2012 ANNUAL REPORT

NOTICE OF 2013 ANNUAL MEETING OF STOCKHOLDERS

PROXY STATEMENT

April 26, 2013

To Our Fellow Stockholders:

FX Energy's focus on Poland is based on a few simple ideas:

- Poland lies within the European Permian Basin, a prolific source of hydrocarbons that extends across Europe, similar to the US Permian Basin.
- Poland is underexplored compared to the US and western Europe (mostly for historical and political reasons).
- Therefore, the opportunity to discover conventional oil and gas should be higher in Poland than in the US or in western European countries.
- Gas prices in Poland, and in Europe generally, are much higher than in the US because there is little domestic supply, resulting in heavy dependence on Russian gas imports.
- Poland has a sound economy and adheres to the rule of law; it is a safe place to invest.

These observations remain as true and compelling today as when we first entered Poland. We have demonstrated the hydrocarbon potential with the drill bit and continue doing so. We believe there is the opportunity to discover significant hydrocarbon reserves in Poland.

Throughout most of our history in Poland, we had very limited funds and usually were able to drill only one or two exploration wells each year. Our position now is very much improved. We have production revenues to support an expanded drilling program, we have better defined prospects on upgraded exploration acreage, and we have appraisal and development drilling opportunities. We are in the strongest position ever to demonstrate the hydrocarbon potential of Poland.

FX Energy's highlights over the last three years:

- Oil and gas revenues have almost tripled since 2009, reaching $34.5 million in 2012, a compound annual growth rate of 39%.
- Total revenues have grown at a compound annual growth rate of 36%.
- Oil and gas production has more than doubled since 2009 to 4.8 Bcfe in 2012, a compound annual growth rate of 30%.

- The 2012 average gas sales price, taking into account currency fluctuations throughout the year, was 36% higher than in 2009.
- The production risk profile is improving, as we currently produce from eight wells in Poland (with two more to be added this year), compared to just three wells in 2009.

Our exploration and development spending continues to increase. The amounts we reported for exploration costs and capital additions for 2012, a record level for us, were triple our 2009 spending. Looking ahead this year, we expect to make capital expenditure commitments with a value nearly double last year's expenditures. At the time of this report we are testing two wells, hope to drill four to six more wells this year, and have a strong inventory of a dozen additional mature prospects to drill. As we go to press with this report to stockholders, we hope to have the most active drilling program in our history during 2013.

Over the past several years, we have been demonstrating that there is substantial opportunity in Poland's oil and gas sector. We remain committed to growing the scope of our operations, focusing on the hydrocarbon potential in Poland.

We greatly appreciate the support of our shareholders, staff, PGNiG, and the Polish authorities.

Sincerely,

David N. Pierce	Thomas B. Lovejoy
President and Chief Executive Officer	Chairman and Executive Vice President

2012 ANNUAL REPORT TO STOCKHOLDERS

SPECIAL NOTE ON FORWARD-LOOKING STATEMENTS

This report contains "forward-looking" statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by the use of the words "believe," "may," "could," "should," "expect," "anticipate," "estimate," "project," "propose," "plan," "intend," and similar words and expressions. Statements that describe our future strategic plans, goals, or objectives are also forward-looking statements. We intend that the forward-looking statements will be covered by the safe harbor provisions for forward-looking statements contained in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Readers of this report are cautioned that any forward-looking statements, including those regarding us or our management's current beliefs, expectations, anticipations, estimations, projections, strategies, proposals, plans, or intentions, are not guarantees of future performance or results of events and involve risks and uncertainties, such as:

- whether we will be able to discover and produce gas or oil in commercial quantities from any exploration prospect;
- whether we will be able to borrow funds to develop our oil and gas discoveries in Poland from our current principal lenders or from any other commercial lenders, even if we increase substantially the quantity and value of our reserves that we may be willing to encumber to secure repayment of such borrowings;
- whether the quantities of gas or oil we discover will be as large as our initial estimate of an exploration target area's gross unrisked potential;
- whether the estimated probable oil and gas reserves will ever be proved or produced;
- the rates at which our resources will be produced, particularly from properties for which we are not the operator;
- whether we will be able to obtain capital sufficient for our anticipated exploration and other capital expenditures;
- how our efforts to obtain additional capital will affect the trading market for our securities;
- whether actual exploration risks, schedules, and sequences will be consistent with our plans and forecasts;
- the future results of drilling or producing individual wells and other exploration and development activities;
- the prices at which we may be able to sell gas or oil;
- foreign currency exchange-rate fluctuations;
- the financial and operating viability and stability of Polskie Górnictwo Naftowe i Gazownictwo, or PGNiG, and other third parties with which we conduct business and on which we rely to supply goods and services and to purchase our oil and gas production;
- exploration and development priorities and the financial and technical resources of PGNiG, our principal joint venture and strategic partner in Poland, PL Energia S.A., another partner in Poland, or other future partners;

- uncertainties inherent in estimating quantities of proved and probable reserves and actual production rates and associated costs;

- the cost and availability of additional capital that we may require and possible related restrictions on our future operating or financing flexibility;

- our future ability to attract industry or financial participants to share the costs of exploration, exploitation, development, and acquisition activities;

- the effect of future changes in reservoir pressure, prices, reservoir mapping, production rates, and other factors on reserve quantities;

- uncertainties of certain terms to be determined in the future relating to our oil and gas interests, including exploitation fees, royalty rates, and other matters;

- uncertainties, restrictions, and increased costs resulting from the current public interest and regulatory focus on hydraulic fracturing, which we intend to use in Poland and which we have used in our Montana oil exploration of the Alberta Bakken and Three Forks formations;

- changes in the regulatory regime for the exploration, development, and production of hydrocarbons in Poland, including changes in the scheme through which prices at which we sell our production may be governmentally established or market influenced and changes in applicable royalty rates;

- environmental hazards, such as uncontrollable flows of crude oil, brine, well fluids, hydraulic fracturing fluids, or other pollutants by us or third-party service providers;

- uncertainties regarding future political, economic, regulatory, environmental, fiscal, taxation, and other policies in Poland and the European Union;

- the impact on us, our industry partners, our lenders, and others with which we deal of the continuing sovereign debt crises within the European Union, of which Poland is a member; and

- the factors set forth under the headings "Risk Factors" and "Management's Discussion and Analysis of Analysis of Financial Condition and Results of Operation" and other factors that are not currently known to us that may emerge from time to time.

The forward-looking information is based on present circumstances and on our predictions respecting events that have not occurred, that may not occur, or that may occur with different consequences from those now assumed or anticipated. Actual events or results may differ materially from those discussed in the forward-looking statements. The forward-looking statements included in this report are made only as of the date of this report.

OUR BUSINESS

Introduction

We are an independent oil and gas exploration and production company with production, appraisal, and exploration activities in Poland. We also have modest oil production and oilfield service activities in the United States, where we have conducted limited exploration during 2012. Our headquarters are in Salt Lake City, Utah, and our Polish operations are headquartered in Warsaw. Definitions of certain oil and gas industry terms used in this report are provided below under Properties – Oil and Gas Terms.

At year-end 2012, independent reserve engineers estimated our worldwide proved oil and gas reserves to be 44.1 billion cubic feet, or Bcf, of natural gas and 0.6 million barrels of oil, or Bbl, or a combined total of 47.7 billion cubic feet of natural gas equivalent, or Bcfe (converting oil to gas at a ratio of one barrel of oil to 6,000 cubic feet of natural gas). Of this 47.7 Bcfe, 93% was in Poland and 7% was in the United States. The independent engineers estimated the PV-10 Value of our proved reserves to be approximately $158 million.

At year-end 2012, independent reserve engineers estimated our worldwide proved plus probable, or P50, oil and gas reserves to be a combined total of 79.4 Bcfe. The independent engineers estimated the PV-10 Value of our P50 reserves to be approximately $208 million.

Our 2012 oil and gas production was 4.8 Bcfe (13.1 million cubic feet equivalent per day, or MMcfed), which was up 9% from 2011 production. Of our 2012 production, 4.5 Bcfe (12.2 MMcfed) of our production was in Poland and 0.3 Bcfe (0.9 MMcfed) was in the United States. All of our production in Poland consisted of natural gas, while all of our United States production consisted of crude oil.

Our oil and gas revenues for 2012 were $34.5 million, which is an increase of 16% over revenues for the preceding fiscal year. We currently expect that our 2013 production will rise measurably from our 2012 production rates with the start of production at our Winna Gora, Lisewo-1, and Komorze-3 wells, which we believe will be greater than the natural declines in production from our currently producing wells. We expect our 2013 first quarter production to average approximately 14.0 MMcfed. Production began at our Winna Gora well in late January of 2013. We expect production facilities to be complete and gas to start flowing at our Lisewo-1 and Komorze-3 wells in the second half of 2013.

Substantially all of our growth in reserves and production in recent years has come from our operations in Poland. We expect this will continue, as most of our technical efforts and capital budget are devoted to these operations in Poland. We believe that these operations represent the most favorable opportunities for success that are available to us. See “Corporate Strategy” immediately below. With a view to future growth in reserves and production, we now hold 2.7 million gross acres (2.0 million net) in Poland and continually review additional acreage acquisition opportunities.

During 2012 in Poland, we drilled one well that we plan to place into production in 2013, one well with gas shows that has been temporarily abandoned pending further evaluation, and one dry hole.

As of December 31, 2012, we had approximately 53.2 million shares of common stock outstanding, and our market capitalization was approximately $219 million (approximately $214 million as of the date of this filing). Our shares are listed on the Nasdaq Global Select Market under the symbol “FXEN.” So far during 2013, our average daily trading volume has been approximately 278,000 shares. Our total assets as of December 31, 2012, were $106.0 million, and our working capital was $30.4 million. Total debt per thousand cubic feet equivalent, or Mcfe, of proved reserves was $0.84 at year end.

Most of our current Polish operations are conducted in partnership with PGNiG, a fully integrated oil and gas company that is largely owned by the Treasury of the Republic of Poland. PGNiG is Poland’s principal domestic oil and gas exploration, production, transportation, and distribution entity. Under our existing agreements, PGNiG has provided us with access to exploration opportunities, previously collected exploration data, and technical and operational support. We also use geophysical and drilling services provided by PGNiG, and we sell almost all of our gas production to PGNiG.

References to "us," "we," and "our" in this report include FX Energy, Inc., and our subsidiaries. In addition to our headquarters in Salt Lake City, Utah, we have operations offices in Warsaw, Poland, and Oilmont, Montana.

Corporate Strategy

We believe Poland is a unique international exploration opportunity. Over the last 50 years or so, Western companies have poured billions of dollars into exploration efforts in the British, Dutch, Norwegian, and German sectors of the offshore and onshore North European Permian Basin (generally the North Sea area). For the industry, these efforts have resulted in the discovery of trillions of cubic feet of gas and more than a billion barrels of oil. However, until the last few years of the twentieth century, Poland was closed to exploration by foreign oil and gas companies. To date, the exploration activities conducted in the Polish onshore portion of the Permian Basin are only a fraction of those conducted in the western part of the basin. Consequently, we believe the Polish Permian Basin is underexplored and underexploited and, therefore, has high potential for discovery of significant amounts of oil and gas relative to the North Sea or other mature oil and gas provinces in the United States and elsewhere. As an example, the estimated gross proved recoverable reserves per well associated with the nine conventional gas discoveries in our core Fences concession in Poland are 14.8 Bcf. The average initial gross production rate for these nine wells is approximately 5.0 MMcfd of natural gas with a relatively long, flat production profile.

Just as important as the reserve and production potential is the fact that Poland is highly dependent upon imported natural gas, which is expensive. There is an attractive and deep market for gas discoveries and production in-country. For example, as of the date of this report the price we receive for natural gas at our Roszkow well is more than double the spot price under natural gas contracts traded on the New York Mercantile Exchange, sometimes referred to as the Henry Hub price.

Acting on this combination of facts, we were one of the first independent oil and gas companies to acquire a large land position, to embark on a focused exploration and development program, and as a result, to begin producing hydrocarbons in Poland. After a number of years of effort in Poland, our exploration efforts are showing significant progress. Our production volumes in the Fences concession area have increased at a compound annual growth rate of 35% from 2009 through 2012, while our natural gas revenues have increased at a compound annual growth rate of 50% during the same period. Though we cannot assert that future results will be similar, this success has encouraged us to continue to focus our efforts in Poland.

More specifically, we have directed the majority of our available capital, management, and technical resources to our core Fences concession area in Poland. We expect to continue concentrating much of our capital budget to this area in an effort to lower drilling risk, shorten the time to first production from successful wells, and optimize opportunities for robust revenue growth.

Outside our core Fences area, we currently hold substantial acreage in other areas of Poland that we consider underexplored and underdeveloped and, therefore, subject to greater exploration risk. With the success that we have achieved from our Fences drilling program, we now have means to increase our activities in our other exploration acreage, through both targeted seismic data acquisition and drilling of higher-risk, higher-reward exploration wells, where we believe we have the opportunity to find significant oil and gas reserves. To the extent that our overall strategy results in substantial revenue growth, we plan to continue to increase our funding of exploration projects over a wide area in Poland.

Current Activities and Presence in Poland

General

We concentrate our exploration efforts in Poland primarily on the Rotliegend sandstones of the Permian Basin. We have identified a core area consisting of approximately 852,000 gross acres surrounding the long-producing 390 Bcf Radlin field, which was discovered in the 1980s by our joint venture partner PGNiG (we do not own an interest in this field, but see it as a geologic analog). We have emphasized improved seismic data acquisition and processing in our exploration efforts surrounding this field, using technology developed by others for Rotliegend exploration in the Southern North Sea.

Since 2000, we have made commercially successful discoveries in nine of the 12 wells we have drilled on Rotliegend structural trap targets in our core Fences concession. In the aggregate, these nine discoveries found gross estimated recoverable proved reserves of approximately 133 Bcf of gas. We have acquired three-dimensional, or 3-D, seismic data over several hundred square kilometers in the Fences concession and plan to acquire 3-D seismic data over more of that concession. Using the data acquired to date, we have identified a number of possible additional structural traps. We believe the 3-D seismic data gives us better definition of the targets and might reduce our drilling risk. However, this is still exploration in an underexplored area. Thus, we expect to drill some wells that do not establish production or reserves, just as we have done in the past. Nonetheless, the extensive production history, well data, and seismic data available for the Fences area have contributed to our success rate there. We plan to continue to direct a significant portion of our available funds to carry out a multiyear exploration, appraisal, and development well drilling program in the Fences concession. We anticipate drilling three to four additional wells in the Fences area during 2013. These operations are the focus of our strategy to increase production and reserves in our core area.

While maintaining our focus on the Rotliegend structural trap exploration model, we are also working to determine the potential for commercial gas production from tight Rotliegend sandstone in the north part of our Fences concession using vertical drilling and fracture technology. The Plawce horst was discovered in the 1970s and 1980s; test wells found large gas columns in tight Rotliegend reservoirs. Modern technology now provides better tools to exploit such resources, which have significant potential. In 2011, we drilled a vertical well in the Plawce horst, encountering approximately 480 meters of relatively tight Rotliegend sandstone. Log, core, and test data show gas saturation with no free water. In the first half of 2013, we plan to fracture three separate intervals in the well and test the potential for commercial production.

We have also identified a number of prospects outside the Fences concession in our other concessions in Poland. These prospects are generally higher risk, as indicated by two noncommercial tests we drilled in these areas in 2012, but drilling success may open new productive areas with significant resources. We are drilling the Tuchola-3K well in our Edge concession at the date of this report and anticipate drilling two to three additional wells in 2013 in one or more of our Edge, Block 246, Warsaw South, and Block 229 concessions. These wells will test various horizons for hydrocarbon potential as part of a planned multiyear program of exploration. We have not entered into new farmout arrangements, but do not rule out the possibility of doing so, either before or after initial drilling, in order to diversify risk and benefit from the capital and technical resources of others.

We have accumulated a large land position in known productive regions or geologic trends and in selected "rank wildcat" areas in Poland located well away from previous drilling where exploration involves a high degree of risk. We have assembled a sophisticated technical team of employees and consultants experienced with using modern exploration tools and have generated a number of attractive oil and gas prospects. To the extent that our overall strategy results in substantial revenue growth, we plan to direct more of our own funds toward exploration of these early-stage exploration licenses, with a view toward long-term results.

Polish Exploration Rights

As of December 31, 2012, we held oil and gas exploration rights in Poland in a number of separately designated project areas encompassing approximately 2.7 million gross acres. We are currently the operator in all areas, except our 852,000 gross-acre core Fences project area, in which we hold a 49% interest in approximately 807,000 acres and a 24.5% interest in the remaining 45,000 acres. PGNiG is the operator in the Fences project area. We hold interests in approximately 2.0 million net acres throughout Poland.

As we build revenues in our core area and further explore and evaluate our acreage in Poland, we expect to increase the operational and financial efforts we expend outside our core area. As we do so, we may add new concessions that we believe have high potential and relinquish acreage that we believe has lower potential. Properties – "Wells and Acreage" below for further information.

Exploratory Activities in Poland

Our ongoing activities in Poland are conducted in several project areas: Fences, Blocks 287, 246, and 229 near the Fences concession, Warsaw South, and Edge. Our drilling activities have been focused primarily on the core Fences area. We have focused on this core area because substantial gas reserves have already been discovered and developed by PGNiG. We and PGNiG have discovered proved gas reserves of over 133 Bcf gross (59 Bcf net to our interest) in nine commercial wells in the Fences area as of the date of this report. We believe it is likely there remains substantial additional natural gas in the same geologic horizon in this area.

We plan to continue concentrating the majority of our efforts and resources on the Fences concession, but we are also increasing our efforts in our other exploration blocks in Poland. In the Fences area during 2012, we completed the Komorze-3K well. In 2013 we are drilling the Mieczewo-1 well, anticipate drilling two or three wells in the eastern part of Fences, and plan to fracture and test the Plawce-2 tight sand well previously drilled in the northern part of Fences. In our other concessions we drilled the Kutno-2 well, a noncommercial deep Rotliegend test in the Kutno concession, the Frankowo-1 well, a noncommercial Zechstein/Rotliegend test in Block 246, and started drilling the Tuchola-3K Ca2/Devonian test in Edge. In 2013 we expect to finish drilling and test the Tuchola-3K well and drill two or three additional exploration wells in one or more of the Edge, Warsaw South, Block 246, and Block 229 concessions.

Fences Area

The Fences concession area encompasses 852,000 gross acres (3,450 sq. km.) in western Poland's Permian Basin. PGNiG gas fields located in the Fences area are "fenced off" or excluded from our exploration acreage. These fields, discovered by PGNiG between 1974 and 1985, produce from structural traps in the Rotliegend sandstone. We hold a 49% interest in approximately 807,000 acres and a 24.5% interest in the remaining 45,000 acres in the Fences area (406,000 total net acres).

The Rotliegend is the primary target horizon throughout most of the Fences concession area, at depths from approximately 2,500 to 4,000 meters. Both structural traps and stratigraphic ("pinch-out") traps are known to produce gas from the Rotliegend in the region. In addition, we may have identified carbonates in the Zechstein formation, a third type of trap that is known to produce both oil and gas in the region.

Fences Area: Structural Traps

Based on our drilling experience since 2000 in the Fences area, we have emphasized the use of seismic data acquisition, processing, and interpretation techniques that have been used successfully in the Rotliegend gas fields of the United Kingdom's offshore Southern Gas Basin. With Rotliegend structures as our target and using improved seismic data processing and acquisition techniques, we have drilled 12 conventional vertical wells targeting Rotliegend structures through the date of this filing. Nine of these wells are commercial, with an aggregate estimated ultimate recovery of 133 Bcf over the life of the wells, with remaining proved gas reserves of over 89 Bcf gross (42 Bcf net to our interest) as of December 31, 2012.

We currently produce approximately 13.2 MMcfed net to us from six of these nine wells, one of which started producing in January 2013. (The oldest of our nine wells had a very small reservoir and was depleted in 2010). We expect to start production in the second half of 2013 from the remaining two wells. The wells that are currently in production are producing under the required production licenses obtained by PGNiG in its capacity as operator or under the two years of test production that is permitted under the exploration concession.

In 2013, subject to our partner's participation, we plan to drill three to four new wells in the Fences concession: the Mieczewo-1 well currently drilling near our Kromolice-1, Sroda-4, and Kromolice-2, or KSK, production facility and two to three wells near the Lisewo production facility that is currently under construction and is scheduled to begin producing in the second half of 2013.

Finally, in the northernmost part of our Fences concession, we have identified a very large upthrown block, or horst, of Rotliegend sandstone that encompasses approximately 12,000 acres (50 sq. km.). In 2011 we drilled a vertical well, Plawce-2, in this horst block, encountering approximately 480 meters of relatively tight Rotliegend sandstone. Log, core, and test data show gas saturation with no free water. In the first half of 2013 we plan to fracture three separate intervals in the well and test the potential for commercial production.

Block 287 Concession Area

The Block 287 concession area is 12,000 acres (50 sq. km.) located approximately 25 miles south of the Fences concession area. We own 100% of the exploration rights. We retained this small portion of Block 287 when we relinquished larger portions in 2007 and 2008.

Within our retained acreage in Block 287, there are three Rotliegend gas wells known as the Grabowka wells. Originally drilled by PGNiG in 1983-85, these three wells tested gas but never produced commercially. In early 2007, we entered into a joint venture agreement with an unrelated party, PL Energia S.A., headquartered in Krzywoploty, Poland, under which all costs of reentering and completing the three Grabowka wells and building production facilities would be paid by our joint venture partner in exchange for discounted pricing on gas. To date, we have reentered the Grabowka-12 well, which has been producing since July 2009, and the Grabowka-6 well, which was connected to the gas plant in December 2012 and is scheduled to begin producing in the first half of 2013. In addition, we plan to reenter the Grabowka-8 well during the first half of 2013, with a view to further increasing production shortly thereafter.

Block 246 Concession Area

In 2008, we acquired a 100% interest in a concession south of our Fences project area covering approximately 241,000 acres (975 sq. km.). We identified an area with potential for Rotliegend sandstone and Zechstein reef reservoirs. In 2012 we drilled the Frankowo-1 well and encountered good reservoir properties and gas shows or accumulations in these two horizons, but we temporarily abandoned the well pending further evaluation. In 2013 we plan to acquire 3-D seismic in the prospective area and, in 2014, drill one or two wells to evaluate its potential.

Block 229 Concession Area

In 2008, we acquired a 100% interest in a concession east of our Fences concession area covering approximately 233,000 acres (941 sq. km.). We have identified potential Zechstein Main Dolomite reef build-ups on two-dimensional, or 2-D, seismic data in Block 229. In 2013 we plan to acquire a small amount of additional 2-D seismic data to support a drill-site selection. We anticipate drilling a well in Block 229 in 2014. We may seek industry participation in drilling wells in this concession area.

Warsaw South Concession Area

We hold a 51% interest in a total of 463,000 acres (1,875 sq. km.) in east-central Poland. During 2011, we entered into a farmout agreement with PGNiG under which it earned a 49% interest in the entire Warsaw South concession in return for paying certain seismic and drilling costs. We subsequently drilled the Machnatka-2 well to test Zechstein and Carboniferous potential in the western part of the concession area. While not commercial, the well encountered a small Zechstein reef, a significant section of reservoir quality Carboniferous, along with good background gas and gas shows. The Warsaw South concession has a number of exploration leads, including carboniferous sands and shales with structural or truncation trapping and possibly Zechstein reefs trapped by overlying evaporites and salt. We believe this area has good potential for gas and condensate production, but there are few existing wells and relatively little seismic data. Nonetheless, we plan to continue our exploration efforts. In 2012, we elected to drop certain concessions that we deemed less prospective for hydrocarbon potential, while acquiring additional new seismic data on our remaining blocks. In 2013 we plan to select one or more prospects to drill, depending on the drilling activity in our other concession areas and on our partner's input.

Edge Concession Area

In 2008, we acquired a 100% interest in four concessions in north-central Poland covering approximately 881,000 acres (3,567 sq. km.). Having reprocessed existing 2-D seismic data, we identified a number of leads, including several Permian age Ca2 reefs and Devonian structures. We acquired additional 2-D seismic data in 2011 and 2012 and started drilling the Tuchola-3K well to test both a Ca2 target and a Devonian target. We are interpreting new seismic data on three of the blocks in the Edge area and may drill in one or two of the concession blocks this year, subject to our drilling plans elsewhere. We have determined that one of the blocks appears to have much higher exploration risk than the others and will not seek to extend it beyond its 2013 expiration date. We may seek industry participation in drilling wells in this concession area.

Dropped Concessions

We previously had exploration interests in the Kutno and Northwest concession areas. We drilled and plugged and abandoned a well in the Kutno concession and intend to let the concession expire. Because of our evaluations of the exploration potential of the Northwest concession, in the light of related costs and risks, we are relinquishing our interest in that concession.

Additional Concession Acreage

We may apply for more concession blocks in Poland in 2013. If we acquire more concession blocks, we will allocate modest technical and financial resources to these areas during 2013, primarily in the form of data collection and seismic reprocessing, with a view to ascertaining relative hydrocarbon potential and exploration risk.

Key Personnel for Poland

Jerzy Maciolek is a director of the Company and heads our exploration team as Vice President of International Exploration. He joined the Company in 1995 specifically to lead us into Poland, where he had identified the exploration opportunity that today is our principal asset. Before joining us, Mr. Maciolek had over 25 years of experience as a geophysicist with PGNiG and Gulf Oil Research and as an independent consultant. He received an M.S. in exploration geophysics from the Mining and Metallurgical Academy in Krakow, Poland.

Our Country Manager in Poland is Zbigniew Tatys, the former General Director of PGNiG's Upstream Exploration and Production Division. During his 20-year career with PGNiG, he rose through the ranks as a production engineer and was serving as Vice Chairman of PGNiG at the time of his retirement. Mr. Tatys has unique qualifications to lead us through our transition from a pure exploration company to a natural gas and oil producer in Poland.

Our chief technical advisor is Richard Hardman, CBE. He also serves on our board of directors. Mr. Hardman has built a career in international exploration over the past 50 years in the upstream oil and gas industry as a geologist in Libya, Kuwait, Colombia, and Norway. In the United Kingdom, his career encompasses almost the whole of the exploration history of the North Sea – 1969 to the present. With Amerada Hess from 1983 to 2002 as Exploration Director and later as Vice President of Exploration, he was responsible for key Amerada Hess North Sea and international discoveries, including the Valhall, Scott, and South Arne fields. Mr. Hardman was made Commander of the British Empire in the New Year Honours, 1998, and has served as the Chairman of the Petroleum Society of Great Britain, President of the Geological Society of London, and President of the European Region of American Association of Petroleum Geologists Europe.

Our U.S. Activities and Presence

Unlike our position in Poland, our U.S. operations have not been a focus of our exploration efforts. Our U.S. operations provide a modest amount of cash flow and are not capital intensive. They consist mostly of shallow, water flood oil-producing wells in the Southwest Cut Bank Sand Unit, or SWCBSU, of Montana. As of December 31, 2012, our U.S. reserves (all of which were proved reserves) were estimated at 594,000 Bbls of crude oil with a PV-10 Value of approximately $10.4 million. At year-end 2012, U.S. reserves were approximately 7% of total proved reserves on a gas equivalent basis. Our oil wells produce approximately 146 Bbls of oil per day, net to our interest. We produce oil from approximately 10,732 gross (10,418 net) acres in Montana and 400 gross (128 net) acres in Nevada.

From our field office in Montana, we also provide oilfield services, which provided approximately $2.1 million in revenue during 2012.

Alberta Bakken and Three Forks Shale Exploration

In 2011, we entered into a joint venture with two other companies, American Eagle Energy, Inc., and Big Sky Operating LLC, in which we pooled our approximately 10,000 net acres in our SWCBSU with their approximately 65,000 net acres, the Americana leases, along with a farmout agreement that provides the group with an ability to earn an interest in an additional 7,000 acres covered by the Somont leases. Under the joint venture, the three parties have equal interests only in the Alberta Bakken formation group and share exploration costs equally. We maintain our original interest only in the mineral rights above the Alberta Bakken and related formations in the SWCBSU, from which we are currently producing oil. During 2011, we drilled three vertical wells on joint venture acreage to obtain log and core data. We also drilled a 3,600-foot lateral from one of these three wells, the Anderson 14-29, and carried out a multistage fracture.

We, either directly or through our joint venture partners, contracted with industry-standard third-party specialists for both the horizontal drilling and completion phases of the well we hydraulically fractured. To date, there have not been any environmental or safety incidents, citations, or suits related to the hydraulic fracturing operations used as part of the completion of the Anderson 14-29 well.

During 2012, we entered into a new joint venture, wherein the existing partners contributed half of their interest in all formations above the base of the Alberta Bakken group in only the Americana leases in exchange for a like interest in the Americana leases in all formations below the Alberta Bakken group, including the Nisku and others that have regionally demonstrated the potential for oil production. The new joint venture resulted in a one-third working interest in all formations below the Cut Bank in our SWCBSU and a one-sixth working interest in the Americana acreage in all formations below the surface. Also during 2012, the Somont lease earn-in option expired, and we sold certain of the Americana leases.

We have determined that none of the wells drilled to date in our Albert Bakken project was economic and have suspended further drilling in the area.

Employees and Consultants

As of December 31, 2012, we had 50 employees, consisting of nine in Salt Lake City, Utah; 20 in Oilmont, Montana; one in Greenwich, Connecticut; two in Houston, Texas; and 18 in Poland. Our employees are not represented by a collective bargaining organization. We consider our relationship with our employees to be satisfactory. We also regularly engage technical consultants to provide specific geological, geophysical, and other professional services. Our executive officers and other management employees regularly travel to Poland to supervise activities conducted by our staff and others under contract on our behalf.

