification of ASU 2014-09. In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606), Principal versus Agent Considerations (Reporting Revenue Gross versus Net) ("ASU 2016-08"), which further clarifies the implementation guidance on principal versus agent considerations. The new guidance requires either a retrospective or a modified retrospective approach to adoption. In April 2016, the FASB issued ASU 2016-10, Revenue from Contracts with Customers (Topic 606), Identifying Performance Obligations and Licensing ("ASU 2016-10"), which clarifies the identification of performance obligations and the licensing implementation guidance, while retaining the related principles for those areas. In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients ("ASU 2016-12"), which provides clarification on assessing the collectability criterion, presentation of sales taxes, measurement date for non-cash consideration and completed contracts at transition.

The updated standard is effective for ICON in the first quarter of the year ended December 31, 2018. ICON has elected to adopt the updated standard using the cumulative effect transition method. Under this transition method, ICON will apply the new standard as of the date of initial application (i.e. January 1, 2018), without restatement of comparative period amounts. ICON plc will record the cumulative effect of initially applying the new standard (to revenue and cost) as an adjustment to the opening balance of equity at the date of initial application. Under this method, ICON will apply the requirements of the new standard to those contracts not completed at the date of initial application.

While we continue to assess all potential impacts of the new standard, we believe the most significant impact relates to our assessment of measurement of performance and percentage of completion in respect of our clinical trials service revenue.

Under current GAAP, the revenue attributable to performance is determined based on both input and output methods of measurement based on the relationship between hours incurred and the total estimated hours of the trial, or on the unit of delivery method. We have evaluated the application of the requirements of ASC 606 to 'recognize revenue when or as the entity satisfies a performance obligation' to its business. We have concluded that under the revised standard, clinical trial service is a single performance obligation satisfied over time i.e. the full service obligation in respect of a clinical trial (including services provided by investigators and other parties) is considered a single performance obligation in respect of the clinical services revenue stream. Promises offered to the customer are not distinct within the context of the contract.

We have also concluded that ICON is the contract principal in respect of both direct services and in the use of third parties (principally investigator services) that support the clinical research project. ICON measure over time performance obligation considering progress towards completion on an input measure being total project costs inclusive of third party costs. The transaction price is determined by reference to the contract or change order value (total service revenue and pass-through) adjusted to reflect historical experience to determine a realizable contract value. Revenue will be recognized as the single performance obligation is satisfied. The progress towards completion for clinical service contracts will be measured based on percentage completion of realizable contract value at each reporting period.

The revised standard includes additional disclosure requirements related to revenue. Our results for the first quarter of the year ended December 31, 2018, being the quarter ended March 31, 2018, will include expanded disclosure in respect of (i) disaggregated revenue disclosures from contracts with customers (ii) separate disclosure of contract assets and liabilities (iii) disclosure of retrospective revenue and (iv) disclosure of the remaining performance obligations by product/service (or backlog).

Due to the complexity of certain of our contracts, the actual revenue recognition treatment required under the new standard for these arrangements may be dependent on contract-specific terms and vary in some instances.
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ICON plc

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the unaudited Condensed Consolidated Financial Statements and accompanying notes included elsewhere herein and the Consolidated Financial Statements and related notes thereto included in our Form 20-F for the year ended December 31, 2016. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States.

Overview

We are a CRO providing outsourced development services on a global basis to the pharmaceutical, biotechnology and medical device industries. We specialize in the strategic development, management and analysis of programs that support all stages of the clinical development process - from compound selection to Phase I-IV clinical studies. Our vision is to be the Global CRO partner of choice, delivering best in class information, solutions and performance in clinical and outcomes research.

We believe that we are one of a select group of CROs with the expertise and capability to conduct clinical trials in most major therapeutic areas on a global basis and have the operational flexibility to provide development services on a stand-alone basis or as part of an integrated "full service" solution. At September 30, 2017, we employed approximately 13,117 employees, in 97 locations in 38 countries. During the nine months ended September 30, 2017, we derived approximately 46.1%, 42.4% and 11.5% of our net revenue in the United States, Europe and Rest of World respectively.

