Summary of Statement of Adam Sieminski, EIA Administrator, August 2, 2012

Oil and Gas Reserves - EIA is releasing the 2010 *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves* report. Net additions to proved reserves were the highest recorded since EIA began publishing estimates in 1977. Proved oil (crude and condensate) reserves - led by Texas, North Dakota, and the Gulf of Mexico Federal Offshore - increased by 13 percent ending at 25.2 billion barrels. Proved reserves of wet natural gas increased by 12 percent, ending the year over 300 Tcf for the first time. Texas, Louisiana, and Pennsylvania had the largest increases.

Production - U.S. oil (crude and lease condensate) production during the first 5 months of 2012 averaged 6.2 million barrels per day (bbl/d), the highest since 1998, led by tight oil plays from North Dakota and Texas. The EIA 2013 forecast is for another 410,000 bbl/d; onshore oil-directed drilling rigs have doubled in the last 18 months. Natural gas production has increased because of production of liquids rich shale gas areas such as the Eagle Ford and wet areas of the Marcellus Shale as well as associated gas from the growth in domestic oil production.

Differences between Federal and Non-Federal Lands - The shale resource basins are largely outside of the Federal lands, so is shale production. Oil production on non-Federal lands increased year on year because of the tight oil plays of North Dakota and Texas. Oil production from Federal lands is dominated by offshore which has been lower since the 2010 Macondo blowout in the Gulf of Mexico. Natural Gas production on non-Federal lands has increased steadily over the last 6 years, largely because of shale gas resources. Natural gas production from Federal lands has decreased each year since FY2003 as production has declined in the Federal OCS as industry has moved from the gas prone shelf to the oil prone deep waters. Production from onshore Federal lands has been growing, exceeding offshore. Decline in natural gas prices has reduced the attractiveness of conventional resources on Federal land.

Resource Projections - The Annual Energy Outlook 2012 projections were based on a natural gas resource estimate of 2,203 trillion cubic feet of technically recoverable resources. These estimates are a "work in progress," changing as more production experience becomes available and as new production technologies are applied to these resources. The uncertainties are complicated by three factors. First, most shale gas and tight oil wells are only a few years old, and their long-term productivity is untested. Second, many shale formations - for example, the Marcellus shale - are so large that only a portion of the formation has been extensively production tested. Third, changes in technology and management practices will occur that cannot be anticipated. These changes can make future wells more productive and less costly.

STATEMENT OF ADAM SIEMINSKI

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U.S. DEPARTMENT OF ENERGY

before the

SUBCOMMITTEE ON ENERGY AND POWER COMMITTEE ON ENERGY AND COMMERCE

U. S. HOUSE OF REPRESENTATIVES

AUGUST 2, 2012

Mr. Chairman and Members of the Subcommittee, I appreciate the opportunity to appear before you today to address the outlook for oil and gas reserves and production and the differences between Federal and non-Federal lands.

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. EIA is the Nation's premier source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views expressed herein should therefore not be construed as representing those of the Department of Energy or any other Federal agency.

My testimony today addresses technically recoverable resources, proved reserves, and current production of hydrocarbons – crude oil, lease condensate, natural gas, and natural gas liquids (NGLs). Technically recoverable resources are an estimate of hydrocarbons that are producible using currently available technologies and industry practices from both discovered resources and estimated potential resources without regard to economic considerations. Estimates of technically recoverable resources, while inherently uncertain, are an important input to EIA's energy projections. Proved reserves are estimates of hydrocarbons that geologic and engineering data demonstrate with reasonable certainty can be recoverable from identified fields under existing economic and operating conditions. Each spring, EIA collects estimates of proved reserves at the end of the prior year from both public and private operators. Publicly-

traded companies also report proved reserves to the Securities and Exchange Commission. Production data are also a major focus of EIA's energy information program. The data and estimates we develop and disseminate reflect a combination of survey data collected directly from operators and information provided by other Federal agencies and the States.

I. RESERVES

This week, EIA is releasing its summary report on U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves as of the end of 2010. As noted in EIA's April 28, 2011, press release the FY 2011 enacted budget cut to the President's budget request, resulted in delay of EIA's processing of this data. The year-end 2011 reserves surveys are being collected; we hope to publish them by the first quarter of next year.

For each fuel, net additions to proved reserves, which reflect the volume of reserves added during 2010 after subtracting the year's production, were--by a large margin--the highest ever recorded since EIA began publishing proved reserves estimates in 1977.

Crude oil (including lease condensate) proved reserves increased by 2.9 billion barrels (12.8 percent) during 2010 ending that year at 25.2 billion barrels (Figure 1). Texas, North Dakota, and the Gulf of Mexico Federal Offshore had the largest increases in oil proved reserves in 2010 (Figure 2). An increase in the oil price boosted oil reserves in States with large producing oil fields. The average WTI spot price used for reserves reporting was $79.79 per barrel in 2010 compared with $61.08 in 2009.

U.S. proved reserves of wet natural gas increased by 33.8 trillion cubic feet (Tcf) (11.9 percent) during 2010, ending that year at 317.6 Tcf (Figure 3). Texas, Louisiana, and Pennsylvania had the largest increases (Figure 4). The average annual spot price at Henry Hub used for estimating reserves rose from $3.83 per million British thermal units (MMBtu) in 2009 to $4.39 per MMBtu in 2010.

The increasing ratio of oil to natural gas prices led operators to focus on "liquids-rich" areas in natural gas formations--a move that has continued over the last 18 months as the oil-to-natural-gas price ratio has further increased. This "liquids boost" is especially important in the development of unconventional resources (such as shale gas) because of the relatively high cost of drilling and completing horizontal wells. Because NGLs sell at a premium to natural gas, the high liquids content of certain shale formations helps operators to profitably develop shale gas resources during periods of low natural gas prices.

These NGLs are extracted at gas separators and at natural gas processing plants and some of the heavier components are blended into the liquid hydrocarbon steam. Generally, natural gas liquids include lease condensate and natural gas plant liquids. In the report, the condensate reserves are included in the oil reserves discussed above, while the natural gas plant liquid reserves are included in the wet natural gas reserves discussed above. EIA also provides separate estimates of lease condensate and natural gas liquids.

U.S. lease condensate proved reserves increased from 1,633 million barrels in 2009 to 1,914 million barrels in 2010, a 17 percent increase driven primarily by extensions, which are reserve additions that result from additional drilling and exploration in previously discovered reservoirs.

By a considerable margin, Texas had the largest increase in lease condensate proved reserves in 2010 (192 million barrels), followed by North Dakota and Oklahoma. In these (and other) States, additions to lease condensate proved reserves can be closely linked to expanding drilling programs in liquids-rich portions of shale and other tight formations, such as the Eagle Ford in Texas and the Bakken in North Dakota. Lease condensate comprised 7.6 percent of total oil proved reserves in 2010.

U.S. natural gas plant liquids proved reserves rose from 8,557 million barrels in 2009 to 9,809 million barrels in 2010, an increase of 15 percent. Texas had the largest volumetric increase in natural gas plant liquids proved reserves in 2010, followed by Oklahoma and Colorado. As is the case with lease condensate, increasing proved reserves of natural gas plant liquids is associated with escalating drilling activity in shale formations, including the Barnett in Texas and Woodford in Oklahoma.

The application of horizontal drilling and hydraulic fracturing in shale and other very low permeability ("tight") formations has played an important role in the growth of both oil and natural gas reserves. Proved natural gas reserves have grown dramatically since the mid 2000s, in step with intensifying horizontal drilling programs. For crude oil the dramatic impact from technology onshore has been more recent. Nevertheless, tight oil developments have contributed significantly to the reversal of more than two decades of generally declining U.S. proved oil reserves. For both oil and natural gas, these reserves increases underscore the potential of a growing role for domestically-produced hydrocarbons in meeting both current and projected U.S. energy demands.

One observation we have made is shown clearly in Figure 5. Because the shale resource basins are largely outside of the Federal lands, so too is shale production. In this case, the geology is working in favor of non-Federal landowners.

