

A NATIONAL STRATEGY FOR ENERGY SECURITY

HARNESSING AMERICAN
RESOURCES AND INNOVATION

2013



ENERGY SECURITY
LEADERSHIP
COUNCIL

A PROJECT OF



Securing America's
Future Energy

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Statement of Purpose

The Energy Security Leadership Council (“Council”) believes that America’s energy security can be fundamentally strengthened through a combination of major reductions in oil consumption, increases in domestic energy production, and reforms to energy-related regulations. Most importantly, we must transform our transportation sector so that oil is no longer its primary fuel. The Council’s recommendations reflect the realities of global energy interdependence and the promise of American resources and technological ingenuity. Taken together, the portfolio of proposed recommendations constitutes a path forward that recognizes both the continued risks to our nation posed by dependence on oil and the available solutions. The Council’s mission is to secure the support of a bipartisan coalition committed to making the necessary hard choices and sustaining efforts to implement meaningful solutions.

Letter to the President, the Congress, and the American People

The recommendations presented by the *Energy Security Leadership Council* (“Council”) in this report are designed to achieve a fundamental necessity: safeguarding the physical and economic security of the United States by significantly reducing our dependence on oil.

Today, this dependence constrains foreign policy, limits military options, and harms economic growth and fiscal stability. Successfully addressing the challenge requires a balanced approach that emphasizes both substantially decreasing oil consumption and expanding domestic energy production.

In December 2006, the Council outlined such an approach in its inaugural report, *Recommendations to the Nation on Reducing U.S. Oil Dependence*. Improved and strengthened fuel-economy standards were a core element of that comprehensive plan. A year later, in December 2007, Congress and President George W. Bush joined together to enact significant increases in fuel-economy standards for the first time in a generation. Unfortunately, access to new areas for oil production was not included. The Council subsequently released *A National Strategy for Energy Security* in November 2008. The Senate Energy and Natural Resources Committee voted on a bipartisan basis for legislation echoing this report in June 2009.

While legislative consensus has since become increasingly difficult to find, we have nonetheless seen some positive developments in the marketplace that, to different extents, correspond with the Council’s aims, including vehicle electrification and the increased domestic production of oil and natural gas. Public-private sector collaboration has also resulted in additional strengthening of vehicle fuel-economy standards, which remains a Council priority. Further progress on these solutions offers a pathway towards job creation, improved fiscal strength, economic growth, and a reduced trade deficit.

The Council is encouraged by the combination of increased domestic oil production and decreased consumption, and recommends policies to advance both trends. However, we caution that the situation has not fundamentally changed, and that it would be dangerous to allow a false sense of security to result in complacency and inaction. The Organization of Petroleum Exporting Countries (OPEC) cartel and national oil companies fully or partially controlled by foreign governments continue to exert substantial influence over global supply and prices. As long as our nation remains dependent on oil—and, therefore, on this captive market—it will remain at risk.

More can and must be done. Government policy must pivot to focus on highly-targeted programs and reforms and research and development initiatives to both maximize domestic production of cost-effective oil and natural gas resources and more rapidly shift the U.S. transportation system away from petroleum and toward a domestic, stable, affordable, and diverse set of fuels.

By harnessing abundant domestic energy resources and American innovation, the United States can meaningfully reduce its exposure to the dangers of the global oil market. This can only be achieved through a serious and sustained national effort. It would be both impossible and ill-advised to prescribe a national energy platform through partisan or ideological prisms. We are all stakeholders.

We urge policymakers to pursue the task of strengthening U.S. energy security as a necessity for the future security and prosperity of our nation.



General P.X. Kelley, U.S. Marine Corps (Ret.)
28th Commandant,
U.S. Marine Corps



Frederick W. Smith
Chairman, President & CEO,
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Summary for Policymakers

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The United States is in the midst of the most important shift in domestic energy production in a generation. Surging output of oil and natural gas is generating important benefits for the country, including increased manufacturing competitiveness, employment growth, new government tax revenues, and a shrinking trade deficit. Equally profound developments are impacting the manner in which Americans consume energy. The nation's transportation sector is now more efficient than at any time in modern history, and it will continue to improve going forward. In addition, electric and other alternative fuel vehicles are being introduced into the marketplace at an increasing rate.

Yet, for as much promise as America's newfound energy abundance holds for the country's future, the United States still faces profound risks. Most notably, the nation today is still dangerously dependent on petroleum fuels to power our massive transportation sector. Our cars, trucks, planes, and ships account for more than 70 percent of U.S. oil demand and rely on petroleum fuels for 93 percent of their primary energy.¹ No other energy source matches the significance of petroleum in America.

This excessive reliance on oil exposes the entire economy to the vagaries of the global oil market at a cost that has become increasingly unsustainable. Oil dependence is one of the greatest threats to U.S. national security, and it deeply undermines our ability to achieve an enduring period of American economic growth and prosperity.

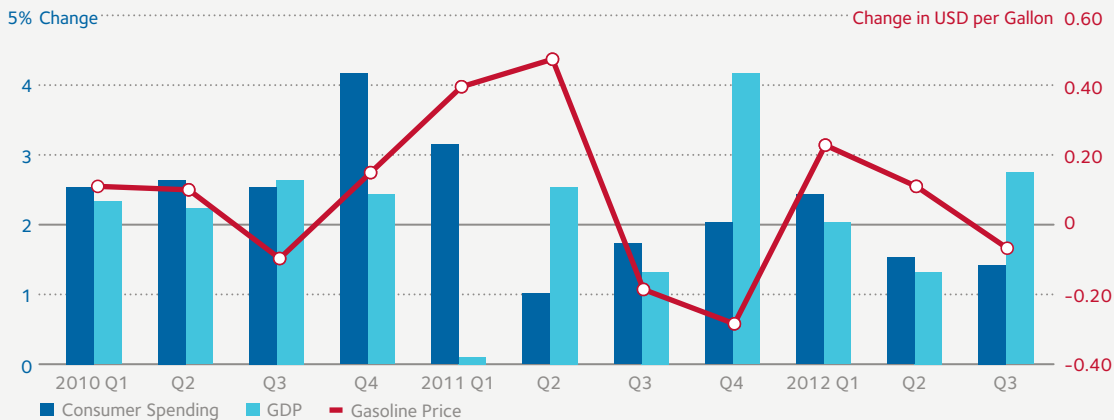
This report presents a vision for achieving a sharp improvement in American energy security through greater diversity in transportation fuels, continued growth in domestic production of oil and natural gas, and a more efficient regulatory system that prioritizes safety and security without sacrificing transparency. While market forces will surely take the country forward, the global oil market suffers from numerous market failures with grave national and economic security costs. This circumstance creates an unavoidable role for government policy. The Council does not take this position lightly, as we recognize that such intervention in the marketplace can produce unintended consequences. For this reason, we have strived to evaluate each individual policy recommendation through the lens of a rigorous and clear-eyed analysis of its costs and benefits.

Such an analysis, however, must be conducted within a framework that captures the significant economic, fiscal, and other costs of the status quo. Oil dependence inflicts staggering economic costs on the United States, and a set of policies designed to address this ongoing vulnerability must be evaluated with that broader context in mind. Therefore, in addition to analyzing the direct budgetary costs of public policies designed to improve U.S. energy security, the Council also considered the costs of oil dependence with regard to the federal government's fiscal position, the U.S. current account balance, and consumer spending and economic growth.

¹ U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Annual Energy Review (AER) 2011*, Tables 5.13c and 2.1e

Quarterly Change in Consumer Spending, GDP, Gasoline Price

FIGURE 1



Source: DOE, EIA; BEA; and SAFE analysis

Fiscal Issues

Oil dependence has both direct and indirect effects on the U.S. fiscal position. The direct effects are fairly straightforward. High oil prices drive larger fuel outlays by federal transportation fleets, most notably the Department of Defense. The military's fuel spending stood at \$17.5 billion in fiscal year 2011, up from less than \$5 billion in 2005.² More importantly, perhaps, the military expends significant resources ensuring the free flow of oil throughout the world at a cost that some estimates place as high as \$60 to \$80 billion annually.³ These figures are miniscule in the context of the federal budget, but they can be significant for an individual agency or branch of the military, and may ultimately displace spending that is more central to the agency's mission.

Indirect effects of high oil prices are sometimes less clear than the direct effects, but they can be far more significant. Almost all of these costs stem from the impact that high and volatile oil prices have on the broader economy. Every U.S. recession since 1973 has been preceded by—or occurred concurrently with—an oil price spike. To the extent that oil price spikes contribute to reduced economic activity and even recessions, they lead to lower federal income, payroll, and other tax revenues. These knock-on effects can be difficult to quantify with great precision, but they are nonetheless observable. For example, in a 2012 report, the trustees of Social Security revised their projection for when the system will no longer be able to pay full benefits. In moving the date forward from 2036 to 2033, the trustees cited higher oil prices, which they expect will undermine economic growth and reduce receipts from worker pay over the coming decades.⁴

Oil dependence represents a fundamental weakness in the U.S. economy, one that has likely contributed to a weaker than expected economic recovery and that will continue to undermine U.S. growth until it is addressed. Though there may be disagreements on how to best remedy the current U.S. fiscal position, there is near unanimous agreement that recessions and weak economic growth—which lead to federal revenue shortfalls—are among the most damaging factors. Simply put, there is no practical pathway to an improved fiscal outlook that does not rely on a period of sustained economic growth. By addressing the issue of American oil dependence, lawmakers can take a critical step toward building our fiscal future on a firm foundation. Failure to do so would ignore a structural risk to the economy that will assuredly return in the future.

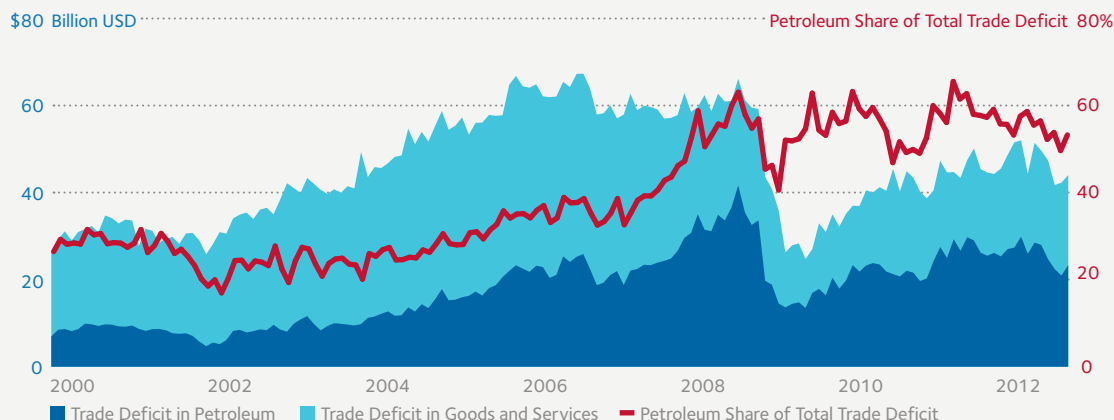
² Moshe Schwartz, Katherine Blakeley, and Ronald O'Rourke, "Department of Defense Energy Initiatives: Background and Issues for Congress," Congressional Research Service (CRS), August 10, 2012, at 8

³ RAND Corporation, "Imported Oil and National Security," at 60–62, 2009

⁴ Social Security and Medicare Board of Trustees, Summary of the 2012 Annual Reports, available at <http://www.ssa.gov/oact/TRSUM/index.html>

FIGURE 2

Share of Petroleum in Monthly U.S. Trade Deficit



Source: U.S. Census Bureau, Office of Foreign Trade Statistics

Trade Deficit and Current Account Balance

Despite the fact that the United States is currently importing less oil than at any time since the early 1990s, oil imports continue to play a substantial role in expanding the U.S. trade deficit. Since January 2007, the United States has run a \$1.7 trillion deficit in crude oil and petroleum product trade, a figure that accounted for 53 percent of the total trade deficit over that period.⁵ In fact, over the past five years, oil has accounted for a larger share of the trade deficit than any bilateral or regional trading partner. At \$386 billion, the annual trade deficit in petroleum was highest in 2008. And though net petroleum imports fell by more than one-third between 2008 and 2012, this year's deficit in oil trade is expected to once again surpass \$300 billion with global oil prices near record levels amid instability in the Middle East and North Africa.

These deficits have exported significant U.S. capital abroad at the expense of greater domestic investment. This effect is exacerbated by the fact that a declining share of U.S. petrodollars is recycled through other trade. While regional trading partners Canada and Mexico now account for roughly 40 percent of U.S. net imports of crude oil, OPEC members still account for nearly 50 percent.⁶ Recent estimates suggest that only 34 cents of every dollar used to purchase oil from OPEC members was returned to the U.S. economy through other trade in 2011, down from the 1970–2000 average of 55 cents.⁷

Consumer Spending and Economic Growth

High and volatile oil prices have a significant impact on U.S. households and businesses, making it difficult to budget and invest, and displacing disposable income that could otherwise be spent on non-petroleum goods. Economy-wide spending on petroleum fuels totaled \$320 billion in 2002. By 2008, it had risen to \$870 billion, and it will surpass \$900 billion in 2012.⁸ In other words, the U.S. economy spends nearly three times more on petroleum fuels now than it did a decade ago—despite the fact that vehicle miles traveled has increased by less than 5 percent and the number of registered vehicles has increased by less than 10 percent.⁹

Fuel-price volatility has clearly damaged fuel-intensive public agencies and businesses like airlines and large commercial fleets. These entities have a relatively fixed base of capital assets that depend on fuel, and rapid swings in prices directly affect the bottom line. Yet oil price volatility is also particularly damaging for U.S. families. The average U.S. household spent roughly \$2,700 on gasoline in 2011, more than double the \$1,200 they spent in 2002.¹⁰ This increase occurred over a time period when

5 SAFE analysis based on data from: U.S. Census Bureau, U.S. Bureau of Economic Analysis (BEA), "U.S. International Trade in Goods and Services," Exhibits 1 and 9

6 DOE, EIA, U.S. Net Imports by Country, available at http://www.eia.gov/dnav/pet/pet_move_net_i_a_EPoo_IMN_mbbldpd_m.htm

7 Javier Blas, "OPEC trade fails to cushion US and Japan," *Financial Times*, April 17, 2012

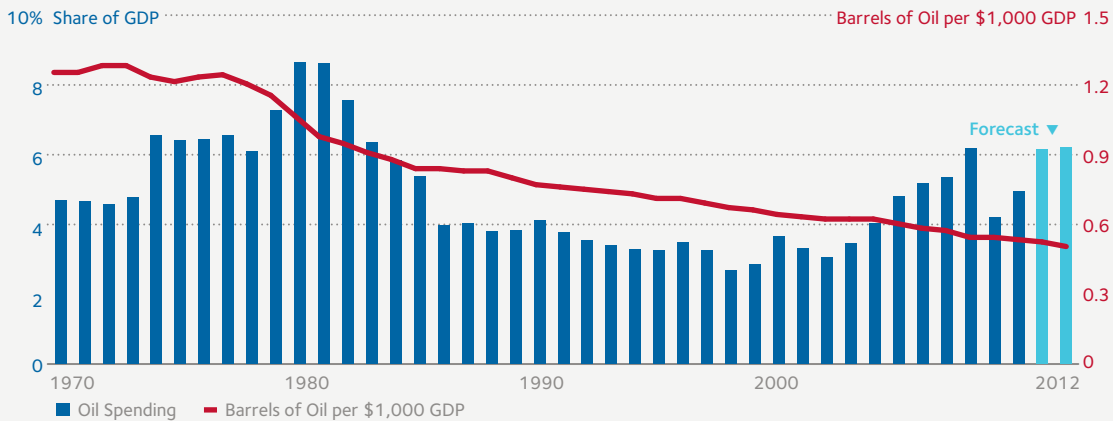
8 SAFE analysis based on data from: DOE, EIA, AER 2011, Table 3.5 and *Monthly Energy Review*, November 2012

9 U.S. Department of Transportation (DOT), Bureau of Transportation Statistics (BTS), Research and Innovative Technology Administration (RITA), "National Transportation Statistics," Table 1-11 and 1-36; and Federal Highway Administration (FHWA), "Traffic Volume Trends," August 2012

10 U.S. Bureau of Labor Statistics (BLS), Consumer Expenditure Survey, 2011

U.S. Oil Intensity and Oil Spending

FIGURE 3



Source: EIA, AER 2010; Department of Commerce, Bureau of Economic Analysis; and SAFE Analysis

the median household income increased by only about 20 percent.¹¹ In an economy where household consumption accounts for roughly 70 percent of GDP, the rapid increase in oil expenditures seen in recent years has likely played an important role in undermining economic growth.

The impact of oil prices on consumer spending and economic growth has been particularly significant during the stalled economic recovery of 2010–2012. Both household spending and overall growth were steady and trending positive throughout 2010, and retail gasoline prices were highly stable, averaging a consistent \$3.00 per gallon. On the heels of rapid global demand growth and the Arab Spring, gasoline prices spiked by \$0.40 per gallon in Q1 2011 and almost \$0.50 per gallon in Q2 2011.¹² GDP growth plunged to nearly zero in early 2011, and consumer spending grew at its slowest pace since the recession for much of the year.¹³ Federal intervention in the form of a payroll tax cut probably averted more serious consequences, but only just so. The cut netted households an additional \$108 billion in 2011 compared to 2010, while higher gasoline prices cost households an additional \$73 billion.¹⁴

No Free Market for Oil

Many have argued that economic forces alone should incentivize the investments necessary to improve U.S. energy security. And while oil prices may be a function of supply and demand, the global oil market is far-removed from the classical definition of a competitive market. By some estimates, as much as 85 percent of global proved oil reserves are held by national oil companies (NOCs), state-run enterprises that often function as government proxies, instead of market-driven enterprises. During the past decade, corruption, mismanagement, and underinvestment by many NOCs have constrained oil production by some of the world's most significant holders of oil reserves, contributing to broader market tightness and volatility. In fact, despite their dominance of proved reserves, only eight NOCs ranked among the top-25 companies in terms of upstream spending in 2011.¹⁵

Beyond the inherent distortions associated with the concentrated power of NOCs, the market is openly and actively manipulated by a cartel of producers, OPEC. OPEC's 12 members have historically controlled nearly 80 percent of global proved reserves of conventional oil, yet they account only for approximately 40 percent of world supplies on average.¹⁶ Making this disparity all the more egregious is the fact that OPEC members control access to the least expensive reserve base in the world.

11 Census Bureau, Historical Tables, Table H-8, available at <http://www.census.gov/hhes/www/income/data/historical/household/>

12 DOE, EIA, Short Term Energy Outlook, November 2012

13 BEA, National Economic Accounts, GDP, Percent Change from Preceding Period, available at: <http://www.bea.gov/national/index.htm#gdp>

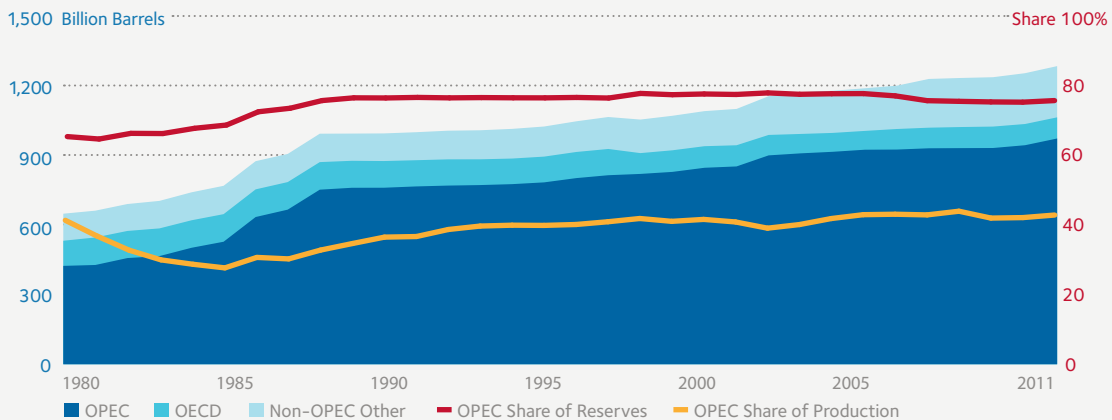
14 SAFE analysis based on data from: BEA, Personal Income and Outlays, Table 2.4.5; and U.S. Department of Treasury, Office of Tax Policy, "A State-by-State Look at the President's Payroll Tax Cut for Middle Class Families," November 30, 2011

15 International Energy Agency (IEA), *World Energy Outlook (WEO) 2011*, at 142

16 BP, plc., *Statistical Review of World Energy (Statistical Review) 2012*, online statistical supplement, "Proved Reserves – History"

FIGURE 4

Global Reserves by Source



Note: Excludes Canadian oil sands not under active development. Also excludes Venezuelan extra-heavy oil.

Source: BP, plc., *Statistical Review of World Energy* 2012

While many of OPEC's NOCs suffer the same mismanagement and underinvestment as state-run enterprises in non-OPEC countries, OPEC's producers also work within a quota system designed to achieve specific oil price targets. Often times, these targets aim to keep oil prices high enough to earn significant export revenues, but low enough to dissuade investment by consumers in alternative fuels.¹⁷

Today, however, OPEC's price targets are also driven by an urgent need to maintain generous domestic spending on social programs to mitigate rising political instability. The fiscal breakeven oil price for Saudi Arabia has recently been estimated at between \$80 and \$100 per barrel.¹⁸ The figures for Iraq, Algeria, Angola, and Nigeria are roughly the same, while the budgets in Iran and Venezuela each require significantly higher oil prices to sustain domestic spending.¹⁹ Total OPEC export revenues exceeded \$1 trillion in 2011 for the first time in history.²⁰

The combination of a manipulated oil market, a gasoline price that fails to reflect important external costs, and the indispensable nature of the underlying commodity to the economy creates a market failure that endangers the economic and national security of the United States. To eschew a public policy response likely would condemn the nation to decades of future oil dependence and, therefore, the risk of debilitating price shocks with serious implications for fiscal stability, economic growth, and foreign policy. Government action in this area carries the risk of failure. Nonetheless, such costs pale in comparison to the potential destructiveness of another forty years of oil dependence, a period that promises to feature both rising instability in much of the oil-producing world and unprecedented economic challenges that render the country especially vulnerable to such volatility.

Economic Benefits of Improved Energy Security and Reduced Oil Dependence

Improving U.S. energy security through increased domestic production of liquid fuels and reduced oil dependence in transportation would generate significant economic benefits for the nation. Producing more crude oil, natural gas liquids, and alternative liquid fuels domestically would directly offset the need for imports of foreign oil, driving meaningful reductions in the trade deficit. Greater investment in domestic fuel production would also create direct and indirect jobs and increase federal revenues through greater collection of income taxes as well as production royalties when such activities occur on federal lands and waters.

¹⁷ See, e.g., Eric Martin, "Alwaleed says Saudi Arabia seeks \$70 to \$80 oil price to preserve sales to the West," Bloomberg, May 28, 2011

¹⁸ IEA, *WEO 2011*, at 140

¹⁹ Id.

²⁰ DOE, EIA, OPEC Revenues Fact Sheet, available at http://www.eia.gov/emeu/cabs/OPEC_Revenues/Factsheet.html

The benefits from reduced oil consumption in the transportation sector would likely be even larger. Reduced demand would have an effect similar to increased production in terms of the trade deficit, reducing capital outflows and increasing domestic investment. However, more importantly, greater adoption of advanced transportation technologies, particularly those powered by electricity and natural gas, would sharply reduce the oil intensity of the economy, making the United States far more resilient to high and volatile oil prices. This increased resiliency would have beneficial long-term effects on consumer spending, business investment, and overall economic growth.

The single most important benefit of reduced oil dependence is that the economy will be much better prepared to withstand the damaging effects of oil price spikes, such as those that were associated with recessions in 1973–74, 1980–81, 1991, 2000–2001, and 2007–2009. By reducing the role of oil in the broader economy, American households and businesses will simply be less vulnerable to the volatility of global oil prices. In other words, a comprehensive policy approach designed to improve U.S. energy security can be thought of as an insurance policy that will make the economy more robust in good times and more resilient when subjected to energy shocks.

Summary of Recommendations

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The proposals presented by the Council are designed to achieve a fundamental necessity: safeguarding the physical, military, and economic security of the United States by significantly reducing our dependence on oil. The report is divided into three parts outlining these proposals in detail and a supplementary part in which the Council highlights a selection of global issues with particular relevance to energy markets and U.S. energy security.

PART I

Reducing Oil Use through Advanced Technology

U.S. energy security is determined by the role of oil in the economy, particularly in transportation. Oil dependence can only be addressed by developing a transportation system that is no longer predominantly beholden to the high and volatile prices characteristic of the global oil market. While continued improvements in fuel efficiency remain a critical part of the solution for vehicles of all sizes, so too is the development and adoption of alternative fuel vehicles that use electricity, natural gas, or other domestic and less price-volatile fuels. Although promising levels of initial uptake are being achieved, alternative fuel vehicles continue to face a number of barriers to widespread market adoption.