Revenue consists primarily of fees earned under contracts with third-party clients. In most cases, a portion of the contract fee is paid at the time the study or trial is started, with the balance of the contract fee generally payable in installments over the study or trial duration, based on the delivery of certain performance targets or "milestones". Revenue from contracts is recognized on a proportional performance method based on the relationship between time incurred and the total estimated duration of the trial or on a fee-for-service basis depending to the particular circumstances of the contract. As is customary in the CRO industry, we contract with third party investigators in connection with clinical trials. All investigator fees and certain other costs, where reimbursed by clients, are deducted from gross revenue to arrive at net revenue. As these costs vary from contract to contract, we view net revenue as our primary measure of revenue growth.

As the nature of our business involves the management of projects having a typical duration of a few weeks to several years, the commencement or completion of projects in a fiscal year can have a material impact on revenues earned with the relevant clients in such years. In addition, as we typically work with some, but not all, divisions of a client, fluctuations in the number and status of available projects within such divisions can also have a material impact on revenues earned from clients from year to year.

Termination or delay in the performance of an individual contract may occur for various reasons, including, but not limited to, unexpected or undesired results, production problems resulting in shortages of the drug, adverse patient reactions to the drug, the client's decision to de-emphasize a particular trial or inadequate patient enrolment or investigator recruitment. In the event of termination the Company is usually entitled to all sums owed for work performed through the notice of termination and certain costs associated with the termination of the study. In addition, contracts generally contain provisions for renegotiation in the event of changes in the scope, nature, duration, or volume of services of the contract.

Our backlog consists of potential net revenue yet to be earned from projects awarded by clients. At September 30, 2017, we had a backlog of approximately $4.8 billion, compared with approximately $4.2 billion at December 31,

2016. We believe that our backlog as of any date is not necessarily a meaningful predictor of future results, due to the potential for cancellation or delay of the projects underlying the backlog, and no assurances can be given on the extent to which we will be able to realize this backlog as net revenue.

Although we are domiciled in Ireland, we report our results in U.S. dollars. As a consequence the results of our non-U.S. based operations, when translated into U.S. dollars, could be materially affected by fluctuations in exchange rates between the U.S. dollar and the currencies of those operations.

In addition to translation exposures, we are also subject to transaction exposures because the currency in which contracts are priced can be different from the currencies in which costs relating to those contracts are incurred. Our operations in the United States are not materially exposed to such currency differences as the majority of our revenues and costs are in U.S. dollars. However, outside of the United States the multinational nature of our activities means that contracts are usually priced in a single currency, most often U.S. dollars or euro, while costs arise in a number of currencies, depending, among other things, on which of our offices provide staff for the contract and the location of investigator sites. Although many such contracts benefit from some degree of natural hedging, due to the matching of contract revenues and costs in the same currency, where costs are incurred in currencies other than those in which contracts are priced, fluctuations in the relative value of those currencies could have a material effect on our results of operations.

As we conduct operations on a global basis, our effective tax rate depends on the geographic distribution of our revenue and earnings among locations with varying tax rates. Our results therefore may be affected by changes in the tax rates of the various jurisdictions. In particular, as the geographic mix of our results of operations among various tax jurisdictions changes, our effective tax rate may vary significantly from period to period.

Results of Operations

Three Months Ended September 30, 2017 compared with Three Months Ended September 30, 2016

The following table sets forth for the periods indicated certain financial data as a percentage of net revenue and the percentage change in these items compared to the prior comparable period. The trends illustrated in the following table may not be indicative of future results.