II. TRENDS IN TOTAL U.S. OIL AND NATURAL GAS PRODUCTION

Moving to production, EIA's estimate of U.S. oil (crude and lease condensate) production during the first 5 months of 2012 averaged 6.2 million barrels per day (bbl/d), the highest level since 1998 (Figure 6). Marked increases in lower 48 onshore oil production, since the fourth quarter of 2011, are mainly because of higher output from tight oil plays from North Dakota and Texas (Figure 7).

The July 2012 Short-Term Energy Outlook forecasts U.S. total oil production increasing to 6.3 million bbl/d in 2012, the highest annual level of production since 1997. In 2013, total oil output rises a further 410,000 bbl/d, most of which is accounted for by increases in lower-48 onshore production. That increase is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes has increased from 777 at the beginning of 2011 to 1,416 on July 27, 2012.

U.S. dry natural gas production has increased since 2005 mainly because of production of shale gas resources (Figure 8). That upward growth trend has been a little bumpy as economic factors affecting gas prices and weather events led to temporary declines in production. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale

has been offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale as well as associated gas from the growth in domestic oil production (Figure 9).

EIA expects continued year-over-year growth in dry production in 2012, though not as strong as the previous year. The July Short-Term Energy Outlook for dry production for 2012, partially reflects upward revisions to historical data for the first few months of the year. However, EIA expects a small drop in production in the coming months, reflecting the decline in rigs since October 2011. According to Baker Hughes, the natural gas rig count was 505 as of July 27, 2012, which was the lowest gas rig count since 1999. In 2013 dry production is expected to continue to rise, though less than in 2012.

Besides the lease condensate produced directly on oil and gas leases, natural gas liquids are produced in natural gas processing plants and in crude oil refineries. In 2011, 78 percent of U.S. NGL marketed production came from gas processing plants. This natural gas plant liquids production is growing rapidly, while refinery production has been relatively constant in recent years.

The huge increase in U.S. shale gas production is the primary cause of increased NGL production. Growing domestic oil and gas development has pushed NGL production to an all-time high in recent months. NGL production from natural gas processing plants was 2.2 million bbl/d in 2011. Most of this production (1.9 million bbl/d) was lighter hydrocarbons, like ethane primarily used in petrochemical plants, and propane used for residential heating, crop drying, etc. These lighter hydrocarbons are gases in a normal atmosphere, but liquefy under pressure.

Ethane and propane production account for most of the increase in NGLs during the past 5 years.

Some 295,000 bbl/d of heavier hydrocarbons (pentanes plus) were also produced, which are liquid at normal atmospheric pressure and are often added directly to the crude oil stream. For the past few years NGL production from natural gas processing plants has been growing faster than natural gas production, as the industry increases exploration in liquids-rich plays. From 2009 through 2011, for example, NGL production grew by 14.3 percent. At the same time, dry natural gas production increased by 11.5 percent. Nearly 500,000 bbl/d of NGLs were sent to U.S. refineries and blenders making up nearly 3 percent of the total domestically produced liquids fuels stream in 2011.

NGL production in 2012 is expected to be about 8 percent higher than in 2011, according to the July Short-Term Energy Outlook. At the same time, dry natural gas production is forecast to grow by 4 percent in 2012. NGL production is projected to be about the same in 2013 as in 2012, while dry natural production is up slightly.

Differences between Federal and Non-Federal Lands

Oil (Crude and Lease Condensate): U.S. oil production declined from 5.7 to 5.0 million barrels per day from Fiscal Year (FY) 2003 to FY2006. It remained about flat for the next 2 years, before rising to 5.6 million barrels per day in FY2011 (Figure 10).

Oil production on non-Federal lands (State and private) decreased from FY2003 through FY2007 by 419,000 bbl/d, remained relatively flat from FY2007 to FY2010, and then increased by

385,000 bbl/d in FY2011 largely because of increases in oil output in North Dakota and Texas. That growth was the result of increased horizontal drilling and hydraulic fracturing in the tight oil plays.

Oil production from Federal lands is dominated by offshore production from the Federal Outer Continental Shelf (OCS). Trends in Federal OCS production reflect the timing of several particularly important deepwater development projects over the past decade, as well as production disruptions and damage as a result of weather events to both producing infrastructure and projects under development. Total oil sales of production from Federal and Indian lands, including the Federal OCS, increased from 1.6 million bbl/d in FY 2008 to 2.0 million bbl/d in FY 2010, but decreased to 1.8 million bbl/d in FY 2011. The most recent data reflect the impact and aftermath of the 2010 Macondo blowout in the Gulf of Mexico. (The sales data for production on Federal and Indian lands are collected by the various programs within the Department of the Interior (DOI), not EIA, for purposes of assessing royalty payments. The sales data are a proxy for marketed production volumes.)

Natural Gas: Production on non-Federal lands has increased steadily from FY2005 to FY2011 by 16.4 billion cubic feet per day (bcf/d), largely because of shale gas resources (Figure 11). Total natural gas sales of production from Federal and Indian lands have decreased each year since FY2003 primarily as production has declined in the Federal OCS. Based on EIA's latest figures for natural gas production in FY2011, the Federal sales share was 21 percent, down from a high of 35 percent in FY2003 (our earliest available data).

Offshore natural gas sales have been on a consistent downward trend over the last 9 years, falling more than 50 percent as development moved from the gas prone shelf to the richer oil prone deep waters of the Gulf of Mexico (Figure 12). As production offshore was declining, however, the production from onshore Federal lands was generally growing over this period, exceeding offshore sales by FY2008. The last 2 years have seen declines, but FY2011 sales from onshore Federal production are still higher than in FY2007.

Policies that pertain directly to leasing and production activities on Federal and Indian lands are only one among the many factors that are reflected in the data. The rapid increase in natural gas production from shale resources, found largely outside the Federal lands, over the last 5 years has significantly reduced natural gas prices and the relative attractiveness of conventional natural gas resources, including those of Federal and Indian lands.

Natural Gas Liquids: NGL production on Federal and non-Federal lands, including the offshore Gulf of Mexico, is not collected or tracked by EIA.

III. DATA COLLECTION FOR OIL AND GAS PRODUCTION

EIA estimates for non-Federal oil production are based on monthly oil production data from State Government agencies and purchased third party data. EIA estimates for annual non-Federal natural gas production also use data reported on Form EIA-914 "Monthly Natural Gas Production Report," in addition to State data.

Many of the States collect production data largely for revenue purposes, though some data are collected in order to regulate oil and gas production. Different data are collected by each State,

and definitions vary from State to State on the most basic of questions, such as: What is an oil well? Most States define oil and gas wells by a gas-oil ratio (GOR). Each State chooses its own GOR. These can range from 6,000 to 100,000 cubic feet per barrel. Some States use the initial GOR; some use the current GOR. Some States do not define oil and gas wells. One State—Illinois—collects no data at all.

EIA uses these State data together with third party purchased data to estimate monthly oil production. One of the most significant problems in using the State production data is that the lag from when the data are first reported to the time when they stop changing significantly varies enormously from State to State. A few States, like North Dakota and Alaska, report relatively complete data within 2 months of the close of the production month. Others, like Texas and Oklahoma, take a year or two to report complete data.

EIA relies on State data to estimate the growing tight oil production. States typically do not report tight oil production separately from other crude oil production, so we estimate tight oil production based on our understanding of the geology of each producing area. Generally, we identify the reservoirs and formations for each oil well, though sometimes we attribute all production in a county to a particular formation. This is a significant undertaking with roughly 535,000 producing oil wells and 65,000 fields in the United States.

Despite these limitations, earlier this year EIA made a significant improvement in reporting EIA's State oil production estimates. Starting with the publication of January 2012 data in March 2012, State oil production estimates are now reported with a 2-month lag, instead of a 4-month lag, as they had been for many years. In addition, State estimates are being revised

monthly going back to the beginning of the last published Petroleum Supply Annual. These changes required extensive internal coordination and were made with current staff and resources as part of an ongoing internal process improvement effort.

