INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

April 12, 2013

The Honorable Kevin Brady
Member of Congress
301 Cannon House Office Building
Washington, DC 20515

The Honorable Mike Thompson
Member of Congress
231 Cannon House Office Building
Washington, DC 20515

Dear Congressmen Brady and Thompson:

The following comments are submitted on behalf of the Independent Petroleum Association of America (IPAA). IPAA appreciates the Energy Working Group's willingness to engage stakeholders and collect information on a critical issue confronting American natural gas and oil production – the role of the tax code with regard to the enhancement or deterioration of American exploration and production of natural gas and petroleum.

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be the most significantly affected by changes to oil and natural gas tax provisions. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 56 percent of American oil, and more than 85 percent of American natural gas. Independent producers historically reinvest over 100 percent of American oil and natural gas cash flow back into new American production.

Additionally, IPAA is the primary national Trade Association representing smaller independent natural gas and oil producers, many of which are marginal well operators. Marginal wells are those with average production of not more than 15 barrels of oil or 90 Million cubic feet (Mcf) of natural gas, per day. An average marginal oil well in the United States produces about 2 barrels/day. Approximately eighty-five percent of all American oil wells are marginal wells, but they provide about twenty percent of American oil production. Seventy-three percent of all American natural gas wells are marginal wells, providing twelve percent of American natural gas production. The marginal well base in the United States is unique and important. Unlike other countries, where governments generally own mineral rights and there is little incentive to keep marginal wells in operation, the United States has a strong, marginal oil and natural gas base.

This marginal base has a low rate of decline and will produce for decades, assuming wells are not made uneconomic because of government policies.

The Bright Future for Oil and Natural Gas Development in America and Positive Impacts on the American Economy

America continues to face a difficult economic situation. Despite strong headwinds, the American oil and natural gas industry is one of the few sectors that is pushing the economy forward, creating jobs and investing here at home. Independent producers are leading this charge. As a result, America has witnessed a revival in oil and natural gas production. The United States is currently third in the world in crude oil and natural gas liquids production and America continues to grow its output. Most importantly, the United States is one of the only countries in the world where energy security is improving. For example, crude production in the United States, after sinking to levels not seen since the mid-1940s, rose more than half a million barrels per day between 2007 and 2011. That size of increase has not been witnessed in the United States in more than forty years. Imports have declined some 2 million barrels per day since 2005. America's reliance on foreign petroleum has drastically shifted in a little over 6 years. According to the Energy Information Administration, net oil imports dropped from 60.3 percent of products supplied in 2005 to less than 45 percent in 2011 and an estimated 40.6 percent in 2012. This is a positive trend that America needs to continue.

The picture is equally bright with respect to natural gas production in the United States. The Potential Gas Committee (PGC) recently determined, in the PGC's 2012 year-end biennial report, that the United States possesses a technically recoverable natural gas resource potential of 2,384 trillion cubic feet (Tcf). The 2012 year-end report was the highest resource evaluation in the PGC's 48 year history—exceeding by 486 Tcf the previous record-high assessment from year-end 2010. The combination of horizontal drilling, coupled with hydraulic fracturing – techniques pioneered by America's independent producers – have resulted in the ever-increasing estimates of technically recoverable natural gas reserves in the United States. The PGC's resource evaluation shows that the United States, at current consumption levels, has a 100 year supply of natural gas.

The economic impacts associated with increased American oil and natural gas production are striking. According to recent studies conducted by IHS Global Insight, onshore independent producers supported 2.1 million jobs in 2010. Independent oil and natural gas producers operating in the offshore Gulf of Mexico accounted for more than 200,000 jobs in 2009. Billions of dollars are injected into the American economy every year by the oil and natural gas industry, in the form of purchased services, in taxes, royalties and bonus payments to governments, and in salaries paid to the millions of individuals employed by these companies. According to an IHS Global Insight study, onshore independents' contributed $320.6 billion in economic activity, accounting for 2.2 percent of U.S. gross domestic product. Independents operating in the offshore Gulf of Mexico accounted for $28 billion in economic benefits in 2009.

Individual states are realizing similar impacts. In Louisiana, for example, IHS determined that unconventional gas activity contributed value-added economic impact of $10.7 billion in 2012. Also noteworthy is the fact that the annual average wage in the State of Louisiana is $57,600 compared to the average wage of direct jobs in unconventional gas activity which is $108,700. Unconventional gas employment generated over$1.2 billion in state and local government taxes in Louisiana in 2012, which is equivalent to fourteen percent of the state's total budget.

The Eagle Ford shale in Texas is another prime example of the economic impact of American oil and natural gas production. According to a study by the Center for Community and Business Research at The University of Texas at San Antonio Institute for Economic Development, in a little over two years since the Eagle Ford's discovery, the Eagle Ford shale provides nearly 47,000 full time jobs and generates $250 million in government revenues. A fraction of these jobs existed in this area of Texas prior to the Eagle Ford's discovery. Similar economic impacts are being realized because of shale plays in different states across the country, including Ohio, Pennsylvania, Colorado, North Dakota, Michigan, and Montana.

The long-term impacts of increased American development are paradigm shifting. The price of natural gas in America, prior to the discovery of the major shale plays, averaged above $8/Mcf. Today, the average price of natural gas in the United States is approximately $4/Mcf. Assuming EIA consumption levels, the price differential because of the discovery of natural gas in shale is approximately $100 billion/year to American consumers.

The natural gas renaissance in the United States will result in America having the lowest long-term natural prices of any industrial nation. The United States, for example, could have natural gas at half the cost of European natural gas and at one third of the cost in Asia. As a result, the United States has a built in price advantage, for energy costs, compared to any of our industrialized competitors. The United States is seeing manufacturing and chemical operations relocate to the United States. The abundance of natural gas in the United States also allows the opportunity for the American economy to utilize natural gas in new ways – an expansion of American chemical production, greater use of natural gas for electricity generation, natural gas vehicle development and exports of liquefied natural gas.

The federal government can enhance or impede the development of American oil natural gas. Changes to oil and natural gas tax provisions would have an immediate impact. If Congress eliminates provisions such as the immediate expensing of intangible drilling costs, independent producers would drill 25 to 40 percent fewer wells (see discussion of Intanigble Drilling Costs deduction below). Congress has a simple choice, it can promote American oil and natural gas production or Congress can harm oil and natural gas production – treatment of oil and natural gas tax provisions are central to determining which path America follows.

Considerations as the Ways and Means Committee Contemplates Tax Reform

As the House Ways and Means Committee (the Committee) decides what provisions to eliminate to lower tax rates, the Committee will, inevitably, benefit some taxpayers at the expense of other taxpayers (i.e. imposing a tax increase on certain industries, by repealing deductions, to lower marginal tax rates across the board). The tax code will always bear on business decisions and the flow of capital in America, regardless of any clarity created by tax reform. Currently, the tax code recognizes the importance of capital intensive industries in the United States and encourages capital to flow to those industries that create jobs and products in America. Eliminating legitimate business deductions to lower corporate tax rates may equalize tax treatment across industries. But, the Committee should consider whether this is in the best interest of America. The end result of creating parity across the tax code will merely incentivize capital to flow to the highest rate of return, not necessarily to those industries that are in the national interest because they create the products and jobs needed to lead American out of its economic malaise and provide secure, middle class jobs.

The Committee's choices regarding tax provisions will, therefore, determine where investments are made in the economy and the types of jobs that will define the American economy. Congress can choose to direct capital toward, or away from, certain industrial sectors. As the Ways and Means Committee (the Committee) moves forward with tax reform, there are a number of threshold questions that IPAA would encourage the Committee to contemplate:

(1) Should the tax code continue to recognize the concepts of capital formation and capital recovery which encourage capital to flow to industries like energy, manufacturing and technological development that ensure the country has a stable, American energy supply and a vibrant manufacturing base?
(2) Should capital intensive industries be treated the same as the retail and other service industries, where jobs are more transitory?
(3) Does the Committee want to encourage increased production of American oil and natural gas or return to an increasing reliance on imported oil and natural gas —imports that have for decades raised national security issues?
(4) Does the Committee want to support smaller, independent oil and natural gas producers that do not have the same access to capital as larger companies and who must finance their operations either (a) with their own cash flow or (b) with private investors?

As Congress contemplates these questions, it should recognize that to date, there have been no proposed changes to oil and natural gas tax provisions – from the Administration or Congress -- that would not result in a tax increase for America's independent natural gas and oil producers.

Simply put, increased taxes on America's independent producers will decrease production of oil and natural gas, as well as investment, in the United States.

Tax Provisions Applicable to Independent Oil and Natural Producers

Federal tax policy has historically played a substantial role in developing America's natural gas and petroleum. Early on, after the creation of the federal income tax, the treatment of costs associated with the exploration and development of this critical national resource helped attract capital and retain it in this inherently capital intensive and risky business. Allowing the expensing of intangible drilling and development costs and percentage depletion rates of 27.5 percent are examples of such policy decisions that resulted in the United States' extensive development of its petroleum.

But, the converse is equally true as Congress has enacted policies that discouraged capital investment in American oil and natural gas production. By 1969, the depletion rate was reduced and later eliminated for all producers except independents. However, even for independents, the rate was dropped to 15 percent and allowed for only the first 1000 barrels per day of petroleum produced. A higher rate is allowed for marginal wells which increases as the petroleum price drops, but even this is constrained – in the underlying code – by net income limitations and net taxable income limits. In 1986 as the industry was trying to recover from the last long petroleum price drop before the 1998-99 crisis, federal tax policy was changed to create the Alternative Minimum Tax (AMT) that sucked millions more dollars from the exploration and production of petroleum and natural gas. These changes have discouraged capital from flowing toward this industry.

The Obama Administration's budget request – and recurring advocacy statements on an almost daily basis – would strip essential capital from new American natural gas and oil investment by radically raising taxes on American production. American natural gas and oil production would be reduced. It runs counter to the Administration's clean energy and energy security objectives. The following is a review of some of the tax provisions applicable to the independent oil and natural gas industry in America.

Intangible Drilling and Development Costs (IDCs) – Expensing IDCs has been part of the tax code since 1913. IDCs generally include any cost incurred that has no salvage value and is necessary for the drilling of wells or the preparation of wells for the production of natural gas or oil. Federal tax policy allows for the expensing of similar costs for a number of industry activities in addition to oil and natural gas production – including research and experimental expenditures and expenditures by farmers for fertilizer.

Only independent producers can fully expense IDCs on American production. Loss of IDCs for independent producers will have significant effects on their capital development budgets. A Raymond James analysis in 2009 reported that the loss of IDCs would result in capital drilling budgets being reduced by 25 to 30 percent. This compares with information provided to IPAA by its members indicating that drilling budgets would be cut by 25 to 40 percent. Regardless of the exactness of the assessments, clearly, the consequences would be significant. And, the consequences would soon be evident. Roughly half of America's current natural gas production is provided by wells developed during the past four years.

Additionally, changes to IDCs expensing could be perilous for smaller independent producers. Unlike larger oil and natural gas companies, smaller independent producers are unable to attract financing from institutional investors or even community banks. The advent of Dodd-Frank has increasingly made lending to smaller producers impossible. As such, smaller producers must finance their drilling operations with cash flow generated from the wellhead. Changing the ability to immediately expense IDCs will drastically curtail drilling budgets for all independent producers and will be especially impactful for smaller producers.

Percentage Depletion – All natural resources minerals are eligible for a percentage depletion income tax deduction. Percentage depletion for natural gas and oil has been in the tax code since 1926 after Congress determined that relying solely on cost depletion was leading to the loss of important American mineral resources. Unlike percentage depletion for all other resources, natural gas and oil percentage depletion is highly limited. It is available only for American production, only available to independent producers and for royalty owners, only available for the first 1000 barrels per day (6000 mcfd of natural gas) of production, limited to the net income of a property and limited to 65 percent of the taxpayer's net income. Therefore, as with IDC expensing, percentage depletion is critical for smaller independent producer's ability to finance drilling operations from cash flow. Percentage depletion provides capital primarily for smaller independents and is particularly important for marginal well operators. These wells – that account for approximately 20 percent of American oil and 12 percent of American natural gas – are the most vulnerable economically. Input to IPAA from its operators who take percentage depletion indicates that the combined effect of eliminating IDC and percentage depletion would reduce drilling budgets in half. At this lower rate, new production will not offset the natural decline in production from existing wells. For example, one producer now drills ten wells per year; without IDC and percentage depletion, this producer could only drill five wells per year. A five well program will not replace declining production in existing wells and the small business company will have to shutdown. Congress' choice is straightforward: reduce American oil production by 20 percent and its natural gas production by 12 percent or retain the current historic tax policies that have encouraged American production.