	Three Months Ended					
	September 30, 2017		September 30, 2016		2017 to 2016 Percentage	
	Percentage of Net Revenue				Increase/ (Decrease)	
Net revenue	100.0	%	100.0	%	4.8	%
Costs and expenses:						
Direct costs	59.0	%	57.9	%	6.8	%
Selling, general and administrative	18.0	%	19.3	%	(2.2	)%
Depreciation	2.6	%	2.5	%	6.4	%
Amortization	1.1	%	1.0	%	27.2	%
Restructuring	-		1.0	%	(100.0	)%
Income from operations	19.3	%	18.3	%	10.1	%

Net revenue for the period increased by $20.1 million, or 4.8%, from $420.2 million for the three months ended September 30, 2016, to $440.3 million for the three months ended September 30, 2017. Net revenue increased by 3.2% in constant currency and decreased by 2.6% in constant dollar organic terms. The increase in revenues in the three months ended September 30, 2017 can be explained by both continued organic growth, and the additional net revenues from the acquisition of ClinicalRM on September 15, 2016 and from the acquisition of Mapi on July 27,

2017. During the three months ended September 30, 2017 we derived approximately 43.8%, 44.8% and 11.4% of our net revenue in the United States, Europe and Rest of World respectively. During the three months ended September 30, 2017 $170.9 million or 38.8% of our net revenues were derived from our top 5 customers compared to $185.4 million or 44.1% of net revenues derived from our top 5 customers during the three months ended September 30, 2016. The largest of these customers related to a Strategic Partnership with a large global pharmaceutical company. Net revenue from this customer contributed 16.6% of net revenue for the quarter, compared to 25.2% of net revenue in respect of the three months ended September 30, 2016. The addition of new customer accounts, particularly mid-tier pharma customers and biotech customers continues to result in a reduction in concentration of revenues from our top five customers.

Net revenue in Ireland increased from $97.3 million for the three months ended September 30, 2016, to $107.8 million for the three months ended September 30, 2017. Net revenue in Ireland is principally a function of the Company's global transfer pricing model (see note 9 Business Segmental Information for further details). Net revenue in our Rest of Europe region increased from $76.4 million for the three months ended September 30, 2016 to $89.5 million for the three months ended September 30, 2017, principally reflecting the acquisition of Mapi in July 2017. Net revenue in our Rest of World region increased from $42.2 million for the three months ended September 30, 2016, to $50.0 million for the three months ended September 30, 2017. This reflects a non-recurring intercompany pricing adjustment for services historically provided by certain Rest of World subsidiaries. Net revenue in the U.S. region decreased from $204.3 million for the three months ended September 30, 2016, to $192.9 million for the three months ended September 30, 2017.

Direct costs for the period increased by $16.5 million, or 6.8%, from $243.2 million for the three months ended September 30, 2016 to $259.7 million for the three months ended September 30, 2017. Direct costs consist primarily of compensation, associated fringe benefits and share based compensation expense for project-related employees and other direct project driven costs. The increase in direct costs during the period arose from an increase in headcount and a corresponding increase in personnel related expenditure of $17.8 million, and increases in other direct project related costs of $0.9 million. These increases were offset by a decrease in laboratory costs of $2.0 million and a decrease travel related costs of $0.2 million. As a percentage of net revenue, direct costs have increased from 57.9% for the three months ended September 30, 2016, to 59% for the three months ended September 30, 2017.

Selling, general and administrative expenses for the period decreased by $1.8 million, or 2.2%, from $81.2 million for the three months ended September 30, 2016, to $79.4 million for the three months ended September 30, 2017. Selling, general and administrative expenses comprise primarily of compensation, related fringe benefits and share based compensation expense for non-project-related employees, recruitment expenditure, professional service costs, advertising costs and all costs related to facilities and information systems. Lease charges of $1.1 million were recorded principally in respect of premises vacated during the period on review of our facilities. The net decrease in selling, general and administration expenses for the period of $1.8 million reflects this item in addition to a continued focus on personnel related expenditure and facilities and related costs. As a percentage of net revenue, selling, general and administrative expenses, decreased from 19.3% for the three months ended September 30, 2016, to 18.0% for the three months ended September 30, 2017.