Offices and Facilities

Our corporate offices, located at 3006 Highland Drive, Salt Lake City, Utah, contain approximately 3,700 square feet and are rented at $3,400 per month under a month-to-month agreement. In Montana, we own a 16,000 square-foot building located at the corner of Central and Main in Oilmont. We also have an office in Warsaw, Poland, located at ul. Chalubinskiego 8, where we rent about 4,900 square feet for approximately 25,000 PLN ($8,000 at December 31, 2012, exchange rate) per month and in Krakow, Poland, located at ul. Smolensk 21/15, where we rent approximately 215 square feet for approximately 1,500 PLN per month.

PROPERTIES

Proved Reserves Disclosures

Internal Controls over Reserves Estimates

Our policies regarding internal controls over the recording of reserves estimates require such estimates to be in compliance with the Securities and Exchange Commission’s definitions and guidance and prepared in accordance with customary petroleum engineering practices. Responsibility for compliance in reserves bookings is delegated to our operations and finance staff, who submit technical and financial data to third-party engineering firms.

Estimates of our proved and probable Polish reserves were calculated by RPS Energy, an independent engineering firm in the United Kingdom. Estimates of our proved domestic reserves were calculated by Hohn Engineering, an independent engineering firm in Billings, Montana. The technical personnel responsible for calculating the reserve estimates at both RPS Energy and Hohn Engineering meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Both RPS Energy and Hohn Engineering are independent firms of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent-fee basis.

Proved and Probable Reserves

Proved reserves are estimated quantities of oil and gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward and recoverable in future years from known reservoirs and under existing economic conditions, operating methods, and governmental regulations, prior to the expiration of the contracts providing the right to operate, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved undeveloped reserves on undrilled acreage are limited to: (i) those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances; and (ii) other undrilled locations if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

We emphasize that the volume of reserves are estimates that by their nature are subject to revision. The estimates are made using geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data. These reserve revisions result primarily from increases or decreases in performance due to a variety of factors such as an addition to or a reduction in recoveries below or above previously established, lowest, known hydrocarbon levels, improvements or deteriorations in drainage from natural drive mechanisms, and increases or decreases to drainage areas. If the estimates of proved reserves were to decline, the rate at which we record depletion expense would increase.

Proved Undeveloped Reserves

As of December 31, 2012, our proved undeveloped reserves totaled 20.4 Bcf of natural gas. All of our proved undeveloped reserves are located in Poland, and all are associated with wells that have been drilled, tested, and completed for production. These reserves are classified as proved undeveloped because relatively major expenditures are required for the completion of production facilities, which includes the construction of pipelines to connect the wells to the existing pipeline in order to fully develop the reserves and commence production. We do not have any proved undeveloped reserves attributable to undrilled locations, so the development of such undeveloped reserves is not dependent on additional drilling on undrilled acreage. All development activities will be completed within five years of reserve bookings.

Changes in Proved Undeveloped Reserves

No reserves were converted from undeveloped reserves at December 31, 2011, to developed reserves at December 31, 2012.

Development Costs

Costs incurred relating to the development of proved undeveloped reserves were approximately $2.3 million in 2012, almost all of which were attributable to the construction of production facilities at our Winna Gora and Lisewo wells.

Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $13.0 million in 2013. The estimated development costs are for the cost of facilities construction at our Lisewo and Komorze production facilities and for drilling the Lisewo-2 well.

For more information, see the following:

- Management’s Discussion and Analysis of Financial Condition and Results of Operations – Proved Reserves, for a discussion of changes in proved reserves;

- Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Oil and Gas Reserves, for further discussion of our reserves estimation process; and

- Financial Statements and Supplementary Data – Supplemental Information, for additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved, proved developed, and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in the standardized measure of discounted future net cash flows.

Other Reserves Information

Since January 1, 2012, no crude oil or natural gas reserves information has been filed with, or included in any report to, any other federal authority or agency.

Reserve Volumes and Values

The following table sets forth our estimated proved developed, proved undeveloped, and probable reserves volumes as of December 31, 2012:

	United States	Poland	Total
	MBbls	MMcf	MMcfe
Proved developed reserves	594	23,759	27,323
Proved undeveloped reserves	--	20,362	20,362
Total proved reserves	594	44,121	47,685
Probable reserves	--	31,724	31,724
Total proved plus probable reserves	594	75,845	79,409

The following table sets forth the estimated PV-10 Value of our proved plus probable reserves as of December 31, 2012:

	Total Net Reserves	PV-10 Value
	(MMcfe)	(In thousands)
Proved	47,685	$157,603
Probable	31,724	50,718
Total Proved and Probable	79,409	$208,321

Our proved reserves were calculated using deterministic methods. Our probable reserves were calculated using probabilistic methods and represent a 50% probability that the actual quantities recovered will be equal to or greater than the proved plus probable estimate. No additional drilling is required at any of our Polish wells to achieve the recovery of the probable reserves. The larger quantity of proved reserves plus probable reserves, as compared to proved reserves only, is attributable largely to using a less certain interpretation of reservoir size and a higher recovery factor in estimating probable reserves.

Economic producibility of reserves and discounted cash flows are based on the use of unweighted, 12-month, first day of the month, historical average prices adjusted for basis and quality differentials, rather than year-end prices. In Poland, average gas prices used in calculating reserve values also take into consideration exchange rates between the U.S. dollar and Polish zloty in effect on the first day of each month. The average prices used to calculate year-end reserve values were $6.60 and $6.44 per Mcf and $78.14 and $84.61 per barrel for 2012 and 2011, respectively.

Drilling Activities

The following table sets forth the exploratory wells that we drilled during the years ended December 31, 2012, 2011, and 2010:

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory productive wells:						
Poland	1.0	0.5	1.0	0.5	--	--
United States	--	--	--	--	--	--
Total	1.0	0.5	1.0	0.5	--	--
Exploratory dry holes:						
Poland	1.0	0.5	1.0	0.5	--	--
United States	4.0	1.6	--	--	--	--
Total	5.0	2.1	1.0	0.5	--	--
Total wells drilled	6.0	2.6	2.0	1.0	--	--

The productive exploratory well drilled in 2012 was our Komorze 3-K well, which had gross proved reserves of 4.7 Bcf of natural gas at year-end 2012. The exploratory dry holes in 2012 include the Kutno-2 well in Poland and four Alberta Bakken wells drilled in Montana. Of these wells, three were drilled in 2011, but all were determined to be noncommercial during 2012. The productive exploratory well drilled in 2011 was our Lisewo-1 well, which had gross proved reserves of 26.5 Bcf of natural gas at year-end 2012. The exploratory dry hole in Poland drilled in 2011 was our Machnatka-2 well. The foregoing does not include the Plawce-1 and Frankowo-1 wells being evaluated in Poland at 2012 year end. We did not drill any development wells in 2012, 2011, or 2010.

Wells and Acreage

As of December 31, 2012, our gross and net producing wells consisted of the following:

	Number of Wells			
	Gas		Oil	
	Gross	Net	Gross	Net
Well count:				
Poland[(1)]	6.0	3.2	--	--
United States	--	--	131.0	112.0
Total	6.0	3.2	131.0	112.0

(1) In addition to the wells producing at year-end 2012, a seventh well began production in January 2013, and an eighth well was being readied for production about the end of the first quarter. We also had two additional wells in Poland awaiting the construction of production facilities.

The following table sets forth our gross and net acres of developed and undeveloped oil and gas acreage as of December 31, 2012. All of our gas production is in Poland and all of our oil production is in the United States:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Poland:[1]				
Fences project area	3,215	1,416	850,000	406,000
Warsaw South project area	--	--	463,000	236,000
Block 287 project area	410	410	12,000	12,000
Edge project area	--	--	881,000	881,000
Block 246 project area	--	--	241,000	241,000
Block 229 project area	--	--	233,000	233,000
Total Polish acreage	3,625	1,826	2,680,000	2,009,000
United States:				
Montana[2]	10,732	10,418	12,765	11,131
Nevada	400	128	9,332	6,351
Total	11,132	10,546	22,097	17,482
Total Acreage	14,757	12,372	2,702,097	2,026,482

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(1) All gross and net undeveloped Polish acreage is rounded to the nearest 1,000 acres.

(2) The figures shown for Montana developed acreage represent the gross and net working interests in the Cut Bank formation in our SWCBSU. In 2011, we entered into a joint venture to explore various formations, including the Alberta Bakken and Three Forks shale formations, which lie below the Cut Bank formation. The incremental acreage that remains subject to the joint venture arrangement at year-end 2012 is included in the total gross and net undeveloped acres in Montana.

Polish Properties

Producing Properties

A summary of our average daily production, weighted average interest, and weighted average net revenue interest for our Poland producing properties during 2012 follows:

	Average Daily Production (Mcfe)		Average	Average Net Revenue
	Gross	Net	Interest	Interest
Fences project area	27,099	11,934	44%	44%
Grabowka	243	243	100%	100%
Total	27,343	12,178		

Production, Transportation and Marketing

During 2012, we resolved a pipeline bottleneck issue that was constraining production at our KSK wells due to restricted pipeline capacity. We began full production from all three KSK wells in late June of 2012. We do not expect to encounter any such production restraints during the foreseeable future.

The following table sets forth, by well, our net daily oil and gas production and volume weighted average sales prices and production costs associated with our Polish production during 2012, 2011, and 2010:

	Production		Average Production Cost	Average Sales Price	
	Gas (Mcf)	Oil (Bbls)	per Mcfe(1)	Gas (Per Mcf)	Oil (Per Bbl)
2012					
Roszkow	2,169,000	-	$0.18	$7.27	$ -
Zaniemysl	492,000	-	0.36	5.44	-
Sroda/Kromolice-1	1,027,000	-	0.24	6.90	-
Kromolice-2	680,000	-	0.27	6.89	-
Other wells(3)	89,000	-	2.54	1.59	-
Total	4,457,000	-	0.28	6.81	-
2011					
Roszkow	2,279,000	-	$0.20	$6.68	$ -
Zaniemysl	799,000	-	0.22	5.11	-
Sroda/Kromolice-1	759,000	-	0.13	6.33	-
Kromolice-2(2)	138,000	-	0.94	6.25	-
Other wells(3)	85,000	-	1.52	1.61	-
Total	4,060,000	-	0.24	6.19	-
2010					
Roszkow	2,443,000	-	$0.20	$5.93	$ -
Zaniemysl	848,000	-	0.21	4.54	-
Other wells(3)	182,000	-	2.27	2.38	-
Total	3,473,000	-	0.29	5.39	-

(1) Production costs include lifting costs (electricity, fuel, water, disposal, repairs, maintenance, transportation, and similar items) and contract operator fees. Production costs do not include such items as general and administrative costs; depreciation, depletion and amortization, or DD&A; or Polish income taxes.
(2) Kromolice-2 production costs include the cost of a workover performed in early 2011.
(3) Production costs at other wells include the ongoing costs of maintaining the production facilities at our Wilga and Kleka wells, neither of which is currently in production.

Poland has a network of gas pipelines and crude oil pipelines traversing the country serving major metropolitan, commercial, industrial, and gas production areas, including significant portions of our acreage. Poland has a well-developed infrastructure of hard-surfaced roads and railways over which oil produced can be transported for sale. There are refineries in Gdansk and Plock in Poland and one in Germany near the western Polish border that we believe could process crude oil produced in Poland. Should we choose to export any gas or oil we produce, we will be required to obtain prior governmental approval.

We are currently selling substantially all of our oil and gas production in Poland to PGNiG or one of its affiliates. We are dependent on PGNiG for the sale of gas in Poland, since there are few other competitive purchasers. Gas is sold pursuant to long-term sales contracts, typically for the life of each well, which obligate PGNiG to purchase all gas produced.

United States Properties

Producing Properties

In the United States, we currently produce oil in Montana and Nevada. All of our producing properties, except for the Rattlers Butte field (an exploratory discovery during 1997), were purchased during 1994. A summary of our average daily production, and average working and net revenue interests, based on the number of producing wells, for our United States producing properties during 2012 follows:

	Average Daily Production (Bbls)		Average	Average Net Revenue
	Gross	Net	Interest	Interest
Montana	181	138	97%	83%
Nevada	34	8	39%	29%
Total United States producing properties	215	146		

In Montana, we operate the Southwest Cut Bank Sand Unit (SWCBSU) and Bears Den fields and have an interest in the Rattlers Butte field, which is operated by an industry partner. Production in the SWCBSU, producing since the 1940s from an average depth of approximately 2,900 feet, is from a waterflood program with 103 producing oil wells, 21 active injection wells, and one active water supply well. The Bears Den field, under waterflood since 1990, is producing oil from five wells at a depth of approximately 2,430 feet, with one active water injection well. In the Rattlers Butte field, we own a 0.683% interest in two oil wells producing at a depth of approximately 5,800 feet and one active water injection well.

In Nevada, we operate the Trap Springs and Munson Ranch fields and have an interest in the Bacon Flat field, which is operated by an industry partner. In the Trap Springs field, discovered in 1976, we produce oil from a depth of approximately 3,700 feet from one well. In the Munson Ranch field, discovered in 1988, we produce oil at an average depth of 3,800 feet from five wells. In the Bacon Flat field, discovered in 1981, we produce oil from one well at a depth of approximately 5,000 feet.

Production, Transportation and Marketing

The following table sets forth our average net daily oil production, average sales prices, and production costs associated with our United States oil production during 2012, 2011, and 2010:

	Year Ended December 31,		
	2012	2011	2010
United States producing property data:			
Average daily net oil production (Bbls)	146	155	168
Average sales price per Bbl	$76.87	$83.02	$68.09
Average production costs per Bbl(1)	$45.00	$50.41	$39.84

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(1) Production costs include lifting costs (electricity, fuel, water, disposal, repairs, maintenance, pumper, transportation, and similar items) and production taxes. Production costs do not include such items as general and administrative costs; depreciation, depletion and amortization; state income taxes, or federal income taxes. Costs in 2011 include approximately $321,000 associated with the cleanup of a minor oil leak. Excluding the cleanup costs, lifting costs per barrel in 2011 would have equaled approximately $44.73 per barrel.

We sell oil at posted field prices to one of several purchasers in each of our production areas. We sell all of our Montana production, which represents over 95% of our total oil sales, to Cenex, a regional refiner and marketer. Posted prices are generally competitive among crude oil purchasers. Our crude oil sales contracts may be terminated by either party upon 30 days' notice.

Oilfield Services – Drilling Rig and Well-Servicing Equipment

In Montana, we perform, through our drilling subsidiary, FX Drilling Company, Inc., a variety of third-party contract oilfield services, including drilling, workovers, location work, cementing, and acidizing. We currently have a drilling rig capable of drilling to a vertical depth of 6,000 feet, a workover rig, two service rigs, cementing equipment, acidizing equipment, and other associated oilfield-servicing equipment.

The Republic of Poland

The Republic of Poland is located in north-central Europe, has a population of approximately 38 million people, and covers an area comparable to New Mexico. During 1989, Poland peacefully asserted its independence and became a parliamentary democracy. Since 1989, Poland has enacted comprehensive economic reforms and stabilization measures that have enabled it to form a free-market economy and turn its economic ties from the east to the west, with most of its current international trade with the countries of the European Union and the United States. The economy has undergone extensive restructuring in the post-communist era. The Polish government credits foreign investment as a forceful growth factor in successfully creating a stable, free-market economy.

Since its transition to a free-market economy and a parliamentary democracy, Poland has experienced significant economic growth and political change. Poland has developed and is refining legal, tax, and regulatory systems characteristic of parliamentary democracies with interpretation and procedural safeguards. The Polish government has taken steps to harmonize Polish legislation with that of the European Union, which it joined in May of 2004.

Poland has created an attractive legal framework and fiscal regime for oil and gas exploration by actively encouraging investment by foreign companies. In July 1995, Poland's Council of Ministers approved a program to restructure and privatize the Polish petroleum sector. So far under this plan, a refinery located in Plock has been privatized as a publicly held company with its stock trading on the London and Warsaw stock exchanges. In September of 2005, PGNiG sold 15% of its stock in an initial public offering on the Warsaw Stock Exchange, raising a total of 2.7 billion Polish zlotys (approximately US$900 million).

Prior to becoming a parliamentary democracy during 1989, the exploration and development of Poland's oil and gas resources were hindered by a combination of foreign influence, a centrally controlled economy, limited financial resources, and a lack of modern exploration technology. As a result of these and other factors, Poland is currently a net energy importer. Oil is imported primarily from countries of the former Soviet Union and the Middle East, and gas is imported primarily from Russia.

Poland continues to enjoy the strongest economy in the European Union, and was the only country in Europe to record positive GDP growth every year from 2008 through 2012. Economists predict another positive year during 2013, as it also builds foundations for sustainable future growth. Poland's economy remains one of the more attractive and safer debt markets in Europe.

Legal Framework

General Usufruct and Concession Terms

All of our rights in Poland have been awarded to us or to PGNiG pursuant to the Geological and Mining Law, or the former Geological and Mining Law of February 4, 1994 (as amended), which specifies the process for obtaining domestic exploration and exploitation rights. Under the Geological and Mining Law, the concession authority enters into mining usufruct (lease) agreements that grant the holder the exclusive right to explore for oil and gas in a designated area or to exploit the designated oil and/or gas field for a specified period under prescribed terms and conditions. The holder of the mining usufruct covering exploration must also acquire an exploration concession by applying to the concession authority and providing the opportunity for comment by local governmental authorities. The usufruct agreements include provisions that give the usufruct holder a claim for an extension of the usufruct (and the underlying concession), subject to having fulfilled all obligations under the usufruct and/or concession agreements. We can request changes to usufruct and concession agreements that either modify the obligations or extend the terms of those agreements.

Under current law, the concession authority requires that concessions be owned by a single entity, without recognizing any minority record ownership such as would reflect our interest in those areas in which we previously have been granted a minority ownership. As such, our ownership is subject to continued compliance with applicable law, the usufruct and concession terms, and respecting the Fences area, the continuity of PGNiG as the record owner.

The concession authority has granted PGNiG oil and gas exploration rights on the Fences project area and has granted us oil and gas exploration rights on all other project areas in which we have an interest. The agreements divide these areas into blocks, each containing up to 300,000 acres.

If commercially viable gas or oil is discovered, the concession owner may be able to produce such gas or oil for test purposes for two years based on the exploration concession. During such two-year period, the concession owner typically applies for an exploitation concession, which generally will have a term of 25 to 30 years or as long as commercial production continues. Upon the grant of the exploitation concession, the concession owner may become obligated to pay a fee, to be negotiated. The concession owner would also be required to pay a royalty on any production, the amount of which will be set by the Council of Ministers, within a range established by legislation for the mineral being extracted. The royalty rate for low-methane gas such as we produce is currently set for 2013 at approximately $0.04 per Mcf. Local governments will receive 60% of any royalties paid on production. The holder of the exploitation concession must also acquire rights to use the land from the surface owner and could be subject to significant delays in obtaining the consents of local authorities or satisfying other governmental requirements prior to obtaining an exploitation concession.

We believe all material concession terms have been satisfied to date.

Existing Project Areas

Fences Project Area

The Fences project area consists of four oil and gas exploration concessions controlled by PGNiG. Three producing fields (Radlin, Kleka, and Kaleje) lie within the concession boundaries, but are excluded from the Fences area in which we participate. The Fences concessions have expiration dates ranging from July 2014 to Sept 2017. The total joint remaining work commitment, which must be satisfied by us and PGNiG according to our respective interests, includes: acquiring 50 kilometers of 2-D seismic data, acquiring 210 square kilometers of 3-D seismic data, and drilling two wells.

Warsaw South/Wilga Project Area

The Wilga project area consists of a single oil and gas exploration and production concession covering Block 255 held by us. Following a full completion of the previous work commitment, a concession extension is in progress and should be completed in 2013. Adjacent to Block 255, we hold two exploration concessions expiring in July 2013 covering Blocks 234 and 254. We currently plan to seek an extension of the Block 254 concession.

Block 287 Project Area

The Block 287 project area consists of a single oil and gas exploration concession held by us. The concession expires in December 2015. Work commitment includes reentering and producing the Grabowka gas field; recompletion of one out of three wells was completed and production began in 2009. The second well was recompleted in late 2012, and production is scheduled to begin in the first quarter of 2013. We plan to recomplete the third well in 2013.

Edge Project Area

The Edge project area consists of four oil and gas exploration concessions granted for five years (2008-2013). The obligatory work commitment is outlined in three phases: Phase I – one year: reprocessing and reinterpretation of existing data; Phase II – two years: acquiring 350 kilometers of 2-D seismic data; Phase III – two years: drilling four wells. Currently, besides reprocessing and reinterpretation of existing data, the acquisition of 600 kilometers of new 2-D seismic data and 50 square kilometers of 3-D have been completed, and the drilling of the first of these four wells began in December 2012. We currently plan to seek an extension of three out of four of these concessions expiring in September 2013.

Block 246 Project Area

The Block 246 project area is adjacent to the Fences project area in the southwest and consists of a single concession granted for six years (2008-2014). The work commitment is outlined in three phases: Phase I – one year: reprocessing and reinterpretation of existing data; Phase II – two years: acquiring 120 kilometers of 2-D seismic data; Phase III – three years: drilling one well. Currently, besides reprocessing and reinterpretation of existing data, the acquisition of 40 kilometers of 2-D seismic data and 26 square kilometers of 3-D seismic data have been completed, as well as the drilling of one well.

Block 229 Project Area

The Block 229 project area is adjacent to the Fences project area in the east and consists of two exploration concessions granted for six years (2008-2014). The total work commitment is outlined in three phases: Phase I – one year: reprocessing and reinterpretation of existing data; Phase II – two years: acquiring 300 kilometers of 2-D seismic data; Phase III – three years: drilling two wells. Currently, besides reprocessing and reinterpretation of existing data, the acquisition of 50 kilometers of 2-D seismic data has been completed.

As of December 31, 2012, all required usufruct/concession payments had been made for each of the above project areas.

OIL AND GAS TERMS

The following terms have the indicated meaning when used in this report:

“Bbl” means oilfield barrel.

“Bcf” means billion cubic feet of natural gas.

“Bcfe” means billion cubic feet of natural gas equivalent using a ratio of one barrel of oil to 6,000 cubic feet of natural gas.

“BTU” means British thermal unit.

“Ca1” and **“Ca2”** refers to specific calcium-rich geological formations, typically a dolomitic reef.

“Deterministic” means a method of estimating reserves in which a simple value for each parameter of geoscience, engineering, or economic data in the reserves calculation is used in the reserves estimation.

“Development well” means a well drilled within the proved area of a gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

“Exploratory well” means a well drilled to find and produce gas or oil in an unproved area, to find a new reservoir in a field previously found to be productive of gas or oil in another reservoir, or to extend a known reservoir.

“Field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic conditions.

“Fracturing” means injecting fluids or slurry under sufficient pressure and rate to fracture the formation, leaving proppants that keep the fractures open to serve as a pathway for gas or oil to flow to the well bore.

“Gross acres” and **“gross wells”** mean the total number of acres or wells, as the case may be, in which a working interest is owned, either directly or through a subsidiary or other enterprise in which we have an interest.

“Horizon” means an underground geological formation that is the portion of the larger formation that has sufficient porosity and permeability to constitute a reservoir.

“MBbls” means thousand oilfield barrels.

“Mcf” means thousand cubic feet of natural gas.

“Mcfe” means thousand cubic feet of natural gas equivalent using a ratio of one barrel of oil to 6,000 cubic feet of natural gas.

“MMcf” means million cubic feet of natural gas.

“MMcfd” means million cubic feet of natural gas per day.

“MMcfe” means million cubic feet of natural gas equivalent using a ratio of one barrel of oil to 6,000 cubic feet of natural gas.

“MMcfed” means million cubic feet of natural gas equivalent using a ratio of one barrel of oil to 6,000 cubic feet of natural gas per day.

“Net” means, when referring to wells or acres, the fractional ownership working interests held by us, either directly or through a subsidiary or other Polish enterprise in which we have an interest, multiplied by the gross wells or acres.

“P50 reserves” means proved reserves plus probable reserves.

“Play” means the activities associated with oil and gas exploration, typically in its early stages, in an area generally believed to contain common reservoir, seal, source, or trapping features.

“Probabilistic” means a method of estimating reserves using the full range of values that could reasonably occur for each unknown from the geoscience and engineering data to generate a full range of possible outcomes and their associated probabilities of occurrence.

“Probable reserves” means those reserves determined by probabilistic methods that are less certain than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“Proved reserves” means the estimated quantities of crude oil, gas and gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. “Proved reserves” may be developed or undeveloped.

“PV-10 Value” means the estimated future net revenue to be generated from the production of proved or probable reserves discounted to present value using an annual discount rate of 10%, the Standardized Measure of Future Net Cash Flows (“SMOG”). These amounts are calculated net of estimated production costs, future development costs, and future income taxes, using prices and costs determined using guidelines established by the SEC, without escalation and without giving effect to non-property-related expenses, such general and administrative costs, debt service, and depreciation, depletion, and amortization.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and that is distinct and separate from other reservoirs.

“**Usufruct**” means the Polish equivalent of a U.S. oil and gas lease.

SELECTED FINANCIAL DATA

The following selected financial data for the five years ended December 31, 2012, are derived from our audited consolidated financial statements and notes thereto, certain of which are included in this report. The selected financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the notes thereto included elsewhere in this report:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 34,461	$ 29,807	$ 22,914	$ 12,772	$ 13,494
Oilfield services	2,137	5,631	2,099	1,892	4,347
Total revenues	36,598	35,438	25,013	14,664	17,841
Operating costs and expenses:					
Lease operating expenses(1)	3,631	3,834	3,473	3,478	3,441
Exploration costs(2)	23,795	16,618	3,038	4,829	15,389
Impairment of oil and gas properties(3)	2,562	72	564	1,864	14,746
Asset retirement obligation gain	--	(52)	(264)	(529)	--
Oilfield services costs	1,610	4,458	1,550	1,412	2,751
Depreciation, depletion and amortization	4,239	3,397	2,626	1,602	1,720
Accretion expense	63	68	92	41	84
Loss on sale of asset	49	--	--	--	--
Stock compensation	2,325	1,744	1,379	1,693	2,367
Bad debt expense	--	--	--	--	460
General and administrative costs (G&A)	8,369	8,396	7,973	7,257	7,030
Total operating costs and expenses	46,643	38,535	20,431	21,647	47,988
Operating income (loss)	(10,045)	(3,097)	4,582	(6,983)	(30,147)
Other income (expense):					
Interest expense	(2,485)	(2,167)	(1,936)	(654)	(672)
Interest and other income	356	188	829	54	394
Foreign exchange (loss) gain	16,292	(23,448)	(4,233)	7,053	(24,279)
Total other (expense) income	14,163	(25,427)	(5,340)	6,453	(24,557)
Net income (loss)	$ 4,118	$(28,524)	$ (758)	$ (530)	$(54,704)

– Continued –

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per share amounts)				
Basic and diluted net income (loss) per common share	$ 0.08	$ (0.57)	$ (0.02)	$ (0.01)	$ (1.35)
Basic and diluted weighted average shares outstanding	52,274	50,262	43,387	42,529	40,420
Cash Flow Statement Data:					
Net cash provided by (used in) operating activities	$ (1,233)	$ (120)	$ 7,249	$ (5,829)	$(14,248)
Net cash (used in) provided by investing activities	(16,350)	(18,486)	(7,814)	(3,999)	(11,772)
Net cash provided by (used in) financing activities	--	50,842	16,092	(2,676)	40,121
Balance Sheet Data:					
Working capital(4)	$ 30,395	$ 49,787	$18,212	$ 3,452	$ 13,965
Total assets	105,954	110,224	66,604	42,070	54,802
Notes payable	40,000	40,000	35,000	25,000	25,000
Total stockholders' equity	54,799	58,627	23,837	10,745	15,154

(1) Includes lease operating expenses and production taxes.
(2) Includes geophysical and geological costs, exploratory dry hole costs, and nonproducing leasehold impairments.
(3) Includes proved and unproved property write-downs relating to our properties in the United States and Poland.
(4) Working capital represents current assets minus current liabilities.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of our historical financial condition and results of operations should be read in conjunction with Selected Financial Data, and our consolidated financial statements and related notes contained in this report.

Overview

As discussed in Business above, the majority of our operations are in Poland, and we have devoted most of our technical talent and capital expenditures in the last several years to our operations in that country. The decision to devote most of our available capital to this area drives our operating results and the changes to our balance sheet and liquidity. Our operations in Poland, which are a combination of existing production and substantial exploration, have grown considerably. Oil and gas production, oil and gas revenues, cash flow, and oil and gas expenditures in this area have grown significantly over the last three years.

Our U.S. operations also have an impact. Our U.S. operations are smaller than those in Poland and do not present the same level of opportunities for expansion; however, our U.S. operations are a relatively stable source of cash flow. This, too, is reflected in our operating results.

Highlights over the past three years include:

- Oil and gas revenues have almost tripled since 2009 to $34.5 million in 2012, a compound annual growth rate of 39% per year.

- Total revenues have likewise increased, with a compound annual growth rate of 36% per year during the same period.

- Oil and gas production has more than doubled since 2009 to 4.8 Bcfe in 2012, a compound annual growth rate of 30%.

- Natural gas prices in Poland continue to show strength in the face of economic uncertainty. At the time of this report, the low-methane tariff in Poland was 40% higher than at year-end 2009.

- The average gas price we received in 2012, taking into account currency fluctuations throughout the year, was 36% higher than the amount we received in 2009.

- We continue to diversify our production risk profile. At the time of this report, we were producing gas from eight wells in Poland, with two additional wells scheduled to begin production during 2013. At the end of 2009, we were producing gas from only three wells in Poland.

- Our exploration and development spending continues to increase. The amounts we reported for exploration costs and capital additions for 2012, which represent a record level of activity for us, were triple our 2009 spending.

- Since 2009, we have been designated to act as the operator for the permitting, designing, and construction of all new production facilities in Poland.