Passive Loss Exception for Working Interests in Oil and Gas Properties – The Tax Reform Act of 1986 divided investment income/expense into two baskets – active and passive. The Tax Reform Act provided an exception for working interests in natural gas and oil from being part of the passive income basket and, if a loss resulted (from expenditures for drilling wells), it was deemed to be an active loss that could be used to offset active income as long as the investor's liabilities were not limited. Natural gas and oil development require large sums of capital and producers frequently join together to diversify risk. Additionally, natural gas and oil operators have sought individual investors to contribute capital and share the risk of drilling wells. Most American wells today are drilled by small and independent companies, many of which depend on individual investors. There is no sound reason for Congress to enact tax rules that would discourage individual investors from continuing to participate in this system. Moreover, Congress applied the passive loss rules only to individuals and not to corporations. The repeal of the working interest rule, therefore, would senselessly drive natural gas and oil investments away from individuals and toward corporations. There is no apparent reason why Congress would or should favor corporate ownership over individual ownership of working interests. Furthermore, since AMT restrictions apply to IDC of individual working interest investors, the application of the passive loss rules to those investors is unnecessary and excessive. In sum, to qualify for the exception, the taxpayer must have liability exposure and definitely be at risk for any losses. If income/loss, arising from natural gas and oil working interests, is treated as passive income/loss, the primary income tax incentive for taxpayers to risk an investment in natural gas and oil development would be significantly diminished. In today's banking climate, smaller producers find banks uninterested or incapable of providing capital; taking private investors away will further exacerbate the challenge of raising capital to sustain American marginal well production.

Geological and Geophysical (G&G) Amortization – G&G costs are associated with developing new American natural gas and oil resources. For decades, they were expensed until a tax court case concluded that they should be amortized over the life of the well. After years of consideration and constrained by budget impacts, in 2005, Congress set the amortization period at two years. It also simplified G&G amortization by applying the two year amortization to failed as well as successful wells; previously, failed wells could be expensed. Later, Congress extended the amortization period to five years for large major integrated oil companies and then extended the period to seven years. Early recovery of G&G costs allows for more investment in finding new resources. Congress recognized that America benefitted if capital used to explore for new natural gas and oil could be quickly reinvested in more exploration or production of American resources, it was in the national interest. Nothing has changed to alter that conclusion. If anything, current capital and credit limitations enhance the rationale to get these funds back into new investment.

Marginal Well Tax Credit – This countercyclical tax credit was recommended by the National Petroleum Council in 1994 to create a safety net for marginal wells during periods of low prices. These wells as stated above account for 20 percent of American oil and 12 percent of American natural gas. They are the most vulnerable to shutting down forever when prices fall to low levels. Congress enacted in this countercyclical tax credit in 2004 after ten years of consideration. It concluded that the nation benefitted if these marginal operations were supported during times of low prices, that the production from these wells were – in effect – a national resource reserve that would be lost forever if the wells had to be shutdown and plugged during difficult economic times. No different conclusion is now warranted. Recent development of America's shale gas and shale oil resources lead experts to predict that the United States will be able to reach a level of energy production not seen in decades. This result will mean that the country will be able to limit its imported oil to allied countries like Canada and Mexico. However, it also recognizes that all current American production must continue – including the components coming from American marginal oil and natural gas wells. The marginal well tax credit is part of the framework that maintains this production. Fortunately, to date, the marginal well tax credit has not been needed, but it remains a key element of support for American production – and American energy security.

Enhanced Oil Recovery (EOR) Tax Credit – The EOR credit is designed to encourage oil production using costly technologies that are required after a well passes through its initial phase of production. Conventional oil well production declines regularly after it begins production. However, millions of barrels of oil remain in formations when the initial production phase is over. The 2001 National Energy Report indicated that "anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields." For example, one of the technologies is the use of carbon dioxide as an injectant. In 2006, the Department of Energy studied the potential for using carbon dioxide enhanced oil recovery (CO_2-EOR) and concluded that: "Ten basin-oriented assessments- four new, three updated and three previously released- estimate that 89 billion barrels of additional oil from currently 'stranded' oil resources in ten U.S. regions could be technically recoverable by applying state-of-the-art CO_2-EOR technologies." Given the increased interest in carbon capture and sequestration, CO_2-EOR offers the potential to sequester the carbon dioxide while increasing American oil production. Currently, the oil price threshold for the EOR tax credit has been exceeded and the oil value is considered adequate to justify the EOR efforts. However, at lower prices EOR becomes uneconomic and these costly wells would be shutdown. The EOR tax credit was enacted in 1990 and provides the potential to maintain important US oil production by supporting the development of these wells in low price periods.

Status

So far, only the Administration has formally proposed eliminating all oil and natural gas tax provisions for all producers. Over the years, the Administration has justified its proposals based on two flawed rationales. First, the Administration claimed in its FY2010 Budget proposal that each provision "… like other oil and gas preferences the Administration proposes to repeal, distorts markets by encouraging more investment in the oil and gas industry than would occur under a neutral system." Second, to the extent that each provision "… encourages overproduction of oil, it is detrimental to long-term energy security and is also inconsistent with the Administration's policy of reducing carbon emissions and encouraging the use of renewable energy sources through a cap-and-trade program."

The first issue neither is unique to natural gas and oil tax provisions nor to the tax code generally. For natural gas and oil production, these tax provisions are intended to encourage the development of American resources; they were never intended to be neutral. More broadly, these provisions reflect business tax policy that is consistent with comparable treatment of other energy sources. In its report, *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010*, the Energy Information Administration (EIA) assesses the federal government's support for energy sources. As the following tables show, EIA demonstrates that natural gas and oil federal treatment is comparable to other major energy sources on a total basis and is well below other sources on a unit basis. The Obama Administration's first justification is simply an inaccurate characterization of the nature of federal energy tax policies that have been crafted over decades by the Congress.

Quantified energy-specific subsidies and support by type, FY 2010

Beneficiary	Direct Expenditures	Tax Expenditures	Research & Development	DOE Loan Guarantee Program	Federal & RUS Electricity	Total	ARRA Related
Coal	42	561	663	0	91	1358	97
Refined Coal	0	0	0	0	0	0	0
Natural Gas and Petroleum Liquids	4	2690	70	0	56	2820	0
Nuclear	0	908	1169	265	157	2499	147
Renewables	4696	8165	1409	269	133	14674	6193
Biomass	57	523	537	0	0	1117	10
Geothermal	160	1	100	12	0	273	228
Hydro	17	17	52	0	130	216	16
Solar	496	120	348	173	0	1134	788
Wind	3556	1178	166	85	1	4986	4852
Other	95	0	205	0	1	302	130
Biofuels	314	6330	0	0	0	6644	169
Electricity-Smart Grid & Transmission	461	58	222	20	211	971	495
Conservation	3387	3206	0	4	0	6597	6305
End-Use	5705	693	832	1011	0	8241	1549
LIHEAP	5000	0	0	0	0	5000	0
Other	705	693	832	1011	0	3241	1549
Total	14295	16284	4365	1570	648	37160	14786

	2010 Fuel Production Excluding That Used for Electricity Generation (quadrillion btu)	FY 2010 Subsidy and Support (million 2010 dollars)	FY 2010 Support/Million btu
Coal	2.94	169	57.5
Natural Gas and Petroleum Liquids	28.55	2165	75.8
Biomass and Biofuels	3.87	7646	1975.7
Geothermal	0.06	73	1216.7
Solar	0.10	169	1690.0
Other Renewables	0.02	226	11300.0

The Administration's second rationale is similarly irrational. Production of American oil and natural gas serves the nation's goal of improving its energy security. Production of American oil and natural gas has been regulated to assure that wells are limited to volumes that conserve the long term production of its reservoir. These limitations have been entrenched since the mid-1930s. Current production reflects the need for American production to be maximized and nothing suggests that it should not be. In fact, it demonstrates that America can return to production levels that will enhance its energy security to levels not seen since before the formation of the Organization of Petroleum Exporting Countries (OPEC). Oil will continue to be a key component of America's energy supply for the foreseeable future and any policies should rely first on American oil rather than foreign sources.

Similarly, the Administration's climate goals of reducing carbon emissions and encouraging the use of renewable energy sources are enhanced by American natural gas and oil production. Natural gas is a clean, abundant, affordable and American resource that must be a part of any climate initiative. In fact, analyses from the Energy Information Administration has reported the lowest levels of US carbon dioxide emissions is decades principally because of increased use of natural gas.

Conclusion

In order to help the Committee better understand independent producers, tax provisions applicable to independent producers and the impacts of the oil and natural gas industry on the American economy, IPAA has included the following documents for your review:

(1) Intangible Drilling Costs, IPAA Fact Sheet
(2) Comparison of Deductible Tax Provisions, IPAA Fact Sheet
(3) Percentage Depletion Deduction, IPAA Fact Sheet

(4) Comparison of Percentage Depletion Tax Provisions, IPAA Fact Sheet
(5) Passive Loss Exception for Working Interests, IPAA Fact Sheet
(6) *The Mighty Bakken*, IPAA Declaration of Independents (February 27, 2013)
(7) *The Federal Oil Plays: Gulf of Mexico and Alaska*, IPAA Declaration of Independents (June 25, 2012)
(8) *The Story of California Crude*, IPAA Declaration of Independents (July 12, 2012)
(9) *The Western & Mid-Continent Oil Revolution*, IPAA Declaration of Independents (May 24, 2012)
(10) *The Eagle Ford – Texas Shale Star*, IPAA Declaration of Independents (December 19, 2012)
(11) *Oil and Natural Gas Strengthening America's Trade Balance*, IPAA Declaration of Independents (December 7, 2011)

Additionally, IPAA would encourage the Committee to examine the following economic reports detailing the economic benefits of oil and natural gas production in the United States:

(1) *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy (Volume 2 – State Economic Contributions)*, IHS, Inc. (2012) (available at http://www.energyxxi.org/sites/default/files/Americas_New_Energy_Future_State_Highlights_Dec2012.pdf)
(2) *The Economic Contribution of the Onshore Independent Oil and Natural Gas Producers to the U.S. Economy*, IHS Global Insight (April 2011) (available at http://www.ipaa.org/wp-content/uploads/downloads/2012/03/IHSFinalReport.pdf)
(3) The Economic Impact of the Gulf of Mexico Offshore Oil and Natural Gas Industry and the Role of the Independents, IHS Global Insight (July 2010) (available at https://images.magnetmail.net/images/clients/IPAA_comm/attach/OffshoreIndependentsContributions.pdf)
(4) The Economic Impact of the Eagle Ford, The Center for Community and Business Research at The University of Texas at San Antonio Institute for Economic Development (available at http://ccbr.iedtexas.org/efs-economic-impact-2013).

As the Committee considers policies related to America's oil and natural gas resources, it must recognize that federal actions can dramatically affect the future of the nation's energy security and the nation's ability to meet the potential for its economic growth. IPAA urges the Committee to support those actions that enhance that future and reject the ill-advised calls for adverse restrictions to capital.

Should you have any questions please contact Lee Fuller, Vice President of Government Relations at IPAA [redacted] or Matt Kellogg Manager of Government Relations at IPAA [redacted]

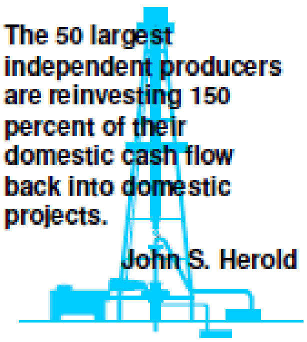
Sincerely,

Barry Russell
President and CEO
Independent Petroleum Association of America

ATTACHMENTS

Drilling and Development Costs

Since 1913, a drilling and development costs deduction has been allowed as an ordinary and necessary business expense for those costs where there is no remaining equipment to value (salvage value) when an oil or natural gas well is completed. Because there is nothing tangible to value, these costs are generally called "intangible drilling costs" or IDCs. For the past 30 years, American tax policy has shortened the depreciation period for equipment to allow capital to be recovered and reinvested in new American projects. Like other rapid depreciation schedules in the tax code, the drilling cost deduction allows for investment capital to be immediately recovered and encourages its reinvestment. It is not a tax subsidy or a "loophole". For American independent producers it has resulted in facilitating reinvestment in new American projects at rates up to 150 percent of American cash flow.



The 50 largest independent producers are reinvesting 150 percent of their domestic cash flow back into domestic projects.

John S. Herold

Issues

Within the past decade the combination of advanced horizontal drilling techniques and sophisticated hydraulic fracturing opened the development of both shale gas and shale oil formations. These American resources can provide up to 100 years of natural gas supply and generated the first increase in American oil production in the past two decades. Clearly, while America has been producing these resources for 150 years, today's production will reflect a vastly different onshore industry than in the past. Similarly, the industry will continue to advance its technology in the offshore where the challenges of deeper formations and deeper water depths have driven significant changes in the past twenty years. What is common to developing all of these resources is the need for capital. In 2010, onshore independent producer capital expenditures were about $62.6 billion. Similarly, offshore independent producer capital expenditures were about $11.8 billion in the federal offshore in 2008.

Independent producers have a history of investing in America. Recent assessments have concluded independents reinvesting up to 150 percent of their American cash flow back into new American projects. And, independents drill 94 percent of wells in the United States. The faster that producers recover the capital invested in projects, the faster it can be reinvested. For independent producers since 1913 – at the inception of the tax code – drilling costs[1] for the elements that are not a part of the final operating well could be deducted in the year they are incurred (expensed). These costs can be 65 to 75 percent of the development costs of a well. Clearly, putting this capital back into new production means more jobs, more production and more federal and state taxes.