Research and development efforts play a critical role in reducing the cost of advanced automotive components, such as batteries for electric vehicles and storage tanks for natural gas vehicles. However, for alternative fuel vehicles to be truly successful, greater understanding is required regarding consumers' public and private refueling needs, the impact of these vehicles on other energy systems—such as the electric grid—and best practices concerning regulation. City-level deployment efforts focused on data aggregation and dissemination will be crucial in advancing the market's understanding of alternative fuel vehicles. Incentives to promote the purchase of vehicles and installation of refueling infrastructure will also remain important components of driving adoption in the near term.

RECOMMENDATIONS

Establish up to six fuel-neutral deployment communities in small- to medium-sized cities.

Reinstate and reform incentives for alternative fuel infrastructure.

Create incentives for medium- and heavy-duty alternative fuel vehicle purchases.

Reorient the Department of Energy's research and development activities to help catalyze those innovations most likely to improve U.S. energy security.

Increase federal investment in research and development for automotive-grade batteries and natural gas storage tanks.

PART II

Maximizing Domestic Energy Production

Driven by a combination of advances in drilling and well-completion technology and generally supportive commodity prices, the U.S. energy industry has engineered a turnaround in output that few observers believed was possible only a few years ago. This is delivering meaningful benefits including direct and indirect job creation, an improved current account deficit, and increased economic competitiveness. However, while the outlook for U.S. production of conventional fuels suggests continued growth over the short and medium term, much more could be done to support sustained increases in domestic energy production over the long term. Most notably, significant oil and natural gas resources on federal lands, both onshore and offshore, remain unavailable for development due to statutory restrictions and bureaucratic inertia.

A rigorous approach to oversight based on best-practices and performance-based evaluation should form the foundation of efforts to expand industry access to frontier areas under federal control. Such an approach acknowledges a basic reality: it is in the nation's interest to expeditiously develop its natural resources, but such development must prioritize safety and sustainability. The nation must also invest in the research and development that will unlock the unconventional liquid fuels of the future.

RECOMMENDATIONS

Require the Department of Interior to begin work on a revised Five Year Plan covering the period from 2015–2020.

Extend Outer Continental Shelf revenue sharing to all coastal states.

Revise the liability limits and financial responsibility requirements set forth in the Oil Pollution Act of 1990 to reflect current economic and financial realities.

Increase funding for the Department of Interior to offer competitive pay in order to engage with operators on equal footing.

Facilitate limited development of the Arctic National Wildlife Refuge using extended reach drilling and strict surface occupancy restrictions.

Establish a federal Energy Security Trust Fund seeded with revenues from new Outer Continental Shelf and Alaskan production.

Increase funding for research and development related to advanced biofuels.

Allow the Department of Defense the flexibility to purchase advanced fuels and technologies.

PART III

Reforming and Streamlining Regulatory Structures

The energy sector operates in a tightly regulated environment under the influence of numerous government agencies. This regulation can sometimes stifle progress. The government should take advantage of opportunities to reform or eliminate overly-stringent and complex rules to the immediate and long-term benefit of U.S. energy production, consumption, and security. Importantly, in a time of constrained budgets, these benefits can be realized without requiring substantial federal outlays.

Specifically, as the country increasingly produces traditional fuels in new ways, deploys advanced or alternative fuels that did not exist decades ago, and works to achieve broad national goals such as enhanced energy security and environmental sustainability, the federal government must ensure that its approach to regulation of the energy industry is clear, consistent, and rational. Its approach must also serve as a framework to promote our energy goals instead of an obstacle to achieving them. This will help foster a more certain operating and investment climate for the energy industry as a whole.

RECOMMENDATIONS

Improve the federal permitting process for major energy projects by streamlining authority, promoting transparency, and reducing frivolous litigation.

In order to increase public confidence in the hydraulic fracturing process, states should participate in the State Review of Oil and Natural Gas Regulations (STRONGER) review process. STRONGER should increase its scope to develop best practices for hydraulic fracturing.

The government should use fuel consumption, measured in gallons per 100 miles of travel, to report fuel economy on vehicle labels and calculate compliance with fuel-economy standards.

The National Highway Traffic Safety Administration and the Environmental Protection Agency should amend the medium- and heavy-duty fuel economy and greenhouse gas emission rules to offer additional incentives for natural gas vehicles.

Encourage federal government adoption of alternative fuel vehicles.

Establish a grant program at the Department of Energy to fund state initiatives to upgrade critical infrastructure which would reduce the risk of severe weather-related energy sector service interruptions.

PART IV

Global Developments with Long-Term Implications for U.S. Energy Security

Significant and sometimes rapid shifts in global and domestic energy markets have defined the energy security landscape for the past decade. Future shifts, anticipated or not, will both afford new opportunities and pose new threats to American prosperity and national security. Today, a selection of developments is already on the horizon. These should be monitored carefully by policymakers on an ongoing basis.

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DEVELOPMENTS

What are the economic and geopolitical implications of the United States exporting liquefied natural gas?

What are the barriers preventing other countries from exploiting their unconventional oil resources using hydraulic fracturing and horizontal drilling techniques?

What if there is a significant slowdown in the growth of the Chinese economy?

How will increasing oil production in Iraq affect the Organization of Petroleum Exporting Countries' (OPEC) ability to manage its production? If Iraq is not perceived as a team player, how will other OPEC members respond?





INTRODUCTION

Harnessing American Resources
and Innovation

Harnessing American Resources and Innovation

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The United States is experiencing the most important shift in energy production and consumption in a generation. Simply put, the nation is producing more energy domestically than seemed possible only a few years ago and is using it more efficiently as well. As a result, whole sectors of the economy are on the cusp of changes that could transform the nation in the coming decades, driving significant job creation, accelerating economic growth, and advancing environmental protection. The United States has an opportunity to achieve nothing less than a fundamental, long-term improvement in economic and national security.

Fully leveraging America's newfound energy abundance will be among the most important tasks facing the country's leaders in the coming years. Success in maximizing energy security and economic growth is not guaranteed. Decisions made today could either prolong the status quo or set the nation on a path toward vastly improved economic competitiveness, cleaner air and water, and enhanced national security based on a foreign policy unencumbered by the geopolitics of oil.

Without question, the remarkable advancements now unfolding have placed the nation in a position of strength as leaders undertake the work of addressing key policy questions.

To begin, American businesses and consumers are using petroleum more efficiently today than at any time in the nation's history, and recently finalized fuel economy regulations have set the country on a path toward even greater efficiency and improved resiliency to oil price volatility. New light-duty vehicle efficiency increased by more than 30 percent between 2005 and 2012, and current standards call for an additional 60 percent in improvements by 2025.¹ Depending upon the manner in which the standards are met, they could reduce U.S. oil consumption by as much as 3.1 million barrels per day (mbd) by 2030, equal to one-fourth of 2012 transportation-related oil demand.² The first ever standards for medium- and heavy-duty trucks could contribute an additional 0.4 mbd in savings by 2030.³

On the supply side, America's shale gas revolution has inaugurated an era of affordability and stability in a key domestic fuel, reduced consumer expenditures on home heating and electricity, and increased U.S. manufacturing competitiveness. Despite a 17 percent increase in demand between 2006 and 2012, U.S. economy-wide spending on natural gas fell by more than one-third during this period, saving households and businesses nearly \$60 billion in 2012 alone.⁴ Moreover, while increased hydrocarbon production is often viewed as incompatible with enhanced environmental quality, the shale gas revolution is already

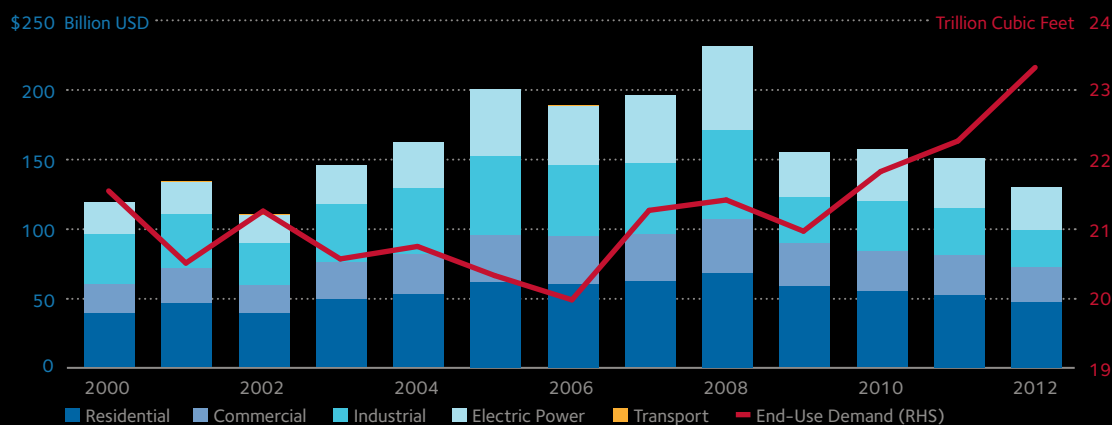
1 SAFE analysis based on data from: DOT, National Highway Traffic Safety Administration (NHTSA), "Summary of Fuel Economy Performance," October 2012; and U.S. Environmental Protection Agency (EPA), "Fact Sheet: EPA and NHTSA Set Standards to Reduce Greenhouse Gases and Improve Fuel Economy for Model Years 2017-2025 Cars and Light Trucks," August 2012

2 Figure reflects cumulative savings associated with 2012-2016 and 2017-2025 fuel economy rules. Oil savings based on: EPA, "Final Rulemaking to Establish Light-Duty Vehicle GHG Emission and Corporate Average Fuel Economy Standards, Regulatory Impact Analysis," at 6-15; and "Regulatory Impact Analysis: Final Rulemaking for 2017-2025 Light-Duty Vehicle GHG Emissions and Corporate Average Fuel Economy Standards," at 5-26

3 EPA, "Final Rulemaking to Establish GHG Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines Vehicles, Regulatory Impact Analysis," at 7-6

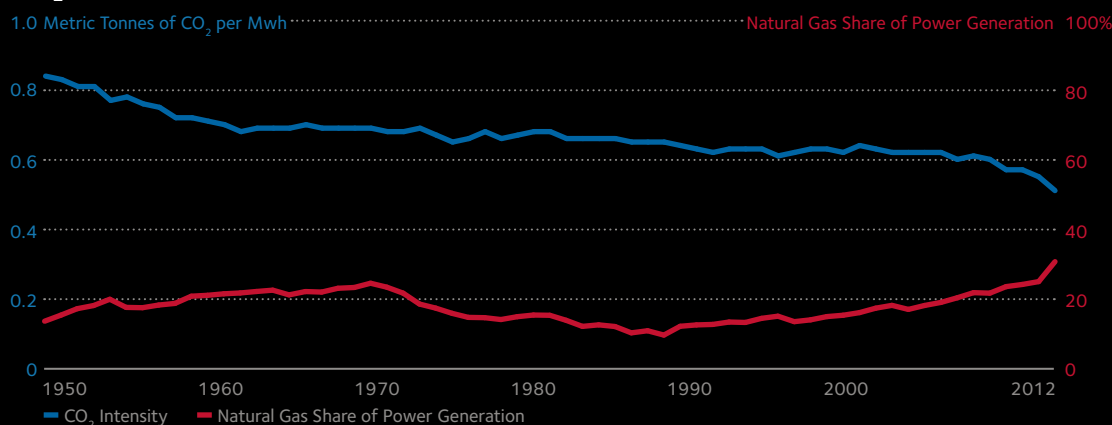
4 SAFE analysis based on data from: DOE, EIA, *Monthly Energy Review*, November 2012, Tables 9.10 and 4.3

U.S. Spending on Natural Gas

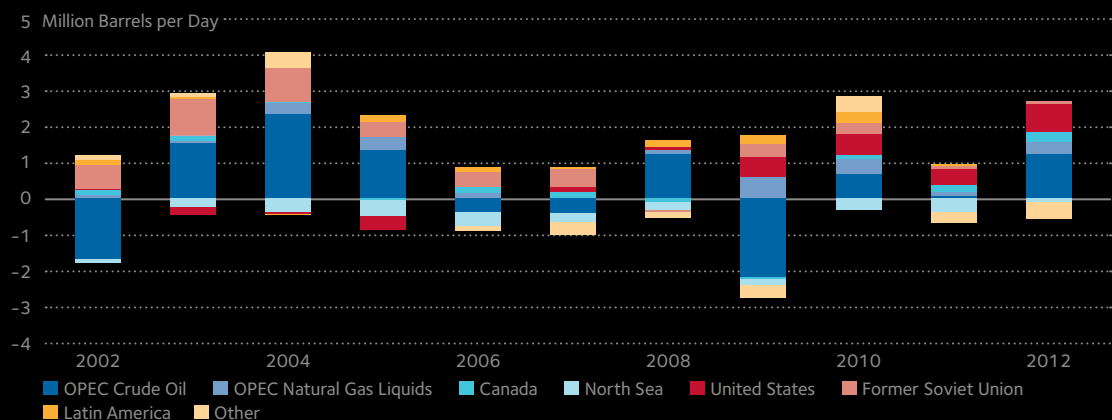


Source: DOE, EIA; and SAFE analysis

CO₂ Intensity of the U.S. Power Grid

Source: DOE, EIA, *Annual Energy Review 2010* and *Monthly Energy Review*, August 2012

Change in Global Liquids Supply, 2002–2012



Source: DOE, EIA

FIGURE 5

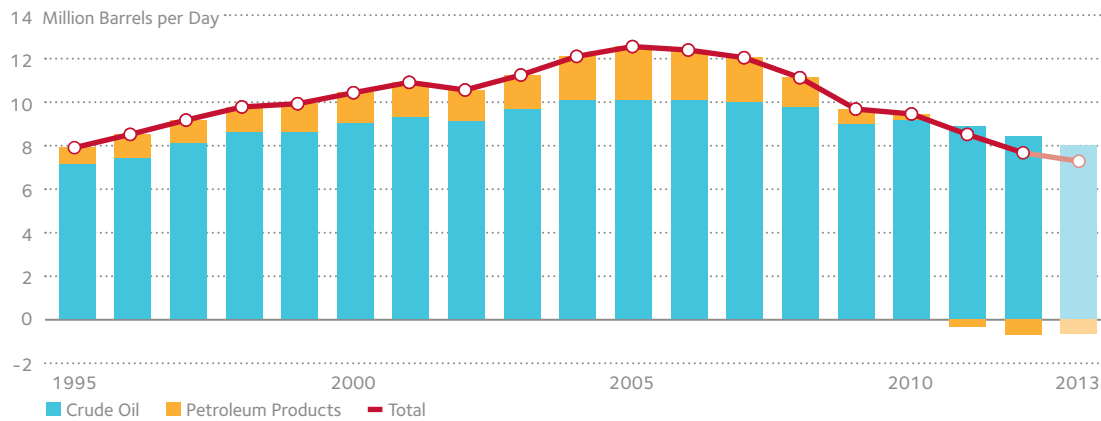
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FIGURE 6

FIGURE 7

FIGURE 8

U.S. Net Imports of Crude Oil and Petroleum Products



Source: DOE, EIA

creating a new paradigm. The carbon-intensity of the U.S. power grid fell to the lowest level in history in 2012, driven by the increased use of inexpensive domestic natural gas for baseload power generation.⁵

Yet, the most dramatic changes in the U.S. energy system pertain to petroleum fuels. Spurred by a period of high crude oil prices and enabled by the same technological advancements that unlocked shale gas, the domestic oil industry has tapped into substantial new petroleum resources collectively referred to as light, tight oil. As a result of newly prolific fields in Texas, North Dakota, Colorado, and elsewhere, U.S. production of crude oil has increased by more than 1.3 mbd in just four years.⁶ In fact, U.S. oil production grew faster than that of any other country between 2008 and 2012.⁷ Combined with production growth in Canada, Brazil, and Mexico, rising U.S. output has made the Western Hemisphere the most important source of new oil supplies, something that would have seemed unthinkable as recently as the turn of the last century.

Rising liquid fuel production is already benefitting the nation in important ways. Net U.S. imports of crude oil and refined petroleum products accounted for just 41 percent of U.S. liquid fuel consumption in 2012, dramatically lower than the historical high of more than 60 percent in 2005.⁸ In the years between 2008 and 2012, a period during which net imports declined by 3.5 mbd, domestic liquids production increased by 2.2 mbd, excluding refinery processing gain.⁹ Put another way, assuming each barrel of increased domestic liquid fuel production displaced a barrel of imported oil, surging U.S. output accounted for nearly two-thirds of the recent decline in oil imports, saving the American economy \$78.6 billion in foregone import expenditures in 2012 alone.¹⁰

While these developments are impressive, they arguably pale in comparison to expected future trends in energy production and consumption. Based on current assessments of U.S. oil and natural gas resources, the nation is on pace to achieve a striking level of domestic oil and natural gas production within the next decade. Current Department of Energy (DOE) projections suggest that the United States could be a net exporter of natural gas as soon as 2020.¹¹ And while expectations regarding petroleum production currently reflect a considerable range of scenarios, DOE's most recent projections show net oil imports equal to roughly one-third of consumption by 2020. This number may even prove conservative.¹²

5 SAFE analysis based on data from: DOE, EIA, *Monthly Energy Review*, November 2012, Tables 7.2a and 12.6

6 DOE, EIA, *Short Term Energy Outlook*, November 2012

7 BP, plc., *Statistical Review 2012*, at 8

8 DOE, EIA, *Short Term Energy Outlook*, November 2012

9 Id.

10 SAFE analysis based on data from: DOE, EIA, *Short Term Energy Outlook*, November 2012

11 DOE, EIA, *Annual Energy Outlook (AEO) 2012*, at 62

12 Id., at 3

Defining Energy Security

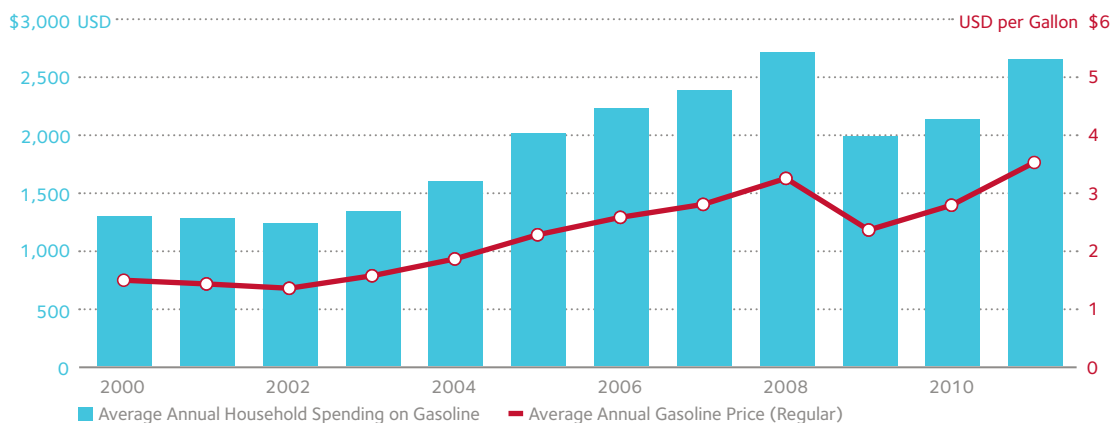
As long as the United States depends on petroleum fuels to power its economy—and its transportation sector, in particular—the nation will be exposed to the economic consequences of high and volatile oil prices. Although the United States is both an important producer and consumer of oil, oil prices are determined globally by a wide range of factors occurring in dozens of countries and markets. There is a single, international oil market defined by benchmark prices that are effectively equivalent after accounting for shipping costs, variations in quality, and other regional market factors. Therefore, a nation's level of energy security is not meaningfully affected by the ratio of foreign to domestic oil supply.

Increased domestic energy production and rising levels of efficiency will generate significant benefits for the nation and the economy. Our leaders, however, must not lose sight of the true nature of America's energy security challenge: the United States remains dangerously dependent on petroleum fuels to power our economy and provide basic mobility for consumers and businesses. At the heart of America's oil dependence is the nation's massive transportation sector, which alone consumes more gasoline, diesel, and other petroleum fuels each year than any national economy in the world.¹³ Transportation energy demand accounts for 70 percent of U.S. consumption, and our cars, trucks, planes, and ships currently depend on petroleum for 93 percent of delivered energy.¹⁴

This utter reliance on a single fuel has generated significant economic costs during the past several years, even as American oil production has increased and imports declined. Gasoline spending among all American households, which averaged little more than \$1,200 in 2002, soared to more than \$2,700 in 2008 and reached nearly the same level in 2011.¹⁵ This additional outlay of \$1,500 per household functioned essentially as a tax. It reduced disposable income and spending on other goods and services and was an important contributor to the onset of the 2007–2009 economic recession.¹⁶ Indeed, even these figures can understate the economic significance of rising petroleum prices. In total, U.S. economy-wide spending on petroleum fuels increased from \$320 billion in 2002 to \$895 billion in 2011, equal to more than six percent of GDP.¹⁷ This level of spending on petroleum fuels was associated with economic recessions in 1973–74, 1979–80, 1981, and 2007–2009.¹⁸

While the precise role of oil prices in triggering the most recent American recession continues to be debated, rising fuel expenditures in recent years inarguably frustrated policy efforts to address the

Household Spending on Gasoline



Source: BLS

13 SAFE analysis based on data from: DOE, EIA, *AER 2011*, Table 5.13c; and BP, plc., *Statistical Review*, at 9

14 DOE, EIA, *AER 2011*, Tables 5.13c and 2.1e

15 U.S. Bureau of Labor Statistics (BLS), *Consumer Expenditure Survey 2011*

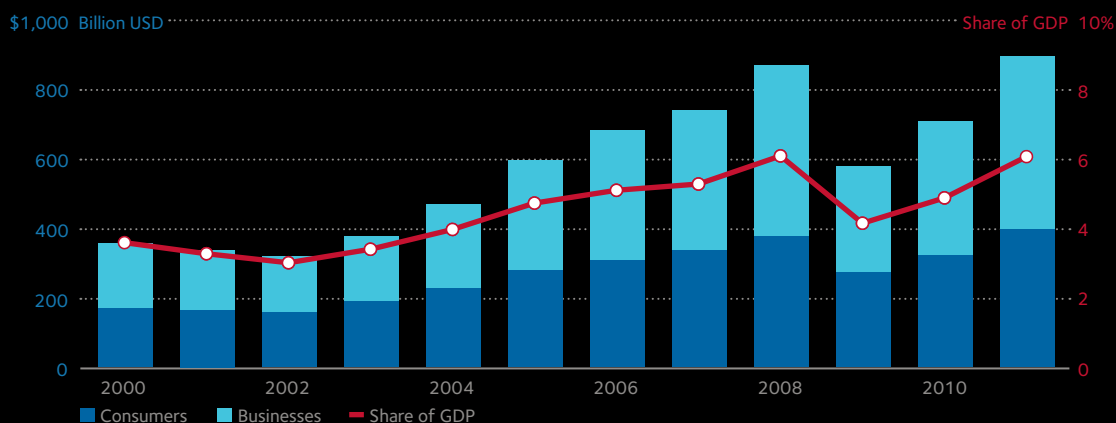
16 See, e.g., James D. Hamilton, "Causes and Consequences of the Oil Shock of 2007–2008," University of California, San Diego