Notwithstanding our positive results, we continue to face challenges operating in a foreign country with a different economic system and culture, including:

- a new hydrocarbon law, which, if enacted as proposed, would increase the royalties and taxes we pay in Poland;

- delays such as those associated with the commencement of production from our Winna Gora and KSK wells, which prevented higher production and revenue gains during 2012 and 2011;

- the pace at which PGNiG, our operating partner in the Fences concession, wishes to proceed or the extent to which PGNiG wishes to participate as a non-operating partner in other concessions;

- operating practices that differ from customary practices in the United States, which generally result in higher capital costs in Poland, longer lead times to drilling, first production, and lower initial production rates;

- obtaining better success ratios in our exploration efforts outside of our core Fences area; and

- volatile noncash adjustments for foreign currency fluctuations that continue to affect our net income in an unpredictable fashion.

There are two other factors that affect our results of operations that, though not unique to us, are different from what United States investors typically see when comparing us with most domestic, small-capitalization independent producers:

- the different pricing model for our Polish gas production; and

- the functional currency for our largest subsidiary, FX Energy Poland, which is the Polish zloty, not the U.S. dollar.

Commodity Prices

Global oil prices continued to be volatile in 2012. Gas prices in the United States remained at depressed levels, which have persisted since 2009. However, the Polish gas market operates quite differently than the U.S. domestic market. In Poland, substantially all of our gas production is sold to PGNiG and is tied to published tariffs (wholesale prices) set from time to time by the public utility regulator for gas sold to wholesale consumers. At the time of this report, the low-methane tariff, which is the basis for all of our gas contracts in Poland, is 40% higher than it was at the end of 2009.

A major component of the gas tariff calculation is the cost of Russian imported gas, which is priced based predominantly on trailing oil prices. Thus, world oil prices can have a significant impact on Polish gas prices. Other major components of the tariff calculation include the cost of gas provided by PGNiG itself, as well as the necessity for PGNiG to cover its internal cost structure. Natural gas prices in Poland are, and for years have been, below European Union average prices for both households and industry, because the prices have been subsidized by the government. European Union rules require Poland to gradually abandon market subsidies and bring Polish gas prices to Western Europe free-market levels.

Poland continues to enjoy the strongest economy in the European Union and was the only country in Europe to record positive GDP growth every year from 2008 through 2012. While the economy is expected to slow somewhat, economists are still predicting positive growth during 2013. These factors may act as cushions against possible declines in prices. As of year-end 2012, gas prices in Poland remained firm and were significantly higher than those of an equivalent BTU content in the United States. For example, as of the date of this report the price we receive for natural gas at our Roszkow well, which has a methane content of 80%, is approximately double the spot price under natural gas contracts for 100% methane gas traded on the New York Mercantile Exchange, sometimes referred to as the Henry Hub price. The volumes of our gas reserves in Poland from 2009 through 2012 were not impacted by changing prices. However, all of our oil and gas reserves can be price-sensitive, and future material reductions in the prices at which we sell our oil and gas could result in the impairment of reserves.

Functional Currency and Exchange Rates

The functional currency of our Polish subsidiary is the Polish zloty. Accounting standards require the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. Because FX Energy Poland's functional currency is the Polish zloty, translation adjustments result from the process of translating its financial statements into the parent company's U.S. dollar reporting currency. Translation adjustments are not included in determining net income, but are reported separately and accumulated in other comprehensive income. The accounting basis of the assets and liabilities affected by the change is adjusted to reflect the difference between the exchange rate when the asset or liability was first recorded and the exchange rate on the date of the change.

The difference in functional currency also affects the amounts we report for our Polish assets, liabilities, revenues, and expenses from those that would be reported were the U.S. dollar the functional currency for our Polish operations. The differences will depend on changes in period-average and period-end exchange rates. Transaction gains or losses may be significant given the volatility of the exchange rate.

We enter into various agreements in Poland denominated in the Polish zloty. The exchange rate between the U.S. dollar and the Polish zloty is subject to fluctuations that are beyond our control. During 2012, the zloty fluctuated between a low of 3.07 zlotys per U.S. dollar to a high of 3.58 zlotys per U.S. dollar, a fluctuation of 17%. Variations in exchange rates affect the U.S. dollar-denominated amount of revenue we report, compared to what we receive in Polish zlotys. As the U.S. dollar strengthens relative to the zloty, our U.S. dollar-denominated revenue actually received in Polish zlotys declines; conversely, when the U.S. dollar weakens relative to the zloty, our U.S. dollar-denominated revenue received in Polish zlotys increases. Likewise, a weak U.S. dollar leads to lower U.S. dollar-denominated drilling, capital, and exploration costs, while a strong U.S. dollar has the opposite effect for the cost structure of our Polish operations. Should exchange rates in effect during early 2013 continue throughout the year, we expect the exchange rates to have a slightly positive impact on our U.S. dollar-denominated revenues, and a slightly negative impact on our dollar-denominated costs, compared to 2012.

In addition, the change in the exchange rate from the end of each reporting period to the next has an impact on foreign exchange gains and losses. At the end of 2012, the exchange rate was 3.10 zlotys per U.S. dollar compared to 3.42 zlotys per U.S. dollar at the end of 2011. This 9% year-end to year-end appreciation of the zloty represents a decrease in the amount of Polish currency required to satisfy outstanding U.S. dollar-denominated intercompany and other loans of FX Energy Poland as of December 31, 2012, and creates the noncash foreign exchange gain recorded on our consolidated statements of operations.

More information concerning the impact of foreign currency transactions can be found in the discussion that follows, as well as in note 1 of the notes to the consolidated financial statements included in this report.

Proposed Changes to Poland's Hydrocarbon Legislation

In late 2012, the Polish government approved guidelines for new hydrocarbon legislation, including, among other things, higher royalties on hydrocarbons produced, a new cash flow tax based on the positive cumulative cash flow from exploration and development projects, as well as changes to how usufruct fees are determined and how concessions are awarded. The Minister of Environment has been directed to prepare a draft law, which was published in early 2013. Comments from the industry/general public will be invited, and either taken into account or not in preparing a revised draft by the Minister. The revised draft will be subject to review by various governmental committees and agencies, and then a final draft will be subject to approval by the government, before it is sent to the Parliament.

The new legislation is meant to increase governmental revenue from the oil and gas industry, with the stated intention for the total royalty and tax burden of an energy company to approach 40% of taxable income, which is approximately double that of the current fiscal regime. The new law, once approved by Parliament, would become effective January 1, 2015, at the earliest, but in any event not prior to the first commercial production of shale gas in the country. The new royalty and tax structure would be applicable to all production, without regard to when the well was drilled or the relevant concession granted.

Although the draft law was recently published, we are unable to estimate the impact of the law on our financial results or operations. However, any increase in royalties or income taxes to which we may be subject would have an adverse impact.

Results of Operations by Business Segment

We operate within two segments of the oil and gas industry: the exploration and production, or E&P, segment in Poland and the United States, and the oilfield services segment in the United States. Direct revenues and costs, including depreciation, depletion and amortization costs, or DD&A, general and administrative costs, or G&A, and other income directly associated with their respective segments are detailed within the following discussion. DD&A, G&A, amortization of deferred compensation, interest income, other income, interest expense, and other costs, which are not allocated to individual operating segments for management or segment reporting purposes, are discussed fully following the segment discussion. The following table summarizes the results of operations by segment for the years ended December 31, 2012, 2011, and 2010 (in thousands):

	Reportable Segments				
	Exploration & Production		Oilfield Services		
	Poland	U.S.		Non-Segmented	Total
Year ended December 31, 2012:					
Revenues	$ 30,344	$ 4,117	$2,137	$ --	$ 36,598
Net income (loss)(1)	2,031	(770)	(582)	3,439	4,118
Year ended December 31, 2011:					
Revenues	$ 25,120	$ 4,687	$5,631	$ --	$ 35,438
Net income (loss)(2)	5,250	1,668	189	(35,631)	(28,524)
Year ended December 31, 2010:					
Revenues	$ 18,730	$ 4,184	$2,099	$ --	$ 25,013
Net income (loss)(3)	12,389	1,818	(194)	(14,771)	(758)

(1) Nonsegmented reconciling items for 2012 include $8,369 of G&A costs, $2,325 of noncash stock compensation expense, $16,292 of noncash foreign exchange gains, $2,129 of interest expense (net of other income), and $30 of corporate DD&A.
(2) Nonsegmented reconciling items for 2011 include $8,396 of G&A costs, $1,744 of noncash stock compensation expense, $23,448 of noncash foreign exchange losses, $1,979 of interest expense (net of other income), and $64 of corporate DD&A.
(3) Nonsegmented reconciling items for 2010 include $7,973 of G&A costs, $1,379 of noncash stock compensation expense, $4,233 of noncash foreign exchange losses, $1,107 of other expense, and $79 of corporate DD&A.

See note 11 in the notes to the consolidated financial statements for additional detail concerning our segment results.

Exploration and Production Segment

Gas Revenues. Revenues from gas sales were $30.3 million during 2012, compared to $25.1 million and $18.7 million in 2011 and 2010, respectively. Our 2012 gas revenues increased $5.2 million from 2011 levels by approximately $2.5 million due to higher gas prices, coupled with approximately $2.7 million related to higher annual production. Gas revenues in 2011 increased $6.4 million from 2010 levels by approximately $2.8 million due to higher gas prices, coupled with approximately $3.6 million related to higher annual production.

Company-wide net gas production increased from a daily rate in 2011 of approximately 11.1 MMcfd to a record rate of approximately 12.2 MMcfd in 2012, an increase of 10%. In early February 2013, gas was flowing in Poland at an average rate of 13.6 MMcfd, net to our interest.

In addition to our increased production, higher gas prices, which were partially offset by negative currency changes, resulted in higher gas revenues during 2012. The Polish low-methane tariff, which serves as the reference price for our gas sales agreements, averaged 21% higher during the full year of 2012 compared to 2011. The increase was primarily a function of a 16.9% increase that became effective for us on April 1, 2012. This increase was preceded by a 12.5% increase that became effective for us on August 1, 2011. However, the increase in prices was partially offset by the effect of currency changes from year to year. Strength in the U.S. dollar against the Polish zloty decreased our U.S. dollar-denominated gas prices. The average exchange rate during 2012 was 3.24 zlotys per U.S. dollar. The average exchange rate during 2011 was 2.96 zlotys per U.S. dollar, a change of approximately 9%.

The primary driver of our increased production in 2012 was the full resolution of a pipeline bottleneck during the second quarter of 2012, following which the KSK wells were placed on full production. Gas production at our three KSK wells averaged 9.5 MMcfd during 2012, compared to 5.0 MMcfd during 2011. At year-end, the wells were producing at a combined rate of 12.7 MMcfd. Gas at KSK is being sold to PGNiG at a contracted rate equal to 86% of the published low-methane tariff. We have a 49% interest in the KSK wells.

Gas production at our Roszkow well averaged 12.1 MMcfd during 2012, compared to 12.7 MMcfd during 2011. At year-end, the well was producing at a rate of 11.7 MMcfd. Gas at Roszkow is being sold to PGNiG at a contracted rate equal to 95% of the published low-methane tariff. We have a 49% interest in the Roszkow well.

Gas production at our Zaniemysl well averaged 5.5 MMcfd during 2012, compared to 8.9 MMcfd during 2011. At year-end, the well was producing at a rate of 2.7 MMcfd. Gas at Zaniemysl is being sold to PGNiG at a contracted rate equal to 70% of the published low-methane tariff. We have a 24.5% interest in the Zaniemysl well.

Gas production began at our Winna Gora well in January of 2013. At the time of this report, the well was producing approximately 1.6 MMcfd (0.8 MMcfd net to our 49% interest). Gas at Winna Gora is being sold to PGNiG at a contracted rate equal to 86% of the published low-methane tariff.

A summary of the amount and percentage change, as compared to their respective prior-year period, for gas revenues, average gas prices, gas production volumes, and lifting costs per Mcf for the years ended December 31, 2012, 2011, and 2010, is set forth in the following table:

	Year Ended December 31,		
	2012	2011	2010
Revenues	$30,344,000	$25,120,000	$18,730,000
Percent change versus prior year	+21%	+34%	+99%
Average price (per Mcf)	$6.81	$6.19	$5.39
Percent change versus prior year	+10%	+15%	+8%
Production volumes (Mcf)	4,457,000	4,060,000	3,473,000
Percent change versus prior year	+10%	+17%	+85%
Lifting costs per Mcf(1)	$0.28	$0.23	$0.29
Percent change versus prior year	+22%	-21%	-40%

(1) Lifting costs per Mcf are computed by dividing the related lease operating expenses by the total volume of gas produced.

Oil Revenues. Oil revenues were $4.1 million, $4.7 million, and $4.2 million for the years ended December 31, 2012, 2011, and 2010, respectively. Lower average oil prices in 2012 compared to 2011 combined with lower production to cause the decrease in revenues. Our average oil price during 2012 was $76.87 per barrel, a 7% decrease compared to $83.02 per barrel received during 2011. Production from our U.S. properties declined by 5% due to normal production declines.

U.S. oil revenues in 2012 decreased from 2011 levels by approximately $.3 million due to lower oil prices, combined with approximately $0.3 million related to production declines. U.S. oil revenues in 2011 increased from 2010 levels by approximately $0.8 million due to higher oil prices, offset by approximately $0.3 million related to production declines.

A summary of the amount and percentage change, as compared to their respective prior-year period, for oil revenues, average oil prices, oil production volumes, and lifting costs per barrel for the years ended December 31, 2012, 2011, and 2010, is set forth in the following table:

	Year Ended December 31,		
	2012	2011	2010
Revenues	$4,117,000	$4,688,000	$4,184,000
Percent change versus prior year	-12%	+12%	+25%
Average price (per Bbl)	$76.87	$83.02	$68.09
Percent change versus prior year	-7%	+22%	+31%
Production volumes (Bbl)	53,553	56,462	61,463
Percent change versus prior year	-5%	-8%	-4%
Lifting costs per Bbl(1)	$44.80	$50.41	$39.84
Percent change versus prior year	-11%	+27%	-1%

(1) Lifting costs per barrel are computed by dividing the related lease operating expenses by the total barrels of oil produced. Light crude oil lifting costs in Poland are based on an allocation of total costs based on relative revenues between oil and gas. Lifting costs include production taxes incurred in the United States. Costs in 2011 include approximately $0.3 million associated with the cleanup of a minor oil leak. Excluding the cleanup costs, lifting costs per barrel in 2011 would have equaled approximately $44.73 per barrel.

Lease Operating Costs. Lease operating costs were $3.6 million in 2012, $3.8 million in 2011, and $3.5 million in 2010. Operating costs in the United States decreased in 2012 by approximately $0.4 million over 2011 costs, due to $0.3 million spent during 2011 to remediate a small oil leak in Montana along with higher workover costs incurred on our existing producing wells during that year. Operating costs in Poland increased 24% in 2012 from 2011 levels. Most operating costs in Poland arise from fixed costs at our production facilities; fees paid to the operator of our production facilities increased year over year.

Exploration Costs. Exploration expenses consist of geological and geophysical costs as well as the costs of exploratory dry holes. Exploration costs were $23.8 million, $16.6 million, and $3.0 million for the years ended December 31, 2012, 2011, and 2010, respectively. The increase in 2012 was a function of increased dry-hole costs, offset by lower geological and geophysical costs.

Geological and geophysical costs, or G&G costs, were $11.1 million, $15.3 million, and $2.0 million for the years ended December 31, 2012, 2011, and 2010, respectively. During all three years, most of our G&G costs were spent on acquiring, processing, and interpreting new 3-D and 2-D seismic data in the Fences area and in our other concession areas in Poland.

Exploratory dry-hole costs were $12.7 million, $1.3 million, and $1.0 million for the years ended December 31, 2012, 2011, and 2010, respectively. Our 2012 dry-hole costs were associated primarily with our Kutno well in Poland. The Kutno well, which was the deepest well ever drilled in Poland, was found to be noncommercial during the third quarter of 2012. Under the terms of a farmout agreement, our partner agreed to pay 60% of the costs of the well. Total costs to us were approximately $12.2 million. Our 2011 dry-hole costs were associated with our Machnatka well. Under the terms of a joint operating agreement, our partner agreed to pay 100% of the costs of the well to a depth of 3,558 meters. After reaching that depth, we agreed to pay 51% of the costs and continue drilling to a depth of approximately 4,500 meters. During 2010, recompletion attempts failed to establish commercial production at our Zakowo project in Poland.

Impairment Costs. Impairments of oil and gas properties were $2.6 million, $72,000, and $0.6 million for the years ended December 31, 2012, 2011, and 2010, respectively. During 2012, we impaired the cost of certain concessions in Poland, in the amount of $0.8 million, due to our determination that they were not prospective for hydrocarbon accumulation. Also during 2012, we impaired all capitalized costs associated with our Alberta Bakken project in Montana, which included $1.4 million in drilling costs incurred during 2011 and $0.4 million in leasehold costs. We have no plans to pursue this project in the near future. During 2011, we dropped a small amount of non-prospective acreage near our Kutno project and impaired the associated undeveloped leasehold costs.

Asset Retirement Obligation. We recorded gains associated with future asset retirement obligations of $0, $52,000, and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. When the present value of a future asset retirement obligation changes due to the increase or decrease of the estimated plugging costs of that asset, we adjust the related asset retirement cost. During 2011 and 2010, the economic lives of our United States oil wells were increased, as higher oil prices resulted in more economic barrels. This change resulted in a decrease in the net present value of the retirement obligations, which in turn resulted in gains associated with those obligations, as the related asset retirement costs had been previously written off due to property impairments.

DD&A Expense - Producing Operations. DD&A expense for producing properties was $3.1 million, $2.3 million, and $1.8 million for the years ended December 31, 2012, 2011, and 2010, respectively. The 35% increase from 2011 to 2012 is a combination of higher DD&A expenses due to increased production at our KSK wells, along with higher DD&A expenses resulting from negative revisions in proved reserves at our KSK and Zaniemysl wells, which are discussed below. The 28% increase from 2010 to 2011 was primarily a function of our increased production in Poland.

Future DD&A costs are expected to generally, but not completely, follow future production trends. However, future DD&A rates can be very different depending upon future capitalized costs and changes in reserve volumes.

Accretion Expense. Accretion expense was $63,000, $68,000, and $92,000 for the years ended December 31, 2012, 2011 and 2010, respectively. Accretion expense is related entirely to our asset retirement obligation associated with expected future plugging and abandonment costs.

Oilfield Services Segment

Oilfield Services Revenues. Oilfield services revenues were $2.1 million, $5.6 million, and $2.1 million for the years ended December 31, 2012, 2011, and 2010, respectively. We drilled five wells for third parties, including one drilled for our Alberta Bakken joint venture, during 2012, along with additional well service work. We drilled eight wells for third parties, including those drilled for our Alberta Bakken joint venture, during 2011, along with additional well service work. We drilled 25 wells for third parties during 2010; however, most of these were shallow wells, which can be drilled in only two to three days and generate less revenue per well than deeper wells. Oilfield services revenues will continue to fluctuate from period to period based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the degree of emphasis on using our oilfield services equipment on our own properties, and other factors. We cannot accurately predict future oilfield services revenues.

Oilfield Services Costs. Oilfield services costs were $1.6 million, $4.5 million, and $1.6 million for the years ended December 31, 2012, 2011, and 2010, respectively, or 76%, 79%, and 74% of oilfield-servicing revenues, respectively. The changes in services costs from year to year were primarily due to the nature of our drilling activity discussed above. In general, oilfield-servicing costs are closely associated with oilfield services revenues. As such, oilfield services costs will continue to fluctuate period to period based on the number of wells drilled, revenues generated, weather, downtime for equipment repairs, the degree of emphasis on using our oilfield services equipment on our own properties, and other factors.

DD&A Expense – Oilfield Services. DD&A expense for oilfield services was $1.1 million, $1.0 million, and $0.7 million for the years ended December 31, 2012, 2011, and 2010, respectively. We spent $0.7 million, $1.2 million, and $1.1 million on upgrading our oilfield-servicing equipment during 2012, 2011, and 2010, respectively. These capital additions resulted in higher DD&A expenses for this segment during 2012 and 2011.

Nonsegmented Items

G&A Costs - Corporate. G&A costs were $8.4 million, $8.4 million, and $8.0 million for the years ended December 31, 2012, 2011, and 2010, respectively. Increased costs in 2012 associated with higher headcount in Poland were offset by lower legal and other fees in the United States. Our 2011 G&A costs rose from 2010 levels primarily due to higher legal and investor relations-related costs.

Stock Compensation. Stock compensation expense recorded for 2012 represents $2.3 million of amortization related to restricted stock and stock options granted to employees in 2012, 2011, 2010, and 2009. Stock compensation expense recorded for 2011 represents $1.7 million of amortization related to restricted stock and stock options granted to employees in 2011, 2010, 2009, and 2008. Stock compensation expense recorded for 2010 represents $1.4 million of amortization related to restricted stock granted in 2010, 2009, 2008, and 2007.

Interest and Other (Income) Expense - Corporate. Interest and other (income) expense was $2.1 million, $2.0 million, and $1.1 million for the years ended December 31, 2012, 2011, and 2010, respectively. During 2012, we incurred $2.5 million in interest expense, which included $0.5 million of amortization of loan fees and $0.5 million in unused commitment fees. Interest and other income was $0.4 million during 2012.

During 2011, we incurred $2.2 million in interest expense, which included $0.6 million of amortization of loan fees and $0.9 million in unused commitment fees. Interest and other income was $0.2 million during 2011. Included in the 2011 amount was interest income of approximately $238,000, offset by a charge of approximately $50,000 associated with the impairment of some obsolete inventory in the United States.

During 2010, we incurred $1.9 million in interest expense, which included $0.6 million of previously unamortized loan fees associated with our prior credit facility, $0.4 million of amortization of loan fees, and $0.2 million in unused commitment fees. Interest and other income was $829,000 during 2010. Included in the 2010 amount was a gain of approximately $0.8 million attributable to the sale of tubing associated with our Grundy-1 well, which was drilled and abandoned during 2008.

Foreign Exchange. We incurred foreign exchange gains of $16.3 million for the year ended December 31, 2012, and foreign exchange losses of $23.4 million and $4.2 million for the years ended December 31, 2011 and 2010, respectively.

Income Taxes. We reported net income of $4.1 million for the year ended December 31, 2012, and net losses of $28.5 million and $0.8 million for the years ended December 31, 2011 and 2010, respectively. No income tax expense was recognized for 2012 due to the reversal of valuation allowances that offset income tax expense for the period. Accounting standards require that a valuation allowance be provided if it is more likely than not that some portion or all of a deferred tax asset will not be realized. Our ability to realize the benefit of our deferred tax asset will depend on the generation of future taxable income through profitable operations and the expansion of our exploration and development activities. The market and capital risks associated with achieving the above requirement are considerable, resulting in our conclusion that a full valuation allowance be provided. Accordingly, we did not recognize any income tax benefit in our consolidated statement of operations for these years.

Proved Reserves

Oil and Gas Reserves

Reserve volumes decreased at year-end 2012 due primarily to negative revisions at our KSK and Zaniemysl wells due to declining well head pressures, along with negative revisions in the United States due to lower oil prices. Positive reserve revisions at our Roszkow, Winna Gora, and Lisewo wells due to more favorable technical data, along with new reserves at our Komorze-3K well (which was completed during the year), partially offset our record 2012 gas production and the negative revisions.

The following table highlights year-end reserve volumes and values and shows the change from 2011 to 2012:

	2012	2011	Change
	(In thousands)		
Proved Reserve Volumes:			
Gas Reserves (Mcf)	44,121	49,636	-11%
Oil Reserves (Bbls)	594	639	-7%
Total Reserves (Mcfe)	47,688	53,470	-11%
Proved Reserve Values:			
Reserves PV-10 Value	$157,603	$169,567	-7%

Changes in proved reserves were as follows:

	2012	2011	2010
(MMcfe)			
Proved Reserves Beginning of Year	53,470	43,793	50,446
Extensions, Discoveries, and Other Additions	2,313	12,245	--
Revisions of Previous Estimates	(3,317)	1,828	(2,814)
Production	(4,778)	(4,396)	(3,839)
Proved Reserves End of Year	47,688	53,470	43,793

Extensions, Discoveries, and Other Additions. All of the 2012 additions to proved reserves that result from the discovery of new fields are associated with our Komorze-3K well, which was completed for production during 2012.

Revisions. Revisions represent changes in previous reserves estimates, either positive revisions upward or negative revisions downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, or development costs. During 2012, excluding the volume reduction due to annual production, we recorded downward revisions at our Zaniemysl and KSK wells due to, respectively, water influx and lower than expected wellhead pressures obtained during the fourth quarter of the year. These were partially offset by upward reserve revisions at our Roszkow, Lisewo, and Winna Gora wells, where new pressure data indicates that the initial gas-in-place for these wells may be more than estimated at year-end 2011. We also recorded upward revisions of approximately 9,000 barrels of oil in the United States, primarily due to lower operating costs resulting in more economically recoverable barrels. During 2011, excluding the reduction due to annual production, we recorded upward reserve revisions at our Roszkow and Winna Gora wells, which were offset by small downward revisions at our Zaniemysl and KSK wells. At Roszkow, new pressure data indicates that the initial gas-in-place may be more than estimated at year-end 2010. We also recorded upward revisions of approximately 56,000 barrels of oil in the United States, primarily due to higher oil prices resulting in more economically recoverable barrels. Revisions at year-end 2010 included downward revisions in Poland due to interpretations of reservoir pressure data at our Roszkow well, while upward revisions occurred in the United States due to higher oil prices. (See Business and Properties).

Production. See “Gas Revenues” and “Oil Revenues” above.

2013 Operational Trends

We currently expect that our 2013 production will be higher than our 2012 production rates with the addition of production at our Winna Gora-1, Lisewo-1, and Komorze 3-K wells. Production began at Winna Gora-1 in late January of 2013. Production is expected to begin at Lisewo-1 and at Komorze-3K during the second half of 2013. We currently expect to receive 86% of the published low-methane tariff, adjusted for energy content, for each of the three new wells. The amount of revenue from this increased production will depend on applicable gas sales prices and prevailing currency exchange rates.

Future oil revenues from our domestic production will depend on the impact of prices we receive as we continue to experience normal production declines. We cannot accurately predict future oilfield services revenues and related costs, which will continue to fluctuate based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the nature and extent of any equipment upgrading, the degree of emphasis on using our oilfield services equipment on our own properties, and other factors.

Costs that vary in concert with production, such as lease operating expenses and DD&A costs, will trend up or down with production increases or decreases. Our 2013 plans for capital expenditures are detailed in the following section, “Liquidity and Capital Resources – Our Capital Resources and Future Expenditures.”

Our U.S. dollar-denominated financial results will continue to be impacted by exchange-rate fluctuations, which cannot be predicted.

Liquidity and Capital Resources

For much of our history, we have financed our operations principally through the sale of equity securities, bank borrowings, and agreements with industry participants that funded our share of costs in certain exploratory activities in return for an interest in our properties. However, as our oil and gas production has increased in Poland in the last several years and as higher oil prices have improved the profitability of our U.S. production, our internally generated cash flow has become a significant source of operations financing.

2012 Liquidity and Capital

Working Capital (current assets less current liabilities). Our working capital was $30.4 million as of December 31, 2012, a decrease of $19.4 million from December 31, 2011. The primary causes of the decrease are our increased exploration costs in 2012 and the classification of $7.0 million as a current portion of our long-term debt. At the time of this report, we are in the process of extending and expanding our credit facility. If we do not complete a new credit facility, we will be required to make a $7.0 million principal payment under the terms of our existing facility on December 31, 2013.

Our current assets at year-end 2012 included approximately $34.0 million in cash and cash equivalents, $4.2 million in accrued oil and gas sales from both the United States and Poland, and $6.8 million in receivables from our joint interest partners in both the United States and Poland that were collected in early 2013. Almost the entire balance of joint interest receivables at year-end 2012 was due from PGNiG, primarily related to the drilling of our Kutno well, where we act at the operator. Our current liabilities at year-end included approximately $7.4 million payable by FX Poland for various drilling and development operations in Poland that were paid in early 2013.

Operating Activities. Net cash used in operations during 2012 and 2011 was $1.2 million and $0.1 million, respectively. Net cash provided by operating activities during 2010 was $7.2 million. A $7.2 million increase in exploration costs offset higher revenues in 2012, leading to a decline in cash provided from operating activities in 2012. Likewise, a $13.6 million increase in exploration costs in 2011 offset higher revenues.

Investing Activities. We used net cash in investing activities of $16.3 million, $18.5 million, and $7.8 million in 2012, 2011, and 2010, respectively. In 2012, we spent $15.8 million for oil and gas property additions, all of which was related to our Polish drilling activities. We also spent $0.7 million adding to our oilfield services and office equipment. In 2011, we spent $17.3 million for oil and gas property additions, $14.8 million of which were related to our Polish drilling activities, with the remainder being spent on our domestic properties. We spent $1.2 million adding to our oilfield services equipment. We also benefited from approximately $12.0 million spent in the Warsaw South project area by PGNiG for seismic and drilling costs in 2011 in order to earn a 49% interest in the concession. In 2010, we spent $6.5 million for oil and gas property additions, $6.0 million of which were related to our Polish drilling activities, with the remainder being spent on our domestic properties. We also spent $1.3 million adding to our oilfield services equipment.

Financing Activities. Our cash flow from financing activities was $50.8 and $16.1 million, during 2011 and 2010, respectively. During 2011, we issued 6.9 million shares of common stock in a registered public offering, which resulted in net proceeds to us, after offering costs, of approximately $45.0 million. We used $35.0 million of those proceeds to repay amounts outstanding under our credit facility at the time of the offering. We borrowed $40 million under our credit facility in the fourth quarter of 2011. We also received proceeds of $800,000 from the exercise of stock options.

During 2010, we borrowed $35 million under our expanded credit facility, using $25 million to repay our 2008 credit facility and $2.5 million in fees associated with the expanded credit facility. In addition, we sold 1.5 million shares of stock in a registered direct offering, resulting in net proceeds to us of $8.4 million. Option holders exercised options to purchase 152,892 shares of common stock, resulting in proceeds to us of an additional $0.2 million.