Two recent studies have addressed the role of independent producers in the US economy – one addresses onshore, the other addresses offshore. The onshore analysis showed that independent producers support almost 4 million direct, indirect and induced jobs (3% of US jobs) with the upstream component accounting for 2.1 million of those jobs. The offshore analysis showed that independent producers supported over 200,000 direct, indirect and induced jobs in 2009 in the Gulf of Mexico and the Gulf states. These investments also mean taxes to the federal and state governments. Onshore upstream taxes totaled $67.7 billion in 2010 while taxes resulting from offshore operations were $7.0 billion in 2009.

Drilling and Drilling Costs (Continued)

Status

The Obama Administration proposes to repeal expensing of drilling costs sacrificing a critical element of the nation's tax policy that encourages American natural gas and oil exploration and production.

Other recent studies have shown that this change in the tax code will reduce independent producers' investment budgets by about 25 percent. This proposal should be rejected because the consequence would be to reduce investment in new American natural gas and oil development – investments that produce the natural gas essential to a clean energy future, the natural gas necessary to grow solar and wind energy, the oil to reduce our growing dependency on foreign sources.

December 2011

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[1] Drilling and Development Costs (IDCs) include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of natural gas and oil. In addition, IDCs include the cost to operators of any drilling or development work[1] done by contractors under any form of contract (including a turnkey contract). Such work includes labor, fuel, repairs, hauling, and supplies which are used in the drilling, shooting, and cleaning of wells; in such clearing of ground, draining, road making, surveying, and geological works (as are necessary in preparation for the drilling of wells); and in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items which have a salvage value (such as pipes and casings), or items which are part of the acquisition price of an interest in the property.

If an election to expense IDCs is made, the taxpayer deducts the amount of the IDCs as an expense in the taxable year the cost is paid or incurred. Generally, if IDCs are not expensed, but are capitalized, they may be recovered through depletion or depreciation, as appropriate. Or, in the case of a nonproductive well ("dry hole"), they may be deducted, at the election of the operator. In the case of an integrated oil company that has elected to expense IDCs, 30 percent of the IDCs on productive wells must be capitalized and amortized over a 60-month period. Notwithstanding the fact that a taxpayer has made the election to deduct IDCs, the Tax Code provides an additional election under which the taxpayer is allowed to capitalize and amortize certain IDCs over a 60-month period beginning with the month the expenditure was paid or incurred. This rule applies on an expenditure-by-expenditure basis; that is, for any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under this provision. This allows the taxpayer to reduce or eliminate the IDC adjustments or preferences under the alternative minimum tax. The election to deduct IDCs applies only to those IDCs associated with American properties. For this purpose, the United States includes certain wells drilled offshore.

AMT Treatment of IDCs

Also as discussed above, in computing its regular tax, a taxpayer who pays or incurs IDCs in the development of American natural gas or oil properties may elect to either expense or capitalize these amounts. The difference between the amount of a taxpayer's IDC deductions and the amount which would have been currently deductible had IDCs been capitalized and recovered over a 10-year period may constitute an item of tax preference for the Alternative Minimum Tax (AMT) to the extent that this amount exceeds 65 percent of the taxpayer's net income from natural gas and oil properties for the taxable year (the "excess IDC preference").

For taxpayers other than integrated oil companies, the Energy Policy Act of 1992 repealed the excess IDC preference for IDCs related to natural gas and oil wells for taxable years beginning after 1992. The repeal of the excess IDC preference, however, may not result in the reduction of the amount of the taxpayer's Alternative Minimum Taxable Income (AMTI) by more than 40 percent of the amount that the taxpayer's AMTI would have been had the excess IDC preference not been repealed.

In addition, for purposes of computing the an integrated oil company's adjusted current earnings (ACE) adjustment to the AMT, IDCs are capitalized and amortized over the 60-month period beginning with the month in which they are paid or incurred. The ACE preference does not apply to independent natural gas and oil producers since enactment of the Energy Policy Act of 1992.

Comparison of Deductible Tax Provisions

Federal tax policy allowing for expenditures to be deducted in the year they are incurred applies to a variety of industrial activities. Several of these provisions are presented in the following table – drilling costs associated with oil and natural gas production, drilling costs for geothermal wells, research and experimental expenditures and expenditures by farmers for fertilizer.

These provisions bear a common theme – *there is no salvage value for the costs that were paid*. That is, while the larger enterprise may have a capital value – the oil or natural gas well, the geothermal well, the products ultimately developed by the research, the farm – these costs are not part of those tangible assets.

Tax Provision	Section 263(c) – Intangible Drilling Costs for Oil and Natural Gas Wells	Section 263(c) – Intangible Drilling Costs for Geothermal Wells	Section 174 – Research and Experimental Expenditures	Section 180 – Expenditures By Farmers For Fertilizer
Basic Provision	A drilling and development costs deduction has been allowed as an ordinary and necessary business expense for those costs where there is no remaining equipment to value (salvage value) when an oil or natural gas well is completed.	Provides for the same deductibility of drilling costs for geothermal wells as for oil and natural gas wells.	A taxpayer may treat research or experimental expenditures which are paid or incurred by him during the taxable year in connection with his trade or business as expenses which are not chargeable to capital account. The expenditures so treated shall be allowed as a deduction. (Tax Credit allowed for incremental R&E over historic baseline.)	A taxpayer engaged in the business of farming may elect to treat as expenses which are not chargeable to capital account expenditures (otherwise chargeable to capital account) which are paid or incurred by him during the taxable year for the purchase or acquisition of fertilizer, lime, ground limestone, marl, or other materials to enrich, neutralize, or condition land used in farming, or for the application of such materials to such land.
Presence in Tax Code	Drilling and development costs treated as a deduction since 1913; codified in 1954	Added to tax code in 1978	Codified in 1954	Codified in 1954
Limitations	Independent producers may deduct 100 percent of drilling costs; integrated companies must capitalize 30 percent of drilling costs over 60 months	No limitations based on structure of organization	No limitations based on structure of organization	No limitations based on structure of organization

Percentage Depletion

> **Independent producers develop 90 percent of America's oil and natural gas wells, produce 68 percent of America's oil and 82 percent of America's natural gas.**

Depletion, like depreciation, allows for the recovery of capital investment over time. Percentage depletion is used for most mineral resources including oil and natural gas. It is a tax deduction calculated by applying the allowable percentage to the gross income from a property. For oil and natural gas the allowable percentage is 15 percent.[1]

A part of the tax code since 1926, percentage depletion has changed over time. Current tax law limits the use of percentage depletion of oil and gas in several ways. First, the percentage depletion allowance may only be taken by independent producers and royalty owners and not by integrated oil companies. Second, depletion may only be claimed up to specific daily American production levels of 1,000 barrels of oil or 6,000 mcf of natural gas. Third, the deduction is limited to 65% of net taxable income. Fourth, the net income limitation requires percentage depletion to be calculated on a property-by-property basis.[2] It prohibits percentage depletion to the extent it exceeds the net income from a particular property. These limitations apply both for regular and alternative minimum tax purposes. Percentage depletion in excess of the 65 percent limit may be carried over to future years until it is fully utilized.

Despite these limitations, percentage depletion remains an important factor in the economics of American oil and natural gas production. Most independent producers do not exceed the 1000 barrel per day limitation. Yet, these producers are a significant component of America's oil production. For example, they are the predominant operators of America's marginal wells. Over 85 percent of America's oil wells are marginal wells – producing less than 15 barrels per day. Yet, these wells produce about 20 percent of American oil production. About 75 percent of American natural gas wells are marginal wells, producing approximately 12 percent of American natural gas. Marginal wells are unique to the United States; other countries shut down these small operations. Once shut down, they will never be opened again – it is too costly. Even keeping them operating is expensive – they must be periodically reworked, their produced water (around 9 of every 10 barrels produced) must be disposed properly, the electricity costs to run their pumps must be paid. The revenues retained by percentage depletion are essential to meet these costs. For larger wells, percentage depletion provides more revenues to be used to find new oil and natural gas in the United States. Independent producers historically invest more than their cash flow back into projects.

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Action Needed

The Obama Administration budget proposal would repeal percentage depletion of oil and natural gas. Loss of percentage depletion would adversely affect American oil and natural gas production. Lost American production runs counter to America's energy security needs, America's move toward cleaner energy and even the development of alternative energy sources like wind and solar that require natural gas backup when they cannot generate energy. The Obama Administration proposal should be rejected.

October 2012

[1] For marginal wells the allowable percentage is increased (from the general rate of 15 percent) by one percent for each whole dollar that the average price of crude oil for the immediately preceding calendar year is less than $20 per barrel. In no event may the rate of percentage depletion under this provision exceed 25 percent for any taxable year. The term "marginal production" for this purpose is domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) is a stripper well property for the calendar year in which the taxable year begins, or (2) is a property substantially all of the production from which during such calendar year is heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less corrected to 60 degrees Fahrenheit). A stripper well property is any oil or gas property which produces a daily average of 15 or less equivalent barrels of oil and gas per producing oil or gas well on such property in the calendar year during which the taxpayer's taxable year begins.

[2] The net income limitation for marginal wells is suspended during 2009.

Comparison of Percentage Depletion Tax Provisions

Federal tax policy allowing for percentage depletion applies to mineral assets[1], including oil and natural gas. Percentage depletion of mineral assets allows the taxpayer to deduct a fixed percent of its income to reflect its production of a depleting asset.

Federal tax law has always recognized the validity of a deduction for depleting mineral assets. Initially, the only deduction was based on the cost of the project. In 1918, Congress recognized the strategic importance of petroleum and it sought to increase petroleum development. It also recognized that cost depletion alone might not be sufficient to enable mineral producers to replace exhausted reserves and could result in abandoning mineral assets before they were fully produced. Consequently, it created a depletion option based on the value of the assets. It recognized that value depletion could exceed cost depletion because it is impossible to fully value mineral assets based on the initial development costs. The initial value depletion approach was too cumbersome and in 1926 Congress created percentage depletion for oil and natural gas because it is straightforward to calculate and audit. Subsequently, Congress applied percentage depletion to other minerals. Similarly, percentage depletion applies to royalty owners of the mineral assets where it is particularly useful because of the challenges to royalty owners to acquire accurate and current cost depletion information.

Both cost depletion and percentage depletion must be calculated and the higher value used as a deduction.

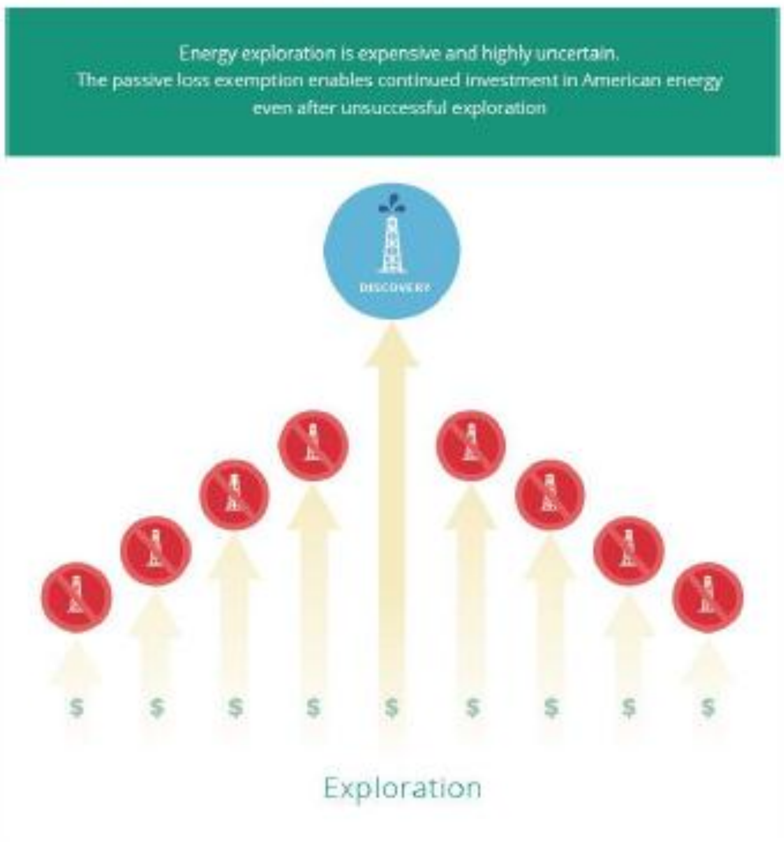
Tax Provision	Section 613 – Percentage Depletion for Oil and Natural Gas Wells	Section 613 – Percentage Depletion for Coal	Section 613 – Percentage Depletion for Sulfur	Section 613 – Percentage Depletion
Basic Provision	Deduction of 15 percent of gross income, excluding rents and royalties paid	Deduction of 23 percent of income, excluding rents and royalties paid	Deduction of 10 percent of income, excluding rents and royalties paid	Deductions of various percentages of income, excluding rents and royalties paid, for other minerals listed in footnote
Presence in Tax Code	Added to the tax code in 1926	Added to the tax code in 1932	Added to the tax code in 1932	Added to the tax code from 1932 to 1954
Limitations	Applies only to US production Available only to independent producers and royalty owners Limited to the first 1000 barrel/day of oil (6000 mcf/day of natural gas) Limited to net income of the producing property, computed without allowance for depletion and without the deduction under the manufacturers tax deduction Limited to 65 percent of the taxpayers net income Applies to both regular and alternative minimum tax	Limited to50 percent net income of the producing property, computed without allowance for depletion and without the deduction under the manufacturers tax deduction	Limited to50 percent net income of the producing property, computed without allowance for depletion and without the deduction under the manufacturers tax deduction	Limited to50 percent net income of the producing property, computed without allowance for depletion and without the deduction under the manufacturers tax deduction Limited for some minerals to US production

[1] Sulfur, uranium, asbestos, brucite, coal, lignite, perlite, sodium chloride, wollastonite, gravel, peat, pumice, sand, scoria, shale, stone, clay, metal mines, rock asphalt, vermiculite and all other minerals (including, but not limited to, aplite, barite, borax, calcium carbonates, diatomaceous earth, dolomite, feldspar, fullers earth, garnet, gilsonite, granite, limestone, magnesite, magnesium carbonates, marble, mollusk shells (including clam shells and oyster shells), phosphate rock, potash, quartzite, slate, soapstone, stone (used or sold for use by the mine owner or operator as dimension stone or ornamental stone), thenardite, tripoli, trona, bauxite, flake graphite, fluorspar, lepidolite, mica, spodumene, and talc (including pyrophyllite)). If from deposits in the United States— oil and natural gas, geothermal energy, gold, silver, copper, iron ore, anorthosite, clay, laterite, and nephelite syenite (to the extent that alumina and aluminum compounds are extracted therefrom), bauxite, celestite, chromite, corundum, fluorspar, graphite, ilmenite, kyanite, mica, olivine, quartz crystals (radio grade), rutile, block steatite talc, and zircon, and ores of the following metals: antimony, beryllium, bismuth, cadmium, cobalt, columbium, lead, lithium, manganese, mercury, molybdenum, nickel, platinum and platinum group metals, tantalum, thorium, tin, titanium, tungsten, vanadium, and zinc.