Depreciation expense for the period increased by $0.7 million, or 6.4%, from $10.7 million for three months ended September 30, 2016, to $11.4 million for three months ended September 30, 2017. Depreciation expense arises principally from continued investment in facilities, information systems and equipment to support the Company's growth. As a percentage of net revenue the depreciation expense for the three months ended September 30, 2017, (2.6%) increased marginally on the percentage of net revenue charge for the three months ended September 30, 2016, (2.5%). Amortization expense for the period increased by $1.0 million, or 27.2%, from $3.9 million for the three months ended September 30, 2016, to $4.9 million for the three months ended September 30, 2017. Amortization expense represents the amortization of intangible assets acquired on business combinations. The main reason for the increase in the amortization expense for the period relates to the additional amortization for the period related to the acquisition of ClinicalRM in September 2016, and the acquisition of Mapi in July 2017. As a percentage of net revenue, amortization expense increased from 1.0% for the three months ended September 30, 2016, to 1.1% for the three months ended September 30, 2017.

During the three months ended September 30, 2016, a restructuring charge of $4.1 million was recognized under a restructuring plan adopted following a review by the company of its operations. The restructuring plan includes resource rationalizations in certain areas of the business to improve resource utilization (see note 4 Restructuring for further information). During the three months ended September 30, 2017, no restructuring charge was recognized.

As a result of the above, income from operations for the three months increased by $7.8 million, or 10.1%, from $77.1 million for the three months ended September 30, 2016, ($81.2 million excluding restructuring charges) to $84.9

million for the three months ended September 30, 2017. As a percentage of net revenue, income from operations increased from 18.3% of net revenues for the three months ended September 30, 2016 (19.3% excluding restructuring charges) to 19.3% of net revenues for the three months ended September 30, 2017.

Income from operations in Ireland decreased from a profit of $63.9 million for the three months ended September 30, 2016 ($64.8 million excluding restructuring charges) to a profit of $62.2 million for the three months ended September 30, 2017. Income from operations in Ireland is impacted by the Group's global transfer pricing model (see note 9 Business Segmental Information for further details). Income from operations in our Rest of Europe region increased from $0.8 million for the three months ended September 30, 2016, ($1.4 million excluding restructuring charges) to $2.5 million for the three months ended September 30, 2017, while income from operations in our Rest of World region increased from $0.9 million for the three months ended September 30, 2016, ($1.2 million excluding restructuring charges) to $4.1 million for the three months ended September 30, 2017. Income from operations in the U.S. region increased from $11.5 million for the three months ended September 30, 2016, ($13.8 million excluding restructuring charges) to $16.2 million for the three months ended September 30, 2017. This reflects the income contribution since acquisition of ClinicalRM, and the impact of refinements to the consideration earned by US subsidiaries under the Group's global transfer pricing model, offset in part by increased amortization charges.

Interest expense of $3.2 million for the three months ended September 30, 2017, is in line with the charge for the three months ended September 30, 2016. Interest income increased by $0.1 million or 36.8%, from $0.5 million for the three months ended September 30, 2016, to $0.6 million for the three months ended September 30, 2017.

Provision for income taxes decreased from $10.5 million ($11.0 million excluding restructuring) for the three months ended September 30, 2016, to $8.2 million for the three months ended September 30, 2017. The Company's effective tax rate for the three months ended September 30, 2017, was 10.0% compared with 14.1% (14.0% excluding restructuring charges) for the three months ended September 30, 2016. The effective tax rate in Q3 benefited from the favourable settlement of a number of tax audits during the quarter and the resulting release of provisions in respect of uncertain tax positions upon the conclusion of those tax audits. The effective tax rate in Q3 also benefited from favourable return to provision true ups in respect of returns filed in certain jurisdictions during the quarter. Apart from these discrete items, the Company's effective tax rate remains principally a function of the distribution of pre-tax profits amongst the territories in which it operates.