There were no financing transactions during 2012.

Our Capital Resources and Future Expenditures

Our anticipated sources of liquidity and capital for 2013 include our working capital of $30.4 million at year-end 2012, available credit under our expanded credit facility, and cash available from our operations.

In August 2010, we refinanced our existing credit facility by executing an expanded credit facility with The Royal Bank of Scotland Plc, ING Bank N.V., and KBC Bank NV. The expanded credit facility calls for a periodic interest rate of LIBOR plus 4.0% and has a term of five years, with semiannual borrowing base reductions of $11 million each beginning on June 30, 2013. As of December 31, 2012, we had $40 million outstanding under the facility, and $15 million of available credit. Our borrowing base is scheduled to be reduced to $44 million on June 30, 2013.

We currently have increased cash from our operating activities to help fund our exploration and development activities in 2013. We expect that our 2013 production will be higher than our 2012 production with the addition of production at our Winna Gora-1, Lisewo-1, and Komorze 3-K wells. Production began at Winna Gora-1 in late January of 2013. Production is expected to begin at Lisewo-1 and at Komorze-3K during the second half of 2013. We currently expect to receive 86% of the published low-methane tariff, adjusted for energy content, for each of the three new wells. The amount of revenue from this increased production will depend on applicable gas sales prices and prevailing currency exchange rates.

We have an effective Securities Act universal shelf registration statement under which we may sell up to $200 million of equity or debt securities of various kinds. In June 2012, we entered into an agreement to possibly sell up to $50 million in common stock during the next two years in at-the-market transactions. Through the date of this filing, we have not sold any stock under that agreement. Assuming all $50 million of common stock covered by the at-the-market facility were sold, the remaining $150 million balance of securities available for sale under the registration statement is available for sale at any time, subject to market conditions and our ability to access the capital markets, to further finance our exploration and development plans in Poland and for other corporate purposes.

At year-end 2012, we were in the process of drilling the Tuchola-3 well, having incurred a total cost of $1.5 million during the year. We began drilling the Mieczewo-2 well in early 2013. Our total costs for these wells once drilling is completed are expected to be approximately $12 million. We have agreed with PGNiG to conduct a fracture stimulation test at the Plawce-2 well during the first half of 2013. We were also in the process of building a pipeline and production facilities at our Lisewo well. We had no other firm commitments for future capital and exploration costs at 2012 year end.

We expect our primary use of cash for 2013 will be for our exploration and development activities in Poland and the United States. Our board of directors has approved projects whose cost is expected to range from $60 million to $70 million for production facilities for existing discoveries, exploration and development wells, and 2-D and 3-D seismic data acquisition and analysis, including those items noted above. All of the approved projects may not be completed during 2013, but we do expect to start work on all of them in the next 12 months. In 2012, we approved a capital budget of similar size. Our actual costs in 2012 were $35.7 million, but by early January of 2013, we had started work on projects totaling $56.3 million originally scheduled for 2012.

The actual amount of our expenditures will depend on ongoing exploration results; the pace at which PGNiG, our operating partner in the Fences project area, wishes to proceed or the extent it wishes to continue to participate with us in concessions we operate; the availability of drilling and other exploration services; and the amount of capital we obtain from the various sources discussed above. Our various sources of liquidity and capital outlined above should more than enable us to meet our capital needs in Poland and the United States for the next 12 months. We have the ability to control the timing and amount of most of our future capital and exploration costs.

We may continue to incur operating losses in future periods, and we continue to fund substantial exploration and development in Poland. We have a history of operating losses. From our inception in January 1989 through December 31, 2012, we have incurred cumulative net losses of approximately $186 million. Despite our recent and expected future increases in production and revenues, our exploration and production activities may continue to result in net losses in future years, depending on the success of our drilling activities in Poland and the United States and whether we generate sufficient revenues to cover related operating expenses.

We may also seek to obtain additional funds for future capital investments from the sale of partial property interests or arrangements such as those negotiated in prior years for our Kutno and Warsaw South project areas in which industry participants are bearing the initial exploration costs to earn an interest in the project or other arrangements, all of which may dilute the interest of our existing stockholders or our interest in the specific project financed.

We will allocate our existing capital, as well as funds we may obtain in the future, among our various projects at our discretion. We may change the allocation of capital among the categories of anticipated expenditures depending upon future events. For example, we may change the allocation of our expenditures based on the actual results and costs of future exploration, appraisal, development, production, property acquisition, and other activities. In addition, we may have to change our anticipated expenditures if costs of placing any particular discovery into production are higher, if the field is smaller, or if the commencement of production takes longer than expected.

Contractual Obligations and Contingent Liabilities and Commitments

Contractual Obligations. At December 31, 2012, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

	Total	2013	2014	2015	2016	2017
			(In thousands)			
Credit facility	$40,000	$7,000	$22,000	$ 11,000	$ --	$ --
Interest payments on long-term debt	3,318	1,885	1,146	287	--	--
Total	$43,318	$8,885	$23,146	$11,287	$ --	$ --

Under the terms of our $55 million credit facility, the amount of credit available is reduced by $11 million each six months, beginning on June 30, 2013. As of December 31, 2012, we had borrowed $40 million under the facility, and the reduction of that amount is illustrated in the table above.

During the ordinary course of business in Poland, we enter into agreements for the drilling of wells, the construction of production facilities, and for seismic projects. These are typically short-term agreements and are completed in less than one year. We are subject to certain work commitments respecting our 100%-owned exploration concessions that must be satisfied in order to maintain our interest in those concessions. These work commitments are optional on our part; however, they must be satisfied in order to maintain our interest in those concessions. We can request changes to usufruct and concession agreements that either modify the obligations to reduce our commitments or extend the terms of those agreements. In addition, we routinely relinquish acreage that we believe has lower potential rather than continue to be subject to the related work commitment. Our exploration budget and related activities are focused on exploration and long-term exploitation of our most promising exploration opportunities and are not specifically or primarily focused on meeting these work commitments.

Our oil and gas drilling and production operations are subject to hazards incidental to the industry that can cause severe damage to and destruction of property and equipment, pollution or environmental damage, suspension of operations, personal injury, and loss of life. To lessen the effects of these hazards, we maintain insurance of various types to cover our United States and Poland operations and also rely on the insurance or financial capabilities of our exploration partners in Poland. These measures do not cover risks related to violations of environmental laws or all other risks involved in oil and gas exploration, drilling, and production. We would be adversely affected by a significant event that is not fully covered by insurance or by our inability to maintain adequate insurance in the future at rates we consider reasonable.

Asset Retirement Obligation. We have liabilities of $1.4 million related to asset retirement obligations on our Consolidated Balance Sheet at December 31, 2012, excluded from the table above. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations.

Critical Accounting Policies

Oil and Gas Activities

We follow the successful efforts method of accounting for our oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, these costs plus the costs of drilling the well are expensed. The costs of development wells are capitalized, whether productive or nonproductive. Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment allowance is provided to the extent that net capitalized costs of unproved properties, on a property-by-property basis, are not considered to be realizable. An impairment loss is recorded if the net capitalized costs of proved oil and gas properties exceed the aggregate undiscounted future net cash flows determined on a property-by-property basis. The impairment loss recognized equals the excess of net capitalized costs over the related fair value, determined on a property-by-property basis. Gains and losses are recognized on sales of entire interests in proved and unproved properties. Sales of partial interests are generally treated as a recovery of costs and any resulting gain or loss is recorded as other income. Revenues associated with oil and gas sales are recorded when title passes, which is upon delivery to the pipeline or purchaser, and are net of royalties. Oilfield service revenues are recognized when the related service is performed. As a result of the foregoing, our results of operations for any particular period may not be indicative of the results that could be expected over longer periods.

Oil and Gas Reserves

All of the reserves data in this Form 10-K are estimates. Estimates of our crude oil and natural gas reserves are prepared by our engineers in accordance with guidelines established by the Securities and Exchange Commission. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. In addition, economic producibility of reserves is dependent on the oil and gas prices used in the reserves estimate. We based our December 31, 2012, reserves estimates on a 12-month average commodity price, unless contractual arrangements designated the price to be used, in accordance with Securities and Exchange Commission rules. However, oil and gas prices are volatile and, as a result, our reserves estimates will change in the future.

Estimates of proved crude oil and natural gas reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. See Financial Statements and Supplementary Data – Supplemental Information.

Stock-based Compensation

Share-based compensation cost is measured at the grant date, based on the estimated fair value of the award, and is recognized as expense over the employee's requisite service period.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Price Risk

Substantially all of our gas in Poland is sold to PGNiG or its affiliates under contracts that extend for the life of each field. Prices are determined contractually and, in the case of our producing wells in Poland, are tied to published tariffs. The tariffs are set from time to time by the public utility regulator in Poland. Although we are not directly subject to such tariffs, we have elected to link our price to these tariffs in our contracts with PGNiG. We expect that the prices we receive in the short term for gas we produce will be lower than would be the case in an unregulated setting and may be lower than prevailing western European prices. We believe it is more likely than not that, over time, the end user gas price in Poland will converge with the average price in Europe.

Realized pricing for our oil production in the United States is primarily driven by the prevailing worldwide price of oil, subject to gravity and other adjustments for the actual oil sold. Historically, oil prices have been volatile and unpredictable. Price volatility relating to our oil production is expected to continue in the foreseeable future.

We currently do not engage in any hedging activities to protect ourselves against market risks associated with oil and gas price fluctuations, although we may elect to do so in the future.

Foreign Currency Risk

We enter into various agreements in Poland denominated in the Polish zloty. The exchange rate between the U.S. dollar and the Polish zloty is subject to fluctuations that are beyond our control. During 2012, the zloty fluctuated between a low of 3.07 zlotys per U.S. dollar to a high of 3.58 zlotys per U.S. dollar, a fluctuation of 17%. Variations in exchange rates affect the U.S. dollar-denominated amount of revenue we receive in Polish zlotys. As the U.S. dollar strengthens relative to the zloty, our U.S. dollar-denominated revenue received in Polish zlotys declines; conversely, when the U.S. dollar weakens relative to the zloty, our U.S. dollar-denominated revenue received in Polish zlotys increases. Conversely, a weak U.S. dollar leads to lower U.S. dollar-denominated drilling, capital, and exploration costs, while a strong U.S. dollar has the opposite effect for the cost structure of our Polish operations. Should exchange rates in effect during early 2013 continue throughout the year, we expect the exchange rates to have a slightly positive impact on our U.S. dollar-denominated revenues compared to 2012. We are also generating revenues in Poland in Polish zlotys, and we keep those zlotys in Poland and use them to pay zloty-based invoices.

Our policy is to reduce currency risk by, under ordinary circumstances and when necessary, converting dollars to zlotys or fixing the exchange rate for future transfers of dollars to zlotys, on or about the occasion of making significant commitments payable in Polish currency, taking into consideration the future timing and amounts of committed costs and the estimated timing and amounts of zloty-based revenues.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the periods specified by the Securities and Exchange Commission's rules and forms, and that information is accumulated and communicated to our management, including our principal executive and principal financial officers (whom we refer to in this periodic report as our Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. Our management evaluated, with the participation of our Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2012, pursuant to Rule 13a-15(b) under the Securities Exchange Act. Based upon that evaluation, our Certifying Officers concluded that, as of December 31, 2012, our disclosure controls and procedures were effective.

Internal Control over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management's report on internal control over financial reporting and the report of PricewaterhouseCoopers LLP, our independent registered public accounting firm, on the effectiveness of internal control over financial reporting are included on pages F-1 and F-2 of this report.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Price Range of Common Stock and Dividend Policy

The following table sets forth, for the periods indicated, the high and low trading prices for our common stock as quoted under the symbol "FXEN" on the NASDAQ Global Select Market, or its predecessor, Nasdaq National Market:

	Low	High
2013:		
First Quarter (through March 9, 2013)	$3.36	$ 4.40
2012:		
Fourth Quarter	3.87	7.58
Third Quarter	5.84	8.78
Second Quarter	4.60	6.11
First Quarter	4.56	6.82
2011:		
Fourth Quarter	3.75	6.38
Third Quarter	4.13	10.10
Second Quarter	6.80	9.24
First Quarter	6.20	11.76

We have never paid cash dividends on our common stock and do not anticipate that we will pay dividends in the foreseeable future. We intend to reinvest any future earnings to further expand our business. As of March 8, 2013, we had approximately 9,500 stockholders.

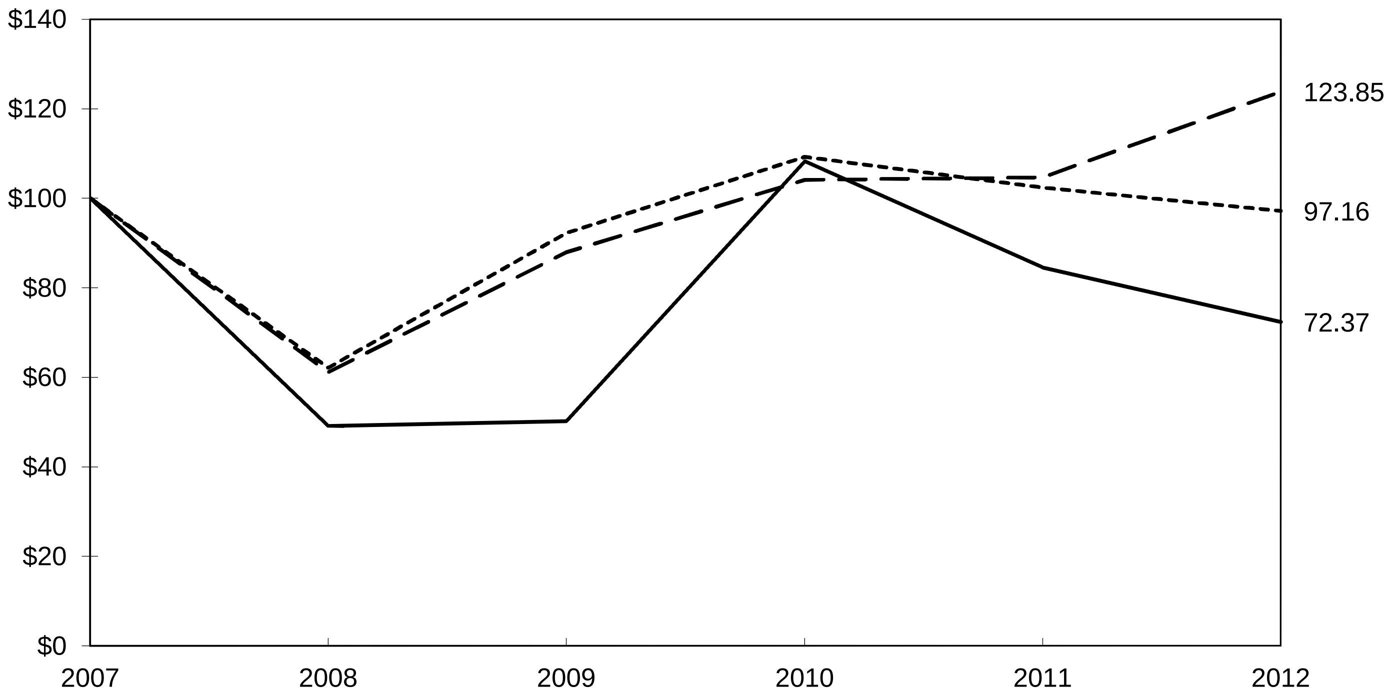
Recent Sales of Unregistered Securities

None.

Comparison of Five-Year Cumulative Total Returns

Performance Graph for

FX Energy Inc.



Legend

Symbol	CRSP Total Returns Index For:	12/2007	12/2008	12/2009	12/2010	12/2011	12/2012
————	FX Energy Inc.	100.00	49.12	50.17	108.28	84.53	72.37
-----------	NASDAQ Stock Market (US Companies)	100.00	61.17	87.93	104.13	104.69	123.85
……….…...	Crude Petroleum and Natural Gas Index	100.00	62.17	92.27	109.25	102.41	97.16

Notes:

A. The lines represent monthly index levels derived from compounded daily returns that include all dividends.
B. The indexes are reweighted daily, using the market capitalization on the previous trading day.
C. If the monthly interval, based on the fiscal year-end, is not a trading day, the preceding trading day is used.
D. The index level for all series was set to $100.0 on 12/31/2007.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of FX Energy, Inc., together with its consolidated subsidiaries (the Company), is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed by the Company's principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

As of the end of the Company's 2012 fiscal year, management conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management has determined that the Company's internal control over financial reporting as of December 31, 2012, was effective.

The Company's internal control over financial reporting includes policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, independent registered public accounting firm, as stated in its report appearing on pages F-2 and F-3.

pwc

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors
of FX Energy, Inc. and its subsidiaries

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of cash flows and of stockholders' equity present fairly, in all material respects, the financial position of FX Energy, Inc. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
March 14, 2013

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2012 and 2011
(in thousands)

	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33,990	$ 50,859
Receivables:		
Accrued oil and gas sales	3,447	3,446
Joint interest and other receivables	7,733	4,768
Value-added tax receivable	1,136	389
Inventory	199	196
Other current assets	614	542
Total current assets	47,119	60,200
Property and equipment, at cost:		
Oil and gas properties (successful-efforts method):		
Proved	63,821	49,388
Unproved	2,337	3,482
Other property and equipment	10,717	9,968
Gross property and equipment	76,875	62,838
Less accumulated depreciation, depletion, and amortization	(19,786)	(14,942)
Net property and equipment	57,089	47,896
Other assets:		
Certificates of deposit	382	406
Loan fees	1,364	1,722
Total other assets	1,746	2,128
Total assets	$ 105,954	$ 110,224

-Continued-

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

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2012 and 2011
(in thousands, except share data)
-Continued-

	2012	2011
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 8,532	$ 9,736
Accrued liabilities	1,192	677
Current portion of long-term debt	7,000	--
Total current liabilities	16,724	10,413
Long-term liabilities:		
Notes payable	33,000	40,000
Asset retirement obligation	1,431	1,184
Total long-term liabilities	34,431	41,184
Total liabilities	51,155	51,597
Commitments and Contingencies (Note 6)		
Stockholders' equity:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized as of December 31, 2012 and 2011; no shares outstanding	--	--
Common stock, $0.001 par value, 100,000,000 shares authorized as of December 31, 2012 and 2011; 53,246,620 and 52,787,350 shares issued and outstanding as of December 31, 2012 and 2011, respectively	53	53
Additional paid-in capital	222,513	219,522
Cumulative translation adjustment	18,027	28,964
Accumulated deficit	(185,794)	(189,912)
Total stockholders' equity	54,799	58,627
Total liabilities and stockholders' equity	$ 105,954	$ 110,224

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

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2012, 2011, and 2010
(in thousands, except per share amounts)

	2012	2011	2010
Revenues:			
Oil and gas sales	$ 34,461	$ 29,807	$ 22,914
Oilfield services	2,137	5,631	2,099
Total revenues	36,598	35,438	25,013
Operating costs and expenses:			
Lease operating expenses	3,631	3,834	3,473
Exploration costs	23,795	16,618	3,038
Impairment of oil and gas properties	2,562	72	564
Loss on sale of assets	49	--	--
Asset retirement obligation gain	--	(52)	(264)
Oilfield services costs	1,610	4,458	1,550
Depreciation, depletion, and amortization (DD&A)	4,239	3,397	2,626
Accretion expense	63	68	92
Stock compensation	2,325	1,744	1,379
General and administrative costs (G&A)	8,369	8,396	7,973
Total operating costs and expenses	46,643	38,535	20,431
Operating income (loss)	(10,045)	(3,097)	4,582
Other income (expense):			
Interest expense	(2,485)	(2,167)	(1,936)
Interest and other income	356	188	829
Foreign exchange gain (loss)	16,292	(23,448)	(4,233)
Total other income (expense)	14,163	(25,427)	(5,340)
Net income (loss)	$ 4,118	$ (28,524)	$ (758)
Basic and diluted net income (loss) per common share	$ 0.08	$ (0.57)	$ (0.02)
Basic and diluted weighted average number of shares outstanding	52,274	50,262	43,387

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

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
For the years ended December 31, 2012, 2011, and 2010
(in thousands)

	2012	2011	2010
Net income (loss)	$ 4,118	$ (28,524)	$ (758)
Other comprehensive income (loss)			
Foreign currency translation adjustment	(10,937)	14,951	3,275
Comprehensive income (loss)	$ (6,819)	$ (13,573)	$ 2,517

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

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2012, 2011, and 2010
(in thousands)

	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ 4,118	$ (28,524)	$ (758)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	4,239	3,397	2,626
Impairment of oil and gas properties	6,979	72	564
Accretion expense	63	68	92
Loss on property dispositions	49	44	--
Stock compensation	2,325	1,744	1,379
Foreign exchange (gains) losses	(16,289)	23,397	4,238
Common stock issued for services (G&A)	666	777	636
Asset retirement obligation revisions	408	(52)	(264)
Loan fee amortization	504	554	971
Increase (decrease) from changes in working capital items:			
Receivables	(2,905)	(5,241)	(1,809)
Inventory	(2)	(3)	(10)
Other current assets	(50)	(253)	101
Other assets	25	--	(143)
Accounts payable and accrued liabilities	(1,320)	3,950	(289)
Asset retirement obligations settled	(43)	(50)	(85)
Net cash provided by (used in) operating activities	(1,233)	(120)	7,249
Cash flows from investing activities:			
Additions to oil and gas properties	(15,836)	(17,300)	(6,475)
Additions to other property and equipment	(735)	(1,221)	(1,339)
Proceeds from sale of assets	221	35	--
Net cash used in investing activities	(16,350)	(18,486)	(7,814)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of offering costs	--	45,041	8,403
Proceeds from notes payable, net of deferred loan fees	--	40,000	32,532
Payments of notes payable	--	(35,000)	(25,000)
Proceeds from exercise of stock options and warrants	--	801	157
Net cash provided by financing activities	--	50,842	16,092
Effect of exchange rate changes on cash	714	(1,117)	(12)
Net increase (decrease) in cash	(16,869)	31,119	15,515
Cash and cash equivalents at beginning of year	50,859	19,740	4,225
Cash and cash equivalents at end of year	$ 33,990	$ 50,859	$ 19,740

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

FX ENERGY, INC., AND SUBSIDIARIES
Consolidated Statement of Stockholders' Equity
For the years ended December 31, 2012, 2011, and 2010
(in thousands)

	Preferred Stock	Common Stock Shares Issued	Common Stock $0.001 Par Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders' Equity (Deficit)
Balance as of December 31, 2009	--	43,038	$ 43	$ 160,594	$ 10,738	$ (160,630)	$ 10,745
Issuance of common stock	--	1,500	1	8,402	--	--	8,403
Common stock issued for services and other	--	594	1	635	--	--	636
Exercise of stock options and warrants	--	153	--	157	--	--	157
Stock compensation	--	--	--	1,379	--	--	1,379
Other comprehensive income	--	--	--	--	3,275	--	3,275
Net loss for year	--	--	--	--	--	(758)	(758)
Balance as of December 31, 2010	--	45,285	45	171,167	14,013	(161,388)	23,837
Issuance of common stock	--	6,900	7	45,034	--	--	45,041
Common stock issued for services and other	--	440	1	776	--	--	777
Exercise of stock options and warrants	--	162	--	801	--	--	801
Stock compensation	--	--	--	1,744	--	--	1,744
Other comprehensive income	--	--	--	--	14,951	--	14,951
Net loss for year	--	--	--	--	--	(28,524)	(28,524)
Balance as of December 31, 2011	--	52,787	53	219,522	28,964	(189,912)	58,627
Common stock issued for services and other	--	460	--	666	--	--	666
Stock compensation	--	--	--	2,325	--	--	2,325
Other comprehensive income	--	--	--	--	(10,937)	--	(10,937)
Net income for year	--	--	--	--	--	4,118	4,118
Balance as of December 31, 2012	--	53,247	$ 53	$ 222,513	$ 18,027	$ (185,794)	$ 54,799

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

FX ENERGY, INC., AND SUBSIDIARIES
Notes to the Consolidated Financial Statements

Note 1: Summary of Significant Accounting Policies

Organization

FX Energy, Inc., a Nevada corporation, together with its subsidiaries (collectively referred to hereinafter as "us," "we," "our," or "the Company"), is an independent oil and gas exploration and production company with principal production, reserves, and exploration in Poland and oil production, oilfield service, and exploration activities in the United States. In Poland, we have projects involving the exploration and exploitation of oil and gas prospects in partnership with Polskie Górnictwo Naftowe i Gazownictwo ("PGNiG"), the Polish national oil and gas company, other industry partners, and for our own account. In the United States, we explore for and produce oil from fields in Montana and Nevada, and we have an oilfield services company in northern Montana that performs contract drilling and well-servicing operations.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and its undivided interests in Poland. All significant intercompany accounts and transactions have been eliminated in consolidation. At December 31, 2012, we owned 100% of the voting common stock or other equity securities of our subsidiaries.

Cash and Cash Equivalents and Marketable Securities

We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. We determine the appropriate classification of our investments in cash and cash equivalents and marketable securities at the time of purchase and reevaluate such designation at each balance sheet date.

Fair Value of Financial Instruments and Nonfinancial Assets and Liabilities

The carrying amounts of our financial instruments, including cash and cash equivalents, marketable securities, accounts receivable, accounts payable, and accrued liabilities, approximate fair value because of their generally short maturities. The accounting standards for fair value measurements provide for fair value measurements of all nonfinancial assets and nonfinancial liabilities not recognized or disclosed at fair value in the financial statements on a recurring basis.

Concentration of Credit Risk

The majority of our receivables are within the oil and gas industry, primarily from the purchasers of our oil and gas and fees generated from oilfield services and our industry partners. Substantially all of our Polish receivables are with PGNiG or one of its affiliates, and substantially all of our domestic receivables are with Cenex, a regional refiner and marketer. The receivables are not collateralized. To date, we have experienced minimal bad debts and have no allowance for doubtful accounts at December 31, 2012 and 2011. The majority of our cash and cash equivalents are held by four financial institutions in Utah, Montana, and Poland.

Derivative Instruments

Accounting standards require derivative instruments to be recognized as either assets or liabilities in the balance sheet at fair value. The accounting for changes in the fair value of derivative instruments depends on their intended use and resulting hedge designation. For derivative instruments designated as hedges, the changes in fair value are recorded in the balance sheet as a component of accumulated other comprehensive income. Changes in the fair value of derivative instruments not designated as hedges are recorded in the consolidated statements of operations, generally as a component of interest and other income (expense). At December 31, 2012 and 2011, we had no derivative instruments.

Inventory

Inventory consists primarily of tubular goods and production-related equipment and is valued at the lower of average cost or market.

Oil and Gas Properties

We follow the successful-efforts method of accounting for our oil and gas operations. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether an individual well has found proved reserves. If it is determined that an exploratory well has not found proved reserves, if the determination that proved reserves have been found cannot be made within one year, or if we are not making sufficient progress assessing the reserves and the economic and operating viability of the project, the costs of the well are expensed. The costs of development wells are capitalized whether productive or nonproductive. Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment charge is provided to the extent that capitalized costs of unproved properties, on a property-by-property basis, are not considered to be realizable. Depreciation, depletion, and amortization ("DD&A") of capitalized costs of proved oil and gas properties is provided on a field-by-field basis using the units-of-production method. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage. An impairment loss is recorded if the net capitalized costs of proved oil and gas properties exceed the aggregate undiscounted future net revenues determined on a field-by-field basis. The impairment loss recognized equals the excess of net capitalized costs over the related fair value determined on a property-by-property basis. Gains and losses are recognized on sales of entire interests in proved and unproved properties. Sales of partial interests are generally treated as a recovery of costs and any resulting gain or loss is recorded as other income.

During 2012, we recorded impairments of oil and gas properties of $2.6 million. We relinquished certain concessions in Poland, impairing the remaining capitalized costs of $787,000. In Montana, we determined that our Alberta Bakken-related wells and leases were not prospective for hydrocarbon potential. We impaired the remaining capitalized costs of $1.8 million. The $7.0 million of impairment of oil and gas properties on the statements of cash flow includes both the $2.6 million of impairment recognized, as well as $4.4 million of exploration costs capitalized in 2011 related to the Kutno-1 dry hole, which were recognized in the third quarter of 2012. During 2011, we relinquished certain concessions in Poland. We impaired the remaining capitalized costs of $72,000. During 2010, production ceased at our Kleka well in western Poland. We impaired the remaining capitalized costs of the well of $564,000.

During 2010, we recorded a gain of approximately $772,000 attributable to the sale of tubing associated with our Grundy-1 well, which was drilled and abandoned during 2008. The gain is included in interest and other income.

The following table reflects the net changes in capitalized exploratory well costs, which are capitalized pending the determination of proved reserves, during 2012, 2011, and 2010:

	December 31,		
	2012	**2011**	**2010**
		(In thousands)	
Beginning balance at January 1	$ 9,965	$ 3,614	$ --
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,984	9,965	3,614
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	--	(3,614)	--
Capitalized exploratory well costs charged to expense	(5,789)	--	--
Ending balance at December 31	$ 11,160	$ 9,965	$ 3,614

The 2012 additions include costs associated with our Mieczewo, Tuchola, Plawce, and Frankowo-1 wells in Poland. The Mieczewo and Tuchola wells were drilling at year-end 2012. The Plawce well was drilled in 2011 and is scheduled to be fracture stimulated during the first half of 2013. The Frankowo well is currently being evaluated for future potential. The exploratory wells costs charged to expense during 2012 include costs at our Kutno-2 well in Poland along with costs associated with all Alberta Bakken test wells drilled in Montana. The 2011 activity includes costs associated with the Plawce-1 and Kutno-2 wells in Poland and our first three Alberta Bakken tests in Montana. All five wells were either in progress or being evaluated or tested at the end of the year. The 2010 activity includes costs associated with the Lisewo-1 well, which was drilling at year-end 2010 and was determined to be a commercial well with proved reserves in 2011.