One exception to the use of State data to estimate monthly oil production is the offshore Gulf of Mexico, where EIA relies on the DOI Bureau of Safety and Environmental Enforcement (BSEE). BSEE routinely reports metered data from the Gulf of Mexico Liquid Verification System (LCVS) about 45 days after the end of the production month. EIA uses LVS data for the most recent few months. After several months, these LVS data are replaced with operator-reported data from the DOI Office of Natural Resources Revenue (ONRR). Over the last few months EIA has been working with BSEE to gain earlier access to the LVS data.

EIA also relies on private companies to some extent to estimate natural gas shale production data. Lippman Consulting, Inc. uses State data to estimate shale gas production and EIA relies on these estimates because they are the best available. EIA also provides annual summary information on production of oil and other fossil fuels on Federal and Indian Lands, including onshore Federal and Indian lands as well as offshore production. These data are collected by various programs within DOI, and not by EIA. Drawing from a variety of DOI sources, EIA has recently issued a report, "Sales of Fossil Fuels Produced from Federal and Indian Lands, FY 2003 through FY 2011," that provides EIA's current best estimates based on sales for fiscal year (FY) 2003 through FY 2011. EIA has worked closely with the ONRR, which has posted on its website and shared information with EIA on sales of fossil fuels produced on Federal and Indian lands based on information reported to it through February 6, 2012. Data on fossil fuel sales

continually flow into the DOI program offices, and those programs also conduct audit activities that may result, over time, in changes in the previously reported data to both sales and royalty payments.

Direct Collection of Natural Gas Data: Unlike oil production, EIA collects data on natural gas production from about 240 operators each month. This EIA-914 survey covers five States and the Federal offshore Gulf of Mexico, lumping all the other States together as "Other States." The five States are: Texas, Louisiana, Oklahoma, New Mexico, and Wyoming. Not all operators are surveyed in these States, just the largest ones. The sample of operators is revised each month to account for operator growth and decline, including sales and mergers, based on a database of operating wells that is continuously updated by HPDI, a private firm.

EIA started collecting data from operators in the five States in 2005, at the request of Secretary of Energy Spencer Abraham, because of the growing importance of timely and accurate monthly natural gas production data. Before 2005 monthly natural gas production was estimated from State data. As a result, natural gas production data were not available until 4 months after the close of the production month. Since January 2007 the EIA survey has provided data just 60 days after the close of a production month.

Though more accurate than the oil production estimates, the current natural gas monthly production survey has limitations. It does not collect data on production on Federal lands or data on natural gas shale production, and it has not been expanded to identify and track major changes in natural gas production in the Other States group, such as the rise in shale gas production in Pennsylvania and Arkansas.

In its FY2013 budget, EIA has proposed spending an additional $550,000 per year to increase the timeliness and accuracy of both oil and natural gas production data. Additional funds would allow EIA to expand the EIA-914 to 15 producing States and to add collection of oil production. Collecting data from 15 States would increase the sample size of the collection from the current 240 operators to about 500 operators. Collection of shale and/or Federal lands production data may come at no additional cost. The proposal would increase data quality as well as enable EIA to identify and report on trends sooner.

IV. OIL AND NATURAL GAS RESOURCES

Finally, I want to speak to the issue of resources. The Annual Energy Outlook 2012 projections were based on a natural gas resource estimate of 2,203 trillion cubic feet of technically recoverable resources (Figure 13). Technically recoverable resources, also known as TRR, is a common measure of the long-term viability of U.S. domestic oil and natural gas as an energy source. TRR estimates are a "work in progress," changing as more production experience becomes available and as new production technologies are applied to these resources.

EIA's energy supply projections address the timing of economic production of oil and natural gas resources, which depend upon the production profile of individual wells over time, the cost of drilling and operating those wells, and the revenues generated by those wells, based on projected oil and gas prices. For this reason EIA is primarily concerned with determining well drilling and operating costs, production decline curves, and other economic parameters, such as tax, depreciation, and royalty rates. Although TRR estimates provide a context for the size of

the potentially available resource, this aggregate number says nothing about whether a large or small portion of the resource will be economic to produce in the foreseeable future.

The economic viability of any resource depends not only on its production costs and revenues, but also the cost of developing alternative resources. Estimates of economically recoverable resources, however, receive little public attention in comparison to technically recoverable resources because they change as the expectations change regarding future prices, costs, and technology.

The EIA relies heavily on the expertise of the United States Geologic Survey (USGS) to develop many of the resource production characteristics and parameters that generate TRR estimates. The USGS estimates of TRR represent a snap shot of resource recoverability based on the wells drilled and technologies deployed prior to the assessment. The USGS re-estimates a formation's TRR, typically updating its estimates every 5 to 10 years, whereas EIA re-estimates production decline curves, and in turn, estimated ultimate recovery (EUR) per well and TRR for every Annual Energy Outlook. In EIA's annual re-estimation process, EIA emphasizes current well productivity data, which inherently incorporates the latest technology. EIA also develops estimates for those formations that have recently gone into production, but for which the USGS has not yet developed a resource estimate.

Whenever possible, the EIA uses the formation parameters developed by the USGS and published in their oil and gas resource assessments. For example, the EIA uses the USGS's land area estimates and the number of wells drilled per square mile. When USGS parameters for a

formation are not available, the EIA will use other public data, such as that provided by the State geologic surveys, and by professional geologists and petroleum engineers.

Although each TRR parameter has some degree of uncertainty associated with it, the greatest uncertainty is associated with the determination of a formation's average production decline curve, which specifies a well's estimated ultimate recovery (EUR). In order to determine a well's production decline curve and EUR, its monthly production profile is statistically fitted to a hyperbolic decline curve so that the well's production profile can be extrapolated into the future for its expected 30-year lifetime.

Variability in well production causes considerable uncertainty around a formation's average EUR. Neighboring well production rates can vary by as much as a factor of 3, while well production rates across the entire formation can vary by a factor of 10. This variability is due to the significant local variations in formation depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, natural fractures and water content. The productive variability across a formation's wells complicates the development of EUR estimates because it is not clear which wells within a formation are truly representative of that formation. The EIA captures the productive variability of a formation's EUR by subdividing a formation into subplays—first across States, if applicable, and then into three productivity categories: best, average, and below average.

The uncertainties in determining well EURs are further complicated by three factors. First, most shale gas and tight oil wells are only a few years old, and their long-term productivity is untested. Consequently, reliable data on long-term production profiles and long-term well

recovery rates are lacking. Second, many shale formations - for example, the Marcellus shale - are so large that only a portion of the formation has been extensively production tested. Third, changes in technology and management practices will occur that cannot be anticipated. These changes can make future wells more productive and less costly.

The issue of technological progress is particularly challenging because the continual improvement in drilling and completion techniques has significantly improved initial well production rates and possibly their long-term EURs. Because of the continual improvement in technology, it is not clear whether the production profiles of the older wells within a formation are representative of future well productivity. In certain instances it is appropriate to exclude some of the older well production data in creating an EUR estimate because the technology embodied in those wells is no longer representative of the wells that are likely to be drilled and completed in the future.