Nine Months Ended September 30, 2017 compared with Nine Months Ended September 30, 2016

The following table sets forth for the periods indicated certain financial data as a percentage of net revenue and the percentage change in these items compared to the prior comparable period. The trends illustrated in the following table may not be indicative of future results.

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	2017 to 2016 Percentage
	Percentage of Net Revenue		Increase/ (Decrease)
Net revenue	100.0%	100.0 %	5.8 %
Costs and expenses:			
Direct costs	58.3 %	57.7 %	7.1 %
Selling, general and administrative	18.5 %	19.7 %	(0.2)%
Depreciation	2.5 %	2.5 %	1.2 %
Amortization	1.0 %	1.0 %	4.9 %
Restructuring	0.6 %	0.7 %	(5.0)%

Income from operations	19.1 %	18.4 %	9.5 %

Net revenue for the period increased by $71.9 million, or 5.8%, from $1,231.4 million for the nine months ended September 30, 2016 to $1,303.3 million for the nine months ended September 30, 2017. Net revenue increased by 5.8% in constant currency and by 1.5% in constant dollar organic terms. The increase in revenues in the nine months ended September 30, 2017, can be explained by both continued organic growth, and the additional net revenues from the acquisition of ClinicalRM on September 15, 2016, and the acquisition of Mapi on July 27, 2017. During the nine months ended September 30, 2017, we derived approximately 46.1%, 42.4% and 11.5% of our net revenue in the United States, Europe and Rest of World respectively. During the nine months ended September 30, 2017, $545.4 million or 41.8% of our net revenues were derived from our top 5 customers compared to $552.3 million or 44.9% of net revenues derived from our top 5 customers during the nine months ended September 30, 2016. The largest of these customers related to a Strategic Partnership with a large global pharmaceutical company. Net revenue from this customer contributed 20.2% of net revenue for the nine months ended September 30, 2017, compared to 27.4% of net revenue in respect of the nine months ended September 30, 2016. The addition of new customer accounts, particularly mid-tier pharma customers and biotech customers continues to result in a reduction in concentration of revenues from our top five customers.

Net revenue in Ireland increased from $293.8 million for the nine months ended September 30, 2016, to $312.9 million for the nine months ended September 30, 2017. Net revenue in Ireland is principally a function of the Company's global transfer pricing model (see note 9 Business Segmental Information for further details). Net revenue in our Rest of Europe region increased from $231.5 million for the nine months ended September 30, 2016 to $239.5 million for the nine months ended September 30, 2017, principally reflecting the acquisition of Mapi in July 2017. Net revenue in our Rest of World region increased from $124.3 million for the nine months ended September 30, 2016 to $150.3 million for the nine months ended September 30, 2017. This reflects a non-recurring intercompany pricing adjustment for services historically provided by certain Rest of World subsidiaries. Net revenue in the U.S. region increased from $581.7 million for the nine months ended September 30, 2016, to $600.6 million for the nine months ended September 30, 2017. Net revenues in the U.S. region for the nine months ended September 30, 2017, was impacted positively by the acquisition of ClinicalRM which was acquired on September 15, 2016.

Direct costs for the period increased by $50.4 million, or 7.1%, from $709.8 million for the nine months ended September 30, 2016, to $760.2 million for the nine months ended September 30, 2017. Direct costs consist primarily of compensation, associated fringe benefits and share based compensation expense for project-related employees and other direct project driven costs. The increase in direct costs during the period arose from an increase in headcount and a corresponding increase in personnel related expenditure of $45.7 million, and increases in other direct project related costs of $7.2 million. This increase was offset by a decrease in travel related costs of $1.6 million and laboratory costs of $0.9 million. As a percentage of net revenue, direct costs increased from 57.7% for the nine months ended September 30, 2016, to 58.3% for the nine months ended September 30, 2017.