Other Property and Equipment

Other property and equipment, including oilfield-servicing equipment, is stated at cost. Depreciation of other property and equipment is calculated using the straight-line method over the estimated useful lives (ranging from three to 40 years) of the respective assets. The costs of normal maintenance and repairs are charged to expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of other property and equipment sold, or otherwise disposed of, and the related accumulated depreciation are removed from the accounts and any gain or loss is reflected in current operations.

The historical cost of other property and equipment, presented on a gross basis with accumulated depreciation, is summarized as follows:

	December 31, 2012	December 31, 2011	Estimated Useful Life (in years)
	(In thousands)		
Other property and equipment:			
Drilling rigs	$ 8,872	$ 8,201	6
Other vehicles	412	408	5
Building	139	137	40
Office equipment and furniture	1,294	1,222	3 to 6
Total cost	10,717	9,968	
Accumulated depreciation	(8,147)	(6,997)	
Net other property and equipment	$ 2,570	$ 2,971	

Supplemental Disclosure of Cash Flow Information

Noncash investing and financing transactions not reflected in the consolidated statements of cash flows include the following:

	Year Ended December 31, 2012	2011	2010
	(In thousands)		
Noncash investing transactions:			
Additions to properties included in current liabilities	$3,374	$3,409	$2,930
Cash paid for interest:			
Cash paid during the year for interest	1,983	1,596	801

Cash paid for interest in 2012, 2011, and 2010 (in thousands) includes $454, $858, and $149, respectively, in commitment and other fees on our expanded credit facility.

Revenue Recognition

Revenues associated with oil and gas sales are recorded when title passes, which is upon delivery to the pipeline or other purchaser, and are net of royalties and value added taxes. Oilfield service revenues are recognized when the related service is performed.

Stock-Based Compensation

We maintain several share-based incentive plans. Under these plans, we may issue options or restricted stock awards. Options are granted at an option price equal to the market value of the stock at the date of grant, have terms ranging from five to seven years, and vest in three equal annual installments. Restricted stock awards have similar terms and vesting requirements. Accounting standards require share-based compensation costs to be measured at the grant date, based on the estimated fair value of the award, and recognized as expense over the employee's requisite service period.

Income Taxes

Deferred income taxes are provided for the differences between the tax bases of assets or liabilities and their reported amounts in the consolidated financial statements. Such differences may result in taxable or deductible amounts in future years when the asset or liability is recovered or settled, respectively.

We did not have any unrecognized tax benefits at December 31, 2012. We are subject to audit in the United States by the Internal Revenue Service and various states for the prior three years and in Poland by Polish tax authorities for the prior five years. We do not believe there will be any material changes in our unrecognized tax positions over the next 12 months. Our policy is to recognize interest and penalties accrued on any unrecognized tax benefits as a component of income tax expense. No tax-related interest expense was recognized during the year ended December 31, 2012.

Subsequent Events

We have evaluated subsequent events after the balance sheet date of December 31, 2012, through the time of filing with the Securities and Exchange Commission.

New Accounting Standards

In June 2011, the Financial Accounting Standards Board ("FASB") issued amended standards that eliminated the option to report other comprehensive income in the statement of stockholders' equity and require companies to present the components of net income and other comprehensive income as either one continuous statement of comprehensive income or two separate but consecutive statements. The amended standards do not affect the reported amounts of comprehensive income. In December 31, 2011, the FASB deferred the requirement to present components of reclassifications of other comprehensive income on the face of the income statement that had previously been included in the June 2011 amended standard. These amended standards are to be applied retrospectively for interim and annual periods beginning after December 15, 2011. We adopted these standards on January 1, 2012.

In May 2011, the FASB issued amended standards to achieve common fair value measurements and disclosures between generally accepted accounting principles in the United States of America (GAAP) and International Financial Reporting Standards. The standards include amendments that clarify the intent behind the application of existing fair value measurements and disclosures and other amendments that change principles or requirements for fair value measurements or disclosures. The amended standards are to be applied prospectively for interim and annual periods beginning after December 15, 2011. We adopted these standards on January 1, 2012.

In January 2010, the FASB issued new standards intended to improve disclosures about fair value measurements. The new standards require details of transfers in and out of Level 1 and 2 fair value measurements and the presentation of activity within the Level 3 fair value measurement roll forward. The new disclosures are required of all entities that are required to provide disclosures about recurring and nonrecurring fair value measurements. We adopted these new rules effective January 1, 2010, except for the gross presentation of the Level 3 fair value measurement roll forward, which we adopted December 31, 2010.

In all cases referenced above, the adoption of the new rules or standards did not have a material impact on our results of operations and financial condition. We have reviewed all other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on our consolidated results of operations, financial position, and cash flows. Based on that review, we believe that none of these pronouncements will have a significant effect on current or future earnings or operations.

Foreign Operations

The functional currency of our Polish subsidiary is the Polish zloty. The functional currency for the Polish subsidiary affects the amounts reported for Polish assets, liabilities, revenues, and expenses from those that would be reported if we used the U.S. dollar as the functional currency. The differences depend on changes in period-average and period-end exchange rates. Translation adjustments result from the process of translating the Polish subsidiary's financial statements into the U.S. dollar reporting currency. Translation adjustments are not included in determining net income but are reported separately and accumulated in other comprehensive income. The accounting basis of the assets and liabilities of FX Energy Poland, our wholly owned subsidiary, is adjusted to reflect the difference between the exchange rate when the asset or liability was first recorded and the exchange rate on the date of the change. We record a cumulative translation adjustment ("CTA") on our balance sheet to reflect those basis differences. At December 31, 2012 and 2011, the CTA balance was $18.0 million and $29.0 million, respectively. Because of the fluctuation in exchange rates between reporting periods and changes in certain account balances, the CTA will change from period to period.

During 2012, we recorded foreign currency transaction gains of approximately $16.3 million attributable to decreases in the amount of Polish zlotys necessary for FX Energy Poland to satisfy outstanding intercompany dollar-denominated loans and unpaid interest to FX Energy, Inc., as well as dollar-denominated notes payable held by FX Energy Poland. There was a corresponding debit to other comprehensive income for the gains attributable to the dollar-denominated loans, notes payable, and unpaid interest, which was then offset by translation adjustments of approximately $5.4 million related to our other balance sheet accounts as discussed above. The total amount of outstanding intercompany loans and accrued interest at December 31, 2012, was approximately $106 million and $53 million, respectively.

During 2011, we recorded foreign currency transaction losses of approximately $23.5 million. We recorded a loss of approximately $23.4 million attributable to increases in the amount of Polish zlotys necessary for FX Energy Poland to satisfy outstanding intercompany dollar-denominated loans and unpaid interest to FX Energy, Inc., as well as dollar-denominated notes payable held by FX Energy Poland. There was a corresponding credit to other comprehensive income for the losses attributable to the dollar-denominated loans, notes payable, and unpaid interest, which was then offset by translation adjustments of approximately $8.6 million related to our other balance sheet accounts as discussed above. The total amount of outstanding intercompany loans and accrued interest at December 31, 2011, was approximately $111 million and $43 million, respectively.

The following table provides a summary of changes in CTA (in thousands) for the years ended December 31, 2012 and 2011:

	Year Ended December 31, 2012	**Year Ended December 31, 2011**
Beginning balance	$ 28,964	$ 14,013
Increase (decrease) related to losses (gains) on dollar-denominated loans and notes payable	(16,289)	23,442
Increase (decrease) related to translation adjustments	5,352	(8,491)
Ending balance	$ 18,027	$ 28,964

Future transaction gains or losses may be significant given the amount of dollar-denominated intercompany loans and notes payable and the volatility of exchange rates. Future translation adjustments will also vary in concert with changes in exchange rates. These gains, losses, and adjustments are noncash items for U.S. reporting purposes and have no impact on our actual zloty-based revenues and expenditures in Poland.

We enter into various operating agreements in Poland denominated in the Polish zloty, which is subject to exchange-rate fluctuations. Our policy is to reduce currency risk by, under ordinary circumstances, converting dollars to zlotys on or about the occasion of making any significant commitment payable in Polish currency, taking into consideration the future timing and amounts of committed costs and the estimated timing and amounts of zloty-based revenues. We do not use derivative financial instruments for trading or speculative purposes.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes, including uncertain tax positions, stock-based compensation, future development and abandonment costs, estimates to certain oil and gas revenues and expenses, and estimates of proved oil and natural gas reserve quantities used to calculate depletion, depreciation, and impairment of proved oil and natural gas properties and equipment.

Net Income (Loss) per Share

Basic earnings per share is computed by dividing the net loss applicable to common shares by the weighted average number of common shares outstanding. Diluted earnings per share is computed by dividing the net income (loss) by the sum of the weighted average number of common shares and the effect of dilutive unexercised stock options, warrants, unvested restricted stock, and convertible preferred stock or debt.

Outstanding options, warrants, and unvested restricted stock as of December 31, 2012, 2011, and 2010, were as follows:

	Options, Warrants, and Unvested Restricted Stock	Price Range
Balance sheet date:		
December 31, 2012	1,930,398	$0.00 - $5.06
December 31, 2011	1,356,041	$0.00 - $10.65
December 31, 2010	1,578,730	$0.00 - $10.65

The above options, warrants, and unvested restricted stock were not included in the computation of diluted earnings per share for the years presented because the effect would have been antidilutive.

Note 2: Asset Retirement Obligation

We account for future site restoration costs by recording a liability for the fair value of asset retirement obligations when incurred, which is typically at the time the assets are placed in service. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. We use an expected cash flow approach to estimate our asset retirement obligations. We recorded accretion expense of $63,000, $68,000, and $92,000 in 2012, 2011, and 2010, respectively. At December 31, 2012, there were no assets legally restricted for purposes of settling asset retirement obligations.

Following is a reconciliation of the yearly changes in the asset retirement obligation at December 31, 2012 and 2011:

	December 31,	
	2012	2011
	(In thousands)	
Asset retirement obligations:		
Beginning balance	$1,184	$1,204
Current year additions	--	218
Current year revisions	270	(189)
Liabilities settled	(172)	(9)
Foreign exchange adjustments	86	(108)
Accretion expense	63	68
Ending balance	$1,431	$1,184

When the present value of a future asset retirement obligation changes due to the increase or decrease of the estimated plugging costs of that asset, we adjust the related asset retirement cost. During 2012, the economic lives of our United States oil wells were decreased, as lower oil prices resulted in less economic barrels. This change, along with an increase in the estimated amount of future plugging costs, resulted in an increase in the net present value of the retirement obligations, which in turn resulted in losses associated with those obligations, as the related asset retirement costs had been previously written off. During 2011, the economic lives of our United States oil wells were increased, as higher oil prices resulted in more economic barrels. This change resulted in a decrease in the net present value of the retirement obligations, which in turn resulted in gains associated with those obligations.

Note 3: Other Assets

As of December 31, 2012 and 2011, we had reclamation bonds with federal and state agencies with face amounts of $614,000 and $638,000, respectively, which were collateralized by certificates of deposit totaling $381,500 and $406,500.

Note 4: Accrued Liabilities

Our accrued liabilities as of December 31, 2012 and 2011 were comprised of the following:

	December 31,	
	2012	2011
	(In thousands)	
Accrued liabilities:		
Credit facility commitment fees	$ 51	$ 47
Compensation-related costs	755	462
Interest expense	103	100
Accrued dry hole costs	269	--
Oilfield equipment installment note	14	68
Total	$ 1,192	$ 677

Note 5: Notes Payable

On August 5, 2010, we refinanced and expanded our existing credit facility by executing a new agreement with The Royal Bank of Scotland, ING Bank N.V., and KBC Bank NV. The expanded credit facility calls for a borrowing base of $55 million, a periodic interest rate of LIBOR plus an interest margin of 4.0%, and has a term of five years, with semi-annual borrowing base reductions of $11 million each beginning on June 30, 2013. The expanded credit facility is an interest-only facility until June 2013. Unamortized deferred financing costs of approximately $577,000 associated with our prior credit facility were charged to interest expense during 2010. Payment of the expanded credit facility is secured by our assets in Poland and guaranteed by us. As of December 31, 2012, the total amount drawn under the expanded credit facility was $40 million. The year-end 2012 interest rate was 4.2% per annum.

In consideration for the expanded credit facility, we paid various arrangement, structuring, legal, and other fees totaling approximately $2.5 million. These fees, which were paid by increasing the amount of debt drawn under the expanded credit facility, have been capitalized as deferred financing costs and are being amortized over the five-year term of the loan, beginning in the third quarter of 2010. An annual unused commitment fee of one-half of the applicable interest margin is charged quarterly based on the average daily unused portion of the expanded credit facility. There are no financial covenants associated with the expanded credit facility. Estimated fair values for notes payable have been determined based on borrowing rates currently available to us for bank loans with similar terms and maturities and are classified as Level 2 (significant observable inputs other than quoted prices) in the FASB's fair value hierarchy.

The following table provides a summary of changes in notes payable (in thousands):

	Year Ended December 31, 2012	**Year Ended December 31, 2011**
Beginning balance	$ 40,000	$ 35,000
Payments of notes payable	--	(35,000)
Proceeds from borrowing	--	40,000
Ending balance	$ 40,000	$ 40,000

At December 31, 2012, the aggregate amounts of our contractually obligated principal payment commitments associated with our notes payable for the next five years are as follows:

	Total	**2013**	**2014**	**2015**	**2016**	**2017**
			(In thousands)			
Credit facility principal	$40,000	$ 7,000	$22,000	$11,000	$ --	$ --

The borrowing base is redetermined twice a year, based on reserve volumes and values estimated by independent engineers as of the last day of the prior year. Our last redetermination was completed in December 2012, with no change in the borrowing base amount.

Note 6: Commitments and Contingencies

None.

Note 7: Fair Value Measurements and Marketable Securities

The accounting standard for fair value measurements provides a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. Fair value is defined as the price that would be received for an asset or the exit price that would be paid to transfer a liability in the principal or most advantageous market in an orderly transaction between market participants on the measurement date. The accounting standard established a fair value hierarchy that requires an entity to maximize the use of observable inputs, where available. The following summarizes the three levels of inputs required as well as the assets and liabilities that we value using those levels of inputs.

- *Level 1*: Unadjusted quoted prices in active markets for identical assets and liabilities.

- *Level 2*: Observable inputs other than those included in Level 1. For example, quoted prices for similar assets or liabilities in active markets or quoted prices for identical assets or liabilities in inactive markets.

- *Level 3*: Unobservable inputs reflecting management's own assumptions about the inputs used in pricing the asset or liability.

A review of fair value hierarchy classifications is conducted on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We had no Level 3 assets as of December 31, 2012 or 2011.

Recurring Fair Value

The following tables set forth the financial assets that we measured at fair value on a recurring basis by level within the fair value hierarchy. We classify assets measured at fair value in their entirety based on the lowest level of input that is significant to their fair value measurement.

Assets measured at fair value on a recurring basis consisted of the following as of December 31, 2012 and 2011 (in thousands):

	December 31, 2012	**Level 1(1)**	**Level 2(2)**	**Level 3(3)**
Cash equivalents:				
Money market funds	$1,127	$1,127	--	--

	December 31, 2011	**Level 1(1)**	**Level 2(2)**	**Level 3(3)**
Cash equivalents:				
Money market funds	$2,799	$2,799	--	--

(1) Quoted prices in active markets for identical assets.
(2) Significant other observable inputs.
(3) Significant unobservable inputs.

Note 8: Income Taxes

We recognized no income tax benefit from the losses generated during 2012, 2011, and 2010. The components of the net deferred tax asset as of December 31, 2012 and 2011, are as follows:

	December 31,	
	2012	**2011**
	(In thousands)	
Deferred tax liability:		
Property and equipment basis differences	$ (1,374)	$ (1,383)
Deferred tax asset:		
Net operating loss carryforwards:		
United States	33,118	31,524
Poland	1,015	1,832
Oil and gas properties	5,009	2,765
Accrued interest expense	10,117	8,220
Foreign exchange translation losses	4,865	7,299
Options issued for services	423	(2)
Asset retirement obligation	389	291
Valuation allowance	(53,562)	(50,546)
Total	$ --	$ --

The change in the valuation allowance during 2012, 2011, and 2010 is as follows:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Valuation allowance:			
Balance, beginning of year	$ (50,546)	$ (47,979)	$ (52,809)
Change in property and equipment basis differences	(2,253)	443	2,405
Decrease (increase) due to foreign exchange translation loss	2,434	(3,512)	(1,112)
Change in accrued interest expense	(1,897)	(1,142)	(586)
Decrease (increase) due to net operating loss	(777)	1,205	3,246
Other	(523)	439	877
Total	$ (53,562)	$ (50,546)	$ (47,979)

Accounting standards require that a valuation allowance be provided if it is more likely than not that some portion or all of a deferred tax asset will not be realized. Our ability to realize the benefit of our deferred tax asset will depend on the generation of future taxable income through profitable operations through expansion of our oil and gas producing activities. The risks associated with that growth requirement are considerable, resulting in our conclusion that a full valuation allowance be provided at December 31, 2012, 2011, and 2010. Due to the full valuation allowance, our effective income tax rate for all three years was zero percent. The statutory rate was increased by permanent differences relating to changes associated with stock options and that tax treatment of interest income and reduced by adjustments for net operating losses expiring, exchange rate differences, and changes to deferred taxes related to temporary differences.

United States NOL

At December 31, 2012, we had net operating loss (“NOL”) carryforwards in the United States of approximately $88,787,000 available to offset future taxable income. The carryforwards began to expire in 2013 and will fully expire in 2032. The utilization of the NOL carryforwards against future taxable income in the United States may become subject to an annual limitation if there is a change in ownership. The NOL carryforwards in the United States include $27,507,000 relating to tax deductions resulting from the exercise of stock options. The tax benefit from adjusting the valuation allowance related to this portion of the NOL carryforward will be credited to additional paid-in capital.

Polish NOL

As of December 31, 2012, we had NOL carryforwards in Poland totaling approximately $5,343,000. The NOLs will be fully expired in 2013. The normal carryforward period in Poland is five years. However, in any given year, no more than 50% of the NOL carryforward may be applied against Polish income in succeeding years.

The following table lists the years of expiration for our net operating losses:

	United States	Poland
	(In thousands)	
Year of NOL expiration:		
2013	$ 6,145	$ 5,343
2014	2,938	--
2015	2,717	--
2016	2,243	--
2017 and thereafter	74,744	--

The domestic and foreign components of our net income (loss) are as follows:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Domestic	$ (9,963)	$ (6,602)	$(4,433)
Foreign	14,081	(21,922)	3,675
Total	$ 4,118	$(28,524)	$ (758)

Note 9: Stockholders' Equity

During 2011, we sold 6,900,000 shares of common stock in a registered public offering at a price of $7.00 per share, resulting in net proceeds, after offering costs, of $45,041,000. Option holders exercised options with cash to purchase 96,799 shares of common stock in 2011, which resulted in proceeds of approximately $801,000. Option holders exercised options to purchase an additional 485,000 shares of common stock at a price of $8.37 per share by surrendering currently owned shares to pay the exercise price. As a result of this exercise, we issued 65,571 incremental shares.

During 2010, we sold 1,500,000 shares of common stock in a registered-direct offering at a price of $6.00 per share. After offering costs, our net proceeds from the offering were $8,403,000. Also during 2010, option holders exercised outstanding options to purchase a total of 39,507 shares of common stock at a price of $3.98 per share, resulting in proceeds to us of $157,000. Additionally, option holders exercised outstanding options to purchase a total of 598,602 shares of common stock at prices ranging from $3.14 to $3.98 per share by surrendering currently owned shares to pay the exercise price. As a result of this exercise, we issued 152,892 incremental shares.

We issued 138,748, 106,301, and 216,977 shares in 2012, 2011, and 2010, respectively, as contributions to our employee benefit plan. In addition, we issued 0, 9,500, and 6,000 shares in 2012, 2011, and 2010, respectively, to consultants for services.

We have a stockholder rights plan, adopted in 2007, that may have the effect of discouraging unsolicited takeover proposals. The rights issued under the stockholder rights plan would cause substantial dilution to a person or group that attempts to acquire us on terms not approved in advance by our board of directors. In addition, our articles of incorporation and bylaws contain provisions that may discourage unsolicited takeover proposals that our stockholders may consider to be in their best interests.

Note 10: Stock Options, Warrants, and Restricted Stock

Equity Compensation Plans

Our equity compensation consists of annual stock option and award plans that have been adopted by the board of directors and subsequently approved by the stockholders at an annual meeting.

The following table summarizes information regarding our stock option and award plans as of December 31, 2012:

	Number of Shares Authorized Under Plan	Weighted Average Exercise Price of Outstanding Options	Number of Options Available for Future Issuance
Equity compensation plans approved by stockholders:			
2011 Long Term Incentive Plan	4,447,962	$4.65	2,535,016
Total	4,447,962	$4.65	2,535,016

All stock option and award plans are administered by the Compensation Committee, consisting of the independent members of the board of directors. At its discretion, the Compensation Committee may grant stock, incentive stock options, or non-qualified options to any employee, including officers. The granted options have terms ranging from five to seven years and vest in three equal annual installments. Under terms of the stock option award plans, we may also issue restricted stock.

Stock Options

The following table summarizes option activity for 2012, 2011, and 2010:

	2012		2011		2010	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Options outstanding:						
Beginning of year	668,129	$5.31	832,332	$8.42	1,470,441	$6.47
Granted	642,170	4.25	636,509	5.06	--	--
Exercised	--	--	(581,799)	8.35	(638,109)	3.92
Cancelled	--	--	(3,380)	5.06	--	--
Expired	(35,000)	9.89	(215,533)	8.37	--	--
End of year	1,275,299	$4.65	668,129	$5.31	832,332	$8.42
Exercisable at year-end	211,063	$5.06	35,000	$9.89	832,332	$8.42

The following table summarizes information about stock options outstanding as of December 31, 2012:

	Outstanding			Exercisable	
Exercise Price Range	Number of Options Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Exercise Price
$4.25 - $5.05	642,170	9.88	$4.25	--	$--
$5.06 - $5.06	633,129	8.72	5.06	211,063	5.06
Total	1,275,299	9.30	$4.65	211,063	$5.06

The aggregate intrinsic value of outstanding stock options at December 31, 2012, was $0.

Restricted Stock

The following table summarizes restricted stock activity during 2012, 2011, and 2010:

	2012	2011	2010
	Number of Shares	Number of Shares	Number of Shares
Unvested restricted stock outstanding:			
Beginning of year	687,912	746,398	739,535
Issued	321,086	318,252	373,500
Forfeited	(564)	(7,100)	(2,382)
Vested	(353,335)	(369,638)	(364,255)
End of year	655,099	687,912	746,398

The aggregate intrinsic value of unvested restricted stock at December 31, 2012, was $2,692,457. The aggregate intrinsic value represents the total pretax intrinsic value, based on our stock price of $4.11 as of December 31, 2012, which would have been received by the restricted stock award holders had all in-the-money restricted stock awards been vested as of that date. The weighted average period over which stock compensation expense related to the restricted stock awards will be recognized is 2.08 years.

Stock Compensation Expense

During 2012, we issued 642,170 stock options, resulting in deferred compensation of $1,421,411, which will be amortized ratably over a three-year vesting period. The options were valued at $2.21 per share using a Black-Scholes valuation model, with assumptions of: (i) expected life of four years; (ii) volatility of 70%; (iii) risk-free interest rate of 0.49%; and (iv) expected dividend yield of 0%. Expense recognized during 2012 totaled $61,010.

During 2012, we issued 321,086 shares of restricted stock, resulting in deferred compensation of $1,364,616, which will be amortized ratably over a three-year vesting period. Expense recognized during 2012 totaled $58,573.

During 2011, we issued 636,509 stock options, resulting in deferred compensation of $1,781,036, which will be amortized ratably over a three-year vesting period. The options were valued at $2.80 per share using a Black-Scholes valuation model, with assumptions of: (i) expected life of four years; (ii) volatility of 75%; (iii) risk-free interest rate of 0.69%; and (iv) expected dividend yield of 0%. Expense recognized during 2012 and 2011 totaled $590,526 and $173,250, respectively.

During 2011, we issued 318,252 shares of restricted stock, resulting in deferred compensation of $1,610,355, which will be amortized ratably over a three-year vesting period. Expense recognized during 2012 and 2011 totaled $533,935 and $156,647, respectively.

During 2010, we issued 373,500 shares of restricted stock, resulting in deferred compensation of $2,259,675, which will be amortized ratably over a three-year vesting period. Expense recognized during 2012, 2011, and 2010 totaled $746,948, $748,548, and $26,899, respectively.

During 2009, we issued 379,500 shares of restricted stock, resulting in deferred compensation of $1,043,625, which is being amortized ratably over a three-year vesting period. Expense recognized during 2012, 2011, and 2010 totaled $333,888, $345,418, and $347,253, respectively.

During 2008, we issued 367,000 shares of restricted stock, resulting in deferred compensation of $1,005,580, which is being amortized ratably over a three-year vesting period. Expense recognized for these shares during 2012, 2011, and 2010 totaled $272, $320,404, and $331,330, respectively.

During 2007, we issued 370,925 shares of restricted stock, resulting in deferred compensation of $2,284,991, which is being amortized ratably over a three-year vesting period. Expense recognized for these shares during 2010 totaled $673,629.

Note 11: Business Segments

We operate within two business segments of the oil and gas industry: exploration and production ("E&P") and oilfield services. Revenues associated with our E&P activities are comprised of oil and gas sales from our producing properties in Poland and oil sales from our producing properties in the United States. During the last three years, essentially all sales of oil and gas in Poland were made to PGNiG or its affiliated companies. Over 95% of our oil sales in the United States were to Cenex during 2012, 2011, and 2010. Gas sales in Poland are pursuant to long-term sales contracts that obligate the buyer to purchase all gas produced. Individual oil sales are negotiated with PGNiG-affiliated entities and are not subject to sales contracts. We believe the purchasers of our oil production in the United States could be replaced, if necessary, without a loss in revenue.

E&P operating costs are comprised of: (1) exploration costs (geological and geophysical costs, exploratory dry holes, and proved property and non-producing leasehold impairments); and (2) lease operating costs (lease operating expenses and production taxes). Substantially all exploration costs are related to our operations in Poland. The majority of lease operating costs are related to our domestic production.

Revenues associated with our oilfield services segment are comprised of contract drilling and well-servicing fees generated by our oilfield-servicing equipment in Montana. Oilfield-servicing costs are comprised of direct costs associated with our oilfield services.

DD&A directly associated with a particular business segment is disclosed within that business segment. We do not allocate current assets, corporate DD&A, general and administrative costs, amortization of deferred compensation, interest income, interest expense, other income, or other expense to our operating business segments for management and business segment reporting purposes. All material intercompany transactions between our business segments are eliminated for management and business segment reporting purposes.