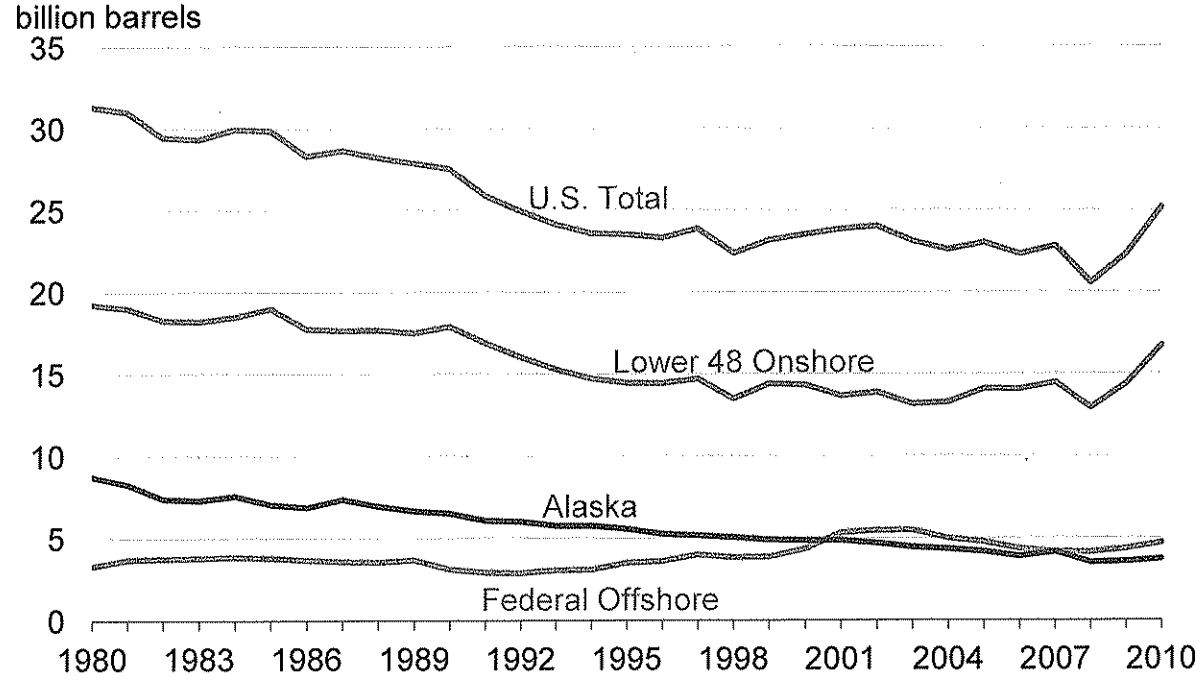
Over time, estimates regarding a formation's average EUR should become less uncertain as more wells are drilled across the entire formation and as more wells produce over a longer period of time. As a formation's EUR estimate changes, so too will the formation's TRR estimate.

EIA will continue to solicit input from geologists, petroleum engineers, statisticians, and other experts to improve the methodology for developing estimates of TRR and to determine specific key assumptions. The ultimate goal is to establish a TRR methodology that is practical, reasonable, defendable, and uses the best available production data. Even so, EIA recognizes that even the best methodology and data will still result in highly uncertain TRRs that will

change over time as more information becomes available and as management practices and technology evolve.

This concludes my statement, Mr. Chairman, and I will be happy to answer any questions you and the other Members may have.

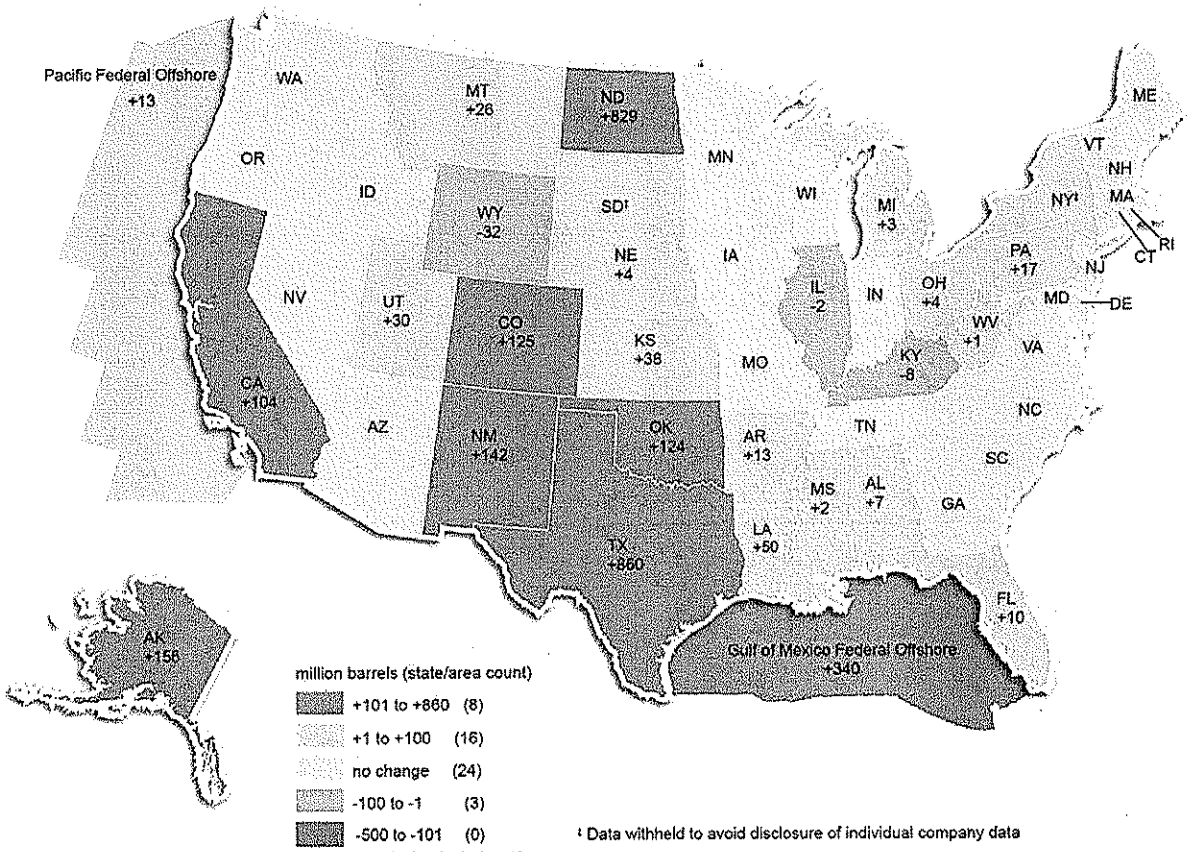
Figure 1. U.S. crude oil plus condensate proved reserves, 1980-2010



Source: U.S. Energy Information Administration

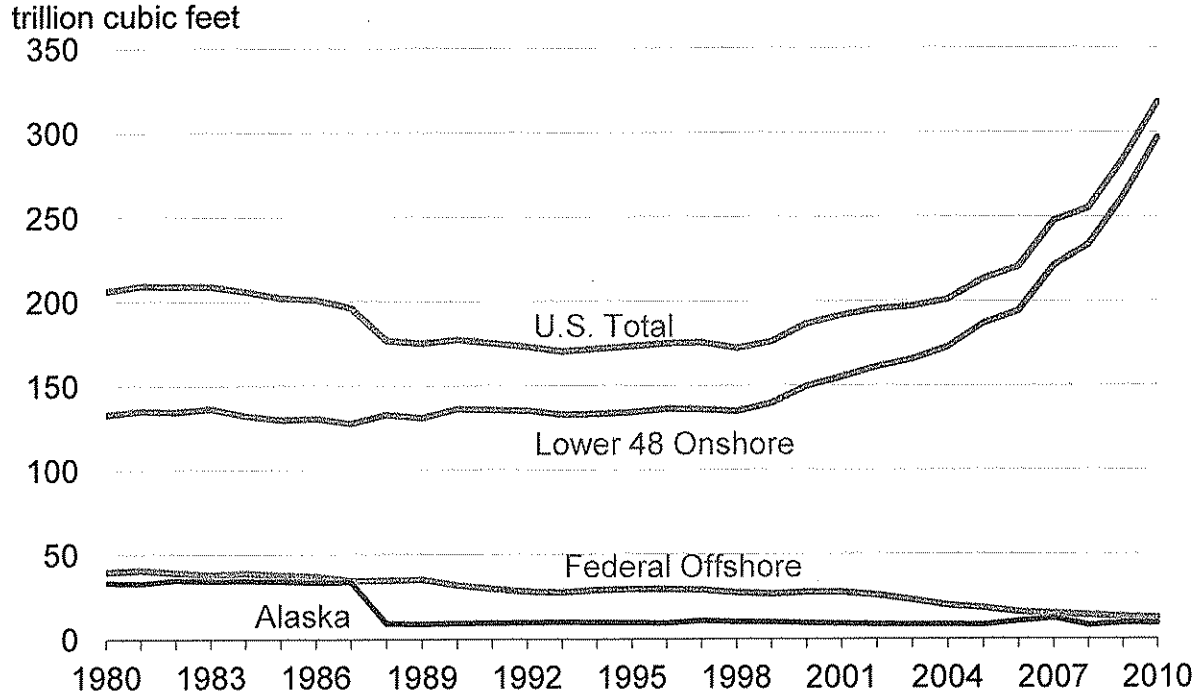
Figure 2. Changes in oil proved reserves by state/area 2009-10