17 SAFE analysis based on data from: DOE, EIA, *AER 2011*, Table 3.5 and Short Term Energy Outlook, November 2012

18 SAFE analysis based on data from: DOE, EIA, *AER 2011*, Table 3.5; and U.S. Bureau of Economic Analysis (BEA)

FIGURE 10

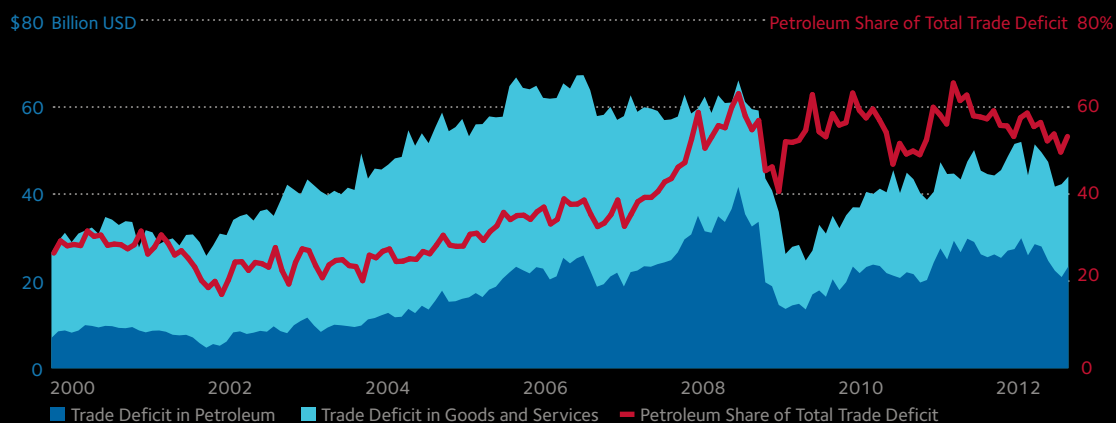
U.S. Spending on Petroleum Fuels



Source: DOE, EIA; BEA; and SAFE analysis

FIGURE 11

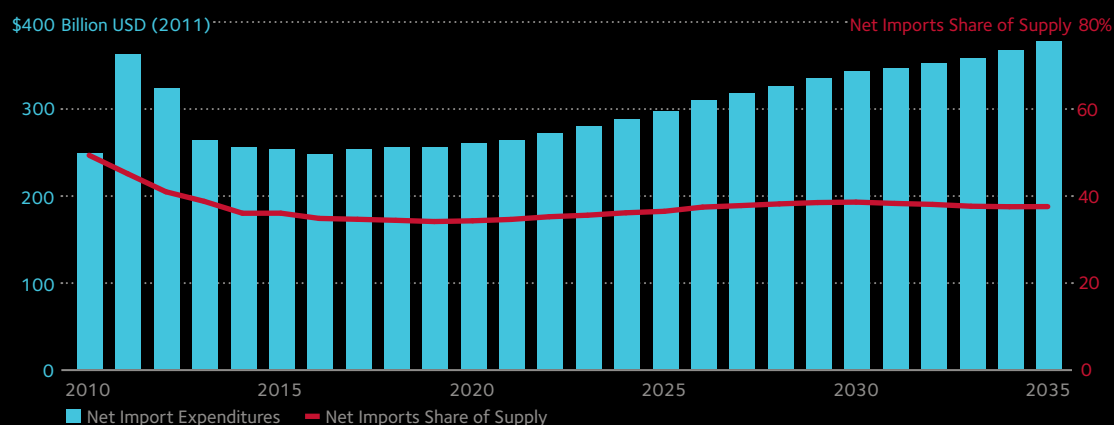
Share of Petroleum in Monthly U.S. Trade Deficit



Source: U.S. Census Bureau, Office of Foreign Trade Statistics

FIGURE 12

Forecast Net Oil Imports and Expenditures

Source: DOE, EIA, *Annual Energy Outlook 2013 Early Release*

economic recession and subsequent sluggish growth. For example, changes to the federal tax code enacted between 2001 and 2008 reduced income and estate taxes for the median U.S. household by about \$1,900.¹⁹ Yet, this reduction was largely offset by higher gasoline expenditures.²⁰ The phenomenon was repeated in 2011, when reductions in the federal payroll tax provided \$108 billion in tax relief for U.S. households at a time when year-over-year gasoline expenditures rose by more than \$70 billion.²¹

The economic costs of oil dependence extend well beyond the budgets of individual consumers, households, and businesses. Since January 2007, the United States has amassed a \$1.7 trillion trade deficit in crude oil and petroleum products, accounting for more than half of the total trade deficit during that time.²² The annual petroleum trade deficit topped \$380 billion in 2008, \$320 billion in 2011, and likely will exceed \$300 billion in 2012.²³ These deficits have contributed to an expanding current account imbalance and a weaker dollar, and they reflect a sizeable increase in the export of productive U.S. capital at a time when the nation would clearly benefit greatly from increased domestic investment. And while declining levels of oil imports should help mitigate the growth of these costs going forward, DOE projections nonetheless reflect significant oil import expenditures through 2035 due to higher oil prices.²⁴

During the past decade, global oil price volatility has been largely driven by the massive expansion in demand for mobility and petroleum fuels in emerging market economies. In China and India, the number of motor vehicles on the road increased by a combined 77.8 million units between 2000 and 2010, representing 30 percent of global growth.²⁵ As a result, global oil demand increased by 10.8 mbd between 2000 and 2010, creating considerable strain on the world's oil supply system.²⁶ Rising fuel demand in China alone accounted for more than 41 percent of the net increase in global oil demand between 2000 and 2010, a period during which demand in the developed world actually decreased.²⁷

Some observers have looked to the recent global economic slowdown and argued that global fuel demand may decelerate in the coming years. The fundamentals supporting greater demand, however, remain strong. The global middle class will expand by several hundred million people in the coming decades and demand for mobility will continue to grow. Today, emerging economies are already the marginal source of growth in both energy and transportation demand, and oil consumption in the developing world will surpass that of the developed world by 2014.²⁸

Between 2011 and 2035, transportation oil demand is projected to grow by more than 30 percent, or 14 mbd, assuming global governments maintain current policy targets.²⁹ This rate of increase is expected to more than offset declining consumption in other sectors, driving total global oil demand growth of 12.3 mbd over the next 25 years.³⁰

As long as the nation depends on petroleum fuels to power its economy—and its transportation sector, in particular—it will be exposed to the economic consequences of high and volatile oil prices.

Supply-side challenges also have undermined oil market stability in recent years and almost certainly will continue to do so. Political instability in the oil-rich Middle East and North Africa (MENA) region,

19 Tax Policy Center, Urban Institute and Brookings Institution, Individual Income and Estate Tax Provision in the 2001–08 Tax Cuts, Table To8–0147, 2008

20 BLS, Consumer Expenditure Survey 2011

21 SAFE analysis based on data from: U.S. Department of Treasury, Office of Tax Policy, “A State-by-State Look at the President’s Payroll Tax Cut for Middle Class Families,” November 30, 2011; and BEA, NIPA Tables, Table 2.4.5

22 SAFE analysis based on data from: U.S. Census Bureau, Office of Foreign Trade Statistics

23 Id.

24 DOE, EIA, AEO 2013 Early Release, Table 11

25 Ward’s Automotive, Vehicles in Operation by Country

26 SAFE analysis based on data from: BP, plc., Statistical Review 2012, online statistical supplement, “Oil Consumption”

27 Id.

28 IEA, Medium Term Oil Market Report (MTOMR) 2012, at 125

29 IEA, WEO 2012, at 88

30 Id., at 85

home to roughly two-thirds of the world's proved conventional oil reserves, has been commonplace. The wave of unrest that spread throughout the region in 2011 and 2012, touching off a significant spike in oil prices, is but one example of the effects that the region can have on the broader global economy. A more fundamental, long-term concern is that as much as 85 percent of global proved oil reserves are held by national oil companies (NOCs), state-run enterprises that often function as government proxies instead of market-driven enterprises. During the past decade, corruption, mismanagement, and underinvestment by many NOCs have constrained oil production by some of the world's most significant holders of oil reserves, contributing to broader market tightness and volatility. In fact, despite their dominance of proved reserves, only eight NOCs ranked among the top-25 companies in terms of upstream spending in 2011.³¹

Free-market advocates often view these trends and argue that economic forces alone should incentivize the investments necessary to improve U.S. energy security. However, while oil prices may be a function of supply and demand, the global oil market is far-removed from the classical definition of a competitive market. Beyond the inherent distortions associated with the concentrated power of NOCs, the market is openly and actively manipulated by a cartel of producers, the Organization of the Petroleum Exporting Countries (OPEC). OPEC's 12 members have historically controlled nearly 80 percent of global proved reserves of conventional oil, yet they account only for approximately 40 percent of world supplies on average.³² Making this disparity all the more egregious is the fact that OPEC members control access to the least expensive reserve base in the world.³³

While many of OPEC's NOCs suffer the same mismanagement and underinvestment as state-run enterprises in non-OPEC countries, OPEC's producers also work within a quota system designed to achieve specific oil price targets. Often times, these targets aim to keep oil prices high enough to earn significant export revenues, but low enough to dissuade investment by consumers in alternative fuels.³⁴ Today, however, OPEC's price targets are driven by an urgent need to maintain generous domestic spending on social programs to mitigate rising political instability. The fiscal breakeven oil price for Saudi Arabia has recently been estimated at between \$80 and \$100 per barrel.³⁵ The figures for Iraq, Algeria, Angola, and Nigeria are roughly the same, while the budgets in Iran and Venezuela each require significantly higher oil prices to sustain domestic spending. Total OPEC export revenues exceeded \$1 trillion in 2011 for the first time in history.³⁶

31 IEA, *WEO 2012*, at 121

32 SAFE analysis based on data from: BP, plc., *Statistical Review 2012*, online statistical supplement, "Oil Proved Reserves" and "Oil Production"

33 IEA, *WEO 2011*, at 140

34 See, e.g., Eric Martin, "Alwaleed says Saudi Arabia seeks \$70 to \$80 oil price to preserve sales to the West," *Bloomberg*, May 28, 2011

35 IEA, *WEO 2011*, at 140

36 DOE, EIA, OPEC Revenues Fact Sheet, available at http://www.eia.gov/emeu/cabs/OPEC_Revenues/Factsheet.html

The Path to Energy Security: Leveraging Energy Abundance While Reducing Consumption

Combined with the importance of oil to the U.S. economy, these market failures therefore require an important role for government. Yet, such action must be predicated on a sober assessment of the intended—and often unintended—outcomes of public policies. The truly global nature of today's oil market renders notions of so-called 'energy independence' meaningless from a practical standpoint. Instead, our nation's leaders must chart a course toward improved 'energy security' measured by spending on petroleum fuels as a share of GDP. This simple metric provides a clear picture of the degree to which businesses and consumers are vulnerable to oil price volatility.

Such an approach reflects neither hostility to petroleum fuels nor an unwillingness to embrace the substantial economic benefits associated with greater self-sufficiency in oil and natural gas supplies. Instead, this focus prioritizes domestic energy production in support of economic growth, continued gains in efficiency, and the technology-neutral displacement of petroleum consumption with other domestic fuels—including electricity, advanced biofuels, and direct use of natural gas—where cost-effective. From a strategic standpoint, government action should be prioritized in three primary areas: reducing oil consumption in transportation, increasing domestic oil and natural gas production, and simplifying regulatory processes to address the harmful effects of regulatory uncertainty in the energy industry.

In the near and medium term, sustained improvements in conventional efficiency will continue to provide a clear path to reduced oil consumption in the transportation sector. Advanced internal combustion engine technologies, low-cost hybrid systems such as stop-start, and other sources of efficiency can meaningfully reduce U.S. oil demand without requiring major changes to infrastructure or consumer behavior. The federal government's recently-finalized rules mandating increased levels of automotive efficiency through 2025 represent the most important progress on energy security in decades, and they should be actively supported and continuously improved.

In addition to further gains in vehicle efficiency, alternative fuel vehicles (AFVs) powered by electricity and natural gas represent the most promising opportunity for significant improvements in U.S. energy security through reduced oil consumption in transportation.

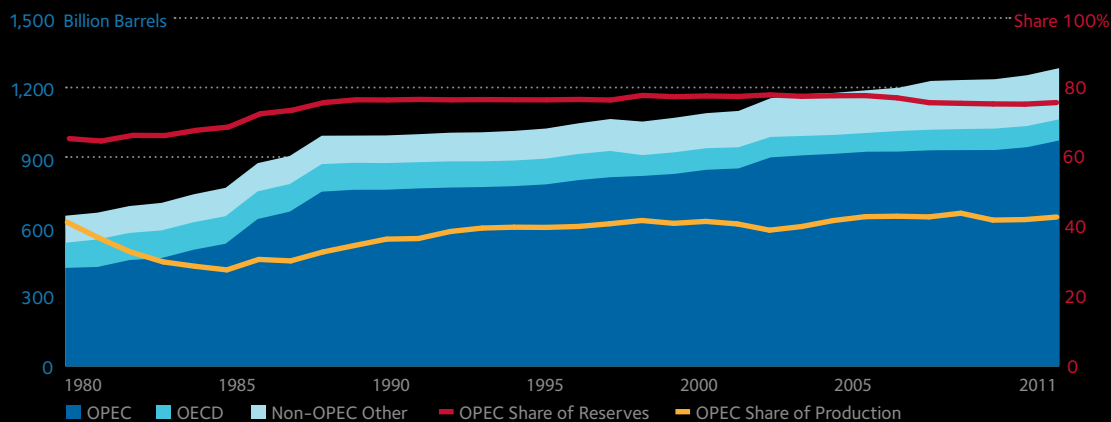
Continued support of AFVs should be a key priority of government policy going forward. However, policy needs to be reoriented away from an approach that has thus far largely emphasized supply-side subsidization through grants and loans to individual companies. Together with temporary purchase incentives for vehicles and infrastructure, more targeted research and development spending geared toward establishing model deployment communities could yield significant gains in AFV adoption over the coming decade.

At the same time, continued growth in domestic production of oil, natural gas, and non-petroleum liquid fuels should be supported. The U.S. energy industry should be held to the highest performance standards and be subject to appropriate oversight. But it should also have access to the nation's most promising resources when and where development can be done safely, including

The development of U.S. energy resources can offset future expenditures on imported oil while generating significant federal revenue that should be used to support solutions to ending our nation's oil dependence.

FIGURE 13

Global Reserves by Source

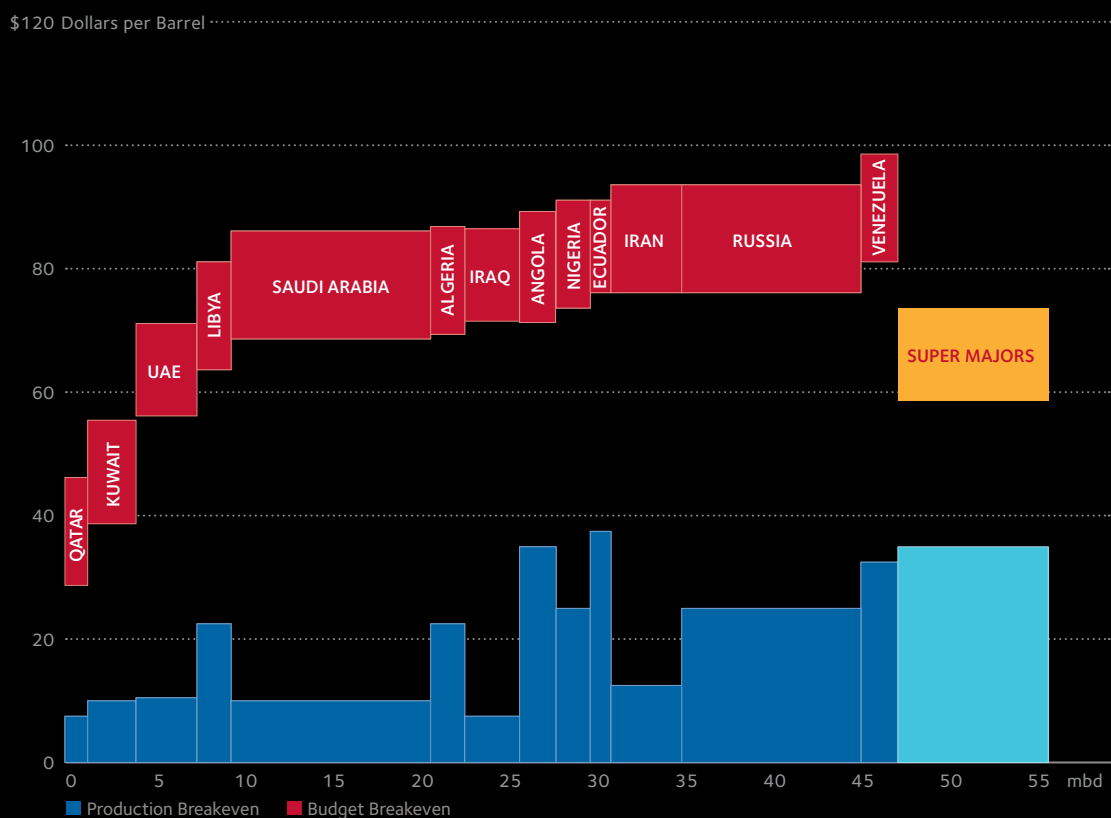


Note: Excludes Canadian oil sands not under active development. Also excludes Venezuelan extra-heavy oil.

Source: BP, plc., *Statistical Review of World Energy* 2012

FIGURE 14

Producer Breakeven Cost

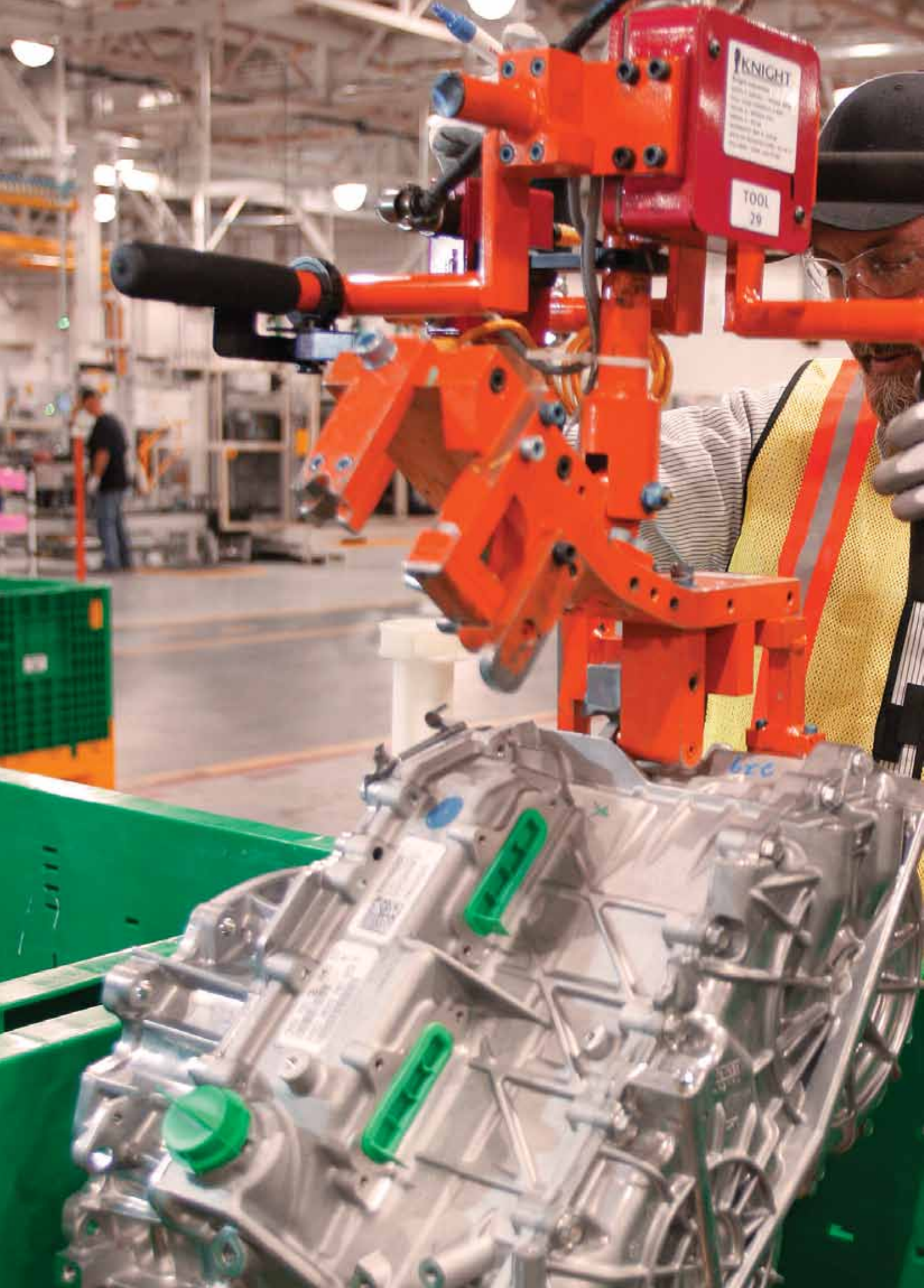


Source: IEA, *World Energy Outlook* 2011

those beneath federal lands and waters currently unavailable for development. Development of these resources can further offset future expenditures on imported oil while generating significant federal revenue that ultimately should be used to support solutions to ending our nation's oil dependence.

Finally, more stable, predictable, and effective government regulation of the energy industry should enable the safe, sustainable, and timely development of the nation's energy resources. Today, regulation is too often an opaque process that serves to dissuade private sector investment through practically unlimited delay. A stable regulatory environment has long ranked among the key advantages setting the United States apart from its competitors. Yet, on several critical issues—from offshore oil, natural gas, and wind power development to hydraulic fracturing and energy exports—there is an unreasonably high level of uncertainty today. Industry activity must be consistent with environmental protection, but the process should provide greater clarity upfront regarding which projects conform to such goals and the timeframe required for approving or denying common activities.

Oil dependence is a primary threat to the nation's economy and security, and requires aggressive government action. The recommendations in this report are designed to form the basis of a broad political consensus on protecting U.S. national security, accelerating economic growth, and enhancing environmental quality. America's newfound resource abundance, combined with remarkable innovations and initiatives, has the potential to place the country on a path to greater prosperity and security. This report outlines a plan to capitalize on these opportunities and avert the looming devastation threatened by oil price volatility.





PART I

Reducing Oil Use Through Advanced Technology

Reducing Oil Use Through Advanced Technology

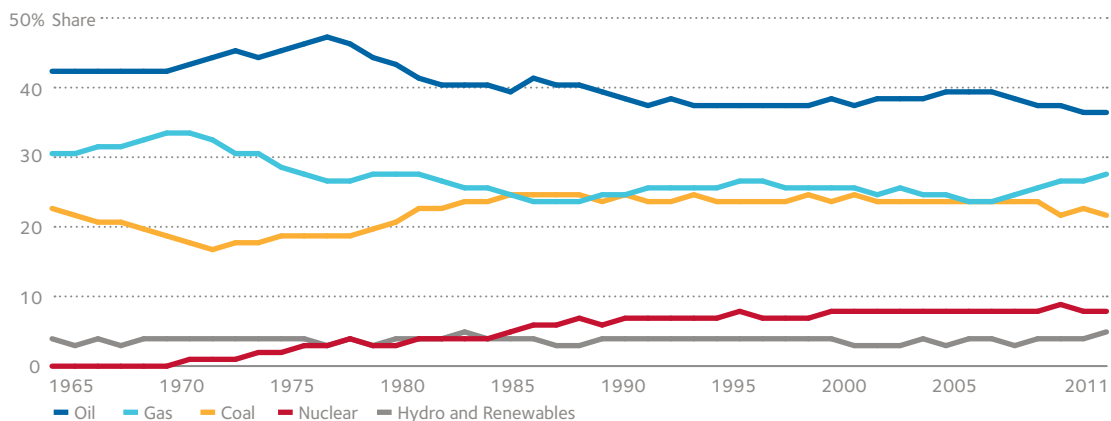
Oil dependence is a primary threat to U.S. national security and long-term economic vitality, and it is the core energy security challenge facing the country today. And while continued growth in domestic liquid fuel production has the potential to minimize and even eliminate some of the negative economic consequences of oil dependence—most notably its effect on the trade deficit—energy security is primarily a function of oil consumption, not production. That is, U.S. energy security is determined by the role of oil in the economy. In this regard, the United States continues to face considerable risks even during this time of monumental increase in domestic supply.

Petroleum fuels accounted for 37 percent of U.S. primary energy demand in 2011, a larger share than any other fuel.¹ Though this level marks a reduction compared to decades past, petroleum consumption still outpaces that of the next closest fuel, natural gas, by a meaningful margin. More importantly, U.S. spending on petroleum fuels, which topped \$890 billion in 2011, currently accounts for approximately three fourths of total spending on energy.²

Achieving significant reductions in the oil intensity of the U.S. economy has been a long-standing goal of public policy as it relates to energy security. This approach prioritizes reductions in the volume of oil needed to produce each unit of GDP, a strategy that can mitigate the economic impacts of high and volatile oil prices (described in detail in the *Introduction*). With recently-finalized vehicle fuel economy standards targeting a light-duty vehicle fleet average of 54.5 miles per gallon by 2025, the transportation sector is on a trajectory that will reduce total oil consumption by approximately 3.1

FIGURE 15

Share of U.S. Primary Energy Demand



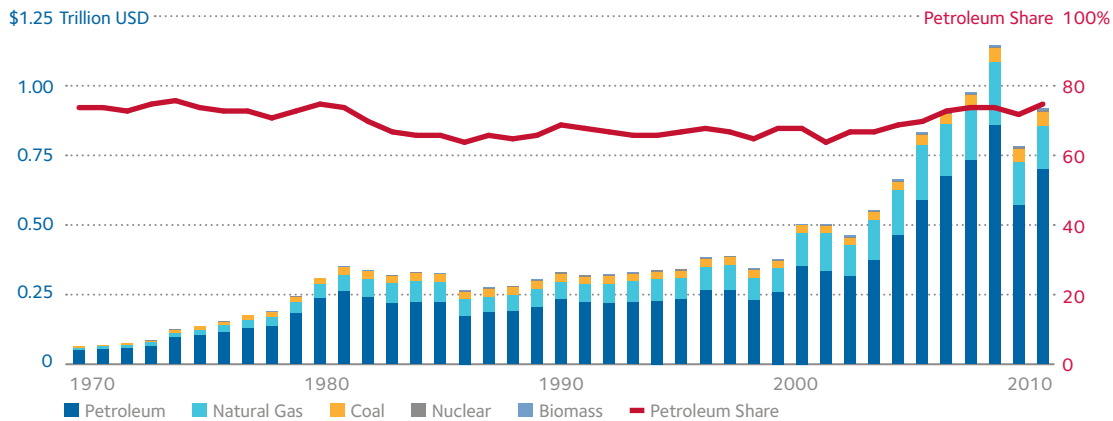
Source: BP, plc., *Statistical Review of World Energy* 2012

1 BP, plc., *Statistical Review* 2012, at 41

2 SAFE analysis based on data from: DOE, EIA

U.S. Primary Energy Spending by Source

FIGURE 16



Source: DOE, EIA

million barrels per day (mbd) by 2030.³ This level of oil savings will have clear, positive implications for U.S. energy security. Yet, even as the country has become a more efficient consumer of oil in recent years, oil prices have risen at a faster pace, negating much of the economic gains from efficiency and jeopardizing current and future prosperity.