Passive Loss Exception

Why is the Passive Loss Exception an Issue?

The passive loss exception enables working interest owners in oil and natural gas production to some parity between their investments and those of corporate shareholders. By counting any working interest investment losses as active instead of passive, investors are able to treat the normal business deductions from their investment in the same way that a corporation would. But the Obama Administration would repeal the passive loss exception.



Why was the Passive Loss Exception Created?

The passive loss exception reflects Congressional recognition that the Tax Reform Act of 1986 created an inequity. The Tax Reform Act divided investment income/loss into two baskets – active and passive. Moreover, the passive loss rules apply only to individuals; corporations pass the same deductions to shareholders as part of the overall value of the stock. If income/loss, arising from natural gas and oil working interests, were treated as passive income/loss, taxpayers would be significantly less willing to risk an investment in natural gas and oil development.

Most American wells today are drilled by small and independent companies, many of which depend on individual investors. There is no sound reason for Congress to enact tax rules that would discourage individual investors from continuing to participate in energy investments. The repeal of the working interest rule, therefore, would senselessly drive natural gas and oil investments away from individuals and toward corporations.

What is Active Versus Passive?

Passive income and loss are based on an activity in which the investor is not "materially" involved. According to the IRS, material involvement is on a "regular, continuous, and substantial" basis. For example, if an investor buys shares in a rental property – in which he or she is not actively involved in operating or maintaining – the investment is considered passive. This is the same for limited partnerships – a limited partner invests in the partnership but is not involved in the day to day activity and operations.

Limited partners are vital to the investment in oil and natural gas, spurring investment in American energy. Unfortunately, drilling a well does not guarantee resource production; yet the capital costs of exploration – successful or not – are extremely high. Because of the passive loss exception, working interests in oil and natural gas are removed from the passive income basket. In other words, all oil and gas working interests are considered active, even if the investor is not the operator of the drilling and production operations.

Importantly, investors in working interests are engaged in the very real activity of exploring for and developing oil and natural gas resources. Moreover, these investors are allowed deductions only for the actual expenses incurred and paid by them with respect their working interests. Working interest owners cannot deduct any expenses that have not actually been incurred by them and for which they are not entirely liable. By defining this income/loss as active, these investors and partners are able to continue advancing American energy exploration and production.

Why is Passive Loss Exception Important to American Energy?

The passive loss exception enables continued investment into American energy exploration, supporting the small businesses and the countless other industries and consumers who benefit from affordable, secure American energy. By allowing individual investors to participate actively in oil and natural gas production ventures, investment is able to continue where it would otherwise be lost.

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The Mighty Bakken

WASHINGTON, DC— Any discussion of the revolution in U.S. upstream technology and its impact on the U.S. energy balance must include the Bakken play, centered in North Dakota but also reaching into Montana and Canada. It's no wonder. It has raised North Dakota to the number two state after Texas in U.S. crude oil production. Now at more than 700,000 barrels per day and still growing, North Dakota's crude oil production accounts for 11 percent of the domestic total, and is contributing to the strongest economic growth and strongest employment of any state. Here we revisit the Bakken to fill in more details for the play that serves as the forerunner and icon of the tight oil revolution.

Geology & Geography

The Williston Basin is a large sedimentary basin that straddles the US – Canadian border and encompasses portions of northern South Dakota, western North Dakota, eastern Montana and northward into southern Saskatchewan. Over geologic time, many sedimentary layers accumulated in the greater Williston Basin. Among these layers are the Bakken Formation and several other significant and potentially emerging productive oil zones or formations.

The recent oil drilling and completion activity has been focused primarily on the Bakken formation located throughout the majority of the Williston Basin. Geologically, the Bakken formation is a rock unit comprising three stacked layers generally described as a slightly geo-pressured, fine grain siltstone center member that is bounded between impermeable, organic rich shale layers on either side. Hydrocarbons have migrated from the upper and lower shales into the middle siltstone member. The middle member is generally seen as the lateral target while drilling. At its deepest, the Bakken lies about two miles under the surface and can be found at lesser depths of 5,000 feet or shallower on the edges of the basin. The Bakken Formation is at most 150 feet thick and can approach only a few feet thick out on the flanks of the basin.

Two additional formations have drawn interest in the past few years for potential oil production. The Sanish formation lies under the Bakken and a prolific oil reservoir in fields such as Parshall have been targeted. The Sanish is significantly more limited in its areal extent than the Bakken and is generally less than 25 feet at its thickest. Most recently, the Three Forks formation has also been the focus of hydrocarbon development.

The Three Forks sits below the Bakken and Sanish formations' lower boundary, and a few operators have had success in producing oil there recently. From a geologic and reservoir architecture perspective, the Three Forks formation is more complicated than the Bakken formation. Its geology is made up of alternating layers of shale and potential reservoir siltstones generally a few inches or less in thickness in the upper half of the formation. The jury has not spoken on the overall reservoir capacity and productivity of the promising Three Forks.

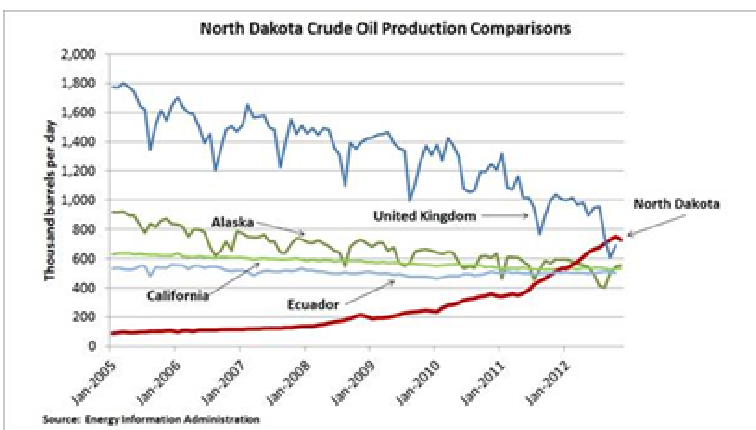
The conventional approach to oil exploration in any region has been to target oil trapped in more permeable layers that are often associated with a structural trap. Conventionally, oil can also be targeted in permeable reservoir rock or stratigraphy that has a barrier to hydrocarbon flow commonly referred to as a stratigraphic trap. Over geologic time, hydrocarbons can migrate to these permeable zones and become trapped until a well is drilled and the hydrocarbons can flow to the well bore and then the surface. Where did the trapped oil come from? It is understood that the oil slowly migrated from relatively impermeable "source rocks" over millions of years. In the Bakken formation, the hydrocarbon-rich, but relatively impermeable upper and lower shales are widely believed to be the source rocks generating the oil that moved to the somewhat more permeable middle shale layer.

Techniques have existed for decades to develop this oil. Hydraulic fracturing is one such technique that engineers have continually refined since its inception in the 1940s, in order to improve the flow in less permeable formations using water and sand or other proppants. The process of fracturing the well makes it possible for oil to flow much more freely through newly-created fractures, held open by sand grains or ceramic proppants, to more permeable zones in the wellbore. In a vertical wellbore, the thickness of a particular hydrocarbon-bearing formation that can be exposed may be relatively small, as is the case with the middle Bakken shale layer which is generally 20 to 50 feet. The ability to drill horizontally within a particular formation, rather than only crossing through it with a vertical well, has enabled wells to expose and tap into much more reservoir in a single formation. This, combined with the ability to economically fracture the neighboring rock in "tight" formations, has made the continuous accumulations or "unconventional reservoirs" accessible in a way that has not been true before. Independent producers have been on the forefront of this revolution with the development of the Bakken, Sanish, and now the prospective Three Forks formation.

History

The history of drilling and production in the Bakken also shows this remarkable shift, brought about by artful combinations of exploration and production technology and evolving drilling practices. Despite earlier attempts at exploring for oil in North Dakota which dates back to the early 20th century, the first commercial oil-producing well in North Dakota was not completed until 1951. That year also saw the first Bakken well, on Henry Bakken's farm in the northwestern corner of the state, completed at a depth of about 11,600 feet. However, subsequent finds and production were primarily in the Madison formation at about 6,000 feet. By 1958, North Dakota had over 1,000 wells producing about 40,000 barrels per day. Even in the 1950s, well-fracturing was taking place, in addition to taking advantage of natural fractures. The development of horizontal drilling in the Bakken did not begin until the late 1980s, with the first horizontal well drilled in the Elkhorn Ranch field in 1987. Activity picked up, with a focus on the upper Bakken shale. Yet finding the key to the Bakken remained elusive. North Dakota production reached about 140,000 barrels per day in the mid-1980s, with nearly 3,500 producing wells, before dipping below 100,000 barrels per day in the 1990s and early 2000s. It became evident that low permeability was still a limiting factor. As a report from the North Dakota Geological Survey stated at the time,

"A large volume of oil and gas remains trapped within the upper black shale of the Bakken Formation.... [E]conomic volumes of oil or gas cannot be produced using today's technology.... Perhaps some other new technology will be developed that will allow the hydrocarbons trapped in the shale to become mobilized and produced at economic rates."



That decisive "new technology" turned out to be horizontal drilling combined with multi-stage hydraulic fracturing – and geologic insight. Based on the inference that the middle Bakken layer could serve as a reservoir rock for the surrounding shales, the Elm Coulee discovery in 2000 eventually demonstrated the potential of this technological innovation in the Bakken, and interest began to climb.

Since then, the Elm Coulee field in Montana has already produced more than 100 million barrels and is still producing. Interest was spurred even further with the discovery in North Dakota of the Parshall field in 2006, also in the middle layer of the Bakken, with wells often still producing 1,000 barrels per day months after they came on line. Interest has more recently extended to the underlying Three Forks formation, and exploration of its multiple benches is just beginning to unfold.

Activity and production has risen especially rapidly during the past three years. Overall, the latest data show North Dakota's crude oil production reaching more than 700,000 barrels per day, with nearly 8,000 producing wells. In 2012, more than 1,600 net new producing wells were added, or about 150 new wells per month. North Dakota's oil production climbed past California's in December 2011 to become the third producer behind Texas and Alaska. Then it surpassed Alaska in March 2012 and in October 2012, production reached around 750,000 barrels per day. Since late 2011, North Dakota's crude oil production has exceeded that of OPEC-member Ecuador. In September last year, North Dakota's production surpassed that of the United Kingdom, the combined effect of rising North Dakota production and temporary shut-ins impacting the U.K.'s overall declining output.

Resource upon Resource

The rapid rise in activity spurred by this innovative technology has led to a rapid, ongoing evolution of resource estimates of the Bakken. Back in 1995, when conventional approaches were the norm, the U.S. Geological Survey (USGS) estimated an average of 151 million barrels of oil technically recoverable. As technology changed, in 2008 the USGS revised upward its earlier estimate by a factor of more than 20 – to 3.65 billion barrels of technically recoverable oil. Even that is now regarded as low by some experts. The North Dakota Industrial Commission, for example, now estimates 6.5 billion barrels recoverable. In an unusual move to update an estimate more quickly than usual, the USGS is working on a new assessment due to come out before the end of this year. According to USGS Energy Resources Program Coordinator Brenda Pierce, "The new scientific information presented to us from technical experts clearly warrants a new resource assessment of the Bakken. The new information is significant enough for the evaluation to begin sooner than it normally would. It is important to look at this resource and its potential contribution to the national energy portfolio."