billion barrels of crude oil and lease condensate



Source: U.S. Energy Information Administration

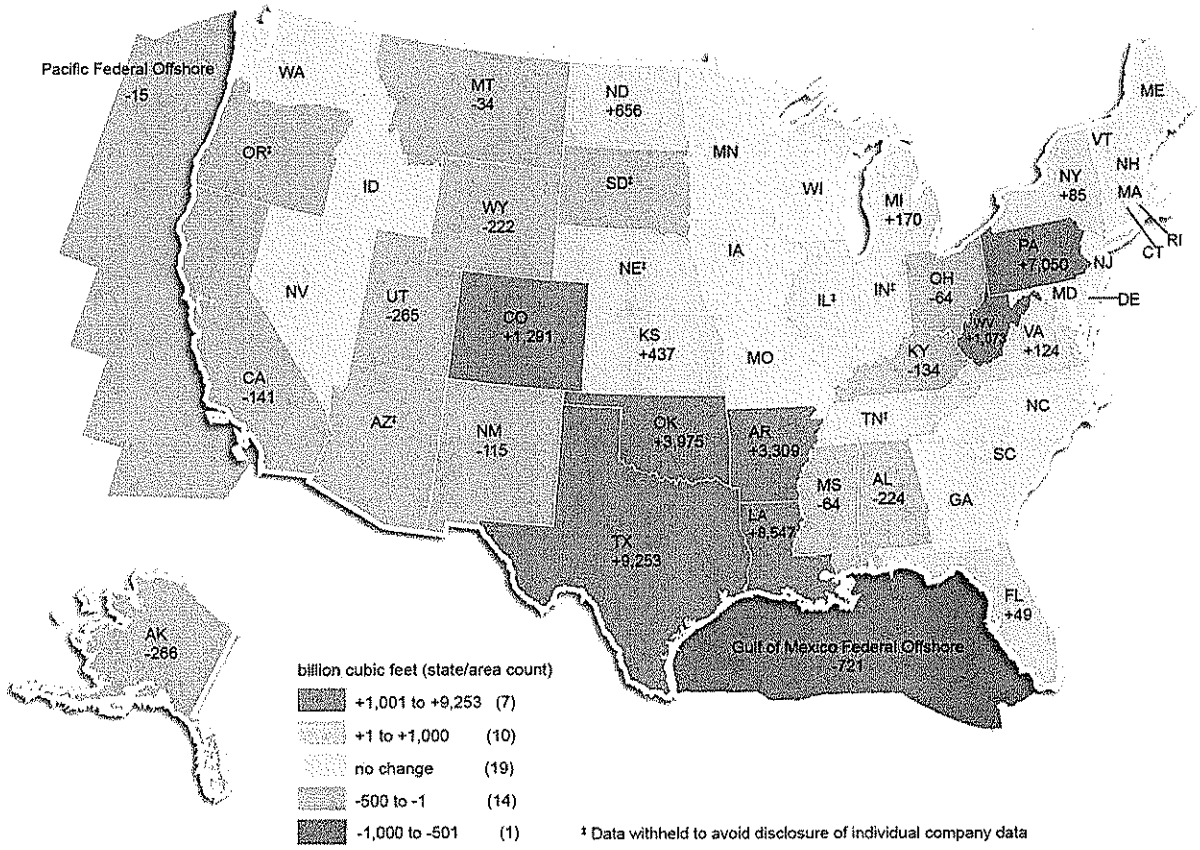
Figure 3. U.S. wet natural gas proved reserves, 1980-2010



Source: U.S. Energy Information Administration

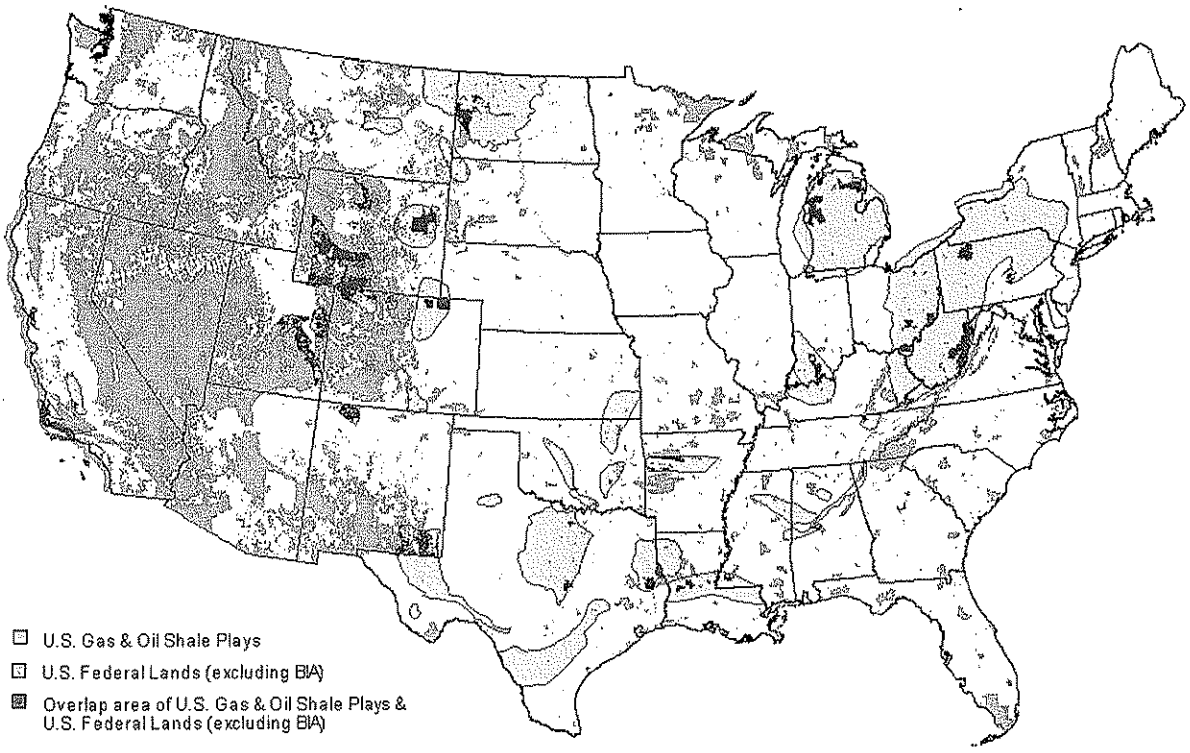
Figure 4. Changes in wet natural gas proved reserves by state/area 2009-10