Truly strengthening U.S. energy security will come from developing a transportation system that is no longer predominantly beholden to the global oil market. Alternative fuel vehicles (AFVs), those vehicles that use fuels derived from something other than petroleum, such as electricity and natural gas, are an attractive solution because they are powered by domestic fuels whose prices are less volatile than oil. Plug-in electric vehicles (PEVs) draw energy from the electric grid, which generates electricity from a diverse range of largely domestic fuels. Petroleum was used to generate less than one percent of the electricity generated in the United States in 2011.⁴ Similarly, U.S. natural gas supplies are almost entirely domestic, and newly abundant resources have the potential to keep natural gas transportation fuel prices low and stable for the foreseeable future.

However, natural gas vehicles (NGVs) and PEVs each face considerable barriers to broader commercialization. While they both rely on existing technologies, they also impose on consumers a larger upfront investment, and suffer from some degree of uncertainty regarding refueling infrastructure. The ongoing debate about the appropriate role for government in supporting the development of energy technology is both healthy and necessary. In the case of America's dependence on oil, however, the overwhelming economic and national security costs of the status quo provides ample justification for smart public policy in support of AFVs.

The capital assets and infrastructure that comprise and support the U.S. on-road fleet represent decades of investment by energy providers, automakers, and government agencies at all levels in a system designed to function on petroleum. Transitioning this system away from its current heavy reliance on petroleum toward a more diverse mix of fuels that does not expose the broader economy to the volatility of global oil markets will take time, technological advancements, and targeted public policy.

3 Figure reflects cumulative savings associated with 2012–2016 and 2017–2025 fuel economy rules. Oil savings based on: EPA, “Final Rulemaking to Establish Light-Duty Vehicle GHG Emission and Corporate Average Fuel Economy Standards, Regulatory Impact Analysis,” at 6–15; and “Regulatory Impact Analysis: Final Rulemaking for 2017–2025 Light-Duty Vehicle GHG Emissions and Corporate Average Fuel Economy Standards,” at 5–26

4 DOE, EIA, *Monthly Energy Review*, September 2012, Table 7.2a, at 95, 2012 data

Current Trends in Transportation

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32

The significance of oil in the national economy is largely a result of its role in the transportation sector. Mobility—the movement of people, goods, and services throughout the country—is a central component of U.S. economic competitiveness and a cornerstone of the American way of life. Today, this mobility is almost entirely powered by petroleum fuels, which accounted for 93 percent of the energy consumed by cars, trucks, planes, and ships in 2011.⁵ Taken as a whole, the transportation sector accounts for more than 70 percent of U.S. oil demand and—at more than 13 million barrels per day—accounts for a larger share of global oil demand than any national economy in the world.⁶

Oil consumption in America's transportation sector is largely driven by demand from surface transportation modes—cars and trucks in particular. The roughly 240 million passenger cars and light trucks on U.S. roads today consume an estimated 8.5 mbd, primarily gasoline, accounting for roughly two-thirds of the nation's total transportation-related oil consumption.⁷ Eleven million medium- and heavy-duty trucks add 2.9 mbd of oil demand, primarily in the form of diesel fuel.⁸ The significance of these two transportation modes—both in terms of their importance to economic activity and their share of total oil demand—has historically made them the logical focus of efforts to increase U.S. energy security through increased efficiency and greater deployment of advanced vehicle technologies and alternative fuels. The recently finalized fuel economy standards for vehicles of all sizes will play a critical role in achieving greater energy security, but while automakers deploy new technology to increase the efficiency of conventional vehicles, it is also necessary to foster the environment needed for successful AFV adoption.

Alternative Fuel Vehicles

Throughout the past decade, the U.S. public and private sectors have invested heavily in the development of AFVs, particularly PEVs and NGVs. Federal government spending on advanced vehicle research, development, and deployment (RD&D) alone has totaled more than \$2.4 billion since 2000.⁹ Economic stimulus programs designed to support manufacturing of AFVs and their components have contributed an additional \$11 billion in grants and low-interest loans to the public sector total since 2009.^{10,11}

In terms of private investment, Bloomberg New Energy Finance places global venture capital and private equity investment in advanced transportation at \$4.5 billion since 2007.¹² Acquisitions contribute an additional \$600 million to the private sector total. Meanwhile, Nissan-Renault alone has

5 DOE, EIA, *AER 2011*, September 2012, Table 2.1e, at 44, 2011 data

6 Id., Figure 2.o, at 37 and Table 5.13c, at 148; and BP, plc., *Statistical Review 2012*, at 9

7 ORNL, TEDB, Edition 31, Table 1.15

8 Id.

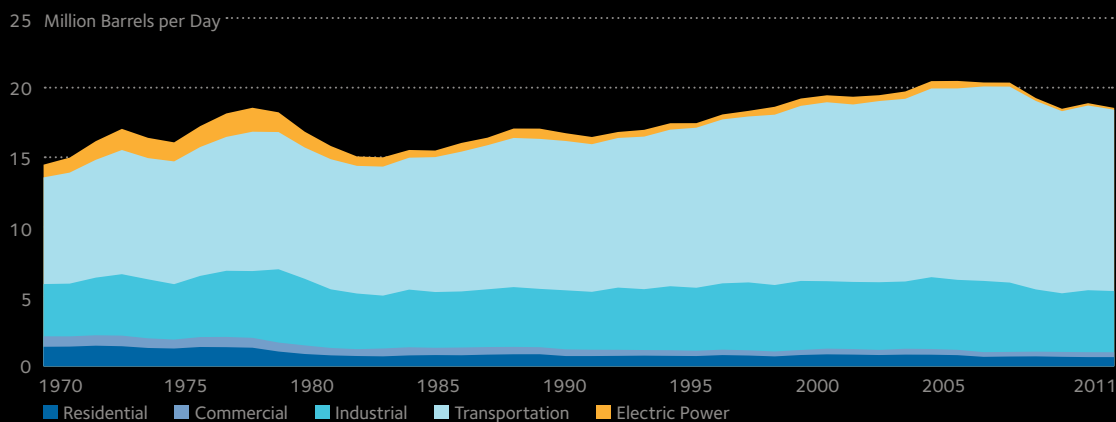
9 Gallagher, K.S. and L.D. Anadon, "DOE Budget Authority for Energy Research, Development, and Demonstration Database," Energy Technology Innovation Policy, John F. Kennedy School of Government, Harvard University, February 29, 2012

10 SAFE analysis based on data from: DOE, Office of Energy Efficiency and Renewable Energy (EERE), Recovery Act Awards for Electric Drive Vehicle Battery and Component Manufacturing Initiative; and DOE, Loan Program Office, Projects Summary

11 Figure excludes Ford's ATVM loan, which was directed toward improving conventional efficiency

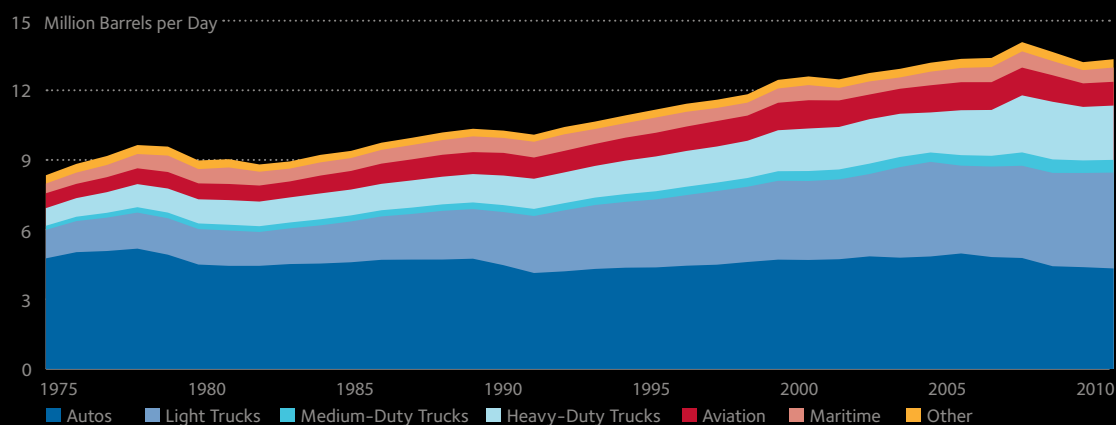
12 SAFE interview with Bloomberg New Energy Finance

U.S. Oil Demand by Sector



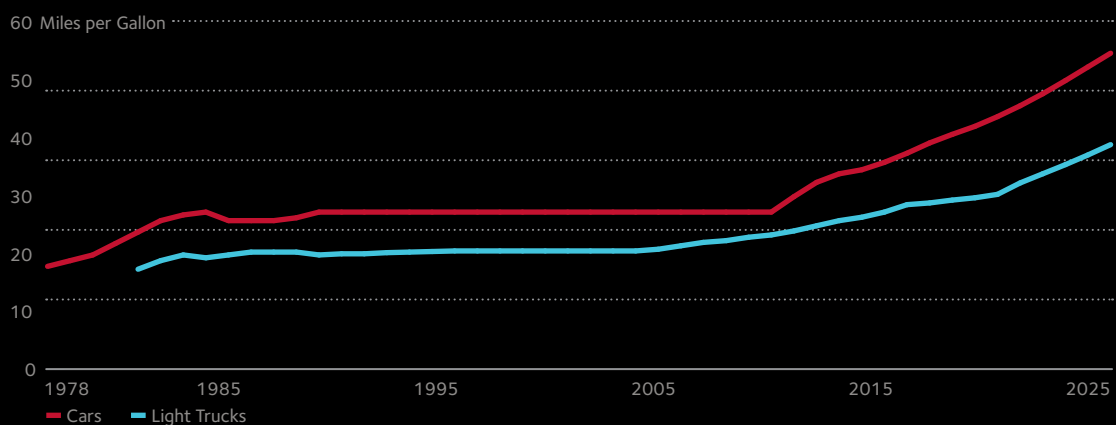
Source: DOE, EIA, *Annual Energy Review 2011*

U.S. Transportation Oil Demand



Source: ORNL

Car and Light Truck Fuel-Economy Standards



Note: Historical standards reflect data from the National Highway Traffic and Safety Administration's *Summary of Fuel Economy Performance*, October 2012. Future standards are the required minimum estimated average as reported in the final rules.

Source: EPA; and NHTSA

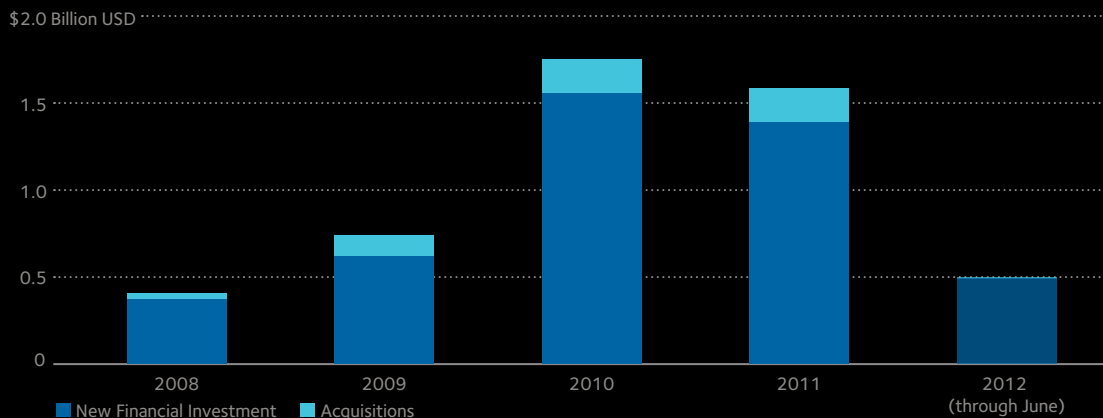
FIGURE 17

FIGURE 18

FIGURE 19

FIGURE 20

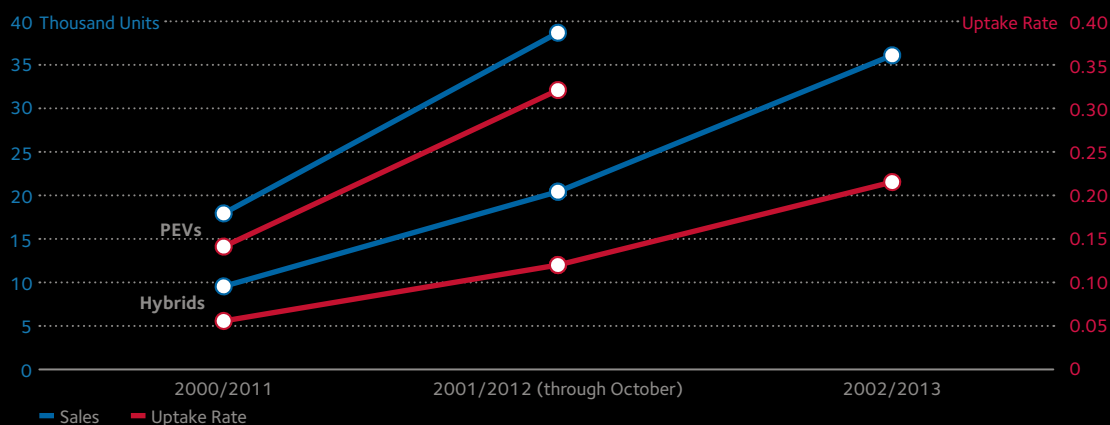
Corporate Investment in Advanced Transportation



Source: Bloomberg New Energy Finance

FIGURE 21

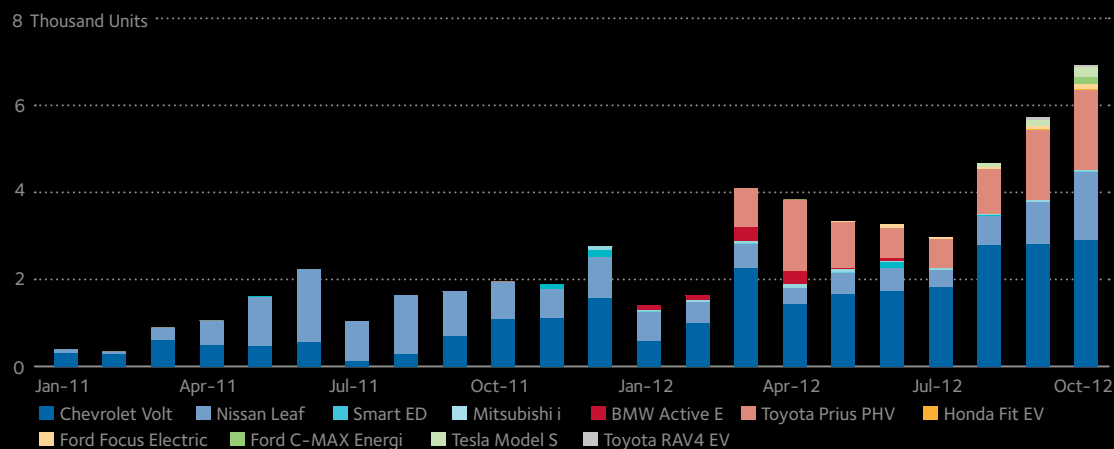
Hybrid and Plug-in Electric Vehicle Sales from Year of Introduction



Source: ORNL; and hybridcars.com

FIGURE 22

Monthly Plug-in Electric Vehicle Sales



Source: hybridcars.com

reportedly invested \$5 billion in the development of the Nissan Leaf, a figure equal to roughly half of its 2007–2012 research budget.¹³ Similarly, total investment by General Motors (GM) in the Chevy Volt has been reported to be near \$1.2 billion.¹⁴ And while most investment to date has focused on vehicle technologies, infrastructure investments are beginning to gain momentum as well. In 2011, Chesapeake Energy announced a \$150 million investment in Clean Energy Fuels designed to construct a network of 150 liquefied natural gas (LNG) refueling stations for long-haul trucking traffic throughout the United States.¹⁵ Earlier this year, Royal Dutch Shell announced a similar \$300 million investment in U.S. LNG refueling infrastructure.¹⁶

These investments have been motivated by a range of factors. The era of high and volatile oil prices that began in 2003 generated numerous negative economic outcomes, from the rising cost of crude oil imports and their effect on the current account deficit to shocks to business and consumer budgets, a phenomenon that likely exacerbated the effects of the 2007–2009 economic downturn and continues to undermine consumer spending today.¹⁷ As a result, consumers and businesses alike have sought ways to minimize their use of petroleum products. AFVs are an obvious solution. Further, curbing the growth of carbon dioxide (CO₂) emissions has played a role—the transportation sector accounted for nearly one-third of U.S. CO₂ emissions in 2011.¹⁸

While not all public and private investments in advanced transportation technologies have been successful, the broader industry has achieved important progress in recent years. For example, just two years after the introduction of a new generation of PEVs, there are currently more than a dozen light-duty models available to U.S. consumers. In fact, cumulative light-duty PEV sales are currently on pace to surpass 60,000 units in the United States since January 2011, placing them well ahead of the sales pace achieved by traditional hybrids like the Toyota Prius during their own initial months of availability in 2000 and 2001.¹⁹ Meanwhile, the Honda Civic Natural Gas is also now more widely available and sales are beginning to grow. Perhaps most importantly, AFV supply is expected to grow further in the coming years, offering consumers more vehicle options and greater availability, including PEVs ranging from two-wheeled vehicles to SUVs and NGVs of all sizes. Nevertheless, the progress has not met the high expectations that President Obama set in establishing as a goal the sale of 1 million PEVs by 2015 or the overly optimistic sales forecasts by automakers set prior to the introduction of many vehicles to the market.

The roughly 240 million passenger cars and light trucks on U.S. roads today consume an estimated 8.5 million barrels of oil each day, accounting for more than 40 percent of the nation's total oil demand.

Commercial vehicle fleets have also increasingly worked to explore opportunities to deploy AFVs. According to an annual survey of U.S. corporations, there were more than 100,000 AFVs on the road in America's top 50 commercial fleets at year-end 2011.²⁰ A number of commercial truck manufacturers offer plug-in hybrid and battery electric trucks ranging in size from class one to class six. Natural gas fuels have long been competitive in heavy applications, including vocational trucks and transit buses, and new natural gas-powered systems are increasingly competing for long-haul freight business. As of Q3 2012, there were more than two dozen heavy-duty and vocational truck models powered by natural gas available for purchase in the United States.²¹ Natural gas has also

13 "Nissan's Carlos Ghosn seeks revenge for the electric car," Yale University, Environment 360, May 4, 2011

14 Bernie Woodall, Paul Lienert and Ben Klayman, "General Motors Co sold a record number of Chevrolet Volt sedans in August — but that probably isn't a good thing for the automaker's bottom line," Reuters, September 10, 2012

15 Clean Energy Fuels, Press Release, Chesapeake Energy to Invest \$150 million in Clean Energy, July 11, 2011

16 Christopher Helman, "Shell Investing \$300M in Fuel LNG-Powered Trucks," Forbes, June 13, 2012

17 See, e.g., James D. Hamilton, "Causes and Consequences of the Oil Shock of 2007–2008," Brookings Papers on Economic Activity, 2009; and Steven Sexton, Jun Jie Wu and David Zilberman, "How High Gas Prices Triggered the Housing Crisis: Theory and Empirical Evidence," University of California Center for Energy and Environmental Economics, 2012

18 DOE, EIA, AER 2011, Tables 11.2 through 11.3

19 ORNL, TEDB, Edition 31, Table 6.4; and hybridcars.com, Hybrid Market Dashboard, monthly data through October 2012

20 Automotive Fleet Magazine, "Top 50 Green Fleets 2012," Bobit Media

21 SAFE analysis based on data from: DOE, EERE, Alternative Fuels Data Center

made inroads into the light-duty truck space in 2012 with new offerings, including the bi-fuel Chevy Silverado and GMC Sierra extended cab pickups and the dedicated CNG Chrysler Ram 2500.²²

Despite such positive indicators, however, AFVs continue to face critical barriers to more widespread adoption, most notably purchase cost. While there are reasons to be optimistic that continued progress will be made in reducing AFV costs, further obstacles aside from cost still remain that could prevent AFVs from achieving broad commercial success. The most significant obstacle is that vehicles powered by fuels like electricity and natural gas are inherently disruptive technologies that can only be truly successful if they drive major changes throughout multiple products, systems, and industries. Infrastructure development and public awareness and education campaigns will be critical to the widespread adoption of these technologies. Facilitating these necessary developments will require a high level of coordination and communication among multiple stakeholders from automakers and their suppliers to public officials, municipalities, energy suppliers, utilities, infrastructure providers, consumers, and more.

Demand for alternative-fuel and efficient vehicles is also affected by volatile petroleum fuel prices.²³ Numerous reports have shown that businesses and consumers do choose to purchase more efficient vehicles when gasoline and diesel prices rise. However, many of the most recent gasoline price spikes have also been both sharp and temporary, a phenomenon that often leads vehicle purchasers to underinvest in efficiency, as they lack confidence that prices will stay high for a long enough period to recoup their capital outlay. Greater stability in fuel prices would allow consumers to invest with higher confidence.

Public sector research and development (R&D) initiatives have clearly complemented private activity thus far. Advancing the technological capacity of automotive energy storage systems, including PEV batteries and NGV storage tanks, will be an ongoing need. However, developing a broader understanding of the challenges associated with deployment of both PEVs and NGVs is an additional critical effort that warrants greater support. The provision of incentives for AFV purchases and refueling infrastructure installations has also played a crucial role, reducing the incremental costs (and therefore payback periods) involved. These incentives will remain important components of the AFV marketplace in the near term.

Combined, R&D and AFV-specific initiatives and incentives will help to reduce costs while improving the quality of product offerings. They will also promote the installation of additional refueling infrastructure, and ultimately wider and more rapid AFV adoption.

22 SAFE analysis based on review of automaker websites

23 See, e.g. Thomas Klier and Joshua Linn, "The Price of Gasoline and the Demand for Fuel Efficiency: Evidence from Monthly New Vehicles Sales Data," September 2008; and Shanjun Li, Roger von Haefen, and Christopher Timmins, "How Do Gasoline Prices Affect Fleet Fuel Economy?," *American Economic Journal: Economic Policy*, American Economic Association, Volume 1(2): 113–137

Policy Recommendations

PRIMARY RECOMMENDATION

Establish up to six fuel-neutral deployment communities in small- to medium-sized cities.