Infrastructure Challenge

In the Bakken and elsewhere, what this new technology means for exploration and production is a shift in the resource development paradigm. While the combination of horizontal drilling and hydraulic fracturing opens up vast, newly-accessible resources, upfront investment is more costly and decline rates per well are more rapid. This trend has reinforced the advantage of being able to drill wells more efficiently, quickly, and cost-effectively. The increasing use of multi-well pad drilling is a case in point. Drilling multiple wells from one location has reduced the time and expense of moving the rig, allowing for consolidation of auxiliary equipment such as storage tanks and lease separators, and cutting down on the need for roads and trucks to move equipment. "Walking rigs" have enabled a rig to be moved to a new site on the lease without taking down and reassembling it. Optimization of proppant types and more efficient water use have also been key contributors to improving the exploration and production learning curve. Better down-hole information, micro-seismic detection of fracture patterns, and operations via remote sensing and control have allowed for improved completions and more productive wells.

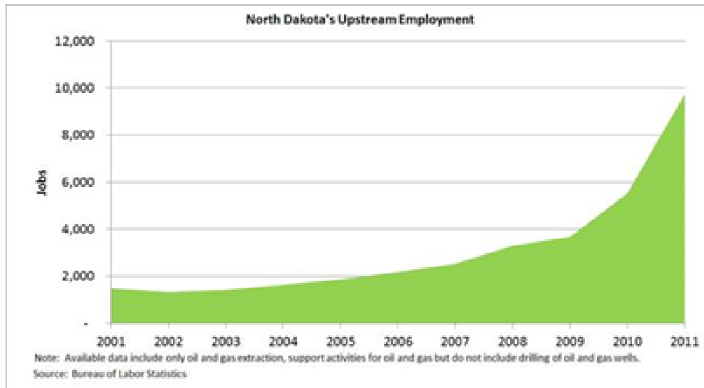
The rapid rise in production in the context of the Bakken's distance from existing crude oil markets, has created an infrastructure challenge. Pipeline transportation is most often the preferred mode for crude oil, being cost effective and reducing the need for trucks, ships, and barges to transport the crude. But the growth in production has been rapid enough that rail transportation has played a significant role in easing the bottleneck. Based on data from the North Dakota Industrial Commission, more than 400,000 barrels per day are moving out of the region by rail to mid-continent markets and beyond. The Association of American Railroads reports that car loadings of crude oil and products in January 2013 were up 55 percent from a year earlier, following a 46 percent annual increase for 2012. It is likely that much of that increase is Bakken crude. Some Bakken crude is already heading to both East Coast and West Coast refineries by rail, and plans are underway for additional rail shipments to both coasts' refineries, even as crude oil pipeline capacity from the Bakken region also expands.

The Bakken is primarily a crude oil play, with less associated natural gas than in many other tight plays across the country. Yet, adding natural gas infrastructure quickly enough has also been a constraint in a state that historically (and still) accounts for less than one percent of total U.S. natural gas production.

This includes a need for facilities to process natural gas to stringent pipeline specifications and extract natural gas liquids from the stream. In 2011 the state added more than 2,300 miles of new pipeline of which more than 2,000 was gathering (majority for natural gas). Even with a more-than-tripling of gas processing facilities in the past five years (six new or expanded natural gas plants coming online over the next 2-3 years), pipeline and gas processing capacity has strained to keep pace. As a result, the associated natural gas, under regulation and permitting from the state, frequently ends up being flared at a loss to producers. It's no surprise that, according to the state governor's office, "Between 2011 and 2013, more than $3 billion will be invested in new or expanded natural gas processing and transportation systems in North Dakota."

Jobs, Jobs, Jobs

Economic well-being in the region has benefitted from the rapid rise in activity in the Bakken. According to Commerce Department data, between 2008 and 2011, North Dakota GDP rose 19.7 percent, contrasting with the U.S. average of just 0.7 percent. North Dakota's growth far surpassed even the number two growth state over the period, Louisiana, which saw its GDP rise 11.9 percent. The state government expects upstream jobs to rise from about 40,000 currently to more than 60,000 jobs by 2020. That does not include jobs created in related industries or to provide consumer goods and services for the rising number of workers.



A recent IHS study on unconventional oil and gas state contributions noted that "economic activity associated with unconventional drilling directly and indirectly supported over 71,800 jobs in the state in 2012 and would increase to over 114,000 jobs by 2020, equating to 5.8% average annual growth (compared to 2.1% for manufacturing and 1.6% overall state job growth for the period)."

Overall, December's unemployment rate in North Dakota was the smallest of any state at 3.2 percent, well below the national average of 7.8 percent. State government revenues have also risen dramatically, with oil development and gross production tax revenues for 2011 reaching $1.3 billion. This is in addition to higher revenues from income and sales taxes because of the strength of economic activity brought about by the activities of independent producers. Local effects have been even stronger. Since 2009, counties in the Bakken region have seen a 60 percent rise in employment and a 40 percent increase in weekly wages.

Bakken Lessons

The lessons of the Bakken will continue to be applied elsewhere in other plays around the country. One of these crucial lessons that companies are still learning is how to help the local communities deal with the growing pains of development. There are many local and state issues from road traffic to housing issues that arise out of the rapid development and influx of people into the region. The industry has stepped up and has helped maintain roads, build hospitals, and sponsor community projects. Working with state and local officials to deal with the stresses that accompany the momentous economic growth is part of being a worthy corporate citizen.

On the geologic front, the Bakken has a unique, mainly crude-oil focus. The Eagle Ford and Permian plays in Texas, Marcellus and Utica in the Northeast, have other considerations and complications with their richer content of natural gas liquids and/or focus on natural gas. The understanding of these tight oil and natural gas plays is still unfolding, and the technology and working methods to most effectively address these issues continue to be refined. Much remains to be learned of their true potential. Nevertheless, the Bakken play clearly illustrates the strength, depth, and heft of the tight oil revolution, and showcases the unparalleled leadership of independents in opening up these frontiers.

North Dakota Economic Indicators

	State unemployment rate	State upstream employment*	Real state GDP ($millions)	State severance taxes & Federal royalties, bonuses, rents ($1000)
2001	2.8	1,483	21,576	91,211
2003	3.6	1,417	23,958	88,320
2005	3.5	1,866	24,670	230,079
2007	3.1	2,525	26,397	250,747
2009	4.1	3,670	29,209	548,278
2011	3.5	9,742	34,262	1,505,001
Change, 2001-2011:				
North Dakota	+0.8	556.9%	58.8%	1550.0%
U.S.	+4.2	66.9%	17.3%	804.8% **

* Includes only oil and gas extraction, support activities for oil and gas

** 2001 - 2010

Sources: Bureau of Labor Statistics, Bureau of Economic Analysis, Office of Natural Resources Revenue, state data sources, IPAA

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DECLARATION OF INDEPENDENTS
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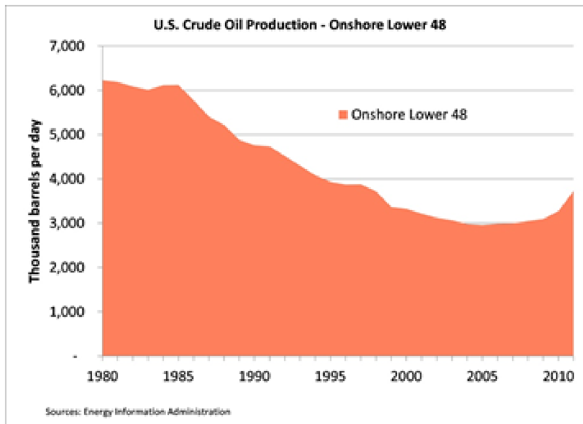
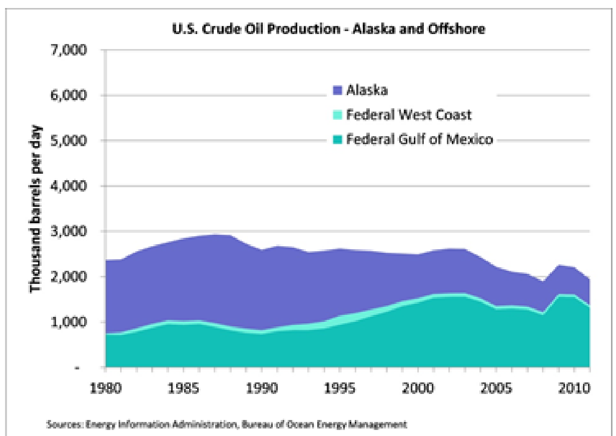
The Federal Oil Plays: Gulf of Mexico and Alaska

WASHINGTON, DC— With all the attention focused on the onshore Lower 48 liquids, largely on private lands, we wouldn't want to leave out the other major frontier regions that have been headliners in the past – namely, the offshore Gulf of Mexico and North Slope Alaska. These two regions, for which the development of resources is heavily influenced by federal policy, together still account for one-third of U.S. proved oil reserves (Energy Information Administration, as of 2009) and one-third of annual U.S. crude oil production. However, as recently as 2003, these two regions' share of crude oil production combined had been as high as 45 percent. Since then, shale plays have bolstered onshore Lower 48 production while the federal offshore has hesitated and Alaskan production has declined.



Offshore Gulf of Mexico

U.S. offshore activity goes back to the end of the 19th century, when California drillers began drilling from wharfs built out over the water. A major step in offshore development was taken in 1947 when the first producing well out of sight of land was drilled by Kerr-McGee in the Gulf of Mexico. Once federal/state jurisdictional issues were addressed in the 1950s, offshore production rose steadily over time. Deepwater drilling, defined as water depths of 1,000 feet or more, made history when the Cognac field began production in 1979, four years after its discovery. Since then, with advances in technology, the average water depth of discoveries has trended deeper, from 1,300 feet in the 1970s, to 3,650 feet in the 1990s, to 5,200 feet for the most recent decade.



The federal outer continental shelf (OCS) has continued to contribute a significant share of U.S. crude oil production, reaching 1.8 million barrels per day in September 2009. Almost all of that has been Gulf of Mexico production, while California and Alaska OCS production accounts for only about 50,000 barrels per day. While the overall count of active offshore rigs has trended downward over much of the past decade, recent year's declines have been primarily for natural gas drilling. In fact, the number of offshore rigs searching for oil actually increased. In more recent years, the Gulf's oil production has varied; then, following leasing and drilling restrictions implemented after the Macondo accident in spring 2010, federal Gulf of Mexico production slipped to the 1.2-1.3 million barrels/day range. More recently it has edged up to around 1.4 million barrels per day. Increasingly, Gulf of Mexico oil production has come from fields in the deepwater and ultra-deepwater (greater water depths than 5,000 feet). According to EIA, deepwater's share rose from 57 percent of the region's oil production in 2004 to 80 percent in 2009, and is no doubt even higher now.

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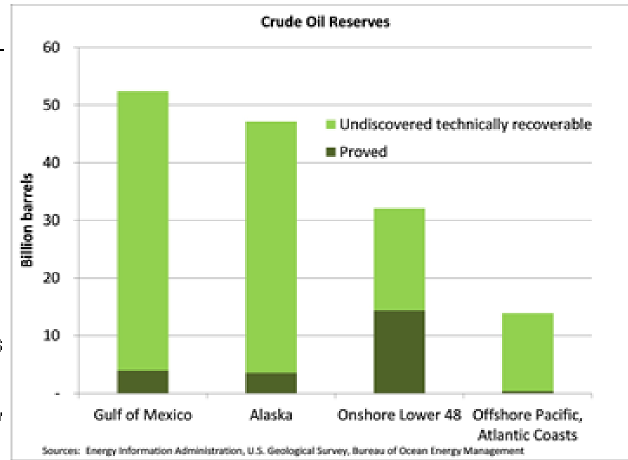
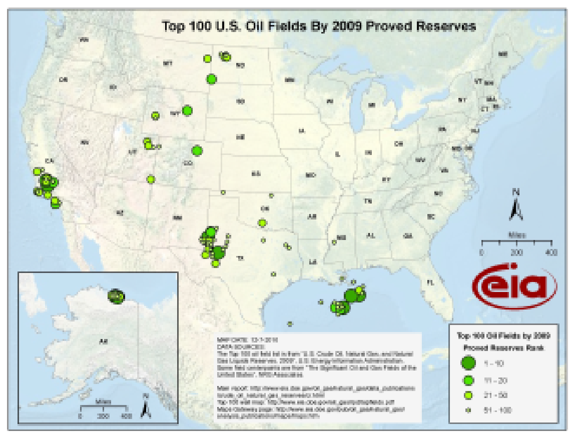
Despite recent lagging production, the Gulf of Mexico has hardly lost its significance. In fact (based on EIA data for 2009), the region accounts for five of the 20 largest oil fields in the U.S., and 17 of the top 100. Some of the top fields, according to that list, include Thunder Horse (discovered 1999, first production 2008), Mars-Ursa (discovered 1989, first production 1996), Atlantis (discovered 1998, first production 2007), Mad Dog (discovered 1998, first production 2005), and Tahiti (discovered 2002, first production 2009). Most of these were found in water depths of roughly 4,000 to 6,000 feet. While projects cover a range of sizes, more than 70 percent of current Gulf of Mexico production comes from the 50 largest fields. As is evident from these fields' histories, the offshore production timeline can easily take up to ten years between preplanning and seismic work to first production, depending on technological advances, existing infrastructure, and current geologic knowledge.