Selling, general and administrative expenses for the period decreased by $0.5 million, or 0.2%, from $242.2 million for the nine months ended September 30, 2016, to $241.7 million for the nine months ended September 30, 2017. Selling, general and administrative expenses comprise primarily of compensation, related fringe benefits and share based compensation expense for non-project-related employees, recruitment expenditure, professional service costs, advertising costs and all costs related to facilities and information systems. During the nine months ended September 30, 2017, a credit of $6 million was recorded being the reduction in the assessment of the fair value of contingent consideration liability relating to the acquisition of ClinicalRM (see note 3). Once-off professional costs of $3.5 million were also recorded in the period. Lease charges of $4.2 million were recorded principally in respect of premises vacated during the period on review of our facilities. The net decrease in selling, general and administration expenses of $0.5 million reflects these items and continued focus on personnel related expenditure and facilities and related costs. As a percentage of net revenue, selling, general and administrative expenses, decreased from 19.7% for the nine months ended September 30, 2016, to 18.5% for the nine months ended September 30, 2017.

Depreciation expense for the period increased by $0.4 million, or 1.2%, from $31.4 million for the nine months ended September 30, 2016, to $31.8 million for the nine months ended September 30, 2017. Depreciation expense arises principally from continued investment in facilities, information systems and equipment to support the Company's growth. As a percentage of net revenue the depreciation expense for the nine months ended September 30, 2017 was 2.5%, which is in line with the nine months ended September 30, 2016. Amortization expense for the period increased by $0.7 million, or 4.9%, from $12.7 million for the nine months ended September 30, 2016, to $13.4 million for the nine months ended September 30, 2017. Amortization expense represents the amortization of intangible assets acquired on business combinations. The main reason for the increase in the amortization expense for the period relates to the additional amortization for the period related to the acquisition of ClinicalRM (September 2016) and Mapi (July 2017). As a percentage of net revenue, amortization expense for the nine months ended September 30, 2017, was 1.0%, which is in line with the nine months ended September 30, 2016.

During the nine months ended September 30, 2017, the Company implemented a restructuring plan which contains Company resource rationalizations in order to improve operating efficiencies and reduce expenses. A restructuring charge of $7.8 million was recognized during the nine months ended September 30, 2017. (See note 4 Restructuring for further information). A restructuring charge of $8.2 million was recognized during the nine months ended September 30, 2016.

As a result of the above, income from operations for the nine months ended September 30, 2017, increased by $21.5 million, or 9.5%, from $227.1 million for the nine months ended September 30, 2016, ($235.2 million excluding restructuring charges) to $248.6 million for the nine months ended September 30, 2017, ($256.3 million excluding restructuring charges). As a percentage of net revenue, income from operations increased from 18.4% (19.1% excluding restructuring charges) of net revenues for the nine months ended September 30, 2016, to 19.1% of net revenues for the nine months ended September 30, 2017, (19.7% excluding restructuring charges).

Income from operations in Ireland decreased from a profit of $178.1 million for the nine months ended September 30, 2016, ($182.7 million excluding restructuring charges) to a profit of $164.8 million for the nine months ended September 30, 2017, ($172.5 million excluding restructuring charges). Income from operations in Ireland is impacted by the Group's global transfer pricing model (see note 9 Business Segmental Information for further details). Income from operations in our Rest of Europe region increased from $9.1 million for the nine months ended September 30, 2016, ($10.0 million excluding restructuring charges) to $15.1 million for the nine months ended September 30, 2017, ($15.1 million excluding restructuring charges), while income from operations in our Rest of World region increased from $5.8 million for the nine months ended September 30, 2016, ($6.1 million excluding restructuring charges) to $15.8 million for the nine months ended September 30, 2017, ($15.8 million excluding restructuring charges). This reflects a non-recurring intercompany pricing adjustment for services historically provided by certain Rest of World subsidiaries. Income from operations in the U.S. region increased from $34.1 million for the nine months ended September 30, 2016, ($36.4 million excluding restructuring charges) to $52.9 million for the nine months ended September 30, 2017, ($52.9 million excluding restructuring charges), principally reflecting a credit of $6 million recorded on revaluation of the contingent consideration related to the acquisition of ClinicalRM, the income contribution since acquisition of ClincalRM, and the impact of refinements to the consideration earned by US subsidiaries under the Group's global transfer pricing model. These increases were offset in part by increased amortization charges.