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The widespread adoption of AFVs offers the nation one of its best long-term opportunities to substantially reduce U.S. oil dependence and improve its economic and national security. These vehicles, including PEVs, NGVs, and at some point in the future, fuel cell vehicles (FCVs), are capable of meeting a large portion of consumer needs for mobility without relying on petroleum-based fuels. AFVs cannot, however, meaningfully reduce oil consumption in the United States if they are not widely adopted by drivers. For example, the approximately 2.2 million conventional hybrid-electric vehicles on the road today, more than a decade after they were first launched, constitute less than one percent of the vehicles on the road and probably save no more than 35,000 barrels of oil per day compared to the vehicles they replaced, which is equivalent to less than one quarter of one percent of 2012 U.S. oil demand.^{24,25}

Despite their promise, AFVs face challenges in the marketplace, the first of which is their cost. Today, light-duty AFVs cost between \$6,000 and \$14,000 more than internal combustion engine vehicles with similar characteristics and performance.²⁶ This increment, however, should decline over time as vehicles are produced at scale, as the result of ongoing innovation, and as competition reduces the cost of AFV components. And in fact despite the existing increment, a May 2012 report by Pike Research concluded that electric vehicles offered the lowest lifecycle ownership costs of 17 vehicles they analyzed when including existing federal incentives.²⁷ Moreover, a July 2012 estimate from McKinsey and Co. suggested that lithium-ion battery costs, the key driver in PEV cost, could fall by as much as two-thirds by 2020.²⁸ The key cost driver for NGVs—their onboard fuel storage tanks—appear to be on a similar trajectory.²⁹

Federal and some state incentives reduce the effective cost of some AFVs. Plug-in electric vehicles weighing up to 14,000 pounds are eligible for a federal tax credit of between \$2,500 and \$7,500.³⁰ Numerous states offer additional tax credits, vouchers and purchase rebates for a variety of AFVs, including passenger vehicles and commercial trucks.³¹ Some states also offer less direct incentives such as access to high-occupancy vehicle lanes or waived fees on high-occupancy toll lanes. Policymakers established these and other non-monetary incentives to reduce the incremental cost of AFVs and offering owners of AFVs additional benefits during the early years of AFV availability in the marketplace would give automakers time to reduce vehicle costs through scale and innovation while consumer demand grows.

Even if vehicle costs decline substantially, however, consumers will not readily purchase AFVs if they do not think that AFVs will meet their transportation needs. Perhaps most importantly, consumers need to feel confident in their ability to conveniently refuel an AFV, and they need to be presented with an attractive total cost of ownership (TCO) proposition that is intuitive and compelling. Stated simply, if consumers do not believe that it will be cost-effective and easy to own and operate an AFV, they are unlikely to buy one.

24 DOE, EERE, Alternative Fuels Data Center, U.S. HEV Sales by Model

25 SAFE analysis based on data from: DOE, EIA, Product Supplied

26 SAFE analysis based on comparison of MSRP from OEM websites

27 Pike Research, "Total Cost of Ownership of Alternative Fuel Vehicles for Fleet Operators," May 2012

28 Russell Hensley, John Newman, and Matt Rogers, "Battery Technology Charges ahead," McKinsey Quarterly, July 2012

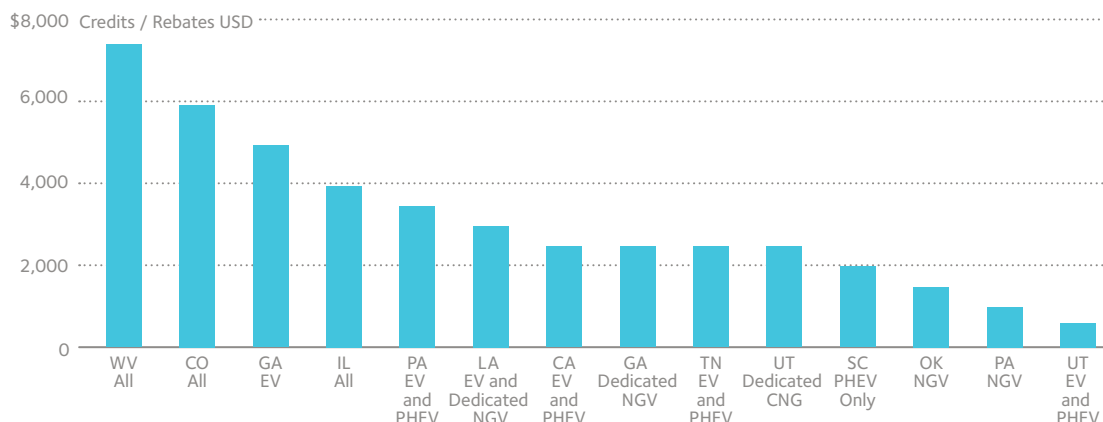
29 See, e.g., Tom Fowler, "America, Start Your Natural Gas Engines," Wall Street Journal, June 18, 2012

30 See, 26 USC § 30D

31 DOE, EERE, Alternative Fuels Data Center, Electricity Laws and Incentives

FIGURE 23

State Vehicle Incentives



Note: Only credits that include PEVs and NGVs are included. Credits for biofuels, hydrogen, and other fuels are excluded.

Source: SAFE analysis based on data from: DOE, Alternative Fuels Data Center

Beyond cost, the most significant concern voiced by consumers considering a plug-in vehicle purchase is range. For instance, a 2011 survey conducted by Deloitte found that only 20 percent of respondents would be willing to buy or lease an EV with only 100 miles of range, while roughly two-thirds of respondents would consider buying or leasing an EV with at least 200 miles of range.³² In this respect, range is also likely to be an issue for drivers of light-duty NGVs. Because CNG is less dense and requires heavier tanks than gasoline, NGVs' range, while exceeding that of most electric vehicles, is shorter than gasoline-powered vehicles.³³ For example, the Honda Civic natural gas has a range of up to 190 miles on a full tank, compared to approximately 420 miles for a fully-fueled conventional Civic.³⁴ These vehicles also are not supported by the ubiquity of refueling stations available to gasoline cars or even the ability to plug into any 110 volt electrical outlet available to electric cars.³⁵

Although 95 percent of U.S. vehicle trips are less than 30 miles, and the average U.S. driver travels just 29 miles per day, it is clear that consumers see the driving range of today's AFVs as a barrier to adoption despite a number of vehicles that can already meet most consumers needs.³⁶ Education efforts would help combat misinformation—such as concern about electric shock and battery fires—and possibly lead more consumers to determine that there are, in fact, AFV options that meet their needs. A 2011 survey conducted by the IBM Institute for Business Value found that 45 percent of drivers believe they have little to no understanding of EVs.³⁷ Equally instructive, 60 percent of the drivers who believed they were relatively knowledgeable about EVs incorrectly thought that the operating costs for these vehicles would be equal to or greater than the operating costs of a gasoline vehicle.³⁸

Because PEVs and NGVs require, and FCVs will require, the support of new networks, they are likely to succeed only if accompanied by changes throughout multiple products, systems, and industries. Making these changes happen will require substantial coordination and open communication among multiple stakeholders, from automakers and their suppliers to cities, fuel suppliers, utilities, infrastructure providers, consumers, and others. In order to successfully deploy AFVs early on in their availability, all of these stakeholders need to come together in communities and make owning and operating an AFV as simple as driving a conventional vehicle. Successful AFV commercialization will require the development of ecosystems within individual communities that contain the appropriate infrastructure, regulatory and permitting environment, and access to vehicles, so that driving an AFV will be a seamless experience. Yet, no one has so far successfully undertaken such an effort at scale.

32 Deloitte, "Unplugged: Electric vehicle realities versus consumer expectations," Figure 4, at 6-7, 2011

33 DOE, EERE, Energy Basics, Natural Gas Vehicles

34 Honda.com, Specifications for Honda Civic Sedan and Honda Civic Natural Gas

35 DOE, EERE, Alternative Fuels Data Center, Natural Gas Fueling Station Locations

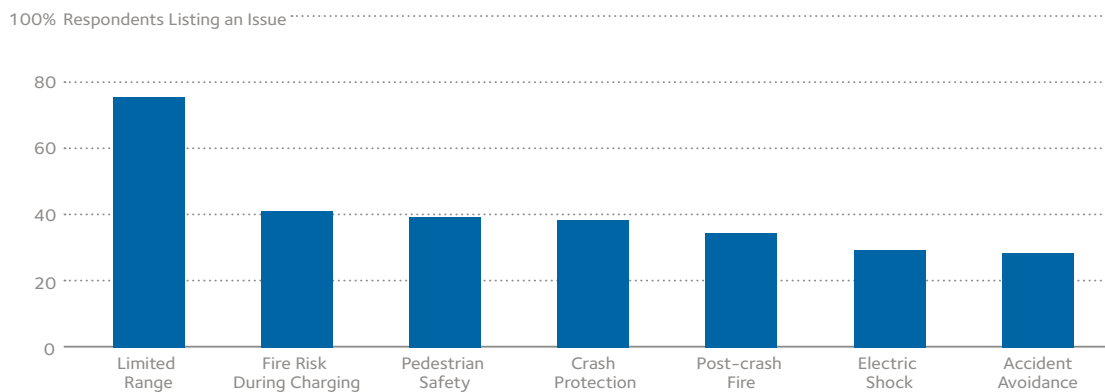
36 ORNL, TEDB, Edition 31, Figure 8.3

37 Kalman Gyimesi and Ravi Viswanatham, "The Shift to Electric Values," IBM Institute for Business Value, 2011

38 Id.

Top Plug-in Electric Vehicle Concerns Reported by Consumers

FIGURE 24



Source: Consumer Reports

Although Nissan and General Motors initially offered the Leaf (all electric) and Chevy Volt (plug-in hybrid electric) for sale in a small number of selected markets, they were not accompanied by the support that would be part of a complete AFV ecosystem. Moreover, the automakers understandably expanded quickly to nationwide sales, which allowed them to market their new cars to a larger pool of early adopters and supported sales during their initial market launches. That approach, however, deprived AFVs' proponents of perhaps the best opportunities to concentrate their efforts in a few communities where they could both learn best how to support the vehicles as well as undertake intense marketing and consumer education efforts.³⁹

Apart from the automakers' decisions as to where the first AFVs on the market should be sold, a number of initiatives are underway that aim to support the adoption of advanced vehicles in select communities, most of which concentrate on deploying PEV charging infrastructure. As part of the American Recovery and Reinvestment Act (ARRA), the federal government helped fund a deployment program known as "The EV Project."⁴⁰ The EV Project supports the deployment of PEVs in 21 major cities and metropolitan areas in 9 states and the District of Columbia.⁴¹ As of Q2 2012, The EV Project includes the participation of 4,998 Nissan Leaf and Chevy Volt drivers, 6,319 public and private charging stations, and has recorded data on 32 million test miles.⁴² The EV Project, however, was focused primarily on deploying charging infrastructure and not on the types of consumer education and experience components that are likely required to help the average consumer learn about and become comfortable with the vehicles.⁴³ Likewise, the ChargePoint network built and managed by Coulomb Technologies, was focused primarily on infrastructure installation.⁴⁴

In contrast to the support that the government has offered for infrastructure, support for community education and readiness activities has been relatively small. In 2011, the Clean Cities Program awarded \$8.5 million to 16 electric vehicle projects in 24 states and the District of Columbia to help communities prepare for PEVs and charging infrastructure.⁴⁵ In late 2012, Clean Cities awarded an additional \$11.2 million to a further 20 grantees.⁴⁶ The disparity between government resources dedicated to deploying vehicles and infrastructure and those dedicated to community readiness and consumer education is significant. In addition, the absence of actively engaged independent coordinators—those with no financial stake in selling either vehicles or infrastructure guiding the existing deployment efforts—

39 Nissan Press Release, "Nissan Announces National Market Roll-Out Plan For Zero-Emission Nissan Leaf," July 27, 2010; and CNN Money, "Chevy Volt to be available in all 50 states," January 27, 2011

40 The EV Project received \$115 million in ARRA grant funds and has raised a matching amount of private capital

41 Ecotality North America, Q2 2012 Report: The EV Project, at 5

42 Id., at 6

43 Id., at 1

44 Chargepoint Press Release, "Coulomb Technologies Celebrates with US Department of Energy, City of LA Significant ChargePoint America Electric Vehicle Program Milestone," May 13, 2011

45 DOE, EERE, Electric Vehicle Community Readiness Project Awards

46 DOE, EERE, "Energy Department Announces New Clean Cities Projects," November 21, 2012

further explains why there has been so much emphasis in installing infrastructure. In retrospect, however, the narrow focus on charging infrastructure is likely to be viewed as a mistake, because it overemphasized installing charging stations without understanding how much infrastructure was needed or where it could be most effectively deployed. A broader approach that recognizes well-placed infrastructure as just one piece of the system required to support PEVs would likely meet with greater success.

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Shortcomings in consumer education and investing in community readiness may help explain, in part, why vehicle sales have fallen short of automakers' public forecasts, and they are likely to fall short of the government's initial deployment goal—the sale of 1 million plug-in vehicles by 2015.^{47,48} Nevertheless, interest is there and appears to grow as drivers gain a better understanding of vehicle benefits. One company in the electric vehicle space, for example, reported that while less than 10 percent of drivers attending PEV public awareness events initially expressed interest in buying a PEV, about 55 percent of attendees were interested in buying one after learning about the vehicles and in some instances driving one.⁴⁹

To address the gaps in the approach to AFV deployment that have characterized the introduction of PEVs to the market, the Council recommends the establishment of between six and eight technology neutral “deployment communities.” Deployment communities are geographic regions in which all relevant parties, including state and local governments, regulators, utilities, employers, and civic groups work together to promote AFV adoption. These small- and medium-sized communities should be chosen on a competitive basis with successful applicants demonstrating the broadest community support and the most promise, proportional to community size, of deploying AFVs. While program rules should be flexible enough to allow funds to be used for any activities that support the primary goal, the expectation should be that funds and active participation will be most effective if used

to help overcome adoption barriers, in particular through consumer education and promoting the interaction of all relevant parties, and not to concentrate solely on subsidizing infrastructure. Although the initiative will take advantage of existing government incentives and some dedicated government funds, the goal is to lay down a foundation to spur greater private sector investment. By choosing small- and medium-sized communities, costs to the government will be minimized, benefits will be more quickly and acutely felt, and lessons learned can be shared broadly.

Deployment communities are intended to ensure that all relevant community institutions work to introduce as many people as possible to the benefits of driving alternative fuel vehicles.

Once established, these communities will become R&D laboratories themselves, offering an opportunity to learn how to best facilitate AFV adoption. Because the stakeholders needed to create a successful deployment community do not regularly work together, a concerted effort must be made to get all relevant stakeholders interested and involved in the process. As the stakeholders learn to work together, the initial communication barriers will be broken down and the promotion of AFVs will be enhanced. The lessons learned from this experience will help guide other communities that are interested in deploying AFVs.

In addition to coordinated efforts between stakeholders, there are a number of things that will need to happen in the deployment community. To convince mainstream consumers to accept AFVs, all of the relevant partners in the initiative will have to be brought together and act in a complementary manner. This is crucial to minimizing regulatory barriers and disincentives to AFV adoption. In short, a deployment community is intended to ensure that all relevant community institutions work to introduce as many people as possible to the benefits of driving AFVs, and to promote their adoption. Most importantly, a well-functioning deployment community will:

47 Daily Tech, “August to be Chevrolet Volt’s Best Sales Month Yet,” August 30, 2012; and Detroit News, “Nissan Leaf sales continue to fall from last year; 20,000 sales target unlikely,” September 4, 2012.

48 DOE, One Million Electric Vehicles By 2015: February 2011 Status Report, 2011.

49 Private conversation between SAFE and leading industry participant.

Facilitate Learning by Doing. Deployment communities will serve as laboratories, showing what works well and what could work better. The lessons learned from these deployment communities will be of benefit to locations nationwide.

Demonstrate Proof of Concept for Consumers. Deployment communities would show the value of a fully operational, smart, integrated AFV transportation system, helping to show that these vehicles can be accepted—and indeed coveted—not just by early adopters, but by typical consumers who will see their economic value.

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Beyond demonstrating AFVs to the mainstream market, the deployment community initiative is intended to identify and document those steps that promote AFV adoption. Accordingly, the initiative must be transparent and well-documented, and all data collected as part of the project should be publicly available in a manner that protects the privacy of individual vehicle owners. The project's documentation would serve as a critical resource for other communities and companies seeking to promote AFVs. Throughout the initiative, the project organizers would record the issues identified, the options available to address them, the decisions reached and the reasoning behind them, the parties involved, and all other relevant information so that they could prepare a comprehensive report or some other means by which the information can be shared widely to all interested parties.

PRIMARY RECOMMENDATION

Reinstate and reform incentives for alternative fuel infrastructure.

Refueling is an important issue for any vehicle technology. However, the deployment of public infrastructure required to provide alternative fuels such as compressed natural gas (CNG) and electricity faces a significant hurdle, namely investment cost-effectiveness. Specifically, the fueling or charging devices require substantial initial outlays for equipment and installation, with still uncertain levels of utilization.

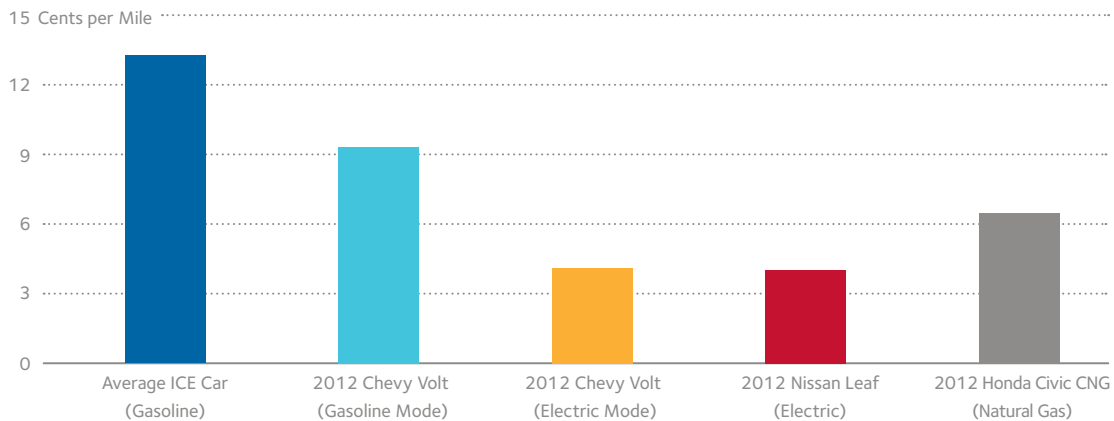
Just as AFVs entering the marketplace require a refueling infrastructure in order to become attractive to buyers, investments in such equipment must be justified by acceptable utilization rates (return on investment). This requires sufficient numbers of AFVs operating on the nation's roads, and importantly, using and paying for public refueling. It therefore represents a classic chicken-and-egg dilemma because at present there are only limited numbers of both vehicles and refueling stations. Individuals and businesses are reluctant to purchase vehicles due to insufficient refueling availability and infrastructure providers are reluctant to install refueling stations due to insufficient numbers of vehicles. Public sector support of this infrastructure through the use of tax credits or accelerated depreciation can ultimately help overcome the chicken-and-egg dilemma that individual drivers and private companies cannot realistically be expected to resolve themselves.

Public refueling infrastructure is critical to supporting early-years marketplace acceptance of AFVs, particularly from the perspective of addressing driver anxiety over limited vehicle range. It will also complement what is likely to be a substantial residential refueling component for light-duty passenger AFVs powered by CNG and electricity, which most potential buyers are likely to embrace. For example, while approximately 61 percent of U.S. households have access to natural gas, nearly 100 percent of households have access to electricity, and an estimated 49 percent of households that own at least one car park within 20 feet of an existing electrical outlet.⁵⁰ For the consumer, residential refueling may actually be more convenient than visiting a public refueling station and is certainly going to be a useful and sometimes requisite component for AFV purchase, particularly before public infrastructure becomes widely available. However, home refueling represents another critical source of uncertainty

50 EIA, Residential Energy Consumption Survey (RECS), 2009 RECS Survey Data, Housing Characteristics Tables

FIGURE 25

Fuel Cost for Selected Alternative Fuel Vehicles, 2012



Source: SAFE analysis based on data from: EPA; and DOE, EERE

for public infrastructure providers already concerned about early-years vehicle numbers and rates of utilization, an issue the industry could learn more about in well-designed deployment communities.

To further address driver range anxiety, automakers are also providing vehicles that can operate on both traditional liquid fuels and an alternative fuel source, thereby extending total driving range and enabling access to the nation's vast network of more than 150,000 gasoline refueling stations.⁵¹ These vehicles can also benefit from access to convenient public refueling options in order to maximize the portion of miles they travel using electricity or natural gas. This helps minimize their operating costs, a preference demonstrated by the fact that Chevy Volt owners charge their vehicles 1.4 times more frequently than Nissan Leaf owners and twice as often away from home, even though the Nissan Leaf can operate only on electricity.⁵² Moreover, this could be a particularly critical issue for sales and service fleets deploying plug-in electric hybrids (PHEVs) and bi-fuel NGVs. Several companies have led the way in developing this new infrastructure and business models including eVgo, Better Place, Coulomb Technologies, and Clean Fuels.

While extensive distribution networks exist for a number of alternative fuels, namely natural gas (CNG) and electricity, the availability of public dispensing infrastructure remains more limited. Today, there are only approximately 13,000 alternative fueling stations nationwide, 80 percent of which are publicly accessible.⁵³ Across these stations, a combined total of seven different fuels are served, and installations for all fuels have been rising in recent years. For example, 302 CNG stations were added in 2012 (through October), a 33 percent increase over 2011.⁵⁴ Alternative fueling stations are also unevenly distributed across the country—almost one-third of CNG stations, for example, are located in either California or New York.⁵⁵ Moreover, while the overwhelming majority of AFV fueling stations supply electricity for PEVs, only a handful of them are fast chargers that will charge a vehicle battery in minutes rather than hours. In short, public refueling infrastructure is at present far from ubiquitous and too limited to satisfy most drivers taking trips outside a restricted geographic area.

Refueling stations have sometimes been constructed by businesses that decided to transition their vehicle fleet from gasoline or diesel to a non-petroleum fuel.⁵⁶ Typically for medium- and heavy-duty vehicles, these fleets have tended to be purchased by operators who refuel consistently at a specific central location and/or in areas where their vehicles routinely operate on dedicated routes. For some other applications, like sales and service vehicles, infrastructure needs will closely mirror those of

51 DOE, EERE, Alternative Fuel Data Center, Fuels and Infrastructure, Public Retail Gasoline Stations by Year, 2010 data

52 DOE, EERE, Vehicles Technology Program, "EV Project Chevrolet Volt Vehicle Summary Report," (Q2 2012 reporting period) at 1; and DOE, EERE, Vehicles Technology Program, "EV Project Nissan Leaf Vehicle Summary Report," (Q2 2012 reporting period) at 1

53 DOE, EERE, Alternative Fuel Data Center, Fuels and Infrastructure, U.S. Alternative Fueling Stations by Fuel Type, 2011 data

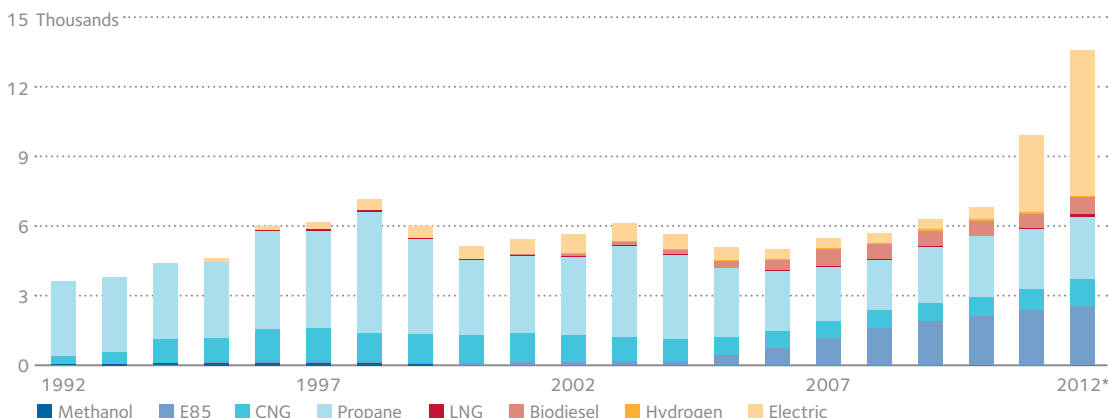
54 Id.; and DOE, EERE, Alternative Fueling Station Locator, Data Download, 2012 data through August

55 DOE, EERE, Alternative Fueling Station Locator, Data Download, 2012 data through August

56 Examples include Lott Oil and Southwestern Energy

U.S. Alternative Fueling Stations by Fuel Type

FIGURE 26



Note: Starting in 2011, electric charging equipment was counted by the plug rather than by the geographic location. This is different than other fuels, which only count the geographic location regardless of how many dispensers or nozzles there are on site. However, as of October 2012, there are still 5,315 geographic locations hosting plugs.