Over just the past five years, the region has provided more than $37 billion in federal revenue from royalties and bonuses, and reserves estimates indicate the potential for further federal revenue inflows, depending on economics, technology, and policy. An assessment of undiscovered technically recoverable **oil and gas resources** performed by the Bureau of Ocean Energy Management (BOEM) in 2011 put the mean estimate for the Gulf of Mexico at 48 billion barrels of oil and 219 trillion cubic feet of gas – or 89 billion barrels and 398 trillion cubic feet when offshore Alaska, Pacific, and Atlantic are also included. The region has also played a significant role in job creation. According to a study by IHS, the offshore industry in the Gulf of Mexico generated almost **400,000 jobs in 2009**.

Alaska



Alaska's large Prudhoe Bay discovery in 1968 deservedly put that state's sizeable potential in the spotlight. Although the first oil production in Alaska was much earlier, in 1905, until the 800 mile Trans-Alaskan Pipeline was built to deliver North Slope oil to market, Alaskan output was modest and concentrated in the south. With North Slope production beginning in 1977, Alaskan output climbed to a high of just over 2 million barrels per day by 1988, replacing Texas as the top-ranked producer for that year and accounting for one quarter of all U.S. oil production. Then, the state began a steady decline, with the most recent production in Alaska hovering around 500,000 – 600,000 barrels per day, its share shrinking to less than a tenth of the nation's crude oil output. In March this year, Alaskan production dipped to 567,000 barrels per day, according to preliminary EIA data, as the state was edged out from its long-standing number 2 ranking by North Dakota.

Nonetheless, exploration and development continues in Alaska, with an average 5 to 10 rigs running during the first half of 2012. Onshore undiscovered technically recoverable oil is put at 16 billion barrels by USGS, with the offshore adding another potential 26.6 billion barrels according to BOEM. The Nikaitchuq field, discovered in 2004, ranks among the top 100 for reserves, according to the EIA's 2009 reserves data. It began production in 2011 with plans for peak production at 28,000 barrels per day and with recoverable reserves put at 180 million barrels. The 2008 federal Chukchi Sea lease sale brought in nearly $2.7 billion in high bids, among the highest for any Alaska offshore lease sale. Though a lengthy lease and permit process and a spill response plan stood in the way of production, the region may soon see drilling begin. The federal government has also reaped more than $400 million in royalty payments over the past five years, and the state has collected more than $12 billion in payments.

Beyond that, as tight oil development is already a major trend in the onshore Lower 48, Alaska's as-yet-undeveloped shale prospects may be on the horizon, as well. Earlier this year, the U.S. Geological Survey (USGS) prepared a new assessment of these resources, concluding that although significant uncertainties are present, the potential is large. For North Slope shale plays, the USGS put the mean estimate at 940 million barrels of oil with a high end of as much as 2 billion barrels. The USGS also assessed a mean of 42 trillion cubic feet for natural gas and 262 million barrels of NGLs. Among other factors, the possibility of liquefied natural gas exports may play a role in how Alaska's natural gas is developed in the future.

Core Pillars

Alaska's ranking for crude oil production has been challenged by North Dakota, and the federal offshore Gulf of Mexico has already been surpassed by Texas as of last year. Onshore plays, largely on private lands, have more recently been the growth areas for production at the expense of areas under greater federal control. While there are a host of factors that affect such trends, these major areas are still too important to be left to chance. The Gulf of Mexico and Alaska will continue to be strategic pillars of America's energy supply. These areas will present their own unique policy and technological challenges going forward, but their historic and future contribution to America's energy matrix remains critical.

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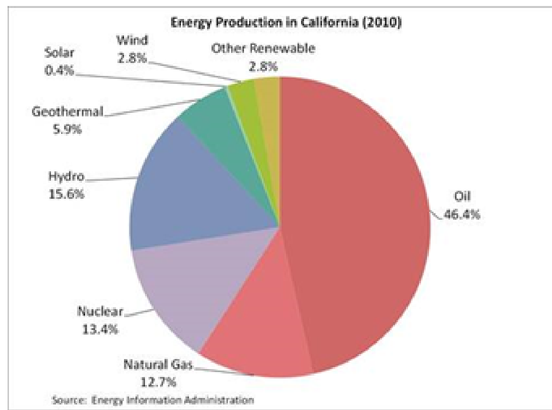
For Immediate Release:
July 12, 2012

The Story of California Crude

WASHINGTON, DC— Since peaking at nearly 1.1 million barrels per day in 1985, California crude oil production has declined steadily. Yet, even though it lost its No. 3 rank to North Dakota late in 2011, the state still hosts some of the country's largest fields and produces more than half a million barrels per day, while supporting 900,000 jobs within the state, according to the American Petroleum Institute. Oil and natural gas account for 59 percent of all the energy produced within the state and 74 percent of its energy consumption. Rig activity has been trending upwards over the past three years, and new, higher assessments of that state's resources have begun to recognize the relevance of shale plays and the technologies required to access them.

Historic Region



California is one of the oldest producing regions in the country. Drilling was already taking place in the 1860s, just a few years after Edwin Drake's Pennsylvania well gave birth to the oil industry in 1859. Offshore production began in the 1890s as operators extended onshore fields by drilling from wharfs. The oil collected from many natural seeps was likely evidence enough that there was more beneath the surface that could be unlocked from Drake's new technology. With discoveries of the Kern River Field in 1899 and the Midway-Sunset field two years later, production boomed. More than a century later, these two fields remain the largest producers in the state.

By 1929, California's crude oil production had climbed to 800,000 barrels per day, nearly matching that of Texas at the time. Interrupted by a decline following the Great Depression, crude oil production in the state bounced back, eventually reaching a peak of 1,079,000 barrels per day in 1985. Since then, production has dropped steadily to a little over 500,000 barrels per day. Yet the state still holds 15 of the top 100 oil fields in proved reserves, as ranked by the Energy Information Administration (EIA). The majority of these top fields, which are still producing today, were discovered before 1920, and all of them date back to 1947 or earlier. EIA's ranking of top fields also includes three off the coast of California in federal waters. Moreover, the expanded capability of newer technologies has led to an enlarged assessment of California's technically recoverable resources.

California Crude

Most of the oil produced in California over the years is believed to have its origin in the Monterey Formation and has migrated to more permeable layers, which has given rise to some of the nation's largest oil fields. These large fields, including Midway-Sunset, Belridge South, Kern River, Cymric, and Wilmington, are situated in the southern half of California (although oil production is found in other parts of the state, as well). About 77 percent of California's crude production is from the state's top 10 fields. The single highest producing county in the state is Kern County, which alone accounts for approximately three-fourths of the state's crude oil output.

Much of the oil found in California is extremely heavy. While definitions of heavy oil vary, nearly two-thirds of California crude has a gravity under 20 degrees. In fact, the state's oil fields are estimated to contain more than 40 percent of the country's heavy oil. The lower the gravity, the more viscous the crude. At some point the crude is too viscous to flow easily without enhanced oil recovery techniques (EOR). While water flooding had been used for many years (and continues to this day), new approaches to the challenge of producing California's heavy oil began in the 1960s with the application of thermal methods. Early attempts with bottom hole heaters and injected hot water gave way to cyclic steam stimulation (pumping down steam to heat the oil and thus reduce its viscosity, then pumping out the oil), and then to full-fledged steam flooding (injecting steam through injection wells and recovering oil from producing wells).

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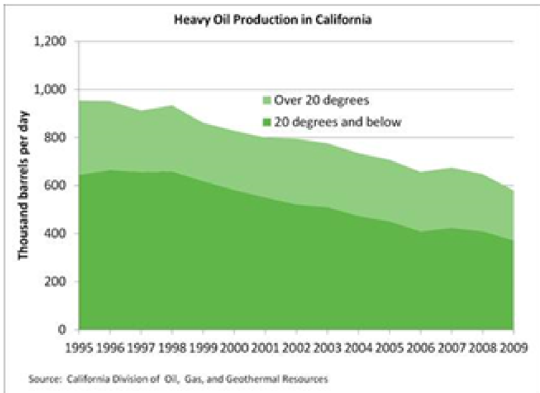
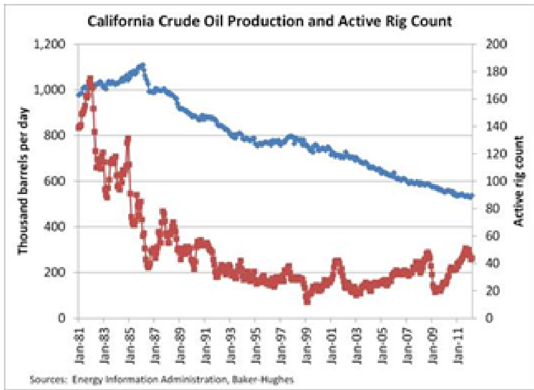
These and other EOR techniques had dramatic effects on production. For example, Kern River field production jumped from under 20,000 barrels per day in the early 1960s to over 120,000 barrels per day in the 1980s. Today, it still produces more than 70,000 barrels per day. Thermal recovery favors larger projects because of economies of scale for steam generation equipment. In addition to the up-front capital costs, thermal recovery also incurs costs for fuel (such as natural gas) to power the steam generators. Currently, roughly half of California's crude oil production is due to the effectiveness of these EOR techniques.



Hydraulic fracturing has been used in California for decades – at least 30 years or more, according to the California Department of Conservation. This technique replaced earlier methods of well fracturing in the state that go back to the early 1900s or before. According to the Western States Petroleum Association, more than 600 wells were fractured in 2011 alone.

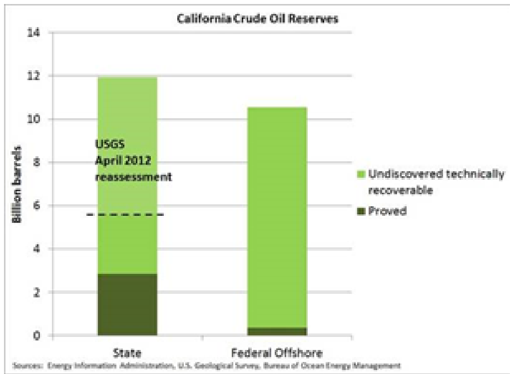
Offshore production, now well into its second century, continues despite the state's restrictions and the fact that California has not leased any new areas since 1969 and the federal government has not leased any new areas since 1984. Averaging 88,000 barrels per day in 2011 (54,000 barrels per day federal waters and 34,000 barrels per day in state waters), the total has decreased from the 250,000 barrels per day peak of 1995. While some of the offshore production comes from onshore fields that extend to the offshore, there are significant fields that are entirely offshore. The Hondo, Sacate, and Pescado fields, which were all discovered around 1970 in federal waters, rank among the top 100 U.S. oil fields by reserves. Furthermore, the Bureau of Ocean Energy Management estimates that federal Pacific waters contain another 10 billion barrels of undiscovered, technically recoverable oil – matching current U.S. Geological Survey (USGS) estimates for onshore California.

Recent Activity



After dropping to less than 20 active rigs in late 2009, activity in California has surged to more than 50 rigs, according to Baker Hughes. Many of those rigs are pursuing traditional production, but shale development has been active as well, particularly in the Monterey formation itself. While much of this activity is done through vertical and directional drilling, the state has also recently experienced steady horizontal drilling since 2011. Horizontal wells tend to run deeper than other wells in the state. The Monterey formation's geology is varied and compartmentalized, but is based on diatomaceous material (the skeletons of microscopic diatoms) that varies from low-permeability diatomite closer to the surface to a more fractured material at greater depths to a quartz phase at the deepest ranges. It presents its own unique challenges, and specific techniques used elsewhere may not be directly applicable in the Monterey. This may be one reason California's shale potential is more latent when compared to many states around the country.

However, independents are very interested in cracking the code of the Monterey. In April, USGS issued a new study of tight oil in the San Joaquin Basin, where fields such as Midway-Sunset, Kern River, Belridge South, Elk Hills, and others are located. USGS estimated a mean of 6.5 billion barrels of undiscovered technically recoverable oil in the areas assessed, which is a substantial change from an earlier assessment of just 0.4 billion barrels and a considerable addition to the earlier 3 billion barrel assessment for all of onshore California. The new, higher figure does not address potential new reserves in smaller fields in the region nor in other parts of the state.



According to the USGS, "Much of the potential reserves could come from improved recovery in diatomite reservoirs of the Monterey Formation, given continued technological evolution. Additional volumes of oil could come from continued application of thermal-recovery technologies to shallow reservoirs containing heavy oil, although the oil remaining in such reservoirs is more difficult to recover than in similar reservoirs already exploited. In a few reservoirs, particularly deep sandstone reservoirs containing relatively light oil such as sandstone reservoirs within the Monterey Formation at Elk Hills field, additional oil could be recovered with injection of carbon dioxide."

Moving Forward

California is clearly a key legacy producing state given the sustainability and resiliency of some of the country's oldest producing fields. The declining production in recent decades continues, but recently, activity has picked up as producers seek new targets. EOR will likely continue to play a dominant role in unlocking these reserves – providing potentially useful intelligence for analog plays in other parts of the country and around the world. Meanwhile, the restrictions imposed by ongoing urbanization in the state have increased the importance of good community relations, while the offshore's potential has been stunted from decades without new state or federal leasing. What remains to be seen is the shape of the next petroleum chapter in a state that is so important to the U.S. economy, accounting for 13 percent of the country's GDP. Geology, technology, and policy will interact in a fashion unique to California, and independents will have a major role to play, given their collective experience in bringing states into the shale phase of fuel development.