Information on our operations by business segment for 2012, 2011, and 2010 is summarized as follows:

	2012 (In thousands)			
	Exploration & Production		Oilfield Services	Total
	U.S.	Poland		
Operations summary:				
Revenues	$ 4,117	$ 30,344	$ 2,137	$ 36,598
Lease operating expense	(2,403)	(1,228)	--	(3,631)
Oilfield services costs	--	--	(1,610)	(1,610)
Exploration expense	(475)	(23,320)	--	(23,795)
Impairment expense	(1,775)	(787)	--	(2,562)
Accretion expense	(39)	(24)	--	(63)
Loss on asset sale	(49)	--	--	(49)
Asset retirement obligation gain	--	--	--	--
DD&A expense	(146)	(2,954)	(1,109)	(4,209)
Operating income (loss)	$ (770)	$ 2,031	$ (582)	$ 679
Identifiable net property and equipment:				
Unproved properties	$ 24	$ 2,313	$ --	$ 2,337
Proved properties	2,330	49,852	--	52,182
Equipment and other	--	10	2,510	2,520
Total	$ 2,354	$ 52,175	$ 2,510	$ 57,039
Net Capital Expenditures:				
Property and equipment	$ 967	$ 23,402	$ 693	$ 25,062
Total	$ 967	$ 23,402	$ 693	$ 25,062

	2011 (In thousands)			
	Exploration & Production		Oilfield Services	Total
	U.S.	Poland		
Operations summary:				
Revenues	$ 4,687	$ 25,120	$ 5,631	$ 35,438
Lease operating expense	(2,846)	(988)	--	(3,834)
Oilfield services costs	--	--	(4,458)	(4,458)
Exploration expense	(74)	(16,544)	--	(16,618)
Impairment expense	--	(72)	--	(72)
Accretion expense	(44)	(24)	--	(68)
Asset retirement obligation gain	52	--	--	52
DD&A expense	(107)	(2,242)	(984)	(3,333)
Operating income (loss)	$ 1,668	$ 5,250	$ 189	$ 7,107
Identifiable net property and equipment:				
Unproved properties	$ 628	$ 2,854	$ --	$ 3,482
Proved properties	2,952	38,490	--	41,442
Equipment and other	--	19	2,926	2,945
Total	$ 3,580	$ 41,363	$ 2,926	$ 47,869
Net Capital Expenditures:				
Property and equipment	$ 2,539	$ 13,613	$ 1,195	$ 17,347
Total	$ 2,539	$ 13,613	$ 1,195	$ 17,347

	2010			
	(In thousands)			
	Exploration & Production		Oilfield Services	Total
	U.S.	Poland		
Operations summary:				
Revenues	$ 4,184	$ 18,730	$ 2,099	$ 25,013
Lease operating expense	(2,449)	(1,024)	--	(3,473)
Oilfield services costs	--	--	(1,550)	(1,550)
Exploration expense	(30)	(3,008)	--	(3,038)
Impairment expense	--	(564)	--	(564)
Accretion expense	(70)	(22)	--	(92)
Asset retirement obligation gain	264	--	--	264
DD&A expense	(81)	(1,723)	(743)	(2,547)
Operating income (loss)	$ 1,818	$ 12,389	$ (194)	$ 14,013
Identifiable net property and equipment:				
Unproved properties	$ 24	$ 3,296	$ --	$ 3,320
Proved properties	1,124	31,116	--	32,240
Equipment and other	--	20	2,746	2,766
Total	$ 1,148	$ 34,432	$ 2,746	$ 38,326
Net Capital Expenditures:				
Property and equipment	$ 513	$ 8,584	$ 1,334	$ 10,431
Total	$ 513	$ 8,584	$ 1,334	$ 10,431

A reconciliation of the segment information to the consolidated totals for 2012, 2011, and 2010 follows:

	2012	2011	2010
		(In thousands)	
Revenues:			
Reportable segments	$ 36,598	$ 35,438	$ 25,013
Non-reportable segments	--	--	--
Total revenues	$ 36,598	$ 35,438	$ 25,013
Net loss:			
Operating income (loss), reportable segments	$ 679	$ 7,107	$ 14,013
Expense or (revenue) adjustments:			
Corporate DD&A expense	(30)	(64)	(79)
General and administrative costs (G&A)	(8,369)	(8,396)	(7,973)
Stock compensation (G&A)	(2,325)	(1,744)	(1,379)
Total net operating income (loss)	(10,045)	(3,097)	4,582
Non-operating income:			
Interest income (net of interest expense) and other income	(2,129)	(1,979)	(1,107)
Foreign exchange gain (loss)	16,292	(23,448)	(4,233)
Net loss	$ 4,118	$ (28,524)	$ (758)
Net property and equipment:			
Reportable segments	$ 57,039	$ 47,869	$ 38,326
Corporate assets	50	27	48
Net property and equipment	$ 57,089	$ 47,896	$ 38,374
Property and equipment capital expenditures:			
Reportable segments	$ 25,062	$ 17,347	$ 10,431
Corporate assets	42	25	3
Total property and equipment capital expenditures	$ 25,104	$ 17,372	$ 10,434

Note 12: Quarterly Financial Data (Unaudited)

Summary quarterly information for 2012 and 2011 is as follows:

	Quarter Ended			
	December 31	September 30	June 30	March 31
	(In thousands, except per share amounts)			
2012:				
Revenues	$ 9,886	$ 9,552	$ 8,578	$ 8,582
Net operating income (loss)	(4,206)	(7,987)	1,425	723
Net income (loss)	(436)	1,989	(12,115)	14,680
Basic and diluted net income (loss) per common share	$ (0.01)	$ 0.04	$ (0.23)	$ 0.28
2011:				
Revenues	$ 8,989	$ 10,120	$ 9,182	$ 7,147
Net operating income (loss)	(1,957)	(860)	(567)	287
Net income (loss)	(10,079)	(27,526)	2,547	6,534
Basic and diluted net income (loss) per common share	$ (0.23)	$ (0.53)	$ 0.05	$ 0.14

FX ENERGY, INC., AND SUBSIDIARIES
Supplemental Information

Disclosure about Oil and Gas Properties and Producing Activities (Unaudited)

Capitalized Oil and Gas Property Costs

Capitalized costs relating to oil and gas exploration and production activities as of December 31, 2012 and 2011, are summarized as follows:

	United States	Poland (In thousands)	Total
December 31, 2012:			
Proved properties	$ 5,981	$ 57,840	$ 63,821
Unproved properties	24	2,312	2,336
Total gross properties	6,005	60,152	66,157
Less accumulated depreciation, depletion and amortization	(3,650)	(7,988)	(11,638)
	$ 2,355	$ 52,164	$ 54,519
December 31, 2011:			
Proved properties	$ 6,456	$ 42,932	$ 49,388
Unproved properties	628	2,854	3,482
Total gross properties	7,084	45,786	52,870
Less accumulated depreciation, depletion and amortization	(3,504)	(4,442)	(7,946)
	$ 3,580	$ 41,344	$ 44,924

Results of Operations

Results of operations are reflected in Note 12, Business Segments. There is no tax provision because we are not likely to pay, and have not received any benefit from, any federal or local income taxes due to our operating losses. Total production costs (in thousands) for 2012, 2011, and 2010 were $3,631, $3,834, and $3,473, respectively.

Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration, and development activities during 2012, 2011, and 2010, whether capitalized or expensed, are summarized as follows:

	United States	Poland (In thousands)	Total
Year ended December 31, 2012:			
Acquisition of unproved properties	$ 134	$ 1	$ 135
Exploration costs	405	31,976	32,381
Development costs	903	2,300	3,203
Total	$ 1,442	$ 34,277	$ 35,719
Year ended December 31, 2011:			
Acquisition of unproved properties	$ 604	$ 65	$ 669
Exploration costs	1,406	26,844	28,250
Development costs	558	3,059	3,617
Total	$ 2,568	$ 29,968	$ 32,536

	United States	Poland (In thousands)	Total
Year ended December 31, 2010:			
Acquisition of unproved properties	$ 3	$ 44	$ 47
Exploration costs	30	6,622	6,652
Development costs	509	4,937	5,446
Total	$ 542	$ 11,603	$ 12,145

Impairment of Oil and Gas Properties

We recorded impairment charges in our E&P segment related to oil and gas properties as follows (in thousands):

	2012	2011	2010
Impairment of properties	$2,562	$72	$564

Exploratory Dry Hole Costs

Total dry hole costs (in thousands) of $12,711 in 2012 were related to the Kutno-2 well drilled in Poland and one Alberta Bakken well drilled in Montana. Dry hole costs of $1,328 in 2011 were principally related to the Machnatka-1 well drilled in Poland. There were no dry holes drilled in 2010.

Summary Oil and Gas Reserve Data (Unaudited)

The following disclosures about our crude oil and natural gas reserves and exploration and production activities are in accordance with GAAP for disclosures about oil and gas producing activities and Securities and Exchange Commission rules for oil and gas reporting disclosures.

Reserves

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

Definitions

The following definitions apply to the terms used in this disclosure:

Reserves Estimate—The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Proved Oil and Gas Reserves—Proved oil and gas reserves are those quantities of oil and gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the expiration of the contracts providing the right to operate, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Developed Oil and Gas Reserves—Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped Oil and Gas Reserves—Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion or production facilities.

For complete definitions of proved natural gas, natural gas liquids, and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22), and (31).

Reserves Estimates Preparation

Estimates of our proved Polish reserves were prepared by RPS Energy, an independent engineering firm in the United Kingdom. Estimates of our proved domestic reserves were prepared by Hohn Engineering, an independent engineering firm in Billings, Montana. The technical personnel responsible for calculating the reserve estimates at both RPS Energy and Hohn Engineering meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Both RPS Energy and Hohn Engineering are independent firms of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent-fee basis.

Proved Developed Reserves:

The following unaudited summary of proved developed reserve quantity information represents estimates only and should not be construed as exact:

	Crude Oil (In thousand barrels of oil)		Natural Gas (In million cubic feet)	
	United States	**Poland**	**United States**	**Poland**
December 31, 2012	594	--	--	23,759
December 31, 2011	639	--	--	31,987
December 31, 2010	639	--	--	31,683

Total Proved Reserves:

The following unaudited summary of proved reserve quantity information represents estimates only and should not be construed as exact:

	Crude Oil (In thousand barrels of oil)		Natural Gas (In million cubic feet)	
	United States	**Poland**	**United States**	**Poland**
December 31, 2012:				
Beginning of year	639	--	--	49,636
Extensions or discoveries(1)	--	--	--	2,313
Revisions of previous estimates(2)	9	--	--	(3,371)
Production	(54)	--	--	(4,457)
End of year	594	--	--	44,121
December 31, 2011:				
Beginning of year	639	--	--	39,959
Extensions or discoveries(3)	--	--	--	12,245
Revisions of previous estimates(4)	56	--	--	1,492
Production	(56)	--	--	(4,060)
End of year	639	--	--	49,636
December 31, 2010:				
Beginning of year	463	--	--	47,668
Revisions of previous estimates(5)	237	--	--	(4,236)
Production	(61)	--	--	(3,473)
End of year	639	--	--	39,959

(1) Volume increase in Poland attributable to new Komorze-3K well drilled during 2012.

(2) Upward oil revisions in the United States attributable to lower average operating costs during 2012 compared to 2011 operating costs. Downward gas revisions in Poland due to the reduction of proved reserves calculated at the Zaniemysl and KSK wells based on new pressure data.

(3) Volume increase in Poland attributable to new Lisewo-1 well drilled during 2011.

(4) Upward oil revisions in the United States attributable to higher average oil prices during 2011 compared to average 2010 oil prices. Upward gas revisions in Poland due to the increase of proved reserves calculated at the Roszkow well based on new pressure data.

(5) Upward oil revisions in the United States attributable to higher average oil prices during 2010 compared to average 2009 oil prices. Downward gas revisions in Poland due to the reduction of proved reserves calculated at the Roszkow well based on new pressure data and cessation of production at the Kleka well.

Standardized Measure of Discounted Future Net Cash Flows ("SMOG") and Changes Therein Relating to Proved Oil Reserves

Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. We believe such information is essential for a proper understanding and assessment of the data presented. The assumptions used to compute the proved reserve valuation do not necessarily reflect our expectations of actual revenues to be derived from those reserves or their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of such reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to errors inherent in predicting the future, variations from the expected production rates also could result directly or indirectly from factors outside our control, such as unintentional delays in development, environmental concerns, and changes in prices or regulatory controls. The reserve valuation assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations also could affect the amount of cash eventually realized. Future development and production costs are computed by estimating expenditures to be incurred in developing and producing the proved oil reserves at the end of the period, based on period-end costs and assuming continuation of existing economic conditions. A discount rate of 10% per year was used to reflect the timing of the future net cash flows. The future net cash flows for our Polish reserves are based on gas sales contracts we have with PGNiG. The average prices used to calculate year-end reserve values were $6.60 and $6.44 per Mcf and $78.14 and $84.61 per barrel for 2012 and 2011, respectively.

The components of SMOG are detailed below:

	United States	Poland	Total
		(In thousands)	
December 31, 2012:			
Future cash flows	$ 46,449	$ 291,160	$ 337,609
Future production costs	(28,171)	(21,020)	(49,191)
Future development costs	--	(25,620)	(25,620)
Future income tax expense	--	(30,570)	(30,570)
Future net cash flows	18,278	213,950	232,228
10% annual discount for estimated timing of cash flows	(7,848)	(66,777)	(74,625)
Discounted net future cash flows	$ 10,430	$ 147,173	$ 157,603
December 31, 2011:			
Future cash flows	$ 54,036	$ 319,840	$ 373,876
Future production costs	(32,396)	(22,020)	(54,416)
Future development costs	--	(17,240)	(17,240)
Future income tax expense	--	(40,868)	(40,868)
Future net cash flows	21,640	239,712	261,352
10% annual discount for estimated timing of cash flows	(9,377)	(82,408)	(91,785)
Discounted net future cash flows	$ 12,263	$ 157,304	$ 169,567
December 31, 2010:			
Future cash flows	$ 43,553	$ 226,310	$ 269,863
Future production costs	(26,762)	(15,130)	(41,892)
Future development costs	--	(12,580)	(12,580)
Future income tax expense	--	(28,134)	(28,134)
Future net cash flows	16,791	170,466	187,257
10% annual discount for estimated timing of cash flows	(7,122)	(52,798)	(59,920)
Discounted net future cash flows	$ 9,669	$ 117,668	$ 127,337

The principal sources of changes in SMOG are detailed below:

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
SMOG sources:			
Balance, beginning of year	$ 169,567	$ 127,337	$ 145,823
Sale of oil and gas produced, net of production costs	(30,830)	(25,973)	(19,442)
Net changes in prices and production costs	4,385	20,809	200
Acquisition of minerals in place	--	--	--
Extensions and discoveries, net of future costs	4,570	38,210	--
Changes in estimated future development costs	(7,358)	(4,951)	728
Previously estimated development costs incurred during the year	2,277	3,059	4,670
Revisions in previous quantity estimates	(13,508)	6,060	(13,839)
Accretion of discount	16,957	12,734	14,582
Net change in income taxes	5,769	(7,384)	3,944
Changes in rates of production and other	5,774	(334)	(9,329)
Balance, end of year	$ 157,603	$ 169,567	$ 127,337

NOTICE OF 2013 ANNUAL MEETING OF STOCKHOLDERS

PROXY STATEMENT

FX ENERGY, INC.
3006 Highland Drive, #206
Salt Lake City, Utah 84106 USA
Telephone: (801) 486-5555
Facsimile: (801) 486-5575

May 10, 2013

Dear FX Energy Stockholder:

Our Proxy Statement for the 2013 Annual Stockholders' Meeting of FX Energy, Inc., and our 2012 Annual Report are enclosed. At this meeting, we will seek your support for the election of directors and the ratification of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2013.

These are important considerations for all stockholders. Therefore, the Board of Directors urges you to review each of these proposals carefully. The enclosed proxy statement discusses the intended benefits as well as possible disadvantages of these proposals.

Your Board of Directors believes that the adoption of each of the proposals is in the best interests of all stockholders.

Sincerely,

FX ENERGY, INC.

David N. Pierce
President

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FX ENERGY, INC.
3006 Highland Drive, Suite 206
Salt Lake City, Utah 84106

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD JUNE 13, 2013

To the Stockholders of FX Energy, Inc.:

The 2013 Annual Stockholders' Meeting of FX Energy, Inc. (the "Annual Meeting"), will be held June 13, 2013, in the Uintah Room, Little America Hotel, 500 South Main Street, Salt Lake City, Utah. The Annual Meeting will convene at 10:00 a.m., local time, to consider and take action on the following proposals:

(1) to elect two directors to serve until the expiration of their respective terms and until their respective successors are elected and qualified; and

(2) to ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2013; and

(3) to transact such other business as may properly come before the Annual Meeting or any adjournment(s) thereof.

Only owners of record of our common stock outstanding as of the close of business April 15, 2013 (the "Record Date"), will be entitled to notice of and to vote at the Annual Meeting. Each share of common stock is entitled to one vote.

Holders of at least a majority of the shares of common stock outstanding on the Record Date must be represented at the meeting to constitute a quorum for conducting business.

The attendance at and/or vote of each stockholder at the Annual Meeting is important, and each stockholder is encouraged to attend.

FX ENERGY, INC.
By Order of the Board of Directors

Scott J. Duncan, Secretary

Salt Lake City, Utah
May 10, 2013

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIAL FOR THE ANNUAL MEETING TO BE HELD ON JUNE 13, 2013

Regardless of whether you plan to attend the meeting in person, please fill in, sign, date, and return the enclosed proxy promptly in the self-addressed, stamped envelope provided. No postage is required if mailed in the United States. If you prefer, you may send your proxy to us by facsimile transmission at 1-801-486-5575 or on the Internet as described below.

Our Notice, Proxy Statement, and Annual Report to Stockholders are available at http://www.fxenergy.com. In addition and in accordance with SEC rules, you may also access the Notice and Proxy Statement and vote via the Internet at http://www.proxyvote.com.

SPECIAL REQUEST

If your shares are held in the name of a brokerage firm, nominee, or other institution, only it can vote your shares. Please *contact promptly* the person responsible for your account and *give instructions* for your shares to be voted.

FX ENERGY, INC.
3006 Highland Drive, Suite 206
Salt Lake City, Utah 84106

PROXY STATEMENT

INTRODUCTION

This proxy statement is furnished in connection with the solicitation of proxies on behalf of FX Energy, Inc., to be voted at the Annual Meeting to be held in the Uintah Room, Little America Hotel, 500 South Main Street, Salt Lake City, Utah, on June 13, 2013, at 10:00 a.m., local time, or at any adjournment thereof. The enclosed proxy, when properly executed and timely returned, will be voted at the Annual Meeting in accordance with the directions set forth thereon. If no instructions are indicated on the enclosed proxy, the proxy will be voted as follows at the Annual Meeting:

(1) FOR the election of our two nominees set forth herein as our directors to serve as directors until the expiration of their respective terms and until their successors are elected and qualified;

(2) TO ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2013; and

(3) IN accordance with the best judgment of the persons acting as proxies on other matters presented for a vote.

The enclosed proxy, even though executed and returned to us, may be revoked at any time before it is voted, either by giving a written notice, mailed or delivered to the Secretary of the Company or sent by facsimile transmission to 1-801-486-5575, by submitting a new proxy bearing a later date, or by voting in person at the Annual Meeting. If the proxy is returned to us without specific direction, the proxy will be voted in accordance with our recommendations as set forth above.

We will bear the entire expense of this proxy solicitation. In addition to this solicitation, our officers, directors, and regular employees, who will not receive extra compensation for such services, may solicit proxies by mail, by telephone, or in person. This proxy statement and form of proxy were first mailed to stockholders on or about May 10, 2013.

Only holders of our 53,415,522 shares of common stock, par value $0.001, outstanding as of the close of business on April 15, 2013 (the "Record Date"), will be entitled to vote at the Annual Meeting. Each share of common stock is entitled to one vote. Holders of at least a majority of the shares of common stock outstanding on the Record Date must be represented at the Annual Meeting to constitute a quorum for conducting business.

Stockholders whose shares are held by a broker, bank, or other nominee (that is, in street name), may either: (a) obtain a proxy form from the institution that holds such stockholder's shares and follow the instructions included on that form regarding how to instruct the broker or other nominee to vote such shares; or (b) obtain an authorization from the stockholder's broker or other nominee allowing the stockholder to vote his shares at the Annual Meeting in person or by proxy. If a stockholder does not give instructions to his broker or other nominee or obtain the authority to vote the shares, such broker or nominee can vote the stockholder's shares on "discretionary" items, but not on "non-discretionary" items. Discretionary items are proposals considered routine under the rules of the NASDAQ Stock Market, Inc., specifying the types of matters on which brokers may vote shares held in street name in the absence of voting instructions from the beneficial owner of such shares. When a broker does not have discretion to vote on a particular non-discretionary matter and the stockholder has not given timely instruction on how the broker should vote, the broker will indicate it does not have authority to vote such shares on its proxy, which is sometimes is called a "broker non-vote." All properly returned proxies, including broker non-votes, will be counted to determine if a quorum is present.

The election of directors is considered nonroutine. Accordingly, brokers do not have discretion to vote on these proposals without the stockholder's instruction. Abstentions and broker non-votes will not be included in the totals for these proposals and will have no effect on the outcome of the vote. The ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2013 is considered routine and therefore may be voted upon by brokers without stockholder instructions.

Officers and directors holding an aggregate of 2,896,791 shares of common stock, or approximately 5.4% of the outstanding shares, have indicated their intent to vote in favor of all proposals.

Our policy is that each member of the Board of Directors, or Board, is encouraged, but not required, to attend the Annual Meeting. No directors attended our annual meeting in 2012.

CORPORATE GOVERNANCE

Executive Officers, Directors

The following sets forth the name, age, term of directorship, and principal business experience of each or our executive officers and directors:

Name	Age	Year Director Since	Year Term Expires	Business Experience During Past Five Years and Other Information
Directors				
David N. Pierce	67	1992	2014	President, Chief Executive Officer, and a director since 1992, Chairman from 1992 through 2003. Co-founder with his brother, Andrew W. Pierce, of our predecessor, Frontier Exploration Company. Executive capacities with privately held oil and gas companies since 1979 and an attorney with more than 30 years of experience in natural resources, securities, and international business law. Mr. Pierce is a member of our Executive Well Approval Committee of our Board. The Board believes Mr. Pierce should serve as a director because of his leadership and strategic vision for the Company.
Thomas B. Lovejoy	77	1995	2013	Chairman of the Board of Directors since October 2003, Executive Vice-President effective February 2007, Chief Financial Officer from 1999 to 2007, Vice-Chairman from 1995 through 2003, and a consultant to us from 1995 to 1999. Between 1992 and 1999, principal of Lovejoy & Associates, Inc., Greenwich, CT, which provided financial strategic advice respecting private placements, mergers, and acquisitions. From 1989 through 1992, Managing Director and Head of Natural Resources, Utility and Mining Groups of Prudential Securities, Inc., New York City. From 1975 through 1988, Senior Vice President, Managing Director and Head of the Energy and Natural Resources Group of Blyth Eastman Dillon/PaineWebber, Inc. From 1993 to 2001, Director of Scaltech, Inc., Houston Texas, a processor of petroleum refinery oil waste. Graduate of Massachusetts Institute Of Technology and Harvard Business School. Mr. Lovejoy was selected as a director because of his experience and access to the energy capital markets and investment community.

Name	Age	Year: Director Since	Year: Term Expires	Business Experience During Past Five Years and Other Information
Jerzy B. Maciolek	63	1995	2015	Vice-President of International Exploration and a director since 1995. Employed by us since September 1995. Instrumental in our exploration efforts in Poland. Geophysicist with more than 30 years of experience in Poland, Kazakhstan, and western United States. Graduate of the Mining and Metallurgy Academy in Krakow, Poland. The Board chose Mr. Maciolek to be a director because of his familiarity with oil and gas exploration in Poland and his familiarity with its governmental, regulatory, and cultural environment. He also identifies FX exploration plays in Poland and is leading our technical team in implementing these plays.
Arnold S. Grundvig, Jr.	64	2003	2013	One of our directors since 2003. President and Chief Financial Officer of A-Systems Corporation, a developer of accounting software, since 1993. Previously held various executive-level positions in financial management. Mr. Grundvig is a member of our Audit Committee and Nomination and Governance Committee and was appointed as Chairman of our Compensation Committee in early 2009. The Board believes Mr. Grundvig's general business and financial experience and expertise contributes to the Board's oversight.
Richard Hardman CBE	77	2003	2015	Exploration Advisor since February 2003 and director since October 27, 2003. Over a career spanning more than 40 years, worked in oil and gas exploration as a geologist in Libya, Kuwait, Colombia, Norway, and the North Sea. Former Chairman of the Petroleum Society of Great Britain, former President of the Geological Society of London, European member of the Advisory Council of the American Association of Petroleum Geologists, and former Chairman and current committee member of APPEX, a farmout fair organization based in London. Commander of the British Empire in New Year Honours List of 1998 for services to the oil industry. Mr. Hardman is a member of our Nomination and Governance Committee, Compensation Committee, and Executive Well Approval Committee of our Board and is Technical Advisor to the Board. The Board chose Mr. Hardman to become a director because of his extensive oil and gas exploration expertise, particularly in exploration areas that may be analogous to Poland.
Dennis B. Goldstein	67	2003	2014	Mr. Goldstein has been a director since October 2003, and was appointed Lead Director November 2003. Attorney engaged in natural resource matters for over 35 years. Mr. Goldstein is Chairman of our Nomination and Governance Committee and is a member of our Audit Committee and Compensation Committee. He previously served as a member of the Board of Directors from 1999 to 2002, and was a member of our Audit Committee prior to his resignation. The Board chose Mr. Goldstein to become a director because of his international natural resources experience in legal affairs.

Name	Age	Year: Director Since	Year: Term Expires	Business Experience During Past Five Years and Other Information
H. Allen Turner	60	2007	2015	Mr. Turner was appointed to the Board of Directors in February 2007. Mr. Turner has 25 years of experience in finance, including 20 years as a senior executive at Devon Energy Corporation. Since 2001, Mr. Turner has served as an advisory director of Cortland Associates, a registered investment advisor, and as a private investor. Mr. Turner is Chairman of our Audit Committee and a member of our Nomination and Governance Committee and Compensation Committee. The Board chose Mr. Turner to become a director because of his extensive executive experience in capital markets, strategic planning, and investor relations.
Executive Officers				
Andrew W. Pierce	65	--	--	Vice-President of Operations since 1992, director from 1992 through his resignation in 2003. Co-founder with his brother, David N. Pierce, of our predecessor, Frontier Exploration Company. More than 30 years of experience in oil and gas exploration, drilling, production and leasing, with primary management and line responsibility for drilling and completion activities.
Clay Newton	56	--	--	Vice-President of Finance, Treasurer, and Chief Accounting Officer since 2003 and a director from 2002-2003. Executive accounting and financial management for energy and technology firms for over 25 years.
Scott J. Duncan	64	--	--	Vice-President Investor Relations and Secretary, director from 1993 through 2004 and financial consultant to us from our inception through April 1993.

Board Leadership Structure

Mr. Lovejoy, our Chairman and Executive Vice President, works closely with Mr. Goldstein, our Lead Director, in planning Board and committee meetings, setting agendas, and monitoring other Board and committee activities.

Director Independence

The Board of Directors has determined that Dennis B. Goldstein, Arnold S. Grundvig, Jr., Richard Hardman, and H. Allen Turner are "independent directors" as that term is defined in Rule 5605(a)(2) of NASDAQ.

Board of Directors' Meetings and Committees

Board of Directors

The Board of Directors held four meetings during 2012 and one meeting to date in 2013. The directors also discussed our business and affairs informally on numerous occasions throughout the year and took several actions through unanimous written consents in lieu of meetings. Each of our directors attended more than 75% of the meetings of the Board and of the committees on which he served during the fiscal year.

Audit Committee

Our Audit Committee Charter is available, as amended, on our website, http://www.fxenergy.com. Our Audit Committee is currently composed of three independent directors: H. Allen Turner, its Chairman, and Arnold S. Grundvig, Jr., each of whom the Board of Directors has determined to be an audit committee financial expert, and Dennis B. Goldstein. The Board of Directors has determined all Audit Committee members to be independent as required by Rule 10A-3(b)(1) promulgated under the Securities Exchange Act of 1934.

The Audit Committee selects our independent accountants, approves the scope of audit and related fees, and reviews financial reports, audit results, debt and equity fundraising matters, internal accounting procedures, related-party transactions, when appropriate, and programs to comply with applicable requirements relating to financial accountability. The Audit Committee met 10 times during 2012 and has met two times to date in 2013, including meetings in early 2013 to review the results of the audit of our 2012 financial statements by our independent accountants and other related matters, as reported below.

Compensation Committee

Our Compensation Committee Charter is available on our website, http://www.fxenergy.com. The Compensation Committee is responsible for reviewing performance of senior management, recommending compensation, and developing compensation strategies and alternatives throughout the Company. The Compensation Committee met five times during 2012 and has met once to date during 2013, in addition to several informal telephone meetings throughout 2012. Our Compensation Committee is composed of four independent directors: Arnold S. Grundvig, Jr., its Chairman, Richard Hardman, Dennis B. Goldstein, and H. Allen Turner.

Nomination and Governance Committee

Our Nomination and Governance Committee Charter is available on our website, http://www.fxenergy.com. The Nomination and Governance Committee is responsible for recommendations to the Board of Directors respecting corporate governance principles; prospective nominees for director; Board member performance and composition; function, composition, and performance of Board committees; succession planning; director and officer liability insurance coverage; and directors' responsibilities. The Nomination and Governance Committee's responsibilities also include the development of policies and procedures for compliance by us and our officers and directors with applicable laws and regulations. The Nomination and Governance Committee met five times during 2012 and has met once to date during 2013. Our Nomination and Governance Committee is composed of four independent directors: Dennis B. Goldstein, its Chairman, Richard Hardman, H. Allen Turner, and Arnold S. Grundvig, Jr.

When considering candidates for directors, the Nomination and Governance Committee takes into account a number of factors, including the individual's reputation for judgment, skill, integrity, and other relevant qualities; relevant business experience; level of professional accomplishments; independence from management under both NASDAQ and Securities and Exchange Commission definitions; existing commitments to other businesses; potential conflicts of interest with other pursuits; corporate governance background and experience; financial and accounting background for Audit Committee candidates; and the size, composition, and experience of the existing Board of Directors. The charter provides that diversity is a factor the committee should consider in nominating directors.

The Nomination and Governance Committee will also consider candidates for directors suggested by stockholders using the above factors. Stockholders wishing to suggest a candidate for director should write to Scott J. Duncan, Secretary of the Company, and include a statement that the writer is a stockholder of record and is proposing a candidate for consideration by the Nomination and Governance Committee; the name of and contact information for the candidate; a statement that the candidate is willing to be considered and would serve as a director if elected; a statement of the candidate's business and educational experience, preferably in the form of a resume or curriculum vitae; information regarding each of the factors identified above, other than facts regarding the existing Board of Directors, that would enable the Nomination and Governance Committee to evaluate the candidate; a statement detailing any relationship between the candidate and any customer, supplier, or competitor of the Company; and detailed information about any relationship or understanding between the stockholder and the proposed candidate.

Before nominating a sitting director for reelection at an annual meeting, the Nomination and Governance Committee considers the director's performance on the Board of Directors and attendance at Board of Directors' meetings, and whether the director's reelection would be consistent with our governance guidelines and ability to meet all applicable corporate governance requirements.

When seeking candidates for director, the Nomination and Governance Committee may solicit suggestions from incumbent directors, active stockholders, management, or others. After conducting an initial evaluation of the candidates, the Nomination and Governance Committee will interview candidates that the Nomination and Governance Committee believes might be suitable for a position on the Board of Directors. The Nomination and Governance Committee may also ask the candidate to meet with management. If the Nomination and Governance Committee believes the candidate would be a valuable addition to the Board of Directors, it will recommend to the full Board of Directors that candidate's nomination.

Executive Well Approval Committee

In early 2013, we created an Executive Well Approval Committee to act on the Board's behalf in approving each exploratory well before our commitment to a third party to undertake such activity if a drilling decision is required between Board meetings or without the Board's unanimous written consent. The members of this committee are David N. Pierce, chief executive officer, and Richard Hardman, Technical Advisor to the Board.

Rights Redemption Committee

In connection with the adoption of a stockholder Rights Agreement, the Board of Directors formed a Rights Redemption Committee during 2007 to perform certain functions in accordance with such agreement. The Rights Redemption Committee must consist of at least three continuing directors, a majority of whom may not be our employees, and may consist of the entire Board of Directors. All current directors are members of the Rights Redemption Committee. The Rights Redemption Committee did not meet during 2012.

Policy on Stockholder Communications with Directors

Our stockholders that want to communicate with the Board of Directors, any of its committees, or with any individual director can write to us at 3006 Highland Drive, Suite 206, Salt Lake City, Utah 84106. Such letter should indicate that it is from a Company stockholder. Depending upon the subject matter, management will:

- forward the communication to the director, directors, or committee to whom it is addressed;
- attempt to handle the inquiry directly if it is a request for information about us or other matter appropriately dealt with by management; or
- not forward the communication if it is primarily commercial in nature or if it relates to an improper or irrelevant topic.