* Data for 2012 is through October

Source: DOE, EERE

personal-use vehicles, and drivers will likely benefit from both residential and public options. These vehicles also tend to log more miles than personal-use vehicles, and therefore may depend more heavily on access to convenient public refueling. In some instances, fleet operators have partnered with a local fueling station and act as the 'anchor' fleet, guaranteeing a level of utilization for a station that is also accessible to the general public. This approach is especially compelling when companies invest in technologies that can closely replicate the public refueling model of gasoline. This includes direct current (DC) fast chargers for PEVs and high-pressure, fast-fill dispensers for CNG-powered NGVs. Some technologies, such as 240-volt electric vehicle chargers, could also be deployed in a wide range of locations, making consumer access a convenient part of regular activities like dining or shopping.⁵⁷

Despite their importance in helping to facilitate AFV adoption, investments in refueling infrastructure can be expensive. Capital costs for full-service CNG stations offering fast-fill dispensing on a scale similar to existing gasoline stations can, for example, reportedly reach as high as \$1.7 million.⁵⁸ Stations offering slower CNG dispensing can be substantially less costly, and still suitable for many fleets, but will typically be unable to provide fuel to individuals and some other kinds of fleet vehicles given time constraints. While far less expensive, PEV recharging infrastructure options also present a tradeoff between recharging times and costs. More generally, there can be significant variation in cost based upon a variety of other factors, sometimes highly specific to the fuel being provided. For example, fuel storage, compressor systems, or safety equipment might be required. Operating costs for refueling stations will also vary. All these costs must be balanced with throughput (utilization)—the primary driver of value due to the price differential between oil and other fuels—to generate an acceptable rate of return.

The Energy Policy Act (EPAct) of 2005 established an Alternative Fuel Infrastructure Tax Credit equal to 30 percent of the cost of installing new fueling equipment for a selection of alternatives to petroleum.⁵⁹ The credit was worth up to a maximum of \$30,000 for business purposes and \$1,000 for residential purposes.⁶⁰ The American Recovery and Reinvestment Act of 2009 increased these tax credits to 50 percent of the cost, and \$50,000 and \$2,000 respectively, for equipment installed in 2009 and 2010.⁶¹ The alternatives to petroleum that qualified for the credit include natural gas,

57 These chargers can recharge a vehicle in approximately half the time required to charge when using a standard 110-volt outlet.

58 SAFE discussions with fleet owners

59 Energy Policy Act 2005, Public Law 109-58, at Section 1342

60 Id.

61 The American Recovery and Reinvestment Act of 2009, Public Law 111-5, at Section 1123

propane, electricity, E85, and diesel blends containing a minimum of 20 percent biodiesel.⁶² After being extended for one additional year at the original levels, the credit expired on December 31, 2011.⁶³

Because of the initial importance of refueling infrastructure to wider AFV adoption, the Council recommends that the Alternative Fuel Infrastructure Tax Credit be reinstated for a period of six years. In addition, the value of multiple vehicle purchases to vehicle adoption ought to be recognized by extending the maximum available limit above \$30,000. For fleets operating between ten and 25 AFVs, the credit should be worth up to a maximum of \$75,000; between 26 and 50 vehicles, \$150,000; and more than 50 vehicles, \$225,000. Other entities that install large numbers of publicly-accessible refueling stations should also be eligible for a higher maximum limit, based on the number of stations that they install.

As an alternative to the tax credit, a business should be allowed to elect to expense (or depreciate) the cost of qualified equipment and related costs in the year in which it was placed into service, effectively treating the equipment as “one-year property” in the Internal Revenue Service’s General Depreciation System. Immediate expensing (or accelerated depreciation) benefits companies by allowing them to retain the time-value-of-money of their near-term tax obligations and defer payment of taxes until later years when those cash flows are less valuable on a discounted basis. This policy possesses the unique fiscal benefit of capitalizing on the arbitrage between a company’s cost of capital (approximately 10 to 20 percent) and the federal government’s cost of capital (approximately 3 percent).

This financial accounting dynamic increases the efficiency of the policy as the company’s benefit outweighs the government’s direct cost. For instance, an item purchased by a company for \$1,000 dollars today has a tax-adjusted net present cost of \$680 if the asset is entirely expensed in the first year. If the item is depreciated over 10 years, however, the item’s purchase represents a tax-adjusted net present cost of \$785, a \$105 premium over the immediate expensing scenario. From the government’s perspective, however, immediate expensing appears to cost \$340 in less tax revenues and the 10-year depreciation scenario costs \$299, a \$41 difference. In effect, the business receives a \$105 subsidy whereas the government incurs a \$41 cost. For the purposes of budget scoring, however, the Joint Tax Office does not typically discount future tax receipts, so this dynamic is further enhanced; immediate expensing should score at close to a zero cost to the government.

These incentives will help promote the deployment of public refueling infrastructure critical to supporting early-years marketplace acceptance of AFVs and the significant benefits to U.S. energy security associated with the oil displacement their use enables.

PRIMARY RECOMMENDATION

Create incentives for medium- and heavy-duty alternative fuel vehicle purchases.

Medium- and heavy-duty vehicles account for approximately 22 percent of the energy used in the transportation sector, second only to light-duty vehicles.⁶⁴ In noticeable contrast to the light-duty segment, however, energy and oil use in the medium- and heavy-duty segment is forecasted to rise, not fall, despite more stringent fuel-efficiency requirements.⁶⁵ This rise is attributable to expected growth in vehicle miles traveled (VMT) of 48 percent from 2010 to 2035—growth supported by rising economic output and an increase in the number of trucks on the road from 8.9 to 12.5 million.⁶⁶ In

⁶² Energy Policy Act 2005, Public Law 109–58, at Section 1342

⁶³ 26 USC § 30C(g)

⁶⁴ ORNL, TEDB, Edition 31, Tables 1.14 and 1.17

⁶⁵ DOE, EIA, *AEO 2012*, Reference Case, Table 46

⁶⁶ *Id.*, at 86

addition to continued improvements in fuel efficiency, which should be maximized to the greatest extent possible through support for advanced conventional vehicles and increased hybridization, a widespread transition from primarily diesel fuel (oil-derived) to alternative fuels could further reduce oil consumption in the segment.

Medium- and heavy-duty AFVs have seen some success in the marketplace thus far. For example, the penetration by natural gas into the nation's bus fleets has expanded from just 2 percent of total fuel consumed in 1995 to 23 percent in 2010.⁶⁷ Natural gas is also showing remarkable growth as a fuel source for waste collection and transfer trucks. For example, CNG-powered vehicles will represent 80 percent of Waste Management's new truck purchases in 2012—a purchasing strategy expected to continue for the next five years.⁶⁸ Approximately 25,000 flexible fuel vehicles (FFVs) that operate on blends of up to 85 percent ethanol (E85) were in operation in the medium-duty segment as of 2010.⁶⁹ LNG-powered vehicles and PEVs are currently being tested by several leading corporations including FedEx, PG&E, UPS, and AT&T, which have deployed limited numbers in their fleets for a variety of operational purposes, taking advantage of significantly lower fueling and maintenance costs in addition to realizing other benefits. These organizations continue to evaluate the TCO economics associated with a higher upfront purchase cost and lower operating costs, and many intend to add more medium- and heavy-duty AFVs to their fleets in the coming years.⁷⁰ These technologies are generating substantial and increasing interest among corporate customers, and the recent finalization of the first-ever standards for medium- and heavy-duty vehicle fuel economy seems likely to further strengthen the opportunity for alternative fuels to play a larger role.⁷¹

To the extent that these commercial vehicles require batteries, storage tanks, and other parts specific to various AFVs, they will help generate scale and learning benefits within the supply chain. This will yield substantial spillover benefits by bringing down the costs of components for all vehicle types. These vehicles also play an important role in overcoming the chicken-and-egg dilemma that faces the industry as a whole, given the often close association between fleet vehicles and the construction of refueling infrastructure for alternative fuels—infrastructure that is in many cases made available to the wider public. Finally, the mere presence of these vehicles in the nation's cities and on the nation's roads is essential in establishing greater public awareness and appeal to a wider audience. Fleet operators have even reported that people stop drivers to ask them about the vehicles and technology.⁷²

In noticeable contrast to the light-duty segment, energy and oil use in the medium- and heavy-duty segment is forecast to rise, not fall, despite more stringent fuel economy standards.

The single largest challenge to the adoption of AFVs remains vehicle purchase cost. Commercial customers typically encounter price premiums for trucks powered by alternative fuels even higher than the substantial premiums found on passenger vehicles. Class 3–6 medium-duty electric trucks, for example, can cost \$60,000 to \$120,000 more than comparable diesel trucks.⁷³ The recently introduced Dodge Ram 2500 CNG pick-up truck costs \$18,510 more than its gasoline version.⁷⁴ Such incremental sums can render the payback periods impractical given capital constraints, and could even render the purchase altogether economically unviable in some instances. Industry efforts focused on cost reduction through scale manufacturing and technology improvements are therefore absolutely critical to the future success of AFVs. These efforts are furthered by strong vehicle demand. A tax credit that offsets a portion of the incremental cost would reduce the financial obstacle to a level at which the economic incentives to potential customers would be increased, and spur greater demand.

67 American Public Transportation Association, 2012 Public Transportation Fact Book, Appendix A, Table 41

68 The Sacramento Bee, "Waste Management Opens Public-Access CNG Fueling Station, Expands Natural Gas-Powered Fleet," August 3, 2012

69 DOE, EIA, Renewable and Alternative Fuels, Alternative Fuel Vehicle Data

70 SAFE interviews

71 EPA, EPA and NHTSA Adopt First-Ever Program to Reduce Greenhouse Gas Emissions and Improve Fuel Efficiency of Medium- and Heavy-Duty Vehicles, Regulatory Announcement, August 2011

72 SAFE interviews

73 SAFE analysis based on: a review of OEM websites

74 SAFE analysis based on: data from Chrysler Group LLC, Ram 2500 and 3500

The Council recommends that the federal government establish tax credits for a percentage of the incremental cost of medium- and heavy-duty trucks powered by non-petroleum fuels. These credits ought to be available to purchasers for three years. For the first two years, the credit should equal 40 percent of the incremental cost and, for the third year, the credit should be reduced to 20 percent. This will both promote faster vehicle adoption and fiscal responsibility. Second, because scale is so important for supply-chain cost reductions and oil displacement, multiple vehicle purchases should be more heavily incentivized. Specifically, for purchasers of between four and ten vehicles, the credits should be increased to 45 percent in the first two years (25 percent in the third year), and for purchasers of more than ten vehicles, the credits should be increased to 50 percent (30 percent). These credits should also be made available to PHEVs, bi-fuel NGVs, and non-conventional hybrids.

As an alternative to the tax credit, for two years, a business should be allowed to elect to expense the cost of qualified vehicles in the year in which they are placed into service, effectively treating the vehicles as one-year property in the Internal Revenue Service's General Depreciation System. For the subsequent two years, newly-purchased qualified vehicles should be treated as "three-year property," after which they should revert to their current treatment as "five-year property."

PRIMARY RECOMMENDATION

Reorient the Department of Energy's research and development activities to help catalyze those innovations most likely to improve U.S. energy security.

Energy security is the nation's most urgent energy challenge and the DOE's R&D activities must be better aligned to meet it. This requires a pivot in focus from a structure aligned by technology to one aligned by functional end-uses such as transportation, power generation and delivery, and buildings. This will enable policymakers to compare fuels and technologies more directly based on their respective merits for a given use. These merits, in turn, can be assessed according to their capacity to strengthen U.S. energy security.

In its recent *Quadrennial Technology Review* (QTR), DOE recognized that additional resources should be dedicated to transportation alternatives due to their ability to strengthen our energy security through reduced oil consumption and diversified fuel sources, an observation that has perhaps been obscured by the Department's current structure and corresponding budget priorities.⁷⁵ The Council agrees with the assessment in the QTR, but also recognizes that available R&D resources are limited. In fact, although there has been a modest increase in federally-funded energy R&D since 2006, this increase followed decades of much more significant declines. Adjusting for inflation, federal funding for energy-related R&D fell by 70 percent between 1978 and 2006, from nearly \$7 billion to just \$2 billion.⁷⁶

Public spending on energy-related R&D is also a far smaller percentage of our economy than it is for several of our competitors. According to a report from the American Energy Innovation Council, public spending on energy-related R&D equaled just 0.3 percent of U.S. GDP in 2007, a level surpassed by China, France, and South Korea, and less than half the level of Japan.⁷⁷ Increased investment is critical if the United States wants to compete successfully with other major players in an increasingly global energy-innovation marketplace, but such investment must be more targeted to achieve intended outcomes.

The Department of Energy's transportation R&D activities fall broadly into three main offices or agencies: the Office of Efficiency and Renewable Energy (EERE), the Office of Science (SC), and the

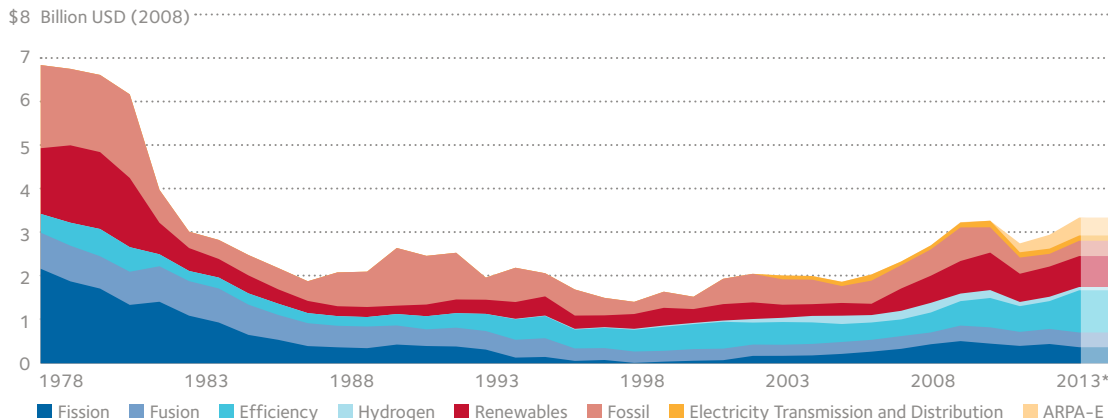
75 DOE, Report on the First Quadrennial Technology Review, September 2011, Executive Summary, at VIII

76 Gallagher, K.S. and L.D. Anadon, DOE Budget Authority for Energy Research, Development, and Demonstration Database, Energy Technology Innovation Policy, John F. Kennedy School of Government, Harvard University, February 29, 2012

77 American Energy Innovation Council, Catalyzing American Ingenuity: The Role of Government in Energy Innovation, Figure 8, at 32

U.S. Department of Energy Spending on Energy R&D

FIGURE 27



Note: Figure excludes one-time funding from the American Recovery and Reinvestment Act of 2009.

Source: Gallagher, K.S. and L.D. Anadon, "DOE Budget Authority for Energy Research, Development, and Demonstration Database," Energy Technology Innovation Policy, John F. Kennedy School of Government, Harvard University, February 29, 2012

Advanced Research Projects Agency – Energy (ARPA-E). Each of these research offices operates at a different point on the innovation chain. EERE is the most applied of the three, focused on accelerating the development and deployment of new technologies. The Office of Science is the lead federal agency supporting fundamental scientific research for energy.⁷⁸ Its research portfolio includes high energy physics, nuclear physics, and fusion research, among others.⁷⁹ ARPA-E focuses on creative, high-risk R&D that industry by itself cannot support, but where success would provide dramatic benefits to the nation—including improving efficiency and reducing energy imports.⁸⁰

ARPA-E is modeled after the Defense Advanced Research Projects Agency (DARPA) which has an established record of incubating the development of a wide range of new technologies, including stealth technology found in modern fighter aircraft.⁸¹ Unsurprisingly, therefore, ARPA-E is doing perhaps the most exciting R&D at DOE with both the highest risk and the highest potential future payoffs. DOE recently announced \$30 million of total funding for 13 projects through ARPA-E, for example, intended to advance a variety of NGV technologies, focused largely on increasing fuel storage capacity.⁸² ARPA-E has similar initiatives targeted at automotive battery, energy storage, and advanced biofuels R&D—Batteries for Electrical Energy Storage in Transportation (BEEST), Advanced Management and Protection of Energy Storage Devices (AMPED), and Plants Engineered to Replace Oil (PETRO) respectively.⁸³ The Council recommends maintaining and gradually increasing the funding available to ARPA-E for energy-related R&D activities moving forward.

While DOE must continue to maintain a balance between medium- and high-risk R&D activities, ARPA-E's emphasis on efficiency and results—and its operational flexibility—are characteristics that if adopted department-wide could have significant implications for effectiveness. The Council proposes several principles for targeting DOE's R&D funding and activities to the highest-value uses—those that will most significantly help reduce U.S. dependence on oil—and promoting operational effectiveness. If followed, these could have enormous positive implications for energy security, in addition to job creation. The principles outlined below promise a more robust and goal-oriented federal energy R&D policy that can both address the challenges the nation faces today and better prepare the nation for the challenges of tomorrow.

78 DOE, Office of Science, About, available at www.science.energy.gov/about/

79 Id.

80 DOE, ARPA-E, Mission, available at arpa-e.energy.gov/About/Mission.aspx

81 DOE, ARPA-E, About, available at arpa-e.energy.gov/About/About.aspx

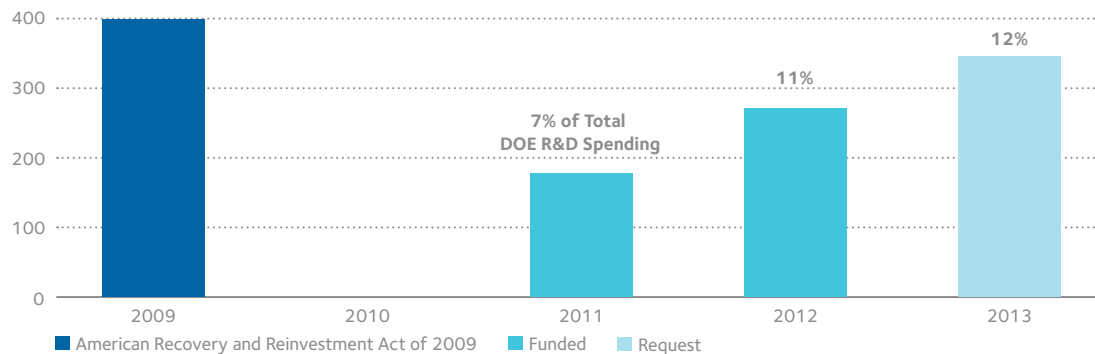
82 DOE, ARPA-E, News, "ARPA-E Announces New Projects to Advance Innovative Natural Gas Vehicle Technologies," available at arpa-e.energy.gov/Media/News.aspx

83 DOE, ARPA-E, Programs and Projects, Programs Main Overview, available at arpa-e.energy.gov/ProgramsProjects/Programs.aspx

FIGURE 28

ARPA-E Funding

\$500 Million USD



Source: DOE

Focus on the transportation sector. Oil dependence is an immediate threat to national security and prosperity, and the transportation sector represents our greatest opportunity for reducing that dependence. Disturbingly, DOE's QTR—which set out to establish a context and framework for DOE's own energy technology activities—found that the department is currently underinvested in the transportation sector relative to stationary energy users like power plants and buildings.⁸⁴ The Department must correct this finding by placing a higher priority on transportation-related R&D activities, as advancements in this area have the highest potential to yield the most significant reductions in U.S. oil consumption. Funding priorities should include advanced combustion technologies, vehicle efficiency, and onboard energy storage. To ensure that the signal given by the QTR is acted upon and momentum maintained, DOE could consider the creation of a new position—Deputy Assistant Secretary for Advanced Transportation—within EERE which would be responsible for all alternative fuel and vehicle research in the Vehicle Technologies Program, the Biomass Program, and the Fuel Cell Technologies Program. This person should also oversee the EV Everywhere project and proactively interface with relevant alternative vehicle and fuel programs in both SC and ARPA-E.

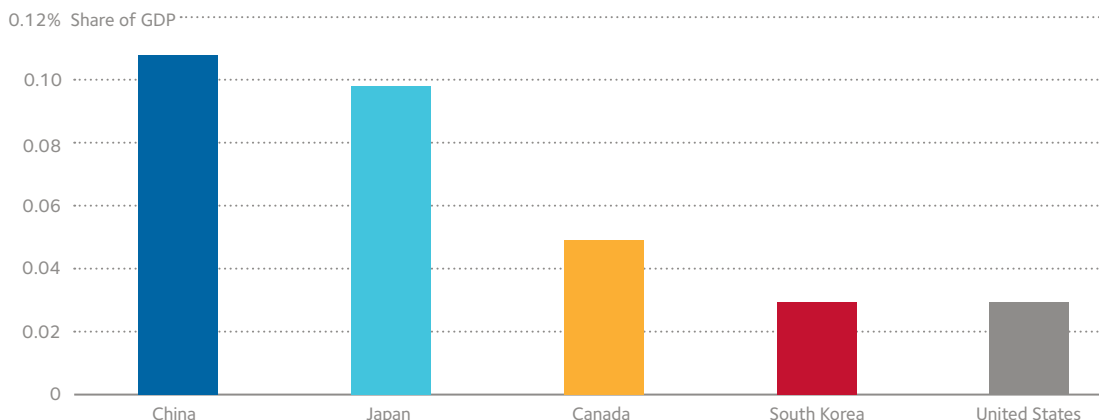
Focus on the point of transition between basic research and commercialization.

DOE must more aggressively focus on R&D for technologies that could be useful to the private sector in the near and medium term. To do this effectively, DOE must develop closer collaborative relationships with industry players including vehicle makers, component suppliers, and infrastructure providers to enhance its capabilities with respect to knowledge of industry needs and trends. DOE should also carefully monitor an ever-evolving regulatory landscape by maintaining close contact with the National Highway Traffic Safety Administration (NHTSA) and the Environmental Protection Agency (EPA). If successful, these efforts are likely to facilitate more effective technology transfer, improving product performance both more directly and more rapidly.

Focus on enhancing data collection, analysis, and dissemination. The effective development and commercialization of so many energy technologies is shaped by policies that are themselves informed by data and information. DOE collects a wide range of energy-related data which it analyzes and disseminates. These capabilities must be strengthened to provide consistent, reliable, and useful information to a wide variety of stakeholders to help promote AFV deployment. As part of this process, DOE has an important role to play convening participants from the public and private sectors in information sharing and deployment initiatives, and providing guidance to the spectrum of stakeholders, from state and local governments, to utilities, industry, and citizens. Today, the marketplace for AFVs

Public Energy R&D Expenditures by Country, 2008

FIGURE 29



Source: American Energy Innovation Council

is in the early stages of development, and while consumers' knowledge of AFV technology is growing, it is still limited and remains insufficient to drive widespread AFV adoption. By gathering, analyzing, and more widely disseminating information from efforts such as The EV Project, DOE has a critical role to play in advancing the market's understanding of vehicle operating cost, infrastructure needs, and consumer behavior.

Focus on accountability. When limited funds are available, effectively allocating these funds to the most promising initiatives is critical. As important, is ensuring that once allocated, these initiatives actually serve their desired purpose successfully. Recent failures of government-funded, energy-related projects have caused substantial debate in the political sphere, shining a spotlight, in part, on the issues of accountability and transparency. Irrespective of any specific programs, all funding allocations, including those for DOE's own R&D initiatives, must be complemented with comprehensive frameworks for how funds will be spent and how progress will be measured. These frameworks should include metrics for the analysis of progress, clear timelines with conditional milestones, and the responsibilities of initiative participants. The Department must carefully monitor the progress of all its initiatives and address problems quickly and effectively when they arise. If successful, such an approach will increase transparency and accountability in the funds allocation (and spending) process, facilitate improved R&D outcomes, and strengthen stakeholder satisfaction with DOE's R&D initiatives.

Finally, to complement its QTR and the principles presented here, DOE should undertake a comprehensive audit of its R&D spending programs and provide an assessment of their importance with respect to meeting the nation's energy goals. This audit should begin in January 2013. Its preliminary findings should be presented by June 2013 and its final recommendations should be released by year-end 2013. The Department should take immediate steps to implement its recommendations.

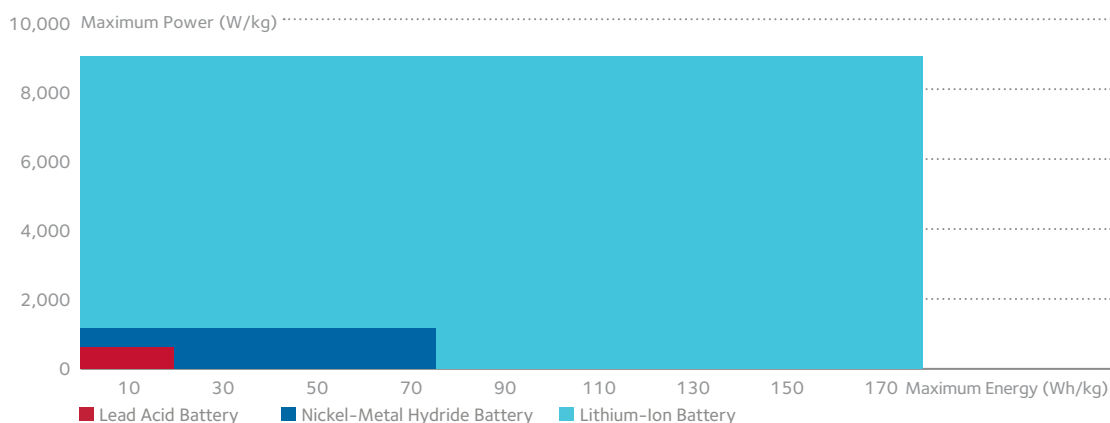
COROLLARY RECOMMENDATION

Increase federal investment in research and development for automotive-grade batteries and natural gas storage tanks.