billion cubic feet



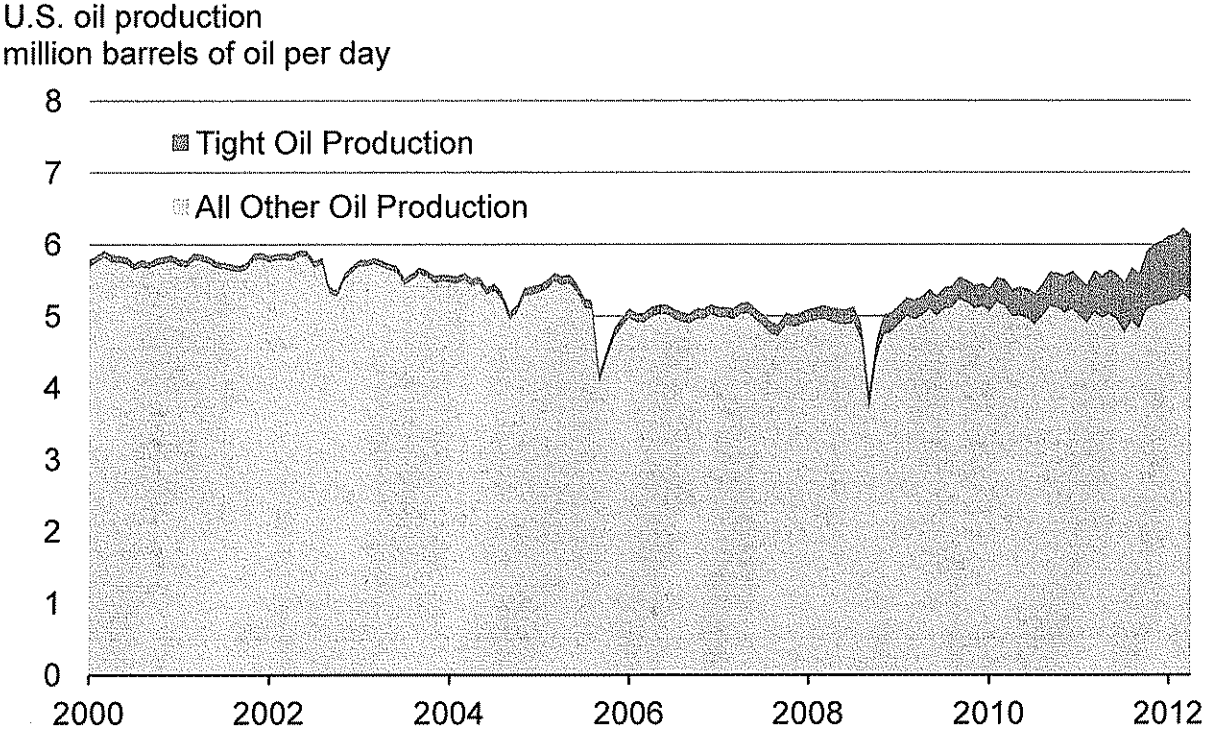
Source: U.S. Energy Information Administration

Figure 5. Lower 48 oil and gas shale formations and federal lands



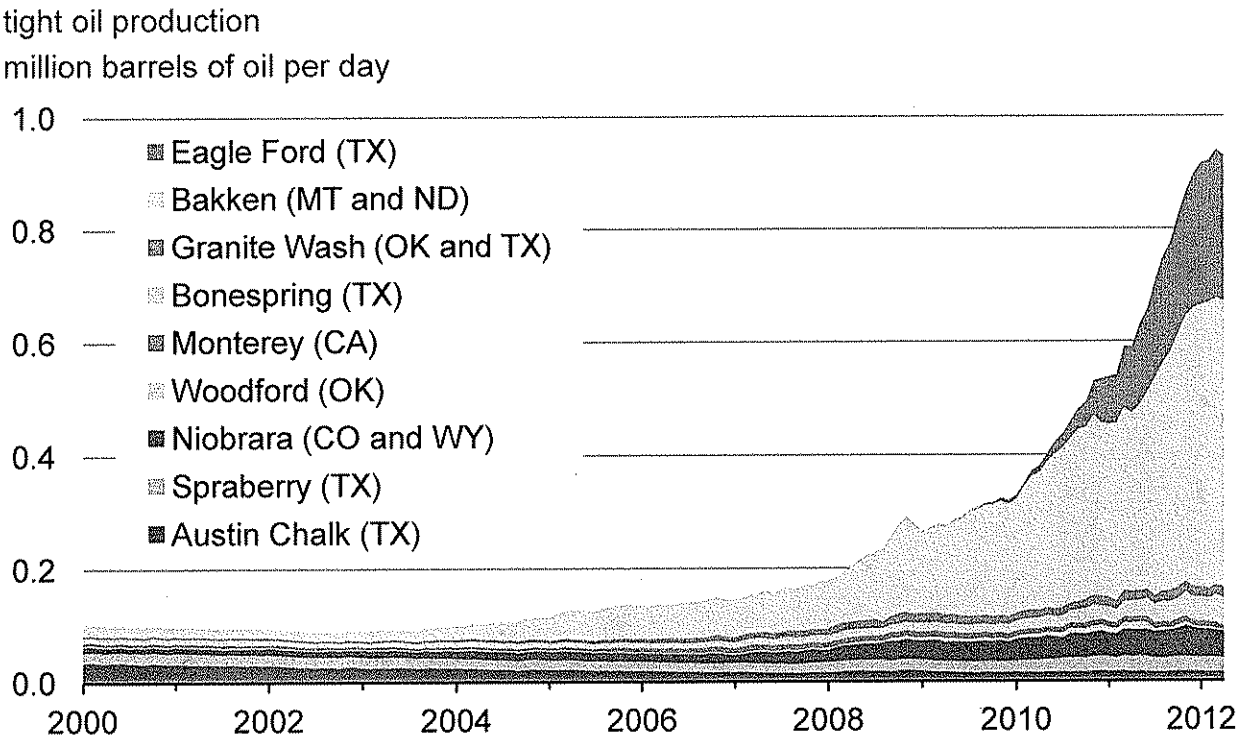
Source: U.S. Energy Information Administration

Figure 6. Crude oil production beginning to grow due to tight oil development, led by Bakken



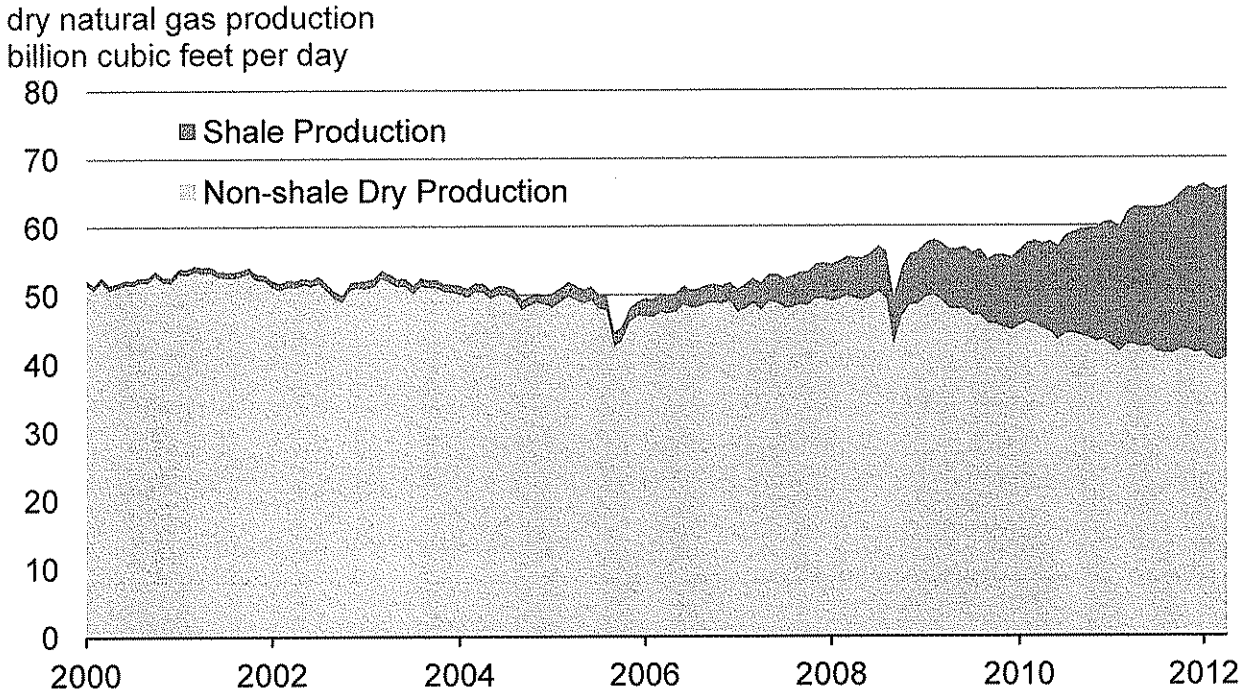
Source: U.S. Energy Information Administration, HPDI, Railroad Commission of Texas, and North Dakota Department of Mineral Resources