At each Board of Directors' meeting, a member of management will present a summary of all communications received since the last meeting that were not forwarded to the directors and make those communications available to the directors on request.

Code of Ethics

We have adopted a Code of Ethics that applies to all of our employees, including our principal executive officer, principal financial officer, and principal accounting officer. The Code of Ethics is available on our website, http://www.fxenergy.com.

Corporate Governance Guidelines

We have adopted Corporate Governance Guidelines to assist our directors in promoting the best interests of the stockholders in terms of corporate governance, fiduciary responsibilities, compliance with applicable law and regulations, and maintenance of accounting, financial, or other controls. The Corporate Governance Guidelines are available on our website, http://www.fxenergy.com.

Stockholder Proposals

No proposals have been submitted by our stockholders for consideration at the Annual Meeting. It is anticipated that the next annual meeting of stockholders will be held during June 2014. Stockholders may present proposals for inclusion in the proxy statement to be mailed in connection with the 2014 annual meeting of stockholders, *provided* the proposals are received by us no later than January 10, 2014, and are otherwise in compliance with applicable laws and regulations and the governing provisions of our Articles of Incorporation and Bylaws.

PROPOSAL 1. ELECTION OF DIRECTORS

Our Articles of Incorporation provide that the Board of Directors shall be divided into three classes, with each class as equal in number as practicable. One class is to be elected each year for a three-year term. At the Annual Meeting, two directors will be elected to serve three-year terms.

The Board of Directors has nominated Thomas B. Lovejoy and Arnold S. Grundvig, Jr., for election as our directors at the Annual Meeting, each to serve for a term of three years expiring at the 2016 annual meeting and until his successor is elected and qualified. Our Nomination and Governance Committee and the Board of Directors unanimously approved the nominations.

Votes will be cast, pursuant to authority granted by the enclosed proxy when properly executed and returned to us, for the election of the named nominees as our directors, except as otherwise specified in the proxy. In the event a nominee shall be unable to serve, votes will be cast, pursuant to authority granted by the enclosed proxy, for such person as may be designated by the Board of Directors. Our officers are elected at the annual meeting of the Board of Directors to hold office until their respective successors are elected and qualified. The information concerning the nominees and directors and their security holdings has been furnished by them to us. Biographical information and business experience of each person nominated and for each director whose term of office will continue after the Annual Meeting are discussed above. (See "Corporate Governance: Executive Officers, Directors.")

Recommendation of the Board of Directors

The Board of Directors recommends a vote "FOR" the election of nominees Thomas B. Lovejoy and Arnold S. Grundvig, Jr., as directors to serve in such capacities until the expiration of their terms at the 2016 annual meeting of stockholders and until their successors are elected and qualified.

Vote Required

Directors are elected by the affirmative vote of the holders of a plurality of the shares of common stock voted at the Annual Meeting. Abstentions and broker nonvotes will not be counted in the election of directors.

PROPOSAL 2. RATIFICATION OF THE APPOINTMENT BY THE AUDIT COMMITTEE OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The firm of PricewaterhouseCoopers LLP has served as our independent registered public accounting firm since 1995. The Audit Committee has appointed PricewaterhouseCoopers LLP to act in that capacity for the year ending December 31, 2013.

Although we are not required to submit this appointment to a vote of our stockholders, the Audit Committee believes it is appropriate as a matter of policy and a desirable corporate governance practice to request that the stockholders ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm. If the stockholders do not ratify this appointment, the Audit Committee will investigate the reasons for that nonratification and determine whether to retain PricewaterhouseCoopers LLP or appoint another independent registered public accounting firm. Even if the appointment is ratified, the Audit Committee may determine to engage a different independent registered public accounting firm at any time if it determines that such a change would be in the best interests of our stockholders.

It is anticipated that representatives of PricewaterhouseCoopers LLP will be present at the Annual Meeting and will be provided the opportunity to make a statement, if they desire to do so, and respond to appropriate questions.

Recommendation of the Board of Directors

The Board of Directors recommends voting "FOR" the ratification of the appointment by the Audit Committee of PricewaterhouseCoopers LLP as our independent registered public accounting firm.

Vote Required

The ratification of PricewaterhouseCoopers LLP as our independent registered public accounting firm requires the affirmative vote of more shares than vote against such ratification. Abstentions and broker nonvotes will not be counted on this matter.

PRINCIPAL STOCKHOLDERS

The following table sets forth, as of March 31, 2013, the name and shareholdings of each person that owns of record, or was known by us to own beneficially, 5% or more of the common stock currently outstanding; the name and shareholdings of each director; and the shareholdings of all executive officers and directors as a group. In computing the number and percentage of shares beneficially owned by each person, we include any shares of common stock that could be acquired within 60 days of March 31, 2013, by the exercise of options or the vesting of stock awards. Unless indicated otherwise in the footnotes, each person named below has, to the best of our knowledge, sole voting and investment power respecting all shares of common stock shown as beneficially owned by each person:

Name	Amount and Nature of Beneficial Ownership	Percent of Class(1)
Principal Stockholders:		
BlackRock, Inc.(2)	3,387,818	6.4%
The Vanguard Group, Inc.(3)	2,866,230	5.4
Directors:		
David N. Pierce(4)	497,402	*
Thomas B. Lovejoy(5)	869,976	1.6
Jerzy B. Maciolek(6)	342,720	*
Arnold S. Grundvig, Jr. (7)	34,079	*
Dennis B. Goldstein(8)	130,865	*
Richard F. Hardman(9)	204,478	*
H. Allen Turner(7)	41,879	*
All executive officers and directors as a group (10 persons)(10)	3,038,148	5.7%

* Less than 1%.

(1) Calculations of total percentages of ownership outstanding for each person or group assume the exercise of derivative securities that are exercisable within 60 days of the March 31, 2013 by the individual or group to which the percentage relates, pursuant to Rule 13d-3(d)(1)(i).

(2) According to a Schedule 13G/A dated February 4, 2013, by BlackRock, Inc., 40 East 52nd Street, New York, NY 10022.

(3) According to a Schedule 13G dated February 7, 2013, by The Vanguard Group, Inc., 100 Vanguard Blvd., Malvern, PA 19355.

(4) The calculation of beneficial ownership includes 103,360 shares held in Mr. Pierce's retirement accounts and 23,700 stock options that were vested as of the table date.

(5) The calculation of beneficial ownership includes 357,675 shares held in trust for the benefit of Thomas B. Lovejoy's children, grandchildren, and a cousin, 142,546 shares held in Mr. Lovejoy's retirement accounts, 10,000 shares held by Mr. Lovejoy's spouse's IRA account, 200,000 shares held by Lovejoy Associates, Inc. (of which Mr. Lovejoy is sole owner), and 13,543 stock options that were vested as of the table date.

(6) The calculation of beneficial ownership includes 88,046 shares held in Mr. Maciolek's retirement account and 21,161 stock options that were vested as of the table date.

(7) The calculation of beneficial ownership includes 3,386 stock options that were vested as of the table date.

(8) The calculation of beneficial ownership includes 6,772 stock options that were vested as of the table date.

(9) The calculation of beneficial ownership includes 22,854 stock options that were vested as of the table date.

(10) The calculation of beneficial ownership includes 141,357 stock options that were vested as of the table date.

Equity Compensation Plans

Plan Category	Number of Securities To Be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,930,398	$3.07	2,535,016

Since inception, we have issued options pursuant to stock option and award plans that have been adopted by the Board of Directors and approved by the stockholders. As of December 31, 2012, we had 1,275,299 outstanding stock options with a weighted-average exercise price of $4.65 per share and unvested restricted stock awards of 655,099 shares under plans that have been approved by the stockholders. We will not grant any compensatory options to officers, directors, or employees outside of stockholder-approved plans.

In addition to the specific provisions noted below, all outstanding options and restricted stock awards provide for antidilution adjustments to the number of shares issuable and the exercise or conversion price in the event of any stock split, stock dividend, or recapitalization of our common stock; restrict transfer; require us to reserve for issuance that number of shares issuable on exercise or conversion; require notice to the holder before certain extraordinary corporate events; require payment of the exercise price of options and warrants in cash or in such other type of consideration as specifically noted; are fully vested and exercisable unless otherwise indicated; and contain other similar miscellaneous items.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires our directors, executive officers, and persons that own more than 10% of a registered class of our equity securities to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of our equity securities. Officers, directors, and greater than 10% stockholders are required to furnish us with copies of all Section 16(a) forms they file.

Based solely upon a review of Forms 3, 4, and 5 and amendments thereto filed with the Securities and Exchange Commission during or respecting the last fiscal year ended December 31, 2012, no person that, at any time during the most recent fiscal year, was a director, officer, beneficial owner of more than 10% of any class of our equity securities, or any other person known to be subject to Section 16 of the Exchange Act failed to file, on a timely basis, reports required by Section 16(a) of the Securities Exchange Act.

CERTAIN RELATIONSHIPS AND RELATED-PARTY TRANSACTIONS

The Board of Directors has adopted a written Related-Party Transactions Policy for the review, approval, or ratification of related-party transactions and has given the Audit Committee the responsibility for overseeing the policy. Related-party transactions consist of all current or proposed transactions, regardless of dollar value, in which we are a participant and any director, executive officer, or immediate family member of any director or executive officer has a direct or indirect material interest. The policy requires all related-party transactions to be approved by the Audit Committee, which takes into account, among other things, whether the transaction is on terms that are no less favorable to us than terms generally available to an unaffiliated third party under similar circumstances and the materiality of the related person's interest in the transaction. We are not aware of any related-party transactions that would require disclosure under existing regulations.

REPORT OF THE COMPENSATION COMMITTEE

Our Compensation Committee is composed of directors who are not our employees and are independent, as that term is defined in Nasdaq Global Market listing standards. Our Compensation Committee is responsible for developing and implementing compensation programs relating to compensation of our key employees, including the Chief Executive Officer and the other executive officers. Our Compensation Committee has adopted a charter that describes its responsibilities in detail, and the Compensation Committee and Board review the charter on a regular basis. Additional information about the Compensation Committee's role in our corporate governance (including the Committee's charter) can be found on our web site at www.fxenergy.com under the 'Our Company' section.

The Compensation Committee is responsible for establishing and administering our executive compensation programs. Our Compensation Committee has reviewed and discussed the compensation discussion and analysis required by Item 402(b) of Regulation S-K with management, and based on such review and discussions, the Compensation Committee recommended to the Board of Directors that the compensation discussion and analysis be included in this proxy statement.

The Compensation Committee:

Arnold S. Grundvig, Jr., Chairman
Dennis B. Goldstein
Richard Hardman
H. Allen Turner

The above report of our Compensation Committee shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall this report be incorporated by reference into any filing made by us under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The following discussion and analysis of compensation arrangements of our Named Executive Officers for 2012 should be read together with the compensation tables and related disclosures set forth below. This compensation discussion and analysis has been prepared by our management and reviewed by our Compensation Committee and Board of Directors. This discussion is intended to provide perspective and context for the compensation tables that follow. After its review, the Compensation Committee recommended the inclusion of this compensation discussion and analysis in this proxy statement. See "Report of the Compensation Committee" above. This discussion contains forward-looking statements that are based on our current plans, considerations, expectations, and determinations regarding future compensation programs. Actual compensation programs that we adopt may differ materially from currently planned programs as summarized in this discussion.

Overview

This compensation discussion and analysis covers the following topics:

- the philosophy and objectives of our executive compensation program;
- our process of setting executive compensation;
- the components of our executive compensation;
- internal pay equity and risk assessment; and
- the tax considerations of executive compensation.

Company Overview / Summary of 2012 Performance

FX Energy is a unique, independent oil and gas company. As the only U.S.-based company whose focus is on early-stage exploration in Poland and one of only a few of its size that operates outside the United States, we face many challenges that go beyond the typical risks associated with an established oil and gas company operating domestically. These challenges include working with Poland's governmental agencies as new energy policies and practices evolve, enhancing the knowledge base of the local industry, and working through a frequently changing political climate. In addition, we face the risk of doing business in a former communist country, where exploration and environmental laws continue to change. Finally, we have a national oil company as the partner and operator of the majority of our significant exploration projects and principal purchaser of production, which means we cannot control the timing and nature of many of our operations.

In addition, while we have been successful in many of our drilling operations and have established reserves and production, we continue to face significant exploration risk. We recognize our risk profile and consider this and our unique operating circumstances when we set executive compensation.

During the past three years, including 2012, we have successfully executed on many of the key objectives that we believe will translate into long-term value for our shareholders. Highlights of our achievements over the past three years include:

- Oil and gas revenues have almost tripled since 2009 to $34.5 million in 2012, a compound annual growth rate of 39% per year.

- Total revenues have likewise increased, with a compound annual growth rate of 36% per year during the same period.

- Oil and gas production has more than doubled since 2009 to 4.8 Bcfe in 2012, a compound annual growth rate of 30%.

- We continue to diversify our production risk profile. At the time of this report, we were producing gas from eight wells in Poland, with two additional wells scheduled to begin production during 2013. At the end of 2009, we were producing gas from only three wells in Poland.

- Our exploration and development spending continues to increase. The amounts we expended for exploration costs and capital additions in 2012 represent a record level that is triple our 2009 spending for the same purposes.

These achievements have positioned us to benefit from Poland's relatively high gas prices. At the time of this report, the low-methane tariff in Poland was 40% higher than at year-end 2009. The U.S. dollar average gas price we received in 2012, taking into account currency fluctuations throughout the year, was 36% higher than the amount we received in 2009.

Our executive compensation programs reflect the achievements stated above, as further described in our Compensation Discussion and Analysis.

Executive Compensation Philosophy

Our executive compensation program, composed primarily of salary, short-term incentives, and long-term incentives, is intended to align the interests of our executives with those of our stockholders. We believe our program accomplishes this objective by rewarding performance that is designed to result in an increase in the value of our stockholders' investments over time. Accordingly, a significant portion of total compensation is directly related to our performance. In order to build a direct link between stockholder interests and executive compensation, we have equity and cash incentive compensation programs that may account for a majority of an executive's compensation. This practice parallels the compensation practices of our peer group. In order to attract and retain the best talent, we compensate at a level that reflects the demand within our peer group for talented executives, especially in a cyclical industry environment. In view of these circumstances, we must balance pay for performance with the need to attract, retain, and incentivize senior executives. The Compensation Committee has the discretion to recommend rewards for superior performance or decreases for inferior performance. While incentivizing performance, the design of our program is intended to mitigate excessive risk-taking by executives. We believe our mix and structure of compensation promote sustained performance without motivating or rewarding excessive risk.

Advisory Vote on Executive Compensation

In 2011, we held our first shareholder advisory vote on the compensation paid to our Named Executive Officers in 2010, which resulted in more than 79% of votes cast approving such compensation. As recommended by the Board, shareholders expressed their preference for an advisory vote on executive compensation once every three years, and we have implemented that recommendation. The next shareholder advisory vote on our executive compensation will occur at the 2014 Annual Stockholders' Meeting.

The Compensation Committee evaluated the results of the 2011 advisory vote on executive compensation and the support expressed by shareholders at our 2011 meeting. The Compensation Committee also considered many other factors in evaluating our executive compensation programs as discussed in this compensation discussion and analysis, including the Compensation Committee's assessment of the interaction of our compensation programs with our corporate business objectives and review of comparative compensation data that included information regarding a selected peer group. While each of these factors bore on the Compensation Committee's decisions regarding our executives' compensation, the Compensation Committee did not make any changes to our executive compensation program and policies as a result of the 2011 "say-on-pay" advisory vote. Given the support stockholders expressed for our executive compensation programs, the Compensation Committee generally elected to continue the same principles in determining the types and amounts of compensation to be paid to the Named Executive Officers in 2012. The Compensation Committee intends to monitor the results of future "say-on-pay" advisory votes when evaluating the effectiveness of our executive compensation policies and practices, particularly in the event of a negative vote or significant changes in the percentage of favorable votes regarding any such proposal.

Executive Compensation Process

The Compensation Committee

The Compensation Committee's responsibilities, which are more fully described in its charter, include each of the following:

- developing and implementing compensation programs that enhance our ability to recruit and retain qualified executives, directors, and other personnel and developing and implementing equity and other performance awards programs that create long-term incentives for executive management, directors, and key employees by enabling them to acquire an equity stake in us;

- reviewing and recommending to the Board of Directors, outside the presence of the Chief Executive Officer, the amount and manner of compensation of the Chief Executive Officer for final determination by the Board of Directors;

- consulting with and considering the recommendations of the Chief Executive Officer respecting the amount and manner of compensation of the other executive officers and recommending to the Board of Directors the amount and manner of compensation for such executive officers for final determination by the Board of Directors; and

- reviewing and recommending to the Board of Directors incentive awards under our equity and other award plans for executive officers, directors, employees, and other eligible participants.

Benchmarking Against Peer Companies

We strive to compensate our executives competitively relative to industry peers. We use both survey data and information from our industry peers as a framework in structuring our total compensation opportunities. Actual compensation paid will be higher or lower than peer group averages, which is our benchmark level for compensation, depending on a number of factors, including Company and individual performance, performance of the peer group, accomplishment of our goals, our financial condition, and industry and economic conditions generally.

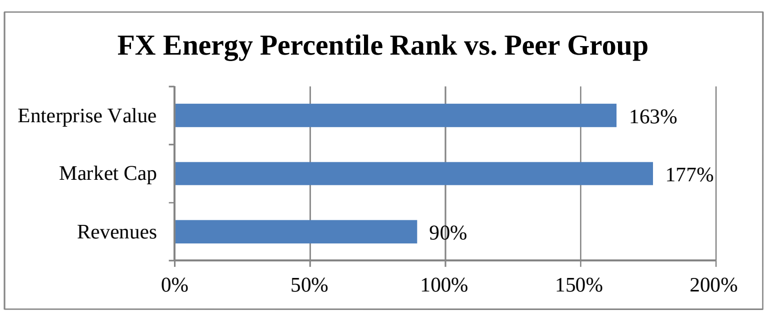
We annually review competitive executive compensation based on public company data compiled by Equilar, Inc., an independent compensation data compiler. We do not engage an independent compensation consultant.

Each year, our Compensation Committee spends considerable time selecting a relevant peer group, with input from management. The scoping criteria from 2011 were reviewed again at the beginning of 2012 and reaffirmed as appropriate benchmarks for selecting the peer group. In selecting the 2012 peer group, we reviewed year-end 2011 data for U.S.-traded public companies engaged in the oil and gas business that were similar to us in market capitalization, annual revenues, and enterprise value. We believe that these criteria were effective in yielding an appropriate peer group of comparable companies. The industry peer group changes from time to time due to business combinations, asset sales, bankruptcies, and other types of events that cause peer companies to no longer exist or no longer be comparable. The Compensation Committee approves any revisions to the peer group on an annual basis. The following 16 companies comprised the industry peer group used during 2012 in connection with executive compensation decisions:

Abraxas Petroleum Corp.	HKN, Inc.
Barnwell Industries, Inc.	Isramco, Inc.
Double Eagle Petroleum Co.	Miller Energy Resources, Inc.
Evolution Petroleum Corp.	Panhandle Oil & Gas, Inc.
GASCO Energy, Inc.	Royale Energy, Inc.
GASTAR Exploration Ltd.	Triangle Petroleum Corp.
GeoMet Inc.	US Energy Corp.
Harvest Natural Resources, Inc.	ZaZa Energy Corporation

The companies included in the selected peer group differ from those listed in the General Industry Classification Standard ("GICS"), a grouping commonly used by advisory services. The Compensation Committee believes that the oil and gas exploration companies listed above constitute a more directly relevant compensation peer group than the broader GICS industry group. The Compensation Committee believes that the GICS industry group does not have adequate pro rata representation of international exploration companies and that the individual companies in the GICS industry group, on average, are too large to be representative of the operations of and assets available to FX Energy.

The table below compares FX Energy's year-end 2011 company metrics versus the peer group metrics:



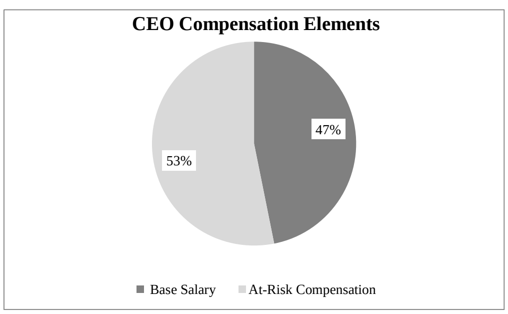
The benchmarking results provided background and context for the Compensation Committee's recommendations and decisions. The information regarding peer companies and pay practices of the peer group assisted in its analysis but did not determine the Compensation Committee's award recommendation for any particular executive.

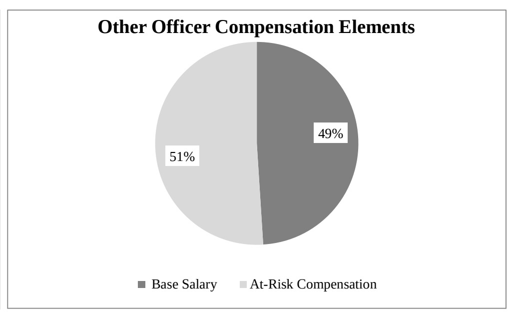
As part of the total compensation review process, the Compensation Committee reviews each element and the mix of compensation that comprises the total executive compensation package. This process includes comparing historical data for the executives in the peer group to similar data for our executives. With the assistance of the Chief Executive Officer, the Compensation Committee assesses skills, experience, and achievements of the executives individually and as a group. To support our compensation objectives, the Compensation Committee may recommend that the Board adjust elements of compensation for our executives to align them with the various elements of the peer group executives, making adjustments when appropriate in instances when the elements are not directly comparable. In addition to adjusting the allocation among elements of compensation for the executive group or Chief Executive Officer, as the case may be, individual pay may differ for any executive based on individual performance, tenure, retention considerations, and a subjective assessment of future potential. We may also adjust compensation or individual elements of compensation based on internal equity among the executive group.

In executive sessions outside the presence of the Chief Executive Officer, the Compensation Committee reviews and recommends to the Board compensation for the Chief Executive Officer based on his performance, using the benchmark data as a reference point. In consultation with the Chief Executive Officer, the Compensation Committee then recommends to the Board the amount of compensation for the remaining executives. The Compensation Committee considers each of the factors comprising performance results in recommending the amount of each executive's compensation. The Board then reviews and considers the Compensation Committee's recommendation in the light of its own analysis of these compensation factors and with further input from the Chief Executive Officer.

Executive Compensation Components

Our Board-approved executive compensation program consists of three key elements: base salary, annual cash incentives, and long-term incentives in the form of stock options and restricted stock awards. The following charts illustrate the mix of compensation components, over the past three years, for our Chief Executive Officer and our other officers:





The actual amount ultimately realized by individual executives from their total compensation opportunities (other than base salary), if any, is dependent upon our actual operational, financial, and/or stock price performance as well as individual performance. Accordingly, if our overall results fail to meet the goals established for the compensation opportunities, earned compensation is likely to fall below the peer group's mean compensation. Conversely, if our overall results exceed goals, compensation is likely to exceed the peer group's mean compensation.

In addition to these three compensation elements, we also provide limited retirement compensation and other employee benefits. The benefit plans are designed to encourage retention and reward long-term employment. We believe perquisites for senior executives should be extremely limited in scope and value and should also be restricted to those types of perquisites that are available to all employees.

We supplement this compensation with some downside protection to minimize the turnover of executive talent and to ensure that our executives' attention remains focused on our stockholders' interests. Such downside protection includes the use of employment and change of control agreements, which are discussed in more detail below.

Base Salary

To remain competitive with compensation levels of executives at comparable companies, we target the base pay of our executives at about the average of our peer group of companies. We believe that targeting base pay at a competitive level helps fulfill our compensation program objective of attracting and retaining high-quality executives. Each executive's salary relative to this competitive framework varies based on the level of his responsibility, experience, time in position, internal pay equity considerations, and individual performance and is reviewed by the Compensation Committee on an annual basis. Specific salary adjustments take into account these factors and the current market for management talent.

Analysis of 2012 Salaries

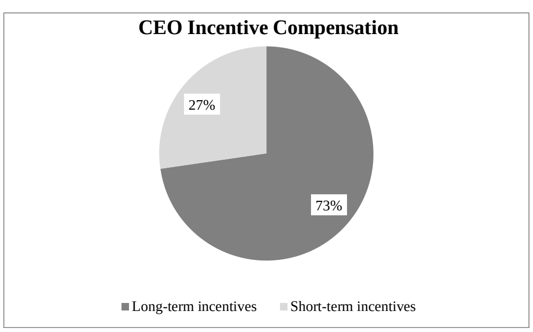
As a result of a review of peer group and other compensation data available, including current compensation trends, talent demand in the oil and gas industry, and consideration of our financial condition, we determined to maintain 2012 Named Executive Officer salaries at their 2011 levels, which, with the exception of one executive, are unchanged from 2008. We considered the impact of inflation in reviewing compensation levels and concluded that the level of inflation since the last salary increases did not warrant salary changes this year. In total, we anticipate that the executive group's base salaries would approximate or be slightly higher than the average of our peer group for executives for both 2011 and 2012.

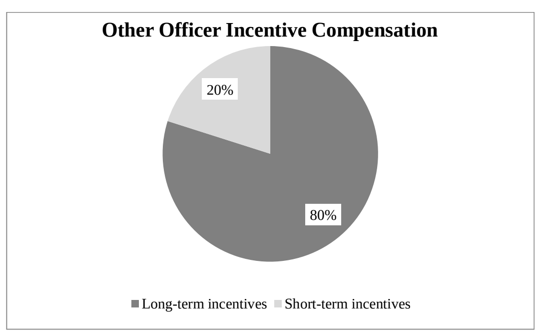
Incentive Compensation

Our stock price is significantly influenced by global oil and gas prices, which are driven by macroeconomic factors that are outside of our control. Accordingly, our incentive compensation program is designed to focus management's efforts in areas where they have the most ability to drive long-term value appreciation. To achieve this, we use a comprehensive incentive compensation structure, ensuring a suitable mix of operational and financial incentives based on:

- annual and long-term performance;
- absolute and relative performance measures; and
- internal and external performance comparisons.

The following charts illustrate the mix of at-risk short-term and long-term incentive compensation over the past three years for our Chief Executive Officer and other officers:





Annual Cash Incentives

As part of each executive's performance-based compensation, we maintain the FX Energy Cash Bonus Plan (the "Bonus Plan"). The purpose of the Bonus Plan is to make a significant portion of each executive's total compensation variable based on our performance respecting goals that are set to enhance stockholder value over the long term.

The Bonus Plan calls for the Compensation Committee to review certain corporate performance criteria as it relates to our peers, as well as certain other absolute measures of performance, and leaves the Compensation Committee the discretion to consider the achievement of other specific corporate objectives, individual contributions, general economic conditions, and other factors when making incentive awards for each year. The Compensation Committee uses this information to recommend annual incentive awards to the Board. The Bonus Plan provides for a preliminary award near year-end based on an analysis of Company performance to date and preliminary peer group data, followed by a final review and payment (which may be zero) later, once all peer group prior-year performance data becomes available.

We set target awards as a percentage of base salary at about the estimated average of peer group award percentages for each executive position. Target awards vary by position. Our CEO's target percentage tends to be higher than that of our other officers, as the members of our peer group tend to award their CEOs a higher percentage of salary in the form of incentive payments than their other officers. Accordingly, our CEO's short-term incentive compensation tends to represent a greater percentage of total incentive compensation than that of our other officers. Our success in meeting our corporate objectives (reviewed as of year-end) and each particular executive's role in meeting those objectives are used to determine whether the actual award should be above, below, or at the anticipated peer group average.

In determining short-term cash incentive awards, the Compensation Committee reviews corporate performance relative to our peer group in the following areas: (i) three-year revenue growth per share; (ii) three-year reserve volume growth per share; (iii) three-year finding and development cost per unit of reserves; and (iv) one-year stock price change. Each measure comprises 12.5% of the incentive award. For each measure, the peer group members, including the Company, are ranked by performance order and divided into quintiles. The incentive award for each measure is determined by the quintile ranking of the Company within the peer group, and the percentage contributions of all four measures are added to determine the overall annual incentive award. Award percentages for the various quintiles range ratably from 25% in the top quintile to 0% in the bottom quintile.

In addition, the Compensation Committee reviews absolute corporate performance in the following areas: (v) production volume per share at year-end; (vi) reserves volume per share at year-end; (vii) earnings before interest, taxes, depreciation, depletion, amortization, and exploration expenses (EBITDAX) per share at year-end; and (viii) net asset value per share at year-end. We compare these measures to our own three-year history. Each of these measures also comprises 12.5% of the incentive award. The incentive award for each measure is determined with reference to a performance matrix approved by the Compensation Committee at the beginning of the year, and the percentage contributions of all four measures are added to determine the overall annual incentive award. Award percentages for the various quintiles range ratably from 25% at the top of the matrix to 0% in the bottom of the matrix.

We believe that success in these performance areas enhances stockholder value in both the short term and the long term. Success in the areas of reserve additions and revenue growth, in particular, reflects our positive achievements in implementing our business model of translating early-stage exploration efforts into tangible assets and cash flow. Lower than industry-average finding costs demonstrate our ability to find and drill exploration targets that contribute meaningfully to increases in reserve volumes and values. Relative changes in share price reflect the market's recognition of our progress in implementing our business model. Success in the four absolute measures reflects the achievement of our internal objectives without regard to how our peers are performing.