Plug-in electric vehicles and natural gas vehicles are two of the most promising AFV technologies available in the marketplace today. These alternatives to conventional, petroleum-powered vehicles represent an opportunity for meaningful displacement of gasoline and diesel use in the transportation sector over the long term. In fact, both technologies have already achieved promising levels of initial uptake by private and commercial customers, and an increasing number of models are available across the vehicle spectrum, with further options under development. However, both PEVs and NGVs face

FIGURE 30

Battery Performance per Technology



Source: Electrification Coalition

significant challenges related to their onboard energy storage systems—batteries for PEVs and fuel storage tanks for NGVs—that could ultimately undermine their commercial success.

The current generation of large-format, lithium-ion automotive batteries represents a sizeable improvement in terms of energy and power density compared to its lead-acid and nickel-metal hydride predecessors. Yet even after achieving these gains, the batteries in today's PEVs are too expensive to offer most consumers a compelling economic value proposition, and their energy density remains well below that of traditional petroleum fuels. The disparity is such that, even after adjusting for the higher efficiency of electric motors compared to combustion engines—electric motors can convert upwards of 90 percent of the potential energy in electricity into mechanical energy—battery electric vehicles available in the marketplace today typically have a range of only 70 to 100 miles per charge.⁸⁵ Meanwhile, a passenger car with an efficiency rating of 30 miles per gallon and a 14-gallon fuel tank could travel up to 420 miles before refueling.

The CNG storage tanks in today's NGVs present similar challenges in terms of cost and performance, though to a lesser degree. For example, while the battery in the fully electric Ford Focus reportedly adds between \$12,000 and \$15,000 to the cost of the vehicle, the CNG tank in the Honda Civic Natural Gas accounts for the bulk of that vehicle's \$6,000 price premium relative to the conventional model.⁸⁶ And while the Civic Natural Gas provides drivers with greater range than most EVs, its 160 to 200 miles per tank is still well below the 422 miles per tank provided by the conventional Civic model.⁸⁷

Over the coming decade, the costs of PEV batteries and CNG storage tanks are expected to decline considerably while their performance improves, extending advancements achieved over the past several years. In the near term, between now and roughly 2015, both technologies are likely to benefit from continued declines in production costs due to rising efficiencies and economies of scale in manufacturing, as global automakers introduce dozens of new PEV and NGV models, and as early adoption levels continue to increase globally.

However, cost savings from scale alone are unlikely to drive AFV energy storage technologies to price points that are sufficiently compelling for mainstream consumers. Instead, technological innovation provides an opportunity for both performance improvements and cost reductions that could perhaps be much greater and more sustainable than the near-term gains from increased manufacturing scale. Therefore, although the existing group of lithium-ion battery chemistries and natural gas storage tanks will be used in the early suite of vehicle offerings to enter the marketplace, scientists and

⁸⁵ DOE, EERE, fueleconomy.gov, Electric Vehicles: Compare Side-by-Side

⁸⁶ SAFE analysis: 2013 Ford Focus EV is compared to a similarly-equipped Ford Focus SE; and 2012 Honda Civic Natural Gas is compared to a similarly-equipped Honda Civic HF

⁸⁷ SAFE analysis: 2012 Honda Civic Natural Gas is compared to 2012 Honda Civic Sedan

engineers are continuing to explore the opportunities presented by different materials, chemistries, processes, and designs.

For batteries, important research is being conducted in many areas, and includes efforts to facilitate battery operation at higher voltages (enabling higher capacity per unit weight and volume) and the development of higher capacity electrode materials, such as silicon or tin anodes.⁸⁸ According to the Department of Energy, successful high-risk research could drive material advances that lead to a 60 percent reduction in battery cost and a 250 percent increase in energy density.⁸⁹ New battery chemistries also offer the possibility of higher energy density as well as significant reductions in the need for heating or cooling systems, ultimately resulting in long-term performance, life, and cost improvements. Entirely new battery technologies are also being developed, such as lithium- or zinc-air.⁹⁰

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The goals for CNG storage tanks with respect to energy storage capacity and affordability are similar, and the technological possibilities for reaching them equally wide-ranging. Tanks utilizing adsorbent internal materials are of particular interest because they could enable higher density CNG storage at significantly lower pressure. These technologies currently remain expensive, and mostly in the research and testing phases, but ultimately they can facilitate the use of smaller, thinner-walled tanks that can be manipulated into a variety of more practical shapes suitable for vehicles of all types and sizes. The successful development of higher-density, lower-pressure storage tanks could also help to reduce the expense associated with natural gas compression. Further optimization of existing tank technologies also remains important, from the use of high-strength metallic materials to alterations in composite material winding patterns (to reduce carbon fiber use).⁹¹

Federally-funded R&D designed to improve the cost and performance of AFV energy storage systems through technological improvement is crucial to—and consistent with—efforts to strengthen U.S. energy security. Without question, important efforts have been initiated in recent years. The Advanced Research Projects Agency – Energy has, for example, received nearly \$900 million in appropriations since 2009, including \$400 million in stimulus funding.⁹² While ARPA-E's portfolio of high-risk energy R&D includes numerous technologies, its Batteries for Electrical Energy Storage (BEEST) initiative received \$36.3 million in 2010.⁹³ The program aims to extend battery life by 300 to 500 percent and improve storage by up to five times—at 30 percent of today's battery cost.⁹⁴

Natural gas vehicles have also recently benefited from high-risk R&D funding. In 2012, ARPA-E initiated its Methane Opportunities for Vehicular Energy (MOVE) program. MOVE has funded 13 projects totaling \$30.2 million designed to develop innovative, low-cost natural gas storage technologies and methods to lower pressure in vehicle tanks.⁹⁵

It is critical that programs like BEEST and MOVE continue to receive the necessary funding going forward. Similarly, the wide range of energy storage research occurring in the Office of Science, the Office of Energy Efficiency and Renewable Energy and throughout the nation's national laboratories must be consistently re-evaluated and monitored to ensure adequate funding. Federal funding for energy storage should be increased by a factor of two by FY 2017, with incremental appropriations being derived from the federal Energy Security Trust Fund described in *Part II* of this report.

88 Argonne National Laboratory, Transportation Technology R&D Center, Advanced Battery Research, Development, and Testing

89 DOE, EERE, EV Everywhere, Grand Challenge, Presentation, Battery Status and Cost Reduction Prospects, July 26, 2012, at 10

90 See, e.g., IBM, The Battery 500 Project; and MIT Technology Review, High Energy Batteries Coming to Market, October 28, 2009

91 Working document of the National Petroleum Council Future Transportation Fuels Study, Advanced Storage Technologies for Hydrogen and Natural Gas, made available August 1, 2012

92 DOE, ARPA-E, Budget, available at arpa-e.energy.gov/About/Budget.aspx

93 DOE, ARPA-E, Batteries for Electrical Energy Storage in Transportation (BEEST), Program Factsheet

94 Id.

95 DOE, ARPA-E, Project Selections – Methane Opportunities for Vehicular Energy (MOVE) Technical Descriptions, July 12, 2012





PART II

Maximizing Domestic Energy Production

Maximizing Domestic Energy Production

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The United States is in the midst of a remarkable expansion of domestic production of oil and natural gas. Driven by a combination of advances in drilling and well completion technology as well as generally supportive commodity prices, the U.S. energy industry has engineered a turnaround in output that few observers believed possible only a few years ago. Domestic liquids production has increased by nearly 30 percent since 2008, and the United States is currently producing more natural gas than it has in its entire history.¹ This increased production is delivering meaningful economic benefits for the country, including direct and indirect jobs, an improved current account deficit and increased economic competitiveness. Most experts expect these benefits to grow as production continues to increase for the next decade—and possibly longer.

However, while the outlook for U.S. production of conventional fuels suggests continued growth over the short- and medium-term, it is generally the case that much more could be done to support sustained increases in domestic energy production over the long term. Most notably, significant oil and natural gas resources on federal lands and waters remain unavailable for development due to statutory restrictions and bureaucratic inertia.

Recent events, such as the 2010 *Deepwater Horizon* oil spill, serve as powerful reminders that effective government oversight of oil and natural gas development is a fundamental necessity and that it must be vigilant and sophisticated in nature. Nevertheless, the promotion of environmental quality and prudent development of the nation's most promising resources need not be mutually exclusive propositions. A rigorous approach to oversight based on global best-practices and performance-based evaluation should be used to create the foundation for unlocking a greater share of the nation's oil and natural gas resources on federal lands, both onshore and offshore. Such an approach acknowledges a basic reality: it is in the nation's interest to expeditiously develop its natural resources, but such development must also prioritize safety and sustainability.

Finally, just as the nation continues to support the development of advanced, transformative surface transportation technologies, such as vehicles powered by electricity and natural gas, it must invest in the research and development (R&D) that will unlock the unconventional liquid fuels of the future. Drop-in renewable fuels generated from feedstocks that do not compete with food—most notably, algae—represent a promising alternative to diesel fuel in the aviation and long-haul shipping segments of the transportation sector, and their commercialization would enhance both economic security and environmental sustainability.

1 DOE, EIA, Short Term Energy Outlook, November 2012 and AER 2011, Table 6.1

Current Trends in U.S. Production of Natural Gas, Crude Oil, and Other Liquids

Natural Gas

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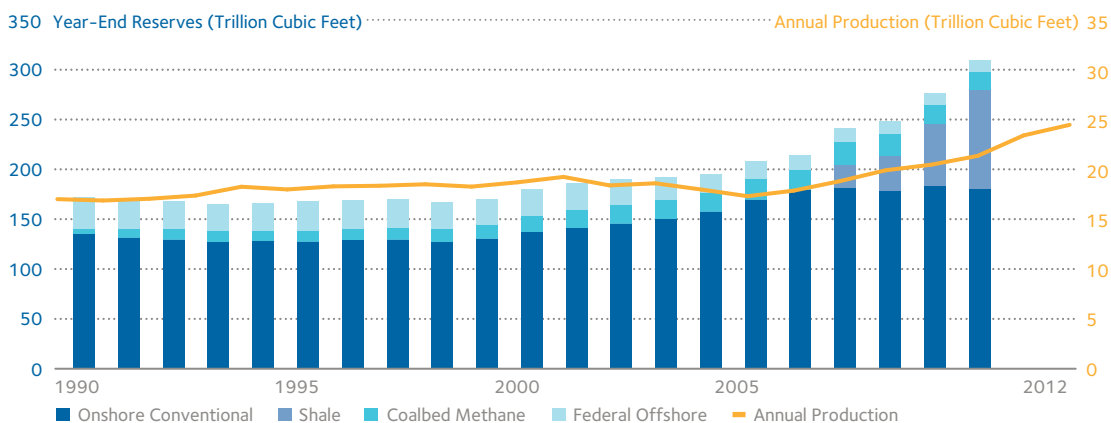
After seven consecutive years of growth, U.S. dry natural gas production is expected to top 65 billion cubic feet per day (bcf/d) in 2012.² Output has increased by 32 percent since 2005 and now stands at its highest level in history.³ Meanwhile, U.S. proved dry gas reserves have increased by an incredible 72 percent in a decade, from 177.4 trillion cubic feet (tcf) in 2000 to 304.6 tcf as of year-end 2010.⁴ More broadly, the United States has been the world's largest natural gas producer since 2009, a distinction it last held in 2002, and only Turkmenistan and Iran have seen more substantial growth in proved reserves over the past decade.⁵

It is well documented that the recent surge in U.S. natural gas production is the direct result of horizontal drilling and hydraulic fracturing.⁶ Applied in tandem, these drilling and recovery techniques have unlocked substantial hydrocarbons by tapping into previously inaccessible resources trapped in deep, low-permeability geological formations—most notably shales—in at least a dozen states. To be sure, shale gas resources were known to exist for decades. In fact, many of the shales being mined for natural gas (and oil) today were the source rocks for some of the most prolific conventional fields in U.S. history. Nonetheless, production from shales and similar unconventional deposits was not attractive until the mid-2000s due to a combination of private sector innovation, publicly-financed R&D, and high natural gas prices.⁷ In 2005, shale gas production represented just 4 percent of total U.S. dry gas production. By the middle of 2012, it had risen to nearly 40 percent.⁸

As impressive as recent gains in natural gas production and proved reserves have been, a number of analyses indicate that potential future supplies could be vastly larger. In its year-end 2010 assessment, the Potential Gas Committee at the Colorado School of Mines estimated total potential U.S. natural gas

U.S. Natural Gas Reserves and Production

FIGURE 3I



Source: DOE, EIA

² DOE, EIA, Short Term Energy Outlook, November 2012

³ DOE, EIA, AER 2011 and Short Term Energy Outlook, November 2012

⁴ DOE, EIA, "U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves," Table 7

⁵ BP, plc., *Statistical Review 2012*, online statistical supplement, "Gas Proved Reserves" and "Gas Production"

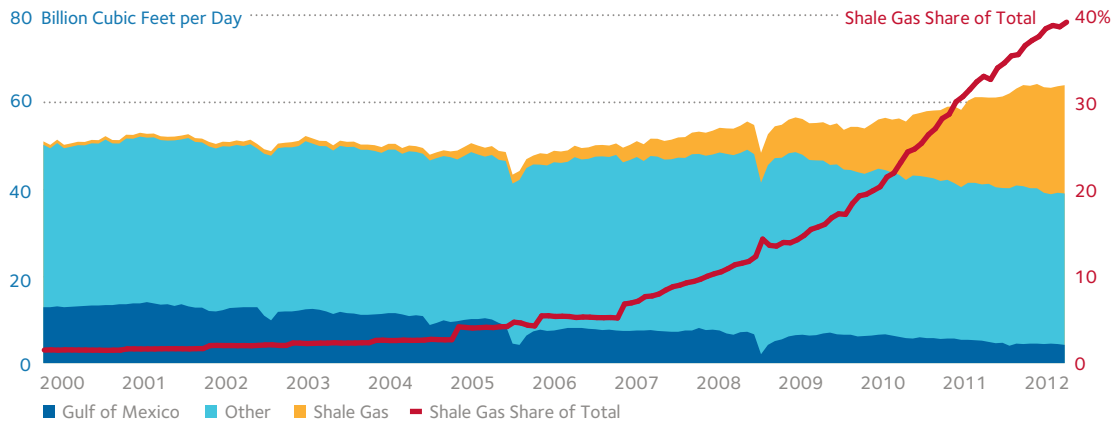
⁶ See, e.g., Massachusetts Institute of Technology (MIT), *Future of Natural Gas*, at 31, 37

⁷ Id., at 163-169; and DOE, "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology," *Drilling and Completion technology fact sheet*, at 7 and 8, 1999

⁸ SAFE analysis based on data from: Adam Sieminski, "Prospects for U.S. Oil and Natural Gas," July 20, 2012; and DOE, EIA, *Monthly Energy Review*, September 2012

FIGURE 32

U.S. Dry Natural Gas Production by Source



Source: DOE, EIA

resources to be in excess of 2,170 tcf, a figure that included 686.6 tcf of shale gas resources.⁹ At current levels of U.S. consumption, this equates to an 85-year domestic gas supply.¹⁰

It is, however, important to note that rising production of shale gas in the lower-48 United States has offset declining output in other key regions, most notably offshore in the federal Gulf of Mexico. At the turn of the century, natural gas output from the Gulf Outer Continental Shelf (OCS) averaged more than 13 bcf/d and accounted for more than one-fourth of U.S. dry natural gas production.¹¹ By January 2012, output from the Gulf had declined to 4.6 bcf/d, representing just 7.0 percent of the U.S. total.¹² While several factors have contributed to this decline, the availability of a large, well-understood, and increasingly cost-effective onshore resource base stands out as a critical factor. Oil and natural gas companies in the United States have simply chosen to allocate more upstream capital to shale gas development, where exploration costs and risks are comparatively lower than those associated with offshore development.

Crude Oil

After decades of near constant decline, U.S. crude oil production increased for four consecutive years between 2009 and 2012, rising from 5.0 million barrels per day (mbd) in 2008 to 6.3 mbd in 2012.¹³ This was the most sustained growth period since the early 1980s and the most significant growth from a volume perspective since the late 1960s.¹⁴ While a number of regions of the country made contributions to this growth, the vast majority of increased production occurred in just two states: North Dakota and Texas. In both cases, growth was driven by the development of unconventional resources similar in nature to shale gas. In fact, crude output from two specific resource plays alone, the Bakken Shale in North Dakota and the Eagle Ford Shale in Texas, grew by 935,000 barrels per day between January 2008 and mid-2012, equal to three-fourths of total U.S. production growth over that period.¹⁵

Resources like the Eagle Ford and Bakken shales represent the most significant developments to date with respect to a larger set of resources collectively referred to as light, tight oil (LTO). Tight oil is currently being produced from shales as well as tight sands, low-permeability carbonates, chinks and other similar geological formations. In a 2011 report, the Department of Energy (DOE) estimated U.S. technically recoverable shale oil resources for year-end 2009 to be 24 billion barrels across just four basins—the Eagle Ford in Texas, Bakken in North Dakota, Monterey in California, and Avalon and

9 Potential Gas Committee, *Potential Supply of Natural Gas in the United States*, April 27, 2011

10 SAFE analysis based on data from: DOE, EIA, October 2012 Monthly Energy Review; and Potential Gas Committee

11 DOE, EIA, "Natural Gas Gross Withdrawals and Production," available at www.eia.doe.gov

12 Id.

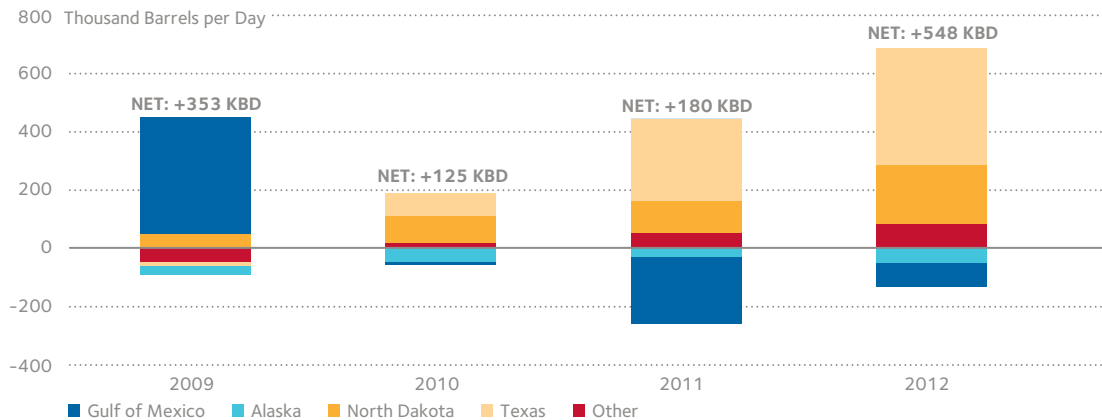
13 DOE, EIA, *AER 2011*, Table 5.1b and Short Term Energy Outlook, November 2012

14 DOE, EIA, *AER 2011*, Table 5.1b

15 SAFE analysis based on data from: Texas Railroad Commission and North Dakota Industrial Commission

Change in Crude Production by Region

FIGURE 33



Note: Data for 2012 is average through August.

Source: DOE, EIA

Bone Spring in Texas and New Mexico.¹⁶ By comparison, total U.S. proved reserves of crude oil and lease condensate were 25.2 billion barrels at year-end 2010.¹⁷ In fact, the DOE estimates are arguably conservative, as they do not include numerous basins that have been added to the list of potential resource plays since 2009, such as the Utica Shale in Ohio and the Niobrara Shale in Colorado.

While total U.S. output has grown by significant margins in recent years, the surge in LTO production in the lower-48 United States has masked notable declines in crude oil production from two critical regions—Alaska and the federal Gulf of Mexico. Alaskan crude oil production is projected to average 538,000 b/d in 2012, a decline of 73 percent from its peak of 2.0 mbd in 1988—a year in which Alaskan crude output accounted for 25 percent of the U.S. total.¹⁸ The decline in oil production from Alaska—the result of depleting existing reserves and a lack of access to new resources on federal lands—has been steady and relentless. In the 25 years between 1988 and 2012, output declined in 22 of them.

Recent trends in the Gulf of Mexico have been driven by a different set of factors. From just 750,000 b/d in 1990, Gulf crude production grew year-over-year at an average annual rate of 6 percent through 2002, when it reached 1.56 mbd.¹⁹ The entire increase came from the development of deepwater resources, defined as projects in greater than 1,000 feet of water.²⁰ In fact, shallow water production actually declined substantially over the same period as the industry invested primarily in developing resources at greater depths throughout the Gulf.

Beginning in 2003, Gulf production began to decline substantially, in part as a result of significant shut-ins during the turbulent 2005 and 2008 hurricane seasons, but also as a result of declining output from a number of significant deepwater projects. By 2008, production had fallen to 1.16 mbd, its lowest level since the late 1990s.²¹ However, beginning in 2009, rising production volumes from ultra deepwater, defined as resources developed in greater than 5,000 feet of water, drove a turnaround in Gulf output, which reached its historical high near 1.6 mbd in 2009 and seemed poised for continued growth.

On April 20, 2010, while completing work on an exploratory well in the Macondo Prospect approximately 50 miles off the coast of Louisiana, the semi-submersible drilling rig *Deepwater Horizon* experienced a catastrophic blowout, leading to several crippling explosions and an uncontrollable

¹⁶ DOE, EIA, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, at X

¹⁷ DOE, EIA, "U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves," Table 1

¹⁸ DOE, EIA, *AER 2011*, Table 5.1b and Short Term Energy Outlook, November 2012

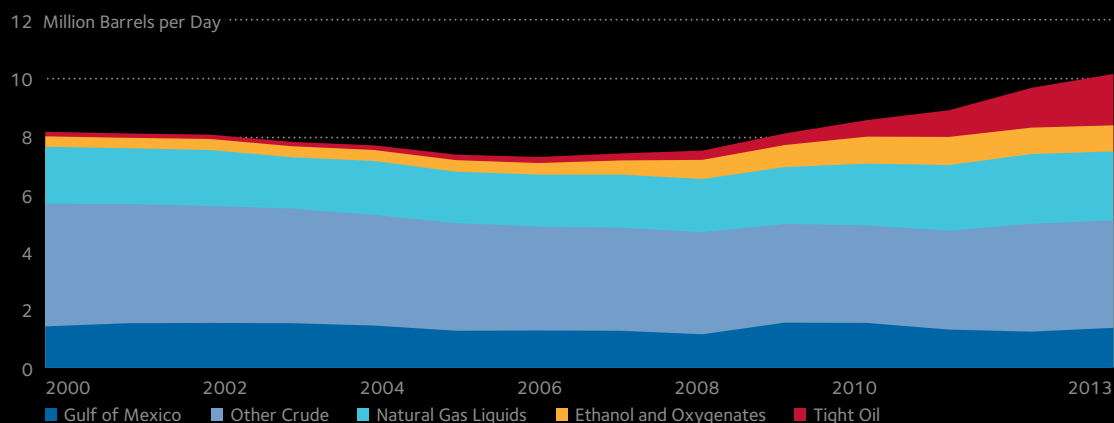
¹⁹ SAFE analysis based on data from: DOE, EIA, Short Term Energy Outlook, October 2012

²⁰ SAFE analysis based on data from: Department of Interior (DOI), Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental

²¹ Id.