Interest expense for the period decreased from $9.6 million for the nine months ended September 30, 2016, to $9.5 million for the nine months ended September 30, 2017. Interest income increased by $0.6 million or 52.9%, from $1.2 million for the nine months ended September 30, 2016 to $1.8 million for the nine months ended September 30, 2017.

Provision for income taxes decreased from $30.6 million ($31.7 million excluding restructuring) for the nine months ended September 30, 2016, to $30.4 million ($31.4 million excluding restructuring) for the nine months ended September 30, 2017. The Company's effective tax rate for the nine months ended September 30, 2017, was 12.6% (12.6% excluding restructuring charges) compared with 14.0% (13.9% excluding restructuring charges) for the nine months ended September 30, 2016. The Company's effective tax rate is principally a function of the distribution of pre-tax profits amongst the territories in which it operates.

Liquidity and Capital Resources

The CRO industry is generally not capital intensive. The Group's principal operating cash needs are payment of salaries, office rents, travel expenditures and payments to investigators. Investing activities primarily reflect capital expenditures for facilities and information systems enhancements, the purchase and sale of short term investments and acquisitions.

Our clinical research and development contracts are generally fixed price with some variable components and range in duration from a few weeks to several years. Revenue from contracts is generally recognized as income on the basis of the relationship between time incurred and the total estimated contract duration or on a fee-for-service basis. The cash flow from contracts typically consists of a small down payment at the time the contract is entered into, with the balance paid in installments over the contract's duration, in some cases on the achievement of certain milestones. Accordingly, cash receipts do not correspond to costs incurred and revenue recognized on contracts.

Cash and cash equivalents and net borrowings

	Balance December 31, 2016	Drawn down/ (repaid) $ in thousands	Net cash inflow/ (outflow)	Other non-cash adjustments	Effect of exchange rates	Balance September 30, 2017
Cash and cash equivalents	192,541	-	13,894	-	3,370	209,805
Private placement notes	(348,511)	-		(282)	-	(348,793)
	(155,970)	-	13,894	(282)	3,370	(138,988)

The Company's cash and short term investment balances at September 30, 2017, amounted to $292.5 million compared with cash and short term investment balances of $260.6 million at December 31, 2016. The Company's cash and short term investment balances at September 30, 2017, comprised of cash and cash equivalents of $209.8 million and short-term investments of $82.7 million. The Company's cash and short term investment balances at December 31, 2016, comprised of cash and cash equivalents of $192.5 million and short-term investments of $68.0 million.

On December 15, 2015, ICON Investments Five Unlimited Company issued Senior Notes for aggregate gross proceeds of $350.0 million in a private placement. The Senior Notes will mature on December 15, 2020. Interest payable is fixed at 3.64%, and is payable semi-annually on the Senior Notes on each June 15 and December 15, commencing June 15, 2016. The Senior Notes are guaranteed by ICON plc.

On June 30, 2014, the Company entered into a five year committed multi-currency Revolving Credit Facility for $100.0 million with Citibank, JP Morgan, Santander and Barclays Bank ("Revolving Credit Facility"). Each bank subject to the agreement has committed $25 million to the facility, with equal terms and conditions in place with all institutions. The facility is guaranteed by ICON plc. The facility bears interest at LIBOR plus a margin. No amounts were drawn at September 30, 2017, or at December 31, 2016, in respect of the Revolving Credit Facility. Amounts available to the Group under the facility at both September 30, 2017 and December 31, 2016 were therefore $100.0 million.