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For Immediate Release:
May 24, 2012

The Western & Mid-Continent Oil Revolution

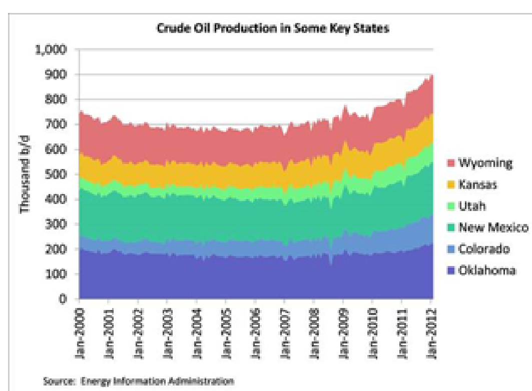
WASHINGTON, DC— While the blockbuster plays in states such as Texas and North Dakota make the biggest headlines for increases in U.S. crude oil production, there's no denying that developments in other states together add up to significant gains. Just like the other plays, many of these involve the technological advances of horizontal drilling and multi-stage hydraulic fracturing. This map of horizontal drilling shows that this technique has become widespread across the country, with activity from the first quarter of this year spanning 21 states.

Oil States

After North Dakota and Texas, there is a significant tier of states where crude oil production is increasing on a steady basis. Six states in the western half of the U.S. combined have increased U.S. oil production by about 240,000 barrels per day (b/d) since early 2007. These include:

- Oklahoma: Crude oil production has risen about 70,000 b/d from January 2007 through February 2012 (the latest available from the Energy Information Administration).
- Colorado and New Mexico: Each saw increases of about 50,000 b/d over that period.
- Utah and Kansas: Each had 30,000 b/d increases.
- Wyoming: While Wyoming's net gain over the period was just 10,000 b/d, the state has seen a steady increase of twice that figure since bottoming out in mid-2009.

Since January 2007, these six states have increased crude oil production from a little more than 650,000 b/d to almost 900,000 b/d, an increase of nearly 37 percent collectively over a five-year span. This is roughly equivalent to the amount of oil produced by Colombia and Indonesia.



Sampling of Plays

The plays behind these noteworthy state-level increases often cross state boundaries. Some are previously explored legacy areas that are getting new attention, while others are new plays or migrations into new geologic zones of older plays. With the already well-supplied natural gas market and the divergence of crude oil versus natural gas prices in the past few years, attention has been increasingly focused on applying the ideal drilling and completion technology to tap into liquids potential of areas that were originally natural gas-oriented plays, as natural gas drilling dominated U.S. activity from 2004-2010.

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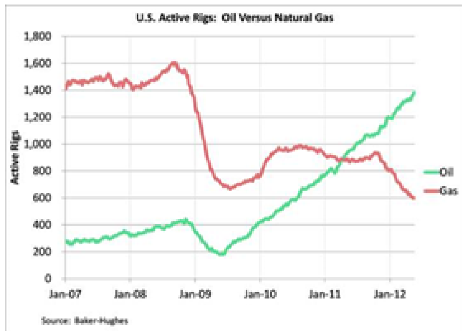
One of the oldest producing states in this group is Kansas, with its first crude oil production in 1889. In fact, all six states have produced crude oil since 1911 or before. While for much of the past decade or so, rig activity in Kansas was tilted more towards natural gas than crude oil. However, in 2008 more wells were completed for oil than for natural gas. Currently, Kansas rig activity is overwhelmingly oil-oriented. Besides shifts in oil/gas targets over time, there are disparities of activity geographically across the state, illustrating that state boundaries and geologic boundaries rarely coincide. Specifically, Kansas continues to be among the states with the largest number of rigs drilling traditional, vertical wells. At the same time, drilling activity in the southern part of the state has seen rising amounts of horizontal drilling over the past year or so.

That drilling trend reflects increasing interest in the Mississippian Lime, a target that stretches southward into northern Oklahoma. It's not that this boundary-crossing geographic region has not already been heavily drilled in in the past, but new technology has enabled commercial production from tighter/less porous Mississippian rocks below the "Chat". While, as the name suggests, the Mississippian Lime is a carbonate formation rather than shale, therefore fracturing combined with horizontal drilling is needed to make the Mississippian Lime economic. Fracturing carbonates tends to be less intensive and less costly than for shale, and the region is also attractive for an oil/gas ratio reported to be above 50-50. Higher porosity, natural vertical fractures, and geologic knowledge gained from past activity also provide some potential advantages. As natural gas prices have weakened relative to crude oil and NGL prices over the past several years, operators have tended to target the more liquids-rich parts of the play.

While Oklahoma shares the Mississippian Lime play with Kansas, there are a number of other active plays in Oklahoma tied to the Woodford shale formation. These include the Cana in west central Oklahoma's Anadarko Basin and the Arkoma Basin in the east. As oil and natural gas prices have diverged, activity has shifted toward the Cana, which trends towards oil and liquids-rich gas, versus the more natural gas-oriented areas of the state. Although the Cana is one of the deepest commercial horizontal plays, it is also one of the more economic plays due to high volumes of condensates and other liquids.



The Granite Wash, a play with mixed oil and liquids-rich natural gas, touches Oklahoma's western border. While as a tight sands play it may have better porosity and permeability than shale, there is apparently much to be learned about its complex geology, which changes from point to point in sometimes unexpected ways. For this play in its early stages, the majority of rig activity has been on the Texas side. Notably, one independent operator believes the Granite Wash could become the largest lower 48 oil and gas field yielding as much as 114 barrels of oil equivalent (boe) over its lifespan (75 percent attributed to natural gas).

Another border-crossing play is Bone Spring in the Delaware Basin, a play within the Permian Basin that extends from New Mexico's southeastern corner of the state into Texas. This is an oil play with multiple, stacked zones. Varied geology adds to the complexity of a play in its early stages. The majority of horizontal activity in New Mexico is in this vicinity, though other parts of the Permian differ in approach as different technologies have been more successful for different areas. While there were approximately 180 horizontal permits issued around Bone Spring for all of 2010, roughly 400 permits have been issued before mid-year in 2012.

The Niobrara is targeted in both Colorado and Wyoming. In Colorado, producers focus on the Wattenberg field in the Denver-Julesburg Basin. The Wattenberg field, in the northeastern corner of the state, was discovered in 1970 and ranks as the thirteenth largest oil field and tenth largest natural gas field in the United States (2009 data from EIA). While operators focused earlier on producing natural gas and de-risking the play, horizontal drilling and multi-stage fracturing have spurred the migration toward NGLs and crude oil. Variability makes location important, as this is not a "blanket play." While the Niobrara Formation varies by location from chalk (marl) to shale, the underlying Codell is a sandstone. Both lie above the traditional "J-Sand" natural gas-producing zones in the Wattenberg and are often produced together. In El Paso County (Colorado Springs), exploratory drilling could extend the play southward. The same holds true in Routt and Moffat counties in northwest Colorado. Further north in Wyoming, the Niobrara and the Mowry are shale formations dependent upon recent, advanced technology. Before the advent of these technologies, they historically have not been as active for liquids. Experience is still shaping up in this play, with results varying by location and operators applying learned lessons in the more economic areas.

In Utah, horizontal drilling is concentrated in the Monument Butte and Central Basin area in the northeast corner of the state. This region lies within the Uinta Basin and is an oil play in sandstones of the Green River and Wasatch formations. One company has calculated the Uteland Butte's net resource potential at nearly 300 million boe, and its production from the Greater Monument Butte field has grown more than 300 percent between 2004 and 2011. Thanks to progress in Utah, the oil production in that state has almost doubled between 2002 and 2011, according to EIA.

Broad Trends

By no means is this a comprehensive survey of U.S. liquids plays, but rather a sample of a complex, unfolding story in these states. Nevertheless, there are broader trends apparent. First, the application of horizontal drilling and multi-stage fracturing is an industry-wide trend reaching into many regions of the country, both in areas that have seen a long history of oil and gas activity as well as newer plays. Second, reflecting in part the divergence in oil and natural gas prices, there has been a trend toward oil over natural gas plays, and liquids-rich gas plays over dry natural gas. These states continue to substantially boost U.S. oil and gas production and will show robust increases year by year based on their impressive potential.

These broader trends should not obscure the fact that each of these plays is different. Keying in on the various technologies required to meet the challenges for each of these unique plays is still at an early stage. Variability abounds in the composition of formations (shale, sandstone, chalk, etc.), their complexity, natural fractures, thermal maturity, proneness to oil, gas, and NGLs, and the degree of existing geologic experience in these areas. Indeed, the breadth and diversity of the application of this new technology is the mark of a watershed innovation, and independent producers continue to be at the vanguard.

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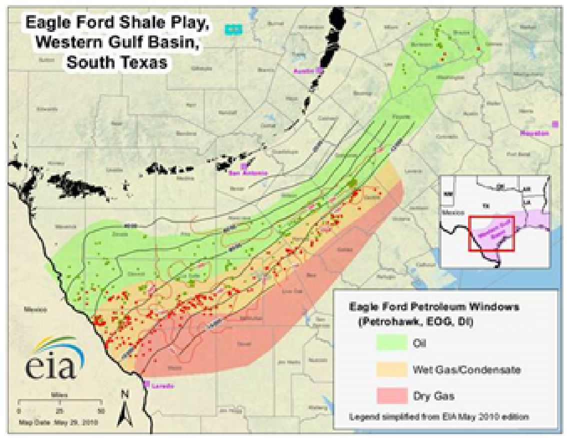
For Immediate Release:
December 19, 2012

The Eagle Ford – Texas Shale Star

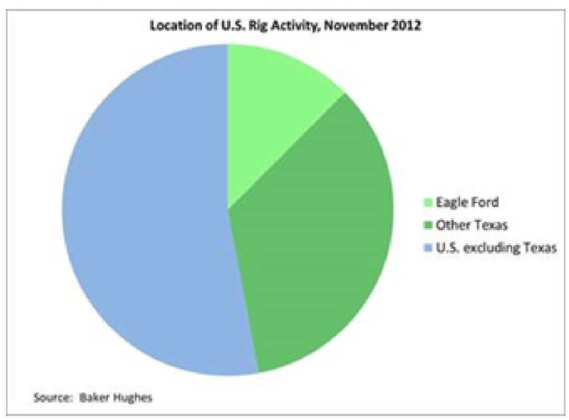
One of the most remarkable sources of gains in U.S. liquids and natural gas production over the past two years has come from Texas's Eagle Ford play, thanks to the application and ongoing refinement of horizontal drilling and hydraulic fracturing techniques. These developments have helped put Texas and North Dakota at the top of the list of regions that have been contributing to the brightening U.S. energy picture.



Oil production in the Eagle Ford, in the southwestern portion of Texas, has gone from a minimal level in 2010 to over 300 thousand barrels per day so far this year, plus another roughly 70 thousand barrels per day of condensates. Besides spurring jobs growth, the jump in Eagle Ford production has been among the major factors driving Texas crude oil production past the 2 million barrels per day mark just this past August – a level not seen since 1988.

What is the Eagle Ford?

The Eagle Ford formation is named for a town in eastern Texas near Dallas – though the formation itself extends to the southwestern end of the state, where the play's activity is concentrated, and on into Mexico. A shale formation roughly 4,000 to 12,000 feet below the surface, it has served as the source rock for the East Texas Field (among the top 100 fields in the U.S.) and for conventional fields in the overlying Austin Chalk. The Austin Chalk has been drilled since the 1920s, but has been an on-again, off-again play with success depending in part on drilling into natural fractures in this otherwise low-permeability formation. Beginning in the 1990s, horizontal drilling has enabled operators to intersect multiple natural fracture systems with the aim of increasing overall well productivity compared with vertical drilling.



With the fine-tuning of horizontal drilling and the refinement of horizontal fracturing technology, the hydrocarbon-rich Eagle Ford has become a major target of independents. As is often the case, independents pioneered the play, which is now drawing considerable interest from majors and international joint ventures. Although the southeastern band of the play has more natural gas, it becomes more "oily" on the northwestern side, with a condensate "window" in between. Since the first horizontal drilling began in 2008, activity has risen sharply to more than 250 active rigs in mid-2012 and currently has more than 230 active rigs. Rigs drilling in Eagle Ford counties account for roughly one of every eight active rigs in the U.S., and for one of every four rigs in Texas. In the Eagle Ford counties, 95 percent of the rigs are drilling horizontal wells, contrasting with just 40 percent for the rest of the state and 60 percent for the U.S. as a whole. This is a major testament to these breakthrough technologies.

According to the first-ever assessment by the U.S. Geological Survey (USGS), published in 2011, the shale held estimated technically recoverable reserves of 853 million barrels of oil, 2 billion barrels of natural gas liquids, and 1.8 trillion cubic feet of natural gas, though some experts suggest that the figures could ultimately turn out to be significantly higher.