2012 Incentive Awards

In determining a preliminary award for 2012, the Compensation Committee undertook the following review: (i) respecting the Bonus Plan's relative measures, the Compensation Committee compared our estimated 2012 performance to that of our peer group's performance for the three-year period that ended in 2011; and (ii) respecting the Bonus Plan's absolute measures, the Compensation Committee compared our estimated 2012 performance with that of our own prior three-year performance. The following table shows the level of achievement for each of the incentive plans goals:

Incentive Plan Measures	FX Energy Performance	Incentive Award Qualification
Absolute(1)		
Reserves Growth	Below Target	0.00%
Production Growth	At Target	12.50%
EBITDAX Growth	Above Target	25.00%
Net Asset Value Growth	Below Target	0.00%
vs. Peers		
Reserves Growth	At Target	12.50%
Revenue Growth	Above Target	18.75%
Finding Costs	Below Target	6.25%
Stock Price Growth	Above Target	18.75%

(1) Absolute measures are calculated on a per-share basis.

Based on these achievements, the Board approved preliminary incentive awards for 2012 equal to 75% of the estimated annual award, as shown in the following table, with the intent to review fully our relative and absolute performance and determine the final 2012 incentive awards after 2012 peer group data becomes available. The 2012 interim award was approximately 65% of the 2011 interim award.

Executive Officer	2012 Interim Award
David N. Pierce	$113,695
Andrew W. Pierce	65,781
Jerzy Maciolek	65,781
Thomas B. Lovejoy	54,141
Clay Newton	34,805

Long-Term Incentives

Equity Awards

We have equity compensation plans under which we can make annual grants of restricted stock and stock option awards to eligible Named Executive Officers and other employees. Equity incentives represent a significant element of our total compensation program. As with other elements, the value received through various stock-based awards is included in our annual total compensation review process. Each year, we collect and review competitive data from the peer group specifically on the use of, and value received through, equity incentives. From this data, management develops and recommends annual awards. Our philosophy is that the award opportunity should match the range of awards made by our peers. Individual awards are then further modified, based on a subjective assessment of individual performance, contribution, and future potential.

In 2011, our shareholders approved our 2011 Incentive Plan, or 2011 Plan. The purpose of the 2011 Plan is to further align our long-term incentive program with that of our peers. We asked shareholders to approve a total number of shares for the plan equal to 7.5% of the number of our shares issued and outstanding, which is approximately equal to the mean number of shares that other companies in our peer group included in equity incentive plans submitted to their shareholders for approval during the preceding three years. Further, an annual award of 1.82% of the number of outstanding shares is approximately equal to the mean number of equity incentive awards granted by the other companies in our peer group. Finally, a ratio of two-thirds of the annual award in options and one-third of the annual award in restricted stock is also approximately equal to the mean ratio of options and restricted stock granted by the other companies in our peer group.

Prior to 2011, awarding restricted stock to senior management was traditionally the focus of our long-term incentive compensation. Restricted stock awards provide value in the form of our stock while resulting in lower share usage and lower dilution than the use of certain other types of equity awards. In addition, the vesting conditions (discussed below) and opportunity for long-term capital appreciation, which are characteristic of restricted stock awards, help us achieve our objectives of management retention and linking pay to our long-term stockholder value. In awarding restricted stock, we consider stock market overhang and run rates. Restricted stock awards do not offer dividend or voting rights until they vest and the shares are subsequently released to the grantee.

Upon approval of the 2011 Plan and in keeping with the practice of our peer group companies, we decreased the number of restricted stock awards to each of our officers, but added new stock option awards. The stock option awards now comprise two-thirds of our equity awards, with the balance being in the form of restricted stock awards. Stock option awards directly align the interests of our executive officers and stockholders. The stock option grants reward executives for growth in the value of Company stock over the long-term. Stock options deliver value to an executive only if the share price, after the date of vesting, is above the grant price. Therefore, stock price volatility will have a greater impact on total compensation results delivered from stock options compared to restricted stock awards.

Analysis of 2012 Equity Awards

Prior to 2011, our long-term incentive compensation was measurably lower than that of our peer group, dating back more than five years. As discussed above, it is our belief that the implementation of our 2011 Plan has made our long-term compensation more comparable to that of our peer group.

Vesting and Other Restrictions

Annual equity awards granted under our equity compensation plans typically vest 33% on each of the first three anniversaries of their grant date, contingent on continued employment with us. In the case of supplemental awards, we may use a shorter or longer vesting period depending upon our retention objectives for the individual recipient. We believe that these provisions serve our objectives of retention and connecting the executives' long-term interests to ours and to those of our stockholders.

Grant Timing and Pricing

Prior to 2011, we granted annual stock awards generally at or near our regularly scheduled, fourth quarter Board meeting each year. In 2011, we granted our annual stock awards immediately following the approval of our 2011 Plan. In 2012, we granted our annual stock awards at our regularly scheduled, fourth quarter Board meeting, and plan to continue this practice in the future. Notwithstanding our grant schedule, we do not grant stock awards before the release of material, nonpublic information that is likely to result in change in our stock price. We may change the date upon which equity awards are granted if there is unreleased material, nonpublic information.

Retirement Compensation

We do not offer a traditional pension plan. We do have a 401(k) Stock Bonus Plan under which we make annual contributions, in the form of FX Energy stock, to the retirement account of each of our Named Executive Officers. Each executive is encouraged to retain the contributed stock for at least one year, and as of the date of this report, no executive has sold any of the shares so contributed. We believe that offering this plan to executives is critical to achieve the objectives of attracting and retaining talent, particularly because we do not offer a defined benefit pension plan or any employee stock purchase, employee stock ownership, deferred compensation, or supplemental early retirement plans.

Other Compensation

We offer limited other perquisites and benefits to our executives, which are reflected in the relevant tables and narratives that follow. The executives participate in basic Company-wide plans and programs, such as group medical, dental, and life insurance, in accordance with the terms of the programs and on the same terms as all other domestic administrative employees. We do not offer disability insurance, automobile allowances, Company-provided automobiles, club memberships/dues, financial planning allowances, first-class travel (unless preapproved by our Chief Executive Officer), security services, or sign-on or retention bonuses.

Internal Pay Equity

Our core compensation philosophy is to pay our Named Executive Officers competitive levels of compensation that reflect their individual responsibilities and contributions to us, while providing incentives to achieve our business objectives. While comparisons to compensation levels of similarly situated executives at companies in our peer group are beneficial in assessing the competitiveness of our various programs, we recognize that our compensation programs must also be internally consistent and equitable. The Compensation Committee and Board evaluated the mix of the individual elements of compensation paid to our executives, as well as the overall composition and responsibilities of the executive team. We do not have a formal policy that addresses Chief Executive Officer compensation multiples as they relate to other Named Executive Officers; however, the Chief Executive Officer's total compensation has historically been less than 160% of the average total compensation of the other Named Executive Officers.

FX Energy's exploration initiative in Poland was originally founded by three individuals, David N. Pierce (currently the Chief Executive Officer), Andrew W. Pierce, and Jerzy B. Maciolek. In recognition of their initial vision and ongoing contribution to our success, we set the salaries of Andrew W. Pierce and Jerzy Maciolek at the same level.

Risk Assessment

The Compensation Committee believes that its approach to choosing performance metrics and evaluation of performance results assists in mitigating excessive risk-taking that could harm our value or reward poor judgment by our executives. Several features of our programs reflect sound risk-management practices. As examples, both net asset value and EBITDAX involve the use of net cash available or generated. The Compensation Committee believes that, in a capital intensive industry like oil and gas exploration, cash assets and cash flow are important determinants of our overall risk exposure. We believe our overall compensation program provides a reasonable balance between short- and long-term objectives, which helps mitigate the threat of excessive risk-taking in the short term. Further, the performance criteria reviewed by the Compensation Committee in determining cash bonuses are Company-wide, and the Compensation Committee and Board use their subjective judgment and discretion in recommending and approving bonus levels for our executives. This is based on the Compensation Committee's and the Board's belief that applying Company-wide metrics encourages decision making that is in the best long-term interests of the Company and our stockholders as a whole. The multi-year vesting of our equity awards for executive compensation discourages excessive risk-taking and properly accounts for the time horizon of risk.

Tax Considerations

Impact of Internal Revenue Code Section 162(m)

Under the Omnibus Budget Reconciliation Act of 1993, provisions were added to the Internal Revenue Code under Section 162(m) that limit our federal income tax deductions for compensation expense in excess of $1 million paid to Named Executive Officers. However, performance-based compensation can be excluded from the limit so long as it meets certain requirements.

No executive of FX Energy, including our Chief Executive Officer, has received nonperformance-based compensation in any given year in excess of $1 million.

Section 409A of the Internal Revenue Code

To the extent one or more compensation elements provided to executives are subject to Section 409A of the Internal Revenue Code, we intend that these elements be compliant so that the executives are not subject to increased income or penalty taxes imposed by Section 409A. Section 409A requires that "deferred compensation" either comply with certain deferral election and payment rules or be subject to a 20% additional tax and in some circumstances penalties and interest imposed on the person who is to receive the deferred compensation. We believe that if the adverse tax consequences of Section 409A become applicable to our compensation arrangements, such arrangements would be less efficient and less effective in incentivizing and retaining employees. We intend to operate our compensation arrangements so that they are compliant with or exempt from Section 409A and have, therefore, amended or modified our compensation programs and awards, including our employment agreements, to the extent necessary to make them compliant or exempt. We have also agreed to provide additional payments to our Named Executive Officers in the event that an additional tax is imposed under Section 409A.

2012 Summary Compensation Table

The following table summarizes the compensation of our Chief Executive Officer and our four highest paid executive officers other than our Chief Executive Officer ("Named Executive Officers") for the fiscal year ended December 31, 2012:

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Option Awards ($)[(1)]	Restricted Stock Awards ($)[(1)]	All Other Compen-sation ($)[(2)]	Total ($)
David N. Pierce	2012	$367,500	$113,695[(3)]	$154,651	$148,470	$ 81,281	$865,597[(3)]
President, Chief Executive Officer	2011	367,500	349,435[(4)]	198,944	179,883	73,114	1,168,876[(4)]
	2010	367,500	240,813[(5)]	--	254,100	67,572	929,985[(5)]
Thomas B. Lovejoy	2012	262,500	54,141[(3)]	88,372	84,843	84,234	574,090[(3)]
Chairman, Executive Vice President	2011	262,500	143,141[(4)]	113,682	102,789	80,756	702,868[(4)]
	2010	262,500	111,168[(5)]	--	145,200	75,101	593,969[(5)]
Andrew W. Pierce	2012	283,500	65,781[(3)]	138,082	132,566	61,179	681,108[(3)]
Vice President Operations	2011	283,500	149,632[(4)]	177,628	160,609	57,552	828,921[(4)]
	2010	283,500	125,301[(5)]	--	226,875	58,802	694,478[(5)]
Jerzy B. Maciolek	2012	283,500	65,781[(3)]	138,082	132,566	75,147	695,076[(3)]
Vice President Exploration	2011	283,500	149,632[(4)]	177,628	160,609	69,840	841,209[(4)]
	2010	283,500	125,301[(5)]	--	226,875	69,101	704,777[(5)]
Clay Newton	2012	225,000	34,805[(3)]	82,849	79,539	69,520	491,713[(3)]
Vice President Finance	2011	225,000	117,581[(4)]	106,578	96,363	66,859	612,381[(4)]
	2010	210,000	71,166[(5)]	--	136,125	63,335	480,626[(5)]

(1) The amount includes the fair value of stock awards on the date of grant as calculated in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 718, Compensation – Stock Compensation, formerly Statement of Financial Accounting Standards No. 123 (revised 2004) Share-Based Payment. For a discussion of valuation assumptions, see Note 1 to our consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2012. The table below shows the 2012 stock grants to each of the Named Executive Officers:

Name	Stock Option Awards	Restricted Stock Awards
David N. Pierce	69,869	34,934
Thomas B. Lovejoy	39,925	19,963
Andrew W. Pierce	62,383	31,192
Jerzy B. Maciolek	62,383	31,192
Clay Newton	37,430	18,714

(2) The amounts reported for each of the Named Executive Officers in "All Other Compensation" for 2012 are shown below (in dollars):

Name	Registrant Contributions to Defined Contribution Plans	Insurance Premiums and Medical Reimbursement
David N. Pierce	$50,000	$31,281
Thomas B. Lovejoy	50,000	34,234
Andrew W. Pierce	50,000	11,179
Jerzy B. Maciolek	50,000	25,147
Clay Newton	45,000	24,520

(3) The bonus consists of a preliminary award under our Bonus Plan for 2012 that was reported in our annual report on Form 10-K for the year ended December 31, 2012. A final award may be approved by the Board later in 2013.

(4) The bonus consists of a preliminary award under our Bonus Plan for 2011 that was reported in our annual report on Form 10-K for the year ended December 31, 2011, plus a subsequent award approved by the Board in June 2012 following the review of peer group operating and compensation data.

(5) The bonus consists of a preliminary award under our Bonus Plan for 2010 that was reported in our annual report on Form 10-K for the year ended December 31, 2010, plus a subsequent award that was approved by the Board in May 2011 following the review of peer group operating and compensation data.

Narrative to Summary Compensation Table and Grants of Plan-Based Awards Table

We maintain the following executive compensation programs for our Named Executive Officers:

- base salary;

- annual cash incentive compensation;
- equity-based awards;
- retirement benefits;
- other employee benefits; and
- employment and change in control agreements

We include further details regarding these programs, including information on performance criteria and vesting provisions, in the "Compensation Discussion and Analysis—Executive Compensation Philosophy" section on page 11.

Outstanding Equity Awards at 2012 Year-End

The following table reflects outstanding stock option awards classified as exercisable and unexercisable as of December 31, 2012, for each of the Named Executive Officers. The table also reflects unvested and unearned stock awards:

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexer-cised Options (#) Exer-cisable[(1)]	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options(#)	Option Exercise Price($)	Option Expiration Date	Number of Shares or Units of Stock Held That Have Not Vested(#)	Market Value of Shares or Units of Stock That Have Not Vested($)[(2)]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested($)
David N. Pierce	23,700	47,399	71,099	$ 5.06	09/16/21			-	-
	-	69,869	69,869	4.25	11/15/22	72,634[(3)]	$298,526		
Thomas B. Lovejoy	13,543	27,085	40,628	5.06	09/16/21			-	-
	-	39,925	39,925	4.25	11/15/22	41,505[(4)]	170,586		
Andrew W. Pierce	21,160	42,321	63,481	5.06	09/16/21			-	-
	-	62,383	62,383	4.25	11/15/22	64,852[(5)]	266,542		
Jerzy B. Maciolek	21,160	42,321	63,481	5.06	09/16/21			-	-
	-	62,383	62,383	4.25	11/15/22	64,852[(5)]	266,542		
Clay Newton	12,696	25,393	38,089	5.06	09/16/21			-	-
	-	37,430	37,430	4.25	11/15/22	38,911[(7)]	159,920	-	-

(1) We granted all options 10 years before the expiration date. The options vest ratably over a three-year period beginning with the first third vesting one year after the date of grant, the second third vesting two years after the date of grant, and the final third vesting three years after the date of grant.

(2) Market value of shares of stock that have not vested is based on the December 31, 2012, closing market price for a share of our common stock, which was $4.11.

(3) Mr. Pierce's restricted shares will vest as follows: 14,000 shares on December 21, 2013; 11,850 shares on each of September 16, 2013 and 2014; 11,645 shares on each of November 15, 2013 and 2014, and 11,644 shares that vest on November 15, 2015. All of the restricted shares will also vest if we terminate his employment other than for cause or if he dies or becomes disabled. Restricted stock awards also vest fully on a change in control.

(4) Mr. Lovejoy's restricted shares will vest as follows: 8,000 shares on December 21, 2013; 6,771 shares on each of September 16, 2013 and 2014; 6,654 shares on each of November 15, 2013 and 2014, and 6,655 shares that vest on November 15, 2015. All of the restricted shares will also vest if we terminate his employment other than for cause or if he dies or becomes disabled. Restricted stock awards also vest fully on a change in control.

(5) Mr. Pierce's restricted shares will vest as follows: 12,500 shares on December 21, 2013; 10,580 shares on each of September 16, 2013 and 2014; 10,397 shares on each of November 15, 2013 and 2014, and 10,398 shares that vest on November 15, 2015. All of the restricted shares will also vest if we terminate his employment other than for cause or if he dies or becomes disabled. Restricted stock awards also vest fully on a change in control.

(6) Mr. Maciolek's restricted shares will vest as follows: 12,500 shares on December 21, 2013; 10,580 shares on each of September 16, 2013 and 2014; 10,397 shares on each of November 15, 2013 and 2014, and 10,398 shares that vest on November 15, 2015. All of the restricted shares will also vest if we terminate his employment other than for cause or if he dies or becomes disabled. Restricted stock awards also vest fully on a change in control.

(7) Mr. Newton's restricted shares will vest as follows: 7,500 shares on December 21, 2013; 6,348 shares on each of September 16, 2013 and 2014; 6,238 shares on each of September 16, 2013 and 2014, 6,239 shares that vest on November 15, 2015. All of the restricted shares will also vest if we terminate his employment other than for cause or if he dies or becomes disabled. Restricted stock awards also vest fully on a change in control.

Option Exercises and Stock Vested During 2012

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)(1)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)(2)
David N. Pierce	--	$ --	39,850	$219,852
Thomas B. Lovejoy	--	--	22,772	125,634
Andrew W. Pierce	--	--	35,581	196,302
Jerzy B. Maciolek	--	--	35,581	196,302
Clay Newton	--	--	21,348	117,776

(1) This value is the difference between the option exercise price and the market value of the underlying shares on the date of exercise, multiplied by the number of shares.

(2) This value is the market value of the shares on the vesting date multiplied by the number of shares.

Other Potential Post-Employment Compensation

Our analysis of the accumulated wealth of our Named Executive Officers shows that a significant portion of their financial well-being is dependent on their compensation and the performance of our common stock. Accordingly, as part of our program to retain our key employees, we have extended employment and change in control agreements to all of our Named Executive Officers. These are separate agreements, with the employment agreement covering only the terms of employment and the change in control agreement covering only a change in Company control. The following summaries describe potential payments payable to our Named Executive Officers upon termination of employment or a change in control. The actual payments to executives are contingent upon many factors as of the time benefits would be paid, including elections by the executive and tax rates, as well as the discretion of the Compensation Committee.

Employment Agreements

We have entered into agreements with each of our Named Executive Officers providing for the terms of employment. Each of the agreements has an initial term of two and one-half years; *provided*, *however*, that such agreements will automatically be renewed each year for successive two and one-half year terms unless we deliver to the applicable executive written notice of nonrenewal at least 40 days before the expiration date. All of the agreements were entered into on January 1, 2007. Notwithstanding the foregoing, these agreements automatically terminate upon the earlier of a change in corporate control (as defined in the change in corporate control agreements described below) or such time as the applicable executive ceases to be employed by us for any reason.

Change in Control Agreements

We also have agreements with our Named Executive Officers providing for certain enhanced severance benefits only in the event of the severance of the employment of such Named Executive Officer following a change in corporate control. Each of the agreements has an initial term of one year, and the expiration date will automatically be extended for one additional year unless in the 60-day period immediately preceding any anniversary date of the agreement either we or the applicable executive rejects such automatic extension. These agreements were entered into on January 1, 2007.

David N. Pierce

If we terminate Mr. Pierce's employment other than for cause (as defined in the agreement) or Mr. Pierce resigns for cause (as defined in the agreement), Mr. Pierce will be entitled to severance pay and up to 24 months of continued health care coverage. The severance pay is payable in a lump sum six months after his termination and is equal to two times the greater of: (i) his then-current annual salary; or (ii) his salary plus bonus compensation for the year most recently ended, including amounts subsequently awarded under our Bonus Plan respecting such year after final peer group performance data are available. In addition, all unvested options, restricted shares, and other equity-based awards will be immediately vested. Under Mr. Pierce's change in control agreement, Mr. Pierce will be entitled to receive similar severance payments and benefits as those described above if we terminate his employment other than for cause or Mr. Pierce's employment is terminated by death or disability within two years after a change in control (as defined in the agreement). The agreements do not provide for a gross-up of income taxes resulting from a payment under either of the agreements for Mr. Pierce or for any of our other Named Executive Officers.

If Mr. Pierce's employment had been terminated under the circumstances noted in the table below as of December 31, 2012, payments and benefits to him would have an estimated potential value as follows:

Termination Reason	Cash Severance	Benefits(1)	Value of Accelerated Equity Awards	Total(1)
Retirement / Voluntary / With Cause	$ -	$ -	$ -	$ -
Without Cause / Change in Control / Death	1,433,870	32,585	298,526	1,764,981

(1) Includes two years of group medical, dental, and life insurance premiums.

Named Executive Officers (Other Than David N. Pierce)

Assuming the employment of the Named Executive Officers noted in the tables below was terminated under the circumstances noted in the table on December 31, 2012, payments and benefits to each Named Executive Officer would have estimated potential values as follows:

Termination Reason	Cash Severance	Benefits(1)	Value of Accelerated Equity Awards	Total(1)
Retirement / Voluntary / With Cause	$ -	$ -	$ -	$ -
Without Cause / Change in Control / Death				
Thomas B. Lovejoy	811,282	32,585	170,586	1,014,453
Andrew W. Pierce	866,264	10,022	266,542	1,142,828
Jerzy B. Maciolek	866,264	23,002	266,542	1,155,808
Clay Newton	685,162	17,563	159,920	862,645

(1) Includes two years of group medical, dental, and life insurance premiums.

DIRECTOR COMPENSATION

The following table sets forth certain information regarding the compensation earned by or awarded to each non-employee director who served on our Board of Directors in 2012. Directors who are our employees are not compensated for their services:

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compen-sation ($)	Total ($)
Dennis B. Goldstein(3)	$51,750	$42,419	$44,187	-	-	$ -	$138,356
H. Allen Turner(4)(5)	54,000	21,212	22,092	-	-	-	97,304
Richard Hardman(6)	85,000	95,447	99,419	-	-	-	279,866
Arnold S. Grundvig, Jr.(4)	56,750	21,212	22,092	-	-	-	100,054

(1) Non-employee directors receive the following annual cash compensation:
- an annual retainer of $20,000;
- an additional annual retainer of $20,000 for the Lead Director;
- an additional annual retainer of $20,000 for the Capital Markets Director;
- an additional annual retainer of $25,000 for the chairman of the Compensation Committee;
- an additional annual retainer of $57,000 for the Technical Advisor;
- an additional annual retainer of $5,000 for the chairman of the Audit Committee;
- a fee of $2,000 for each Board meeting attended;
- a fee of $750 for each Audit Committee meeting attended; and
- each director is entitled to reimbursement for reasonable out-of-pocket expenses incurred in connection with travel to and from, and attendance at, meetings of the Board of Directors or its committees and related activities.

(2) Non-employee directors receive the following annual stock awards:
- an annual grant of 4,991 shares of restricted stock and 9,981 stock options;
- an additional annual grant of 4,991 shares of restricted stock and 9,981 stock options for the Lead Director; and
- an annual grant of 17,467 shares of restricted stock and 34,935 stock options for the Technical Advisor.

The amount includes the fair value of stock awards on the date of grant as calculated in accordance with FASB ASC Topic 718. For a discussion of valuation assumptions, see Note 1 to our consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2012.

(3) Lead Director and Chairman of the Nomination and Governance Committee.

(4) Mr. Grundvig served as Chairman of the Audit Committee until June 4, 2007, at which time Mr. Turner was appointed to serve as Chairman of the Audit Committee. Mr. Grundvig was appointed Chairman of the Compensation Committee in 2009.

(5) Capital Markets Advisor to the Board of Directors.

(6) Technical Advisor to the Board of Directors.

AUDIT COMMITTEE REPORT

The Audit Committee oversees the financial reporting process for us on behalf of the Board of Directors. In fulfilling its oversight responsibilities, the Audit Committee reviewed the annual financial statements included in the Annual Report and filed with the Securities and Exchange Commission. The Audit Committee also reviewed the unaudited financial statements filed with our quarterly reports on Form 10-Q.

The Audit Committee discussed with management and the independent registered public accountants the acceptability and the quality of the accounting principles used in the financial statements. These discussions included the clarity of the disclosures made therein, the underlying estimates and assumptions used in the financial reporting, the reasonableness of the significant judgments and management decisions made in developing the financial statements, and the independent registered public accountants' evaluation of our internal controls.

The Audit Committee met privately with the independent registered public accounting firm and discussed issues deemed significant by the accounting firm, including those required by Public Company Accounting Oversight Board AU 380, *Communication with Audit Committees*. In addition, the Audit Committee discussed with the independent registered public accounting firm its independence from the Company and its management, including the matters in the written disclosures required by Public Company Accounting Oversight Board Rule 3526; received the written disclosures and the letter required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the audit committee concerning independence; and considered whether the provision of nonaudit services was compatible with maintaining the accounting firm's independence.

The Audit Committee has also discussed issues related to the overall scope and objectives of the audits conducted, the internal controls used by us, and the selection of our independent registered public accountants with our management and our independent registered public accountants.

The Audit Committee discussed with management our disclosure controls and procedures and the certifications by our Principal Executive Officer and Principal Financial Officer, which are required by the Securities and Exchange Commission under the Sarbanes-Oxley Act of 2002 for certain of our filings with the Securities and Exchange Commission. During 2012, we did not engage PricewaterhouseCoopers LLP to perform any management or financial information systems design consulting services.

Pursuant to the reviews and discussions described above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the fiscal year ended December 31, 2012, for filing with the Securities and Exchange Commission.

The foregoing report has been furnished by:

H. Allen Turner, Chairman

Arnold S. Grundvig, Jr.
Dennis B. Goldstein

RELATIONSHIP WITH INDEPENDENT AUDITORS

Independent Registered Public Accountants

Audit Fees

The aggregate fees billed by PricewaterhouseCoopers LLP for professional services rendered for the audit of our annual financial statements for the fiscal year ended December 31, 2012, for the reviews of the financial statements included in our quarterly reports on Form 10-Q for that fiscal year, comfort letters, and for assistance with documents filed with the Securities and Exchange Commission were $321,750. The aggregate fees billed by PricewaterhouseCoopers LLP for professional services rendered for the audit of our annual financial statements for the fiscal year ended December 31, 2011, for the reviews of the financial statements included in our quarterly reports on Form 10-Q for that fiscal year, and for reviews of registration statements and for assistance with the Securities and Exchange Commission's review of our prior year financial statements were $360,000.

Audit Related Fees

PricewaterhouseCoopers LLP did not bill us for any professional services that were reasonably related to the performance of the audit or review of financial statements for either the fiscal years ended December 31, 2012 and 2011, that are not included under Audit Fees above.

__Tax Fees__

The aggregate fees billed by PricewaterhouseCoopers LLP for professional services rendered for domestic and international tax compliance, tax advice, and tax planning for the fiscal years ended December 31, 2012 and 2011, were $16,985 and $38,725, respectively.

__All Other Fees__

The aggregate fees billed by PricewaterhouseCoopers LLP for other services for the fiscal years ended December 31, 2012 and 2011, were $1,800 and $1,800, respectively.

The engagements of PricewaterhouseCoopers LLP to perform all of the above-described services were approved by the Audit Committee before we entered into the engagements, and the policy of the Audit Committee is to require that all services performed by the independent registered public accountants be preapproved by the Audit Committee before the services are performed.

OTHER MATTERS

Management does not know of any business other than that referred to herein that may be considered at the Annual Meeting. If any other matters should properly come before the Annual Meeting, it is the intention of the persons named in the accompanying form of proxy to vote the proxies held by them in accordance with their best judgment.

In order to assure the presence of the necessary quorum and to vote on the matters to come before the Annual Meeting, please indicate your choices on the enclosed proxy and date, sign, and return it promptly in the envelope provided. The signing of a proxy by no means prevents your attending the meeting.

FX ENERGY, INC.
By Order of the Board of Directors

Scott J. Duncan

Scott J. Duncan, Secretary

Salt Lake City, Utah
May 10, 2013

Corporate Information

Officers and Board of Directors
David N. Pierce
President and Chief Executive Officer
Director

Thomas B. Lovejoy
Chairman of the Board
Executive Vice President

Andrew W. Pierce
Vice President, Operations

Jerzy B. Maciolek
Vice President, International Exploration
Director

Scott J. Duncan
Vice President, Investor Relations
Corporate Secretary

Clay Newton
Vice President, Finance

General Counsel
James R. Kruse
Kruse Landa Maycock & Ricks, LLC
136 East South Temple, Suite 2100
Salt Lake City, Utah 84111

Independent Public Accountants
PricewaterhouseCoopers, LLP
201 South Main Street, Suite 900
Salt Lake City, Utah 84111

□ – Member of Nomination and Governance Committee

○ – Member of Compensation Committee

◊ - Member of Audit Committee

Independent Directors
Dennis B. Goldstein □ ○ ◊
Director
Former Corporate Counsel
And Assistant Secretary,
Homestake Mining

Richard Hardman, CBE □ ○
Director
Former Vice President, Worldwide
Exploration for Amerada Hess
Chairman of the Petroleum Society,
Great Britain

Arnold S. Grundvig, Jr. □ ○ ◊
Director
President and Chief Financial Officer,
A-Systems Corporation

H. Allen Turner □ ○ ◊
Director
Former Senior Vice President, Corporate
Development, Devon Energy

Independent Reservoir Engineers
RPS Energy plc
309 Reading Road
Henley-on-Thames
Oxfordshire RG9 1EL
United Kingdom

Hohn Engineering, PLLC
2708 1st Avenue North
Billings, Montana 59101

Stock Transfer Agent
Fidelity Transfer Company
8915 South 700 East
Salt Lake City, Utah 84115
801-562-1300

Communications regarding the transfer of lost shares, lost certificates, duplicate mailings, or changes of address should be directed to the transfer agent.

10-K Request
Stockholders interested in obtaining, without cost, additional copies of the Annual Report on Form 10-K filed by the Company with the Securities and Exchange Commission can do so by writing to Scott J. Duncan at:

FX Energy, Inc.
3006 Highland Drive, Suite 206
Salt Lake City, Utah 84106

or by visiting FX Energy, Inc.'s website at:

www.fxenergy.com

Nonexecutive Offices
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Corner of Central and Main
Oilmont, Montana 59466

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