The Group also has an uncommitted short-term revolving credit facility of $30 million. No amounts were drawn under this facility at 31 December 2016, or at September 30, 2017.

Net cash provided by operating activities was $277.2 million for the nine months ended September 30, 2017 compared with cash provided by operating activities of $129.0 million for the nine months ended September 30, 2016. This reflects the positive cash flow impact of the increase in revenues and underlying profitability of the Company.

The dollar value of these balances and the related number of days revenue outstanding (i.e. revenue outstanding as a percentage of revenue for the period, multiplied by the number of days in the period) can vary over a study or trial duration. Contract fees are generally payable in instalments based on the delivery of certain performance targets or “milestones” (e.g. target patient enrolment rates, clinical testing sites initiated or case report forms completed), such milestones being specific to the terms of each individual contract, while revenues on contracts are recognized as contractual obligations are performed. Days revenue outstanding can vary therefore due to, amongst others, the scheduling of contractual milestones over a study or trial duration, the delivery of a particular milestone during the period or the timing of cash receipts from customers. A decrease in the number of days revenue outstanding during a period will result in cash inflows to the Company while an increase in days revenue outstanding will lead to cash outflows. The number of days revenue outstanding at September 30, 2017, was 50 days compared to 50 days at December 31, 2016. The number of days revenue outstanding at September 30, 2016, was 50 days compared to 41 days at December 31, 2015.

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Net cash used in investing activities was $162.9 million for the nine months ended September 30, 2017, compared to net cash used in investing activities of $79.1 million for the nine months ended September 30, 2016. Net cash used in the nine months ended September 30, 2017, relates to capital expenditure of $23.7 million, which was mainly comprised of investment in facilities and IT infrastructure and $125.5 million net cash outflow on the acquisition of Mapi. During the nine months ended September 30, 2017, $36.5 million was used for the purchase of short term investments and $22.7 million was generated by the sale of short term investments. Net cash used in investing activities during the nine months ended September 30, 2016, relates to capital expenditure of $29.3 million, $54.0 million for cash paid for acquisitions, which is inclusive of $52.4 million being the cash consideration for the ClinicalRM acquisition offset by $1.8 million acquired with Clinical RM and a further $1.6 million for a working capital adjustment in relation to the PMG acquisition (see note 3 Business Combinations for further details). During the nine months ended September 30, 2016, $19.0 million was used for the purchase of short term investments offset by the sale of short term investments of $21.5 million.

Net cash used in financing activities during the nine months ended September 30, 2017, amounted to $100.4 million compared to net cash provided by financing activities of $65.6 million for the nine months ended September 30, 2016. Cash outflows in respect of financing includes cash payments in respect of the Company’s share repurchase program totaling $108.1 million during the nine months ended September 30, 2017. In addition, $7.8 million was received by the Company from the exercise of share options. During the nine months ended September 30, 2016, $5.4 million was recognized in relation to the tax benefit from the exercise of share options. In addition, $7.2 million was received by the Company from the exercise of share options. During the nine months ended September 30, 2016, there was $53.0 million drawn down from the five year committed multi-currency Revolving Credit Facility. There was also $20.0 million drawn down and subsequently repaid by the Company under a one year uncommitted short term revolving credit facility (of $30.0 million) with Santander UK plc. The facility bears interest at LIBOR plus a margin. No amounts were drawn under this facility at September 30, 2017.

As a result of these cash flows, cash and cash equivalents increased by $17.3 million for the nine months ended September 30, 2017, compared to an increase of $115.4 million for the nine months ended September 30, 2016.

Inflation

We believe the effects of inflation generally do not have a material adverse impact on our operations or financial condition.

Legal Proceedings

We are not party to any litigation or other legal proceedings that we believe could reasonably be expected to have a material adverse effect on our business, results of operations and financial condition.

SIGNATURES

Pursuant to the requirements 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.

	ICON plc
	/s/Brendan Brennan
Date: October 26, 2017	Brendan Brennan
	Chief Financial Officer

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