Figure 7. Tight oil production for selected plays through April 2012 approaches 950,000 barrels per day



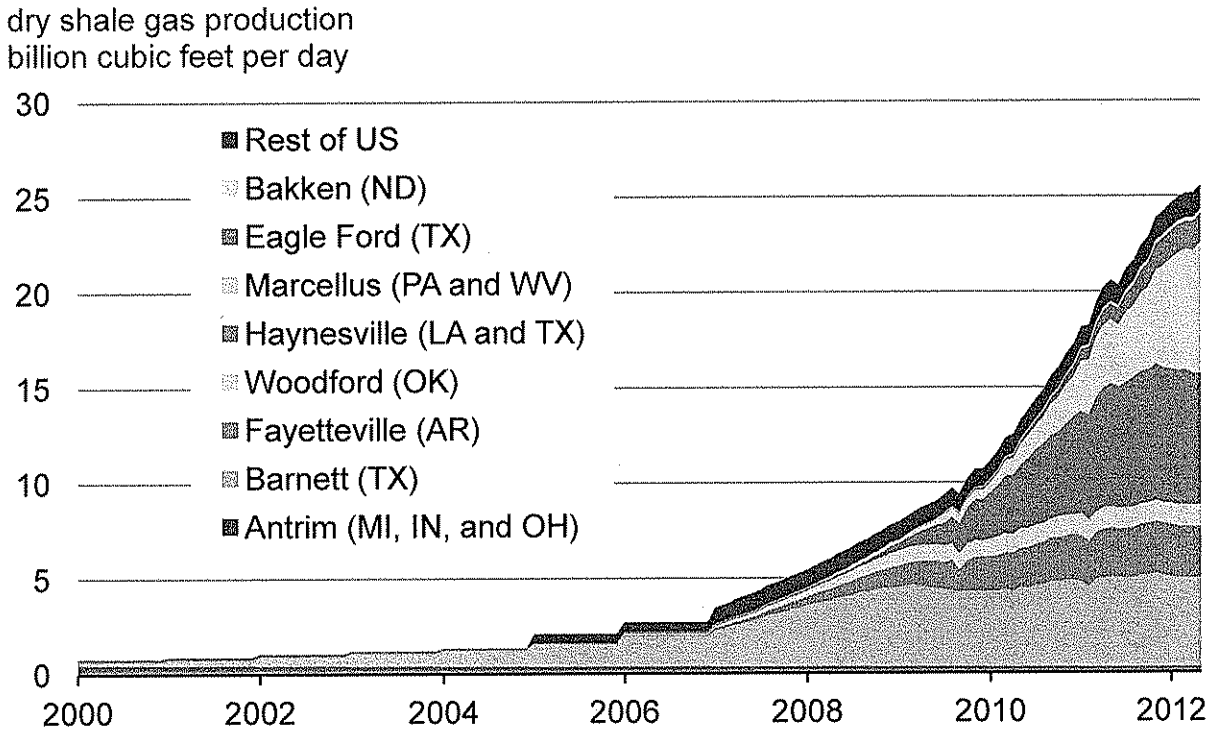
Source: U.S. Energy Information Administration, HPDI, Railroad Commission of Texas, and North Dakota Department of Mineral Resources, through April 2012

Figure 8. U.S. shale gas production comprised over 30 percent of total U.S. dry production in 2011



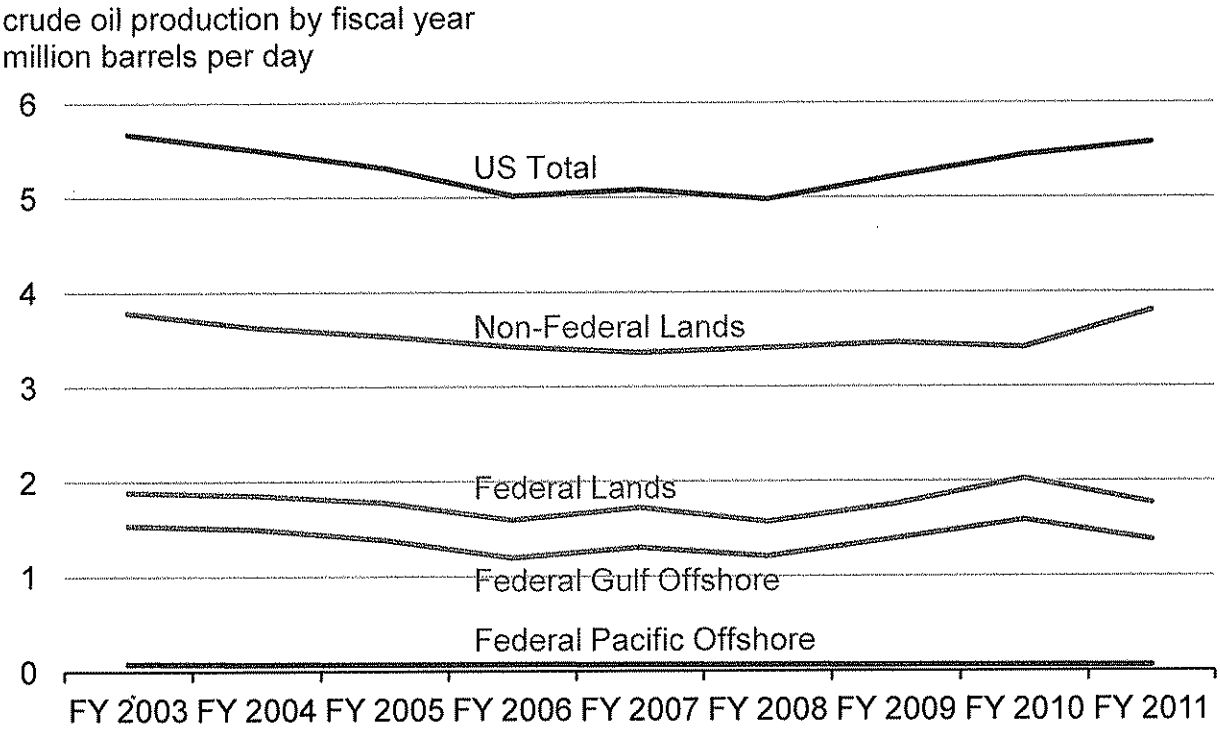
Source: U.S. Energy Information Administration and Lippman Consulting, Inc.

Figure 9. Shale gas production comprised over 30 percent of total U.S. dry production in 2011