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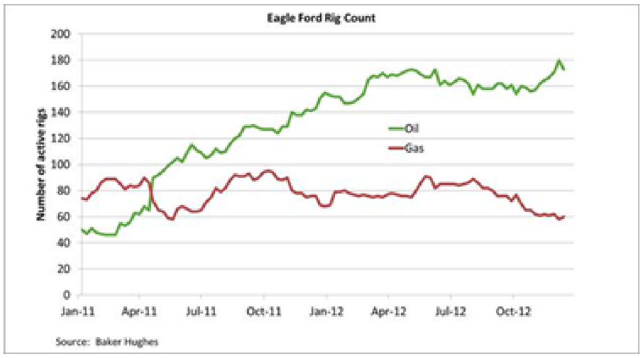
In many ways, the Eagle Ford has some attractions over the Bakken in North Dakota. Besides being more "fracturable," the Eagle Ford is not as deep, translating into more rapid completions and lower drilling and completion costs (perhaps 30 percent lower, according to some reports). Wells tend to be more productive compared with Bakken wells, according to a recent IHS study. The Eagle Ford potentially has more oil in place, and has the decided advantage of proximity to processing infrastructure and markets. Generally, the Eagle Ford has enjoyed a premium versus West Texas Intermediate, mid-continent, and North Dakota crudes on the order of $20/barrel, as it is closer to existing pipelines, gas processing facilities, and delivery points along the Gulf Coast, while West Texas and North Dakota crudes have been more infrastructure-constrained. It still experiences discounts versus Louisiana Light Sweet due to higher transportation costs.



Development Trends

Early activity in the Eagle Ford was focused on the gas-rich areas in the southeast window of the play. However, with weaker natural gas prices, industry attention has turned to oil and condensate windows, as well as natural gas prospects richer in liquids (natural gas liquids, or NGLs). By the spring of 2011, the number of rigs designated as searching for oil began to outnumber the count for rigs searching for natural gas, and currently, there are three oil rigs for every natural gas rig in the region. The Eagle Ford is also likely among the largest plays for supplying NGLs, a fuel that is extracted from natural gas streams and has grown considerably over the past four years.

As the Eagle Ford play has matured, experience has led to improvements and refinements as the technology advances, such as the use of 3-D seismic to more accurately place the horizontal segments of wells and the increase in the number of fracturing stages to enhance productivity. Fracturing stages now often run in the 10 to 20 range, and have gone as high as 25 or more in the region. Experience and analysis has allowed companies to drill and complete wells more quickly and efficiently, at lower cost, requiring fewer rigs in operation at any one time. Pipeline projects that connect with processing facilities and major refining centers in the region reduce the amount of trucking and overall transportation costs.

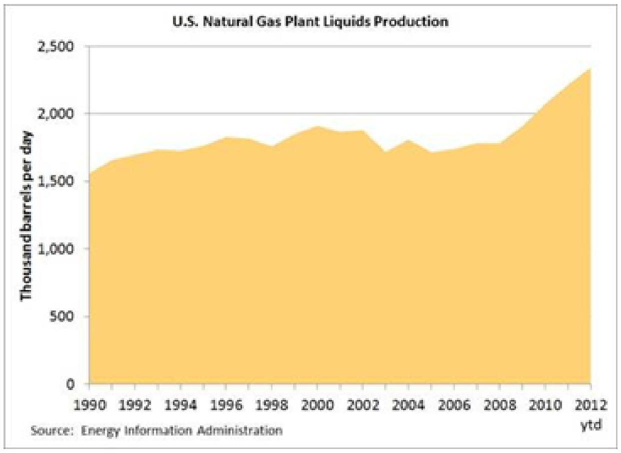
Economic Impacts

Development of the Eagle Ford play has significantly benefited the regional economy. Direct employment has been boosted by increased demand for workers to drill and complete wells, to provide the geophysical and engineering analysis to guide projects, and to build pipelines and processing facilities. This in turn, has increased diverse jobs for workers who provide housing, transportation, and consumer goods and services of all kinds for the larger regional workforce. This also means a workforce with rising wages with more money to re-inject into the local economy. According to analysis by the Dallas Federal Reserve Bank, the average weekly pay in the entire region rose 14.6 percent annually from the first quarter of 2010 to the third quarter of 2011, more than double the 6.3 percent rate for the U.S. as a whole. According to a study by the Institute for Economic Development at the University of Texas at San Antonio (UTSA), Eagle Ford activity supported 38,000 jobs in 2011. That figure was forecast to grow to over 82,000 jobs by 2021. In that year, it is estimated that the boost in economic activity will add more than $1.5 billion to state revenues and $888 million to local government revenues.

Eagle Ford in Perspective

The Eagle Ford, still in an early stage of development, may end up being more complex than some of the earlier big resource plays such as the Barnett or Haynesville shale plays, with its greater range of liquids potential versus natural gas and thus more options for operators to target the highest-value resources.

The Barnett Shale in northwest Texas was the first big shale play, and the fruitful result has been that Barnett counties now account for roughly a third of all Texas natural gas production. In 2008, rig activity was running at a high of over 190 rigs as operators pursued natural gas targets that also happened to have significant liquids content. This meant a large addition of gas processing capability to extract sizeable volumes of by-product NGLs and natural gas. However, as natural gas prices softened, the rig count has dwindled to the 30s as companies shifted toward the most liquids-rich projects. Activity is particularly focused on the "Barnett combo" play in the northwest end of the region, where the higher ratio of liquids relative to natural gas greatly improves current economics. The Haynesville Shale, straddling western Louisiana and eastern Texas, has competed with the Barnett for the title of largest natural gas producing play. Even more pronounced than the Barnett, the Haynesville is primarily a natural gas play, and as a result, has witnessed an especially large slowdown in rig activity.



Both of these plays have had more time to develop than the Eagle Ford, which is still in its early stages. Nevertheless, as objectives across plays have shifted toward liquids as a target and not just a by-product, the importance of developing pipeline infrastructure and mid-stream processing capability has grown, in the Eagle Ford and elsewhere. The oil focus has also led to the application of technological advances in revisiting older plays. In the Austin Chalk, for example, horizontal drilling and hydraulic fracturing are giving new life to that decades-old oil play.

In short, the concept of resource development has been evolving toward a fuel portfolio perspective, where the prospective options for liquids (especially oil) versus natural gas within an individual play have become increasingly part of the investment decision. There are already signs of this occurring in the Utica in eastern Ohio.

While the Eagle Ford is in earlier stages of development than the Barnett and Haynesville, the Utica is even less developed. Every play is different and operators are gathering information and gaining experience as they assess the geology and deal with different infrastructure issues. Like the Eagle Ford, the Utica has a wide range of liquids vs. natural gas potential depending upon the location, each, like all shale plays, unique in geology, potential, and technological approaches. If going through a natural gas phase before re-targeting toward oil has been the pattern for several other plays, the economics of the past several years have accelerated this shift, and even before the Utica has brought on significant production, rig count data show that this shift to liquid targets and away from dry gas-only targets has already taken place.

Each play continues to evolve. Independent producers will continue to be at the forefront of this transformation that has heralded a new role for American oil and natural gas. Independents are connecting yesterday's plays with tomorrow's plays through innovation, technology, risk-taking, and entrepreneurship. Companies from around the world are interested in being part of the Eagle Ford success, a sign that this evolving transformation is global as well as awesome in scope.

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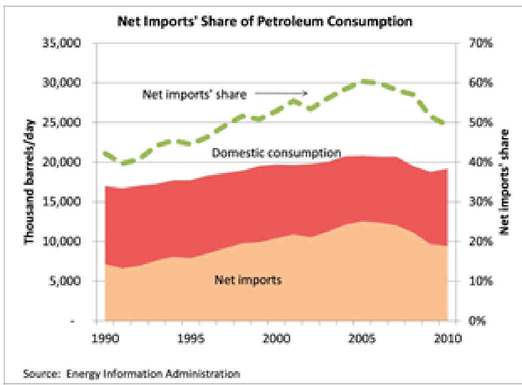
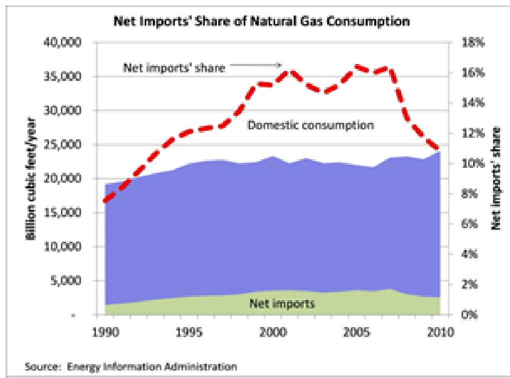
OIL AND NATURAL GAS STRENGHTHENING AMERICA'S TRADE BALANCE

Surprises seem to have become the order of the day in the energy world—especially when it comes to America's oil and natural gas reserves. Once thought to be "outdated' fuels, the abundance of America's oil and natural gas reserves, now unleashed through hydraulic fracturing and horizontal drilling, are truly shifting the balance of trade in America's favor.

The surprise has taken the form of a solid increase in American liquids production and a shift towards declining imports. In addition, natural gas plant liquids (NGPL) output has been exceeding 2 million barrels per day for the first time ever, providing additional feedstock for the industry at home. In fact, both petroleum product and natural gas exports are even increasing – a topic we will more fully address next time. The import trends are also occurring on the natural gas front, with a turnaround that has put American natural gas production in position to reach an all-time high this year. It's worth a detailed look at the significant impact all these positive developments have had on U.S. trade, as well as some thoughts on where this might lead.





On the liquids side, imports have declined some 2 million barrels per day since 2005, while product exports nearly tripled over that period. In fact, product exports in August exceeded 3 million barrels per day for the first time ever, according to Energy Information Administration (EIA) data. As a result – in a positive trend for energy security – our reliance on foreign petroleum has shrunk from over 60 percent in 2006 to under 50 percent last year. A slow economy surely results in lower demand, which accounts for part of the shift away from imports. However, the effect of a slow economy is insufficient to explain the entire shift. American liquids production – including both crude oil and natural gas liquids – has jumped roughly 1 million barrels per day between 2008 and so far in 2011. Much of that has come from the increased production of the onshore lower 48 and reflects the significant contributions of America's independent producers.

On the natural gas side, the reversals brought about by increased American energy production have also been striking. Even with natural gas consumption increasing over the past five years by more than 2 Tcf, or nearly ten percent, net imports have fallen by 1 Tcf, from 3.6 Tcf in 2005 (and a peak of 3.8 Tcf in 2007) to 2.6 Tcf in 2010. What enabled that remarkable development was the work of the American oil and gas industry, which through innovative technology brought about a jump in U.S. natural gas production of nearly 20 percent in just five years. As a result, the net import percentage for natural gas was at its lowest point in seventeen years at 10.8 percent, down from a peak of 16.4 percent in 2005.

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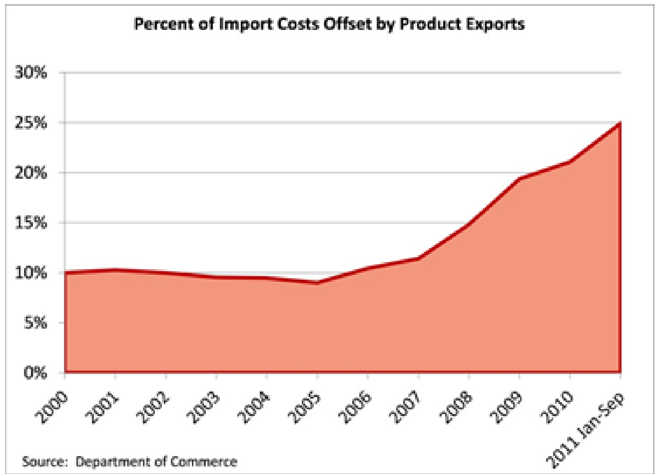

The impact on trade in dollar terms of the takeoff of natural gas production has been even more dramatic, if one allows that the increasing abundance of America's resources has contributed to lower market prices for natural gas. Lower prices have greatly reduced the cost of what natural gas the U.S. still imports, even as the need for imports has declined. In 2005, the cost of U.S. net trade in natural gas was about $32 billion. For 2010, that had fallen to $12 billion, with roughly a third attributable to lower net imports and the rest to lower prices. So far in 2011, the net cost on the natural gas balance has fallen even further from a year ago, trailing 2010's January-September dollar figure by nearly one third. Rising U.S. supplies have also led to increasing interest in the prospect of LNG exports, with one new project recently approved and several more under review – contrasting with the many dozens of licenses being pursued just a few years earlier to import, rather than export, LNG.

Where do things go from here? To the degree that the U.S. experiences a much-needed economic recovery over the next several years, American energy demand is likely to rise with economic recovery. Also, on the flip side, we have demonstrated that petroleum consumption is a key component to economic growth.

One thing is clear in the larger world energy picture: an ever-increasing share of Middle East petroleum is heading to supply burgeoning developing economies in the East, rather than Western economies. In fact, roughly three-fourths of Middle Eastern petroleum now already goes to Asia. Thus, supplies from the Western Hemisphere and from the U.S. in particular, are of increasing strategic value. This is especially true, given that some 80 percent of the world's oil reserves are already controlled by government-owned national oil companies that are not always subject to market-based behavior. The United States is in a great position. According to a recent Goldman Sachs study, the U.S. is on target to be the world's top producer of oil, bypassing Russia and Saudi Arabia in just five years. The U.S. – especially its policymakers – cannot neglect the tools in its own hands that can enhance American energy security and increase the availability and affordability of energy essential to our economy.

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