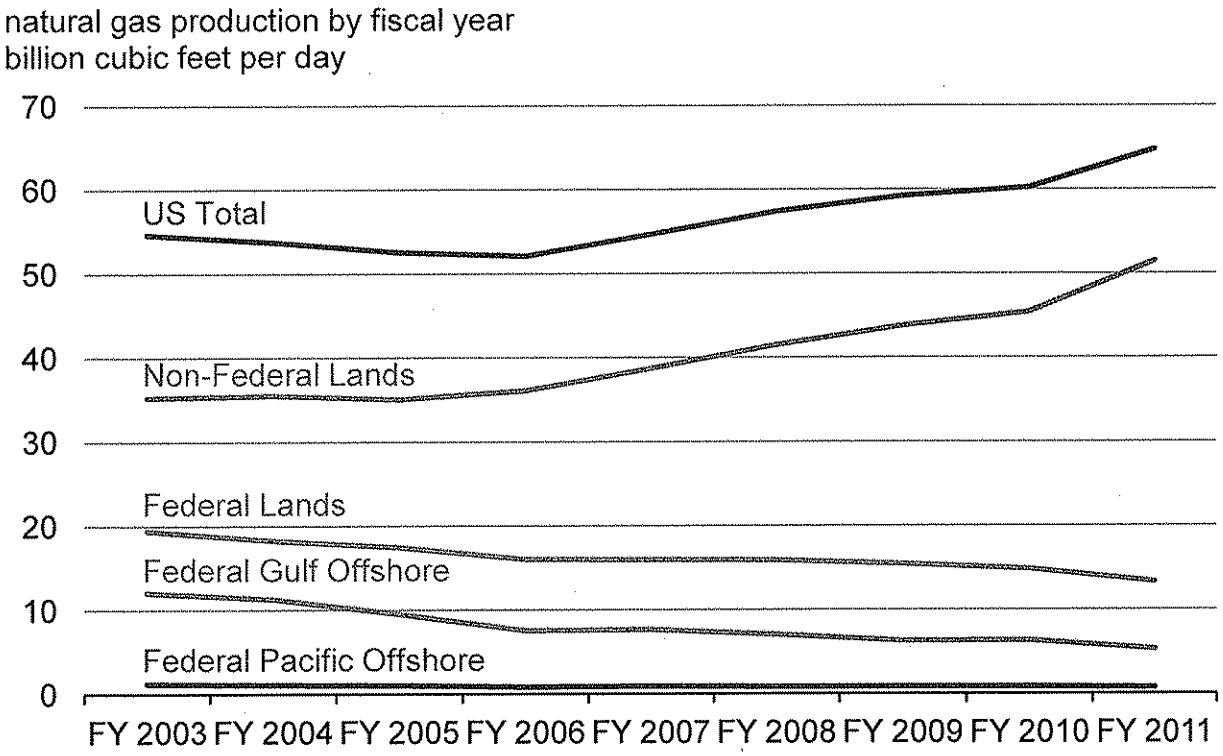
Sources: Lippman Consulting, Inc., adjusted by the U.S. Energy Information Administration

Figure 10. U.S. crude production on federal and non-federal land



Sources: U.S. Energy Information Administration, U.S. Dept. of the Interior's Office of Natural Resource Revenue and Bureau of Safety and Environmental Enforcement

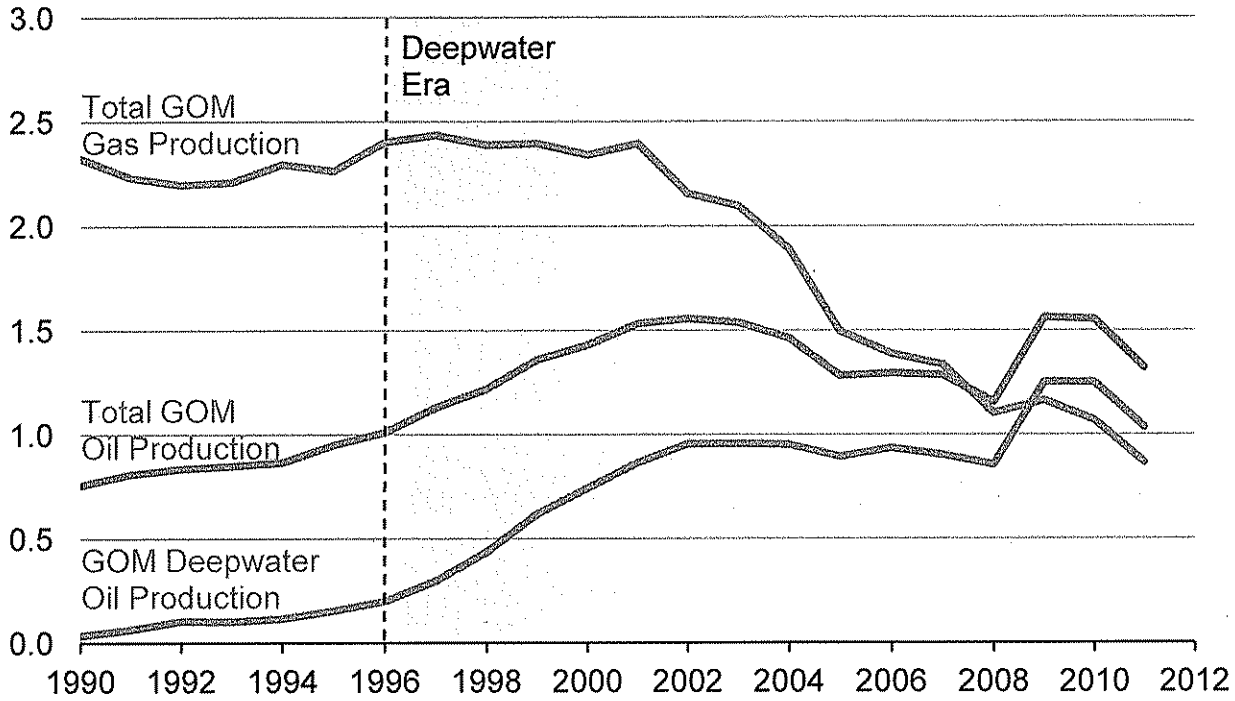
Figure 11. U.S. natural gas production on federal and non-federal lands



Sources: U.S. Energy Information Administration, U.S. Dept. of the Interior's Office of Natural Resource Revenue and Bureau of Safety and Environmental Enforcement

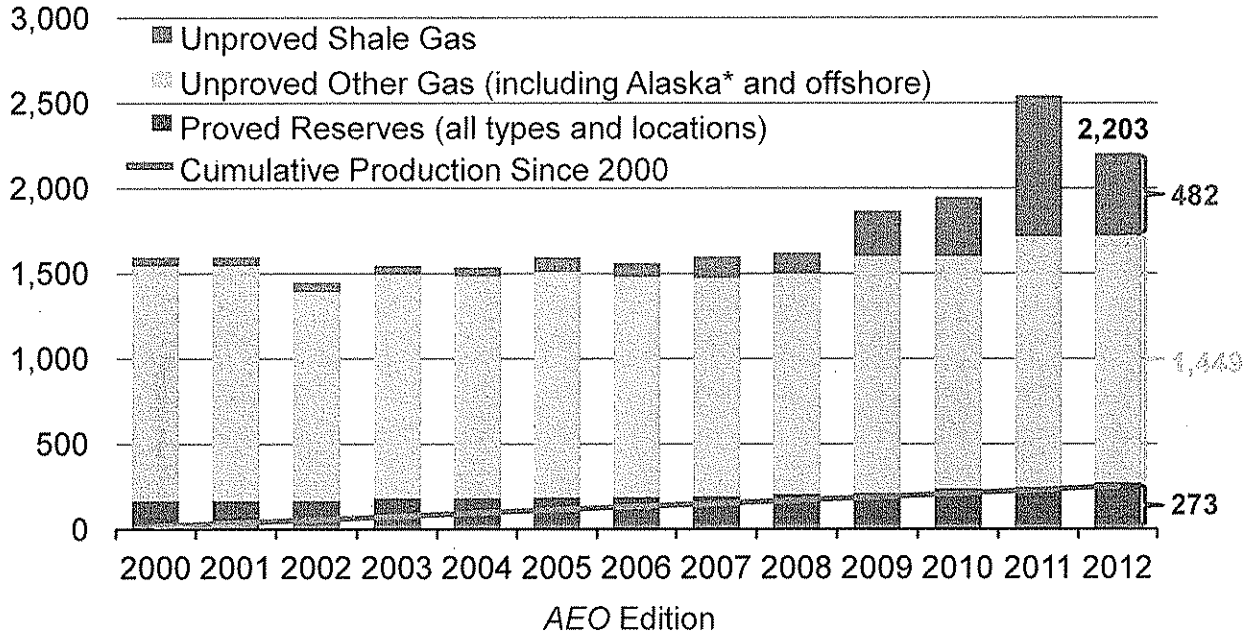
Figure 12. Federal Gulf of Mexico oil and gas production

million barrels of oil equivalent per day



Source: U.S. Energy Information Administration based on HPDI

Figure 13. Technically recoverable resources



**Alaska resource estimates prior to AEO2009 reflect resources from the North Slope that were not included in previously published documentation.*

Source: U.S. Energy Information Administration, Annual Energy Outlook 2012