FIGURE 34

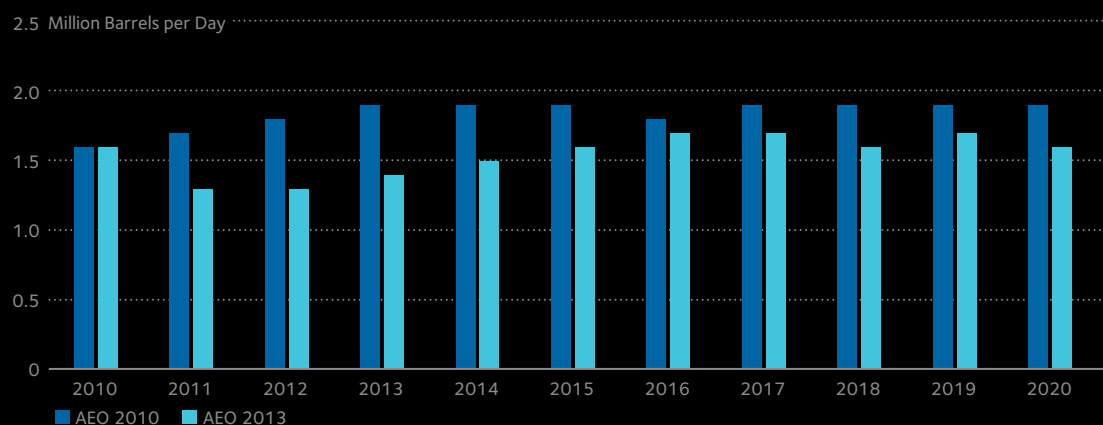
U.S. Liquids Production, Historical and Forecast



Source: DOE, EIA; Short Term Energy Outlook, October 2012; and September 2012 Presentation from Administrator of EIA

FIGURE 35

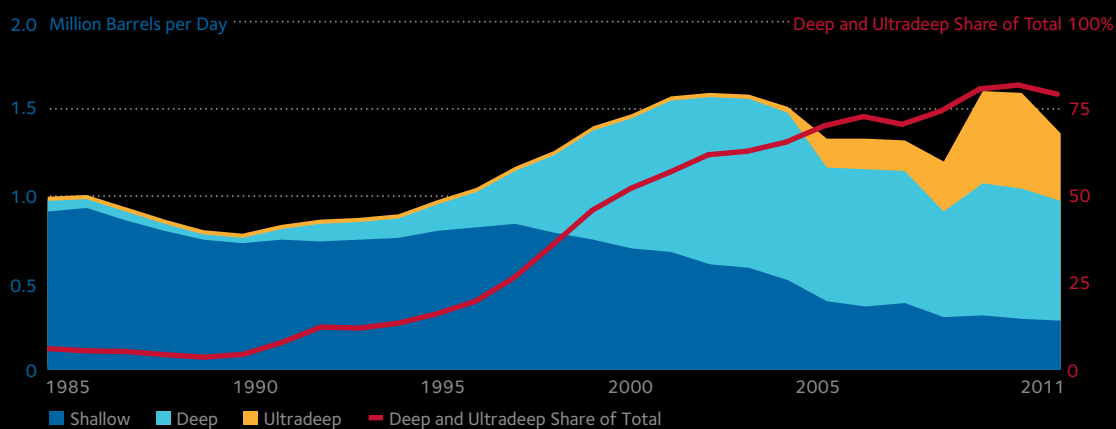
Gulf of Mexico Crude Production, Historical and Forecast



Source: DOE, EIA

FIGURE 36

Gulf of Mexico Crude Production by Depth, 1985-2011



Source: DOI, BOEM; and SAFE analysis

fire that resulted in the deaths of 11 rig workers. Two days later, the rig sank in approximately 5,000 feet of water.²² The accident severed the rig's connection to the seafloor, and the blowout preventer experienced a complete failure, allowing oil from the reservoir to plume into the Gulf of Mexico.²³ The federal government estimates that the *Deepwater Horizon* incident released 4.9 million barrels of crude oil into the Gulf of Mexico before the damaged well was stabilized on July 15, making it the single worst offshore incident in U.S. history.²⁴

On May 27, 2010, amid the initial uncertainty regarding the causes of the blowout, the difficulty of a major reorganization, and heavy public criticism, the Department of Interior (DOI) announced a six-month moratorium on new deepwater drilling at depths greater than 500 feet in the Gulf of Mexico.²⁵ The ban halted approval of any new permits for deepwater drilling and suspended drilling of 33 exploratory wells in the Gulf.²⁶ While the moratorium officially ended in October 2010, the first permits to drill exploration and development wells were not granted until February 2011. In essence, exploration and development activity was halted in the Gulf of Mexico for nearly a full year, stunting reserves growth and accelerating decline rates at existing fields.

The spill and moratorium had a measurable impact on U.S. energy production. A comparison of pre- and post-disaster forecasts from DOE illustrates the medium-term impact of the disaster and subsequent moratorium. In its Annual Energy Outlook (AEO) for 2010, DOE forecast a steady increase in Gulf of Mexico oil production between 2009 and 2020, driven largely by surging ultra deepwater production. The 2010 AEO projected Gulf production to reach more than 1.9 mbd by 2020.²⁷ The recently-released 2013 iteration of the Outlook reveals a starkly different trend. In the near term, Gulf production falls short of pre-spill projections by roughly 500,000 b/d in several years.²⁸ Even looking out through 2020, AEO 2013 does not envision Gulf production returning to the pre-spill forecast.²⁹

Increasing Domestic Supply

The United States is unquestionably in a better position than it was just a few short years ago with respect to domestic oil and natural gas development. Production of both fuels is on the rise, and the expanding unconventional resource base suggests that there is ample justification to be confident in continued growth over the coming decade. Net imports of crude oil and refined petroleum products, already at their lowest level since the early 1990s, are expected to continue to decline, keeping billions of dollars within U.S. borders where it can be productively deployed. And while the prospect of self-sufficiency in petroleum supply remains a fairly uncertain and ambitious—though certainly attractive—target, true self-sufficiency has effectively arrived for natural gas, with significant export volumes already on the horizon and net imports expected to fall to zero as soon as 2020.³⁰

In this context, calls to expand industry access to federal lands currently unavailable for oil and natural gas development may seem unnecessary or even misplaced to some. Indeed, much of the urgency regarding access to federally restricted areas both offshore and onshore has receded as the industry has turned its attention to developing unconventional resources on state and private lands. While touting the benefits of developing these new resources, policymakers have simultaneously questioned the need to make additional tracts of land available to an industry in the midst of a nearly unprecedented growth phase.

22 Rigzone, "Deepwater Horizon Sinks Offshore Louisiana," April 22, 2010

23 Transocean provides a detailed overview of blowout preventers at http://www.deepwater.com/_filelib/FileCabinet/pdfs/o8_TRANSOCEAN_Ch_3-4.pdf

24 See, e.g., <http://www.restorethegulf.gov/release/2011/04/10/one-year-later-press-pack>

25 United Press International, "U.S. announces drilling moratorium details," May 30, 2011

26 Michael Kunzelman, "Judge blocks Gulf offshore drilling moratorium," Associated Press, June 22, 2010

27 DOE, EIA, *AEO 2010*, Table 113

28 SAFE analysis based on data from: DOE, EIA, *AEO 2010 and AEO 2013 Early Release*

29 Id.

30 DOE, EIA, *AEO 2012*, High Technically Recoverable Resource Scenario, Table 13

This approach to managing the nation's energy resources is both short-sighted and misguided. The inclination of the nation's policy apparatus to prejudge which resources are most attractive for industry development has preempted the market's ability to allocate capital to the most efficient projects. Worse still, vast tracts of federal territory in the Atlantic, Alaskan, and Eastern Gulf OCS remain largely unexplored using modern technologies. Policymakers simply do not have adequate information at their disposal to make informed decisions or to develop anything approaching a comprehensive plan for deciding which of the nation's resources to develop and which to set aside.

Given the gravity of the nation's energy security challenges, U.S. policy should prioritize growth in domestic oil and natural gas production by increasing access to areas with high potential and letting industry invest in developing the most promising resources as long as they are meeting the highest performance standards. The recommendations that follow outline an approach for doing so while remaining mindful that resource development must not come at the expense of the natural environment. The *Deepwater Horizon* incident generated a number of important lessons with respect to safe and sustainable industry operations, and these lessons should help inform policy, oversight, and resource development going forward.

Policy Recommendations

Conventional Resources

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61

PRIMARY RECOMMENDATION

Require the Department of Interior to begin work on a revised Five Year Plan covering the period from 2015–2020.

More than two years after the *Deepwater Horizon* incident, operations in the federal Gulf of Mexico are beginning to return to normal. The number of rotary rigs drilling for oil in the Gulf was near 30 between September and November of 2012, levels last seen in the weeks and months immediately prior to the Macondo blowout.³¹ The average approval time for a permit to drill a new deepwater well in the Gulf of Mexico was 42.2 days in the second half of 2012, similar to pre-spill timelines.³² In general, operators report that they are moving forward with greater confidence in the permitting process, though current experience suggests that added layers of oversight will add roughly 10 percent to the cost of drilling a well in the Gulf going forward.³³ And while Gulf oil production declined for three years between 2010 and 2012, current government forecasts envision a return to growth in 2013.³⁴

While these developments suggest that there is forward progress being made in the aftermath of a significant setback, the *Deepwater Horizon* incident had far-reaching implications for U.S. energy policy that extend well beyond routine development in the Western and Central planning areas of the Gulf of Mexico. In particular, U.S. policy has shifted in significant ways concerning the development of additional resources in regions of the OCS outside the Western and Central Gulf. The United States is currently on track to pursue a Gulf-centric approach to resource development that serves to the detriment of national energy security, economic growth, and the Gulf region itself.

The U.S. Outer Continental Shelf—the region of offshore territory beyond state waters but within the exclusive economic zone of the United States—is resource rich. It contains what are believed to be some of the nation's most substantial undiscovered technically recoverable oil and natural gas resources, a large share of its most promising renewable energy potential, and some of the most productive fisheries and unique ecosystems found anywhere in the world. For commercial planning purposes, the OCS is broken up into four separate regions: the Gulf of Mexico, the Atlantic, the Pacific, and the Alaskan OCS. These regions are further divided into sub-regions, or planning areas. The vast majority of oil and gas wells drilled in federal waters to date have been in just two planning areas: the Western and Central Gulf of Mexico off the coasts of Texas, Louisiana, Mississippi, and Alabama.³⁵

To be sure, the concentration of OCS oil and natural gas development in the Gulf of Mexico is based in part on resource potential. The U.S. offshore industry was born in the Gulf as producers sought to continue developing some of the nation's most prolific oil and gas fields, many of which extended into the shallow waters off the coasts of Texas and Louisiana. However, numerous federally-managed resource assessments have found that the broader OCS is likely to contain substantial oil and gas resources.

31 Baker Hughes

32 SAFE analysis based on data from: DOI, BSEE, eWell Database, available at http://www.data.bsee.gov/homepg/data_center/plans/apdform/master.asp

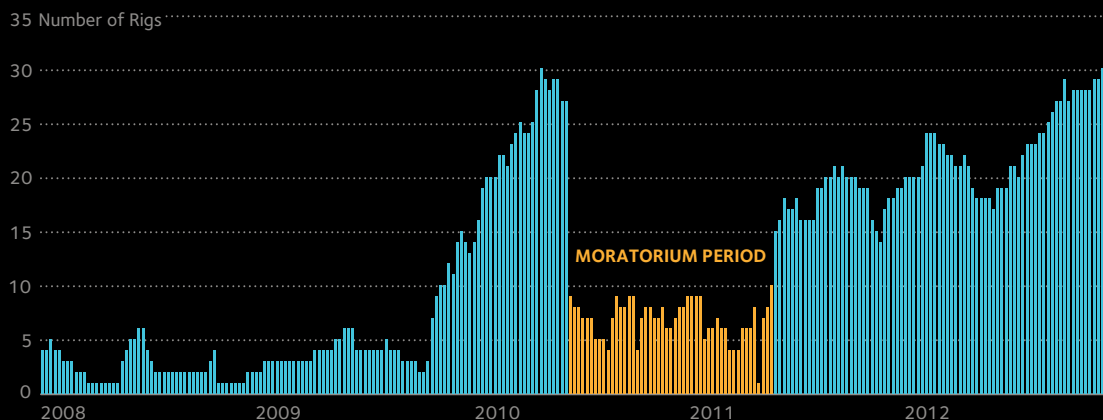
33 SAFE conversations with individual operators

34 DOE, EIA, November 2012 Short Term Energy Outlook

35 SAFE analysis based on data from: DOI, BSEE, "Oil and Gas Well Drilling on Federal Offshore Leases Since 1960," and DOI, "Increased Safety Measures for Energy Development on the Outer Continental Shelf," 2010, at 3

FIGURE 37

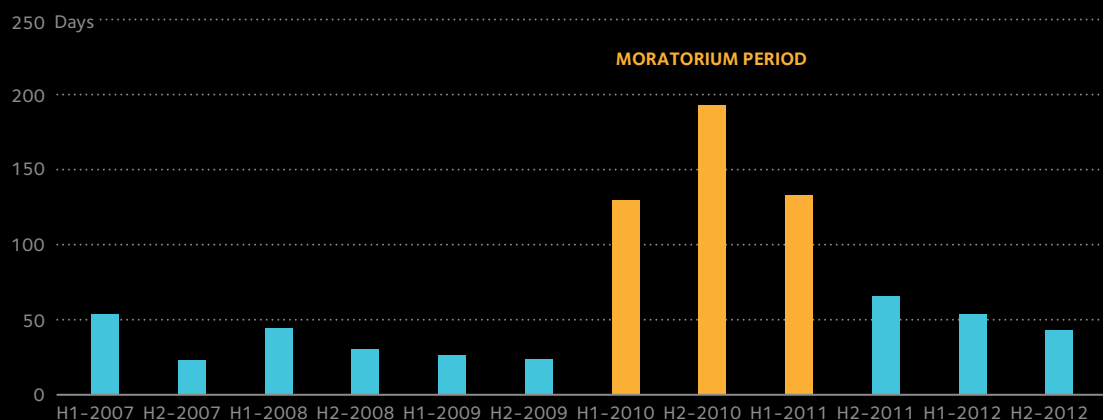
Gulf of Mexico Oil Rotary Rig Count



Source: Baker Hughes

FIGURE 38

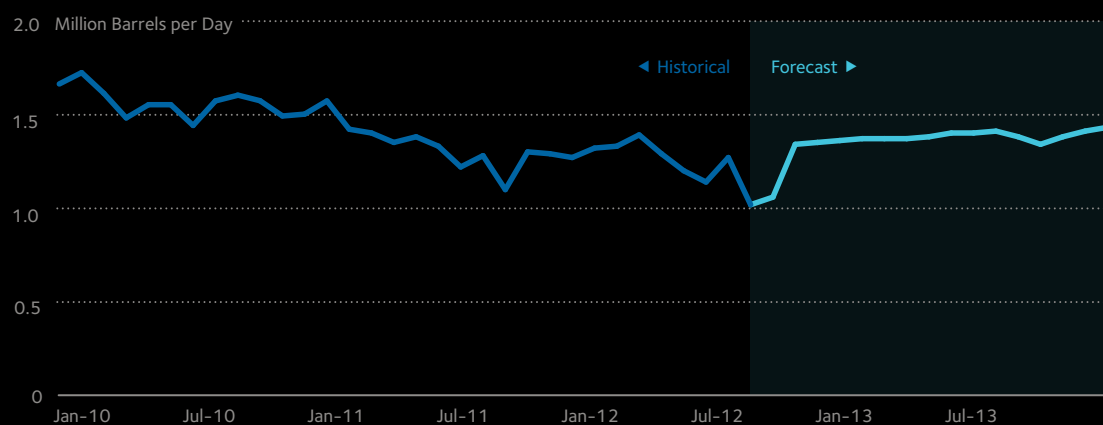
Average Approval Time: New Gulf of Mexico Deepwater Well



Source: DOI, BSEE

FIGURE 39

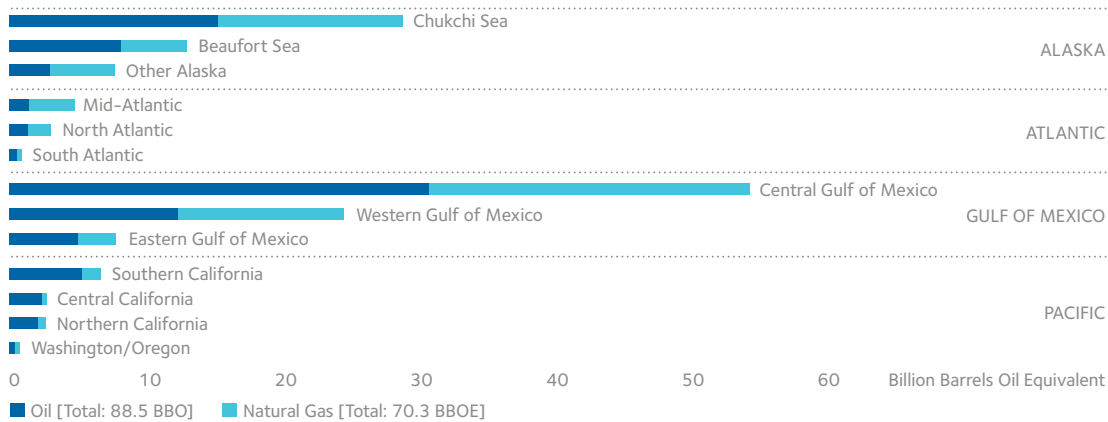
Gulf of Mexico Crude Production, Historical and Forecast



Source: DOE, EIA

Outer Continental Shelf Oil and Natural Gas Resources by Planning Area

FIGURE 40



Source: DOI, BOEM

The most recent assessment, completed by the Department of Interior in 2011, placed undiscovered technically recoverable resources (UTRR) for the entire OCS at 88.5 billion barrels of oil—an increase of 3 percent from the previous assessment, completed in 2006.³⁶ While the Western and Central Gulf contain 49 percent of the assessed potential, the Atlantic, Pacific, Alaskan, and Eastern Gulf planning areas all contain significant resources according to Interior.³⁷ Furthermore, the most recent seismic studies of the Atlantic and Eastern Gulf OCS regions were conducted in the 1970s and 1980s, a fact that suggests greater potential given the advances in exploration and development technology achieved in the decades since.³⁸

For a variety of reasons, the majority of oil and natural gas resources in OCS regions beyond the Western and Central Gulf of Mexico have been withheld from development for decades. Congressional moratoria enacted between 1982 and 1992 barred the Department of Interior from leasing tracts within roughly 85 percent of the OCS territory bordering the lower-48 United States.³⁹ Complementary executive withdrawals affecting much of the OCS were first enacted by President George H.W. Bush in 1990 and extended by President Bill Clinton in 1998.⁴⁰ Finally, in 2006, Congress passed, and President George W. Bush signed, the Gulf of Mexico Energy Security Act (GOMESA), which allowed access to drilling in a portion of the Central and Eastern Gulf that was previously off limits and also restricted access to the vast majority of the Eastern Gulf of Mexico planning area.⁴¹

In 2008, amid the record increase in energy prices and the political dynamics of a presidential election year, President George W. Bush ended all executive withdrawals on OCS territory and Congress allowed its moratoria to expire, though the Eastern Gulf region remained restricted by statute.⁴² In January of 2009, in an effort to set forward a plan for developing newly available OCS regions, the Bush Administration's Interior Department released a Draft Proposed Program (DPP) outlining a possible revised Five Year Plan covering the period from 2010 to 2015.⁴³ The DPP was designed to replace the existing program—which covered the period from 2007 to 2012—with a plan to conduct 31 lease sales between 2010 and 2015, including 5 in the Atlantic region, 3 in the Pacific region, 9 in Alaska, and 3 in the Eastern Gulf of Mexico, assuming Congress lifted its statutory ban (a prospect that seemed eminently possible throughout 2009).⁴⁴

Upon entering office, and before it could fully evaluate the Bush DPP, the Obama administration was confronted with a series of critical issues with respect to offshore oil and gas development.

36 DOI, BOEM, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources on the Nation's Outer Continental Shelf," 2011

37 Id.

38 See, e.g., DOI, BOEM, "Atlantic OCS, Proposed Geological and Geophysical Activities," Mid-Atlantic and South Atlantic Planning Areas, Draft PEIS, Volume 1, Chapters 1–8, 2012, at vii

39 DOI, Minerals Management Service (MMS), "Oil and Gas Resources in OCS areas unavailable for development," 2007

40 DOE, EIA, Office of Oil and Gas, "Overview of U.S. Legislation and Regulations Affecting Offshore Natural Gas and Oil Activity," 2005, at 11

41 Curry L. Hagerty, "Outer Continental Shelf Moratoria on Oil and Gas Development," CRS, March 23, 2011, at 7

42 Id., at 2

43 DOI, MMS, "Draft Proposed Outer Continental Shelf Oil and Gas Leasing Program 2010–2015," January 2009

44 Id., at 6

Most notably, on April 17, 2009, the Federal Appeals Court for the District of Columbia “vacated and remanded” the existing 2007–2012 Five Year Plan in a suit that challenged the adequacy of Environmental Impact Statements (EIS) conducted for certain leases in the plan.⁴⁵ The court’s decision required Interior to correct the EIS deficiencies and “rebalance the timing and location of the leasing program so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.”⁴⁶

Nearly one year later, on March 31, 2010, the Obama administration announced its plans for addressing the Appeals Court decision on the 2007–2012 Five Year Plan and for moving ahead with a new Five Year Plan. Interior announced that it would cancel the four remaining 2007–2012 lease sales off the North Slope of Alaska in the Beaufort and Chukchi Seas.⁴⁷ The president also issued a memorandum banning leasing in the Bristol Bay area of the North Aleutian Basin until June 30, 2017.⁴⁸ The Revised Program retained the two special interest sales in the Cook Inlet offshore Alaska. Planning for a sale off the coast of Virginia scheduled for 2011 was expected to continue.

Finally, President Obama announced that the Bush administration DPP was being discarded. The Revised 2007–2012 Five Year Plan would remain in effect through its expiration. It was determined that the next Five Year OCS Plan would come into place on the regular scheduled date in June 2012 and run through 2017. The administration announced that the 2012–2017 plan would not include any areas in federal waters off the Pacific Coast, and that Atlantic OCS areas would only be included pending the results of environmental analysis. The administration further indicated that it would consider lease sales in the southwest corner of the Eastern Gulf of Mexico—no closer to Florida than 125 miles—assuming Congress lifted the existing ban.⁴⁹ Interior would evaluate continued leasing off the North Slope of Alaska in the Beaufort and Chukchi Seas as part of future plans.⁵⁰

The *Deepwater Horizon* oil spill occurred less than two weeks after the Obama Administration’s announcements. In its aftermath, the administration significantly altered its proposed offshore development plans. With respect to the 2007–2012 Plan, Lease Sale 220 off the coast of Virginia was cancelled in May of 2010.⁵¹ Regarding the forthcoming 2012–2017 Plan, Interior announced in December 2010 that it was scaling back the OCS regions being considered for leasing, withdrawing the mid- and south-Atlantic as well as Eastern Gulf planning areas from the scoping process.⁵²

In mid-2012, Interior finalized its Five Year Plan for the 2012–2017 period. The plan contains 15 total sales: annual sales in the Western and Central Gulf of Mexico, two sales in the non-moratorium areas of the Eastern Gulf, and three potential sales off the coast of Alaska in 2016 and 2017. It does not contain sales in the Atlantic, Pacific or Eastern Gulf planning areas of the OCS, essentially taking almost 20 billion barrels of oil and 60 tcf of natural gas off the table for development. It is important to note that this is occurring despite strong state-level support in some cases, most notably in the mid-Atlantic region.⁵³ It is true that, in an effort to lay the foundation for the possibility of mid-Atlantic leasing after 2017, Interior is currently finalizing a Programmatic EIS for the first seismic inventory activity in the Mid-Atlantic OCS since the 1970s.⁵⁴ Yet, in the absence of any clear indication of potential leasing activity in the near future—and therefore likely commercial interest—it is unclear why any private geophysical contractor would expend the resources necessary to conduct such activity.

45 United States Court of Appeals, District of Columbia, Opinion No. 07-1247, at 3

46 Id., at 34–35

47 DOI, “Secretary Salazar Announces Comprehensive Strategy for Offshore Oil and Gas Development and Exploration,” March 31, 2010, available at http://www.doi.gov/news/pressreleases/2010_03_31_release.cfm

48 Id.

49 DOI, “Notice of Intent to Prepare and Scope an Environmental Impact Statement for the OCS Oil and Gas Leasing Program for 2012–2017,” at 2, available at <http://www.doi.gov/whatwedo/energy/ocs/upload/Scoping-For-5yr-Leasing-Program-on-OCS-2012-2017.pdf>

50 Id.

51 DOI, “Salazar Calls for New Safety Measures for Offshore Oil and Gas Operations; Orders Six Month Moratorium on Deepwater Drilling; Cancels Western Gulf and Virginia Lease Sales, Suspends Arctic Drilling,” May 27, 2010, available at <http://www.doi.gov/news/pressreleases/Salazar-Calls-for-New-Safety-Measures-for-Offshore-Oil-and-Gas-Operations-Orders-Six-Month-Moratorium-on-Deepwater-Drilling.cfm>

52 Oil and Gas Financial Journal, “Update: Salazar announces revised OCS leasing program,” December 1, 2010

53 Matthew V. Veazey, “Offshore Drilling a Purple Issue in Swing State Virginia,” *Rigzone*, October 5, 2012

54 DOI, BOEM, Atlantic Geological and Geophysical Activities PEIS, available at <http://www.boem.gov/oil-and-gas-energy-program/GOMR/GandG.aspx>

Comparison of Recent OCS Planning Documents

FIGURE 4I

Proposed Lease Sales	Bush 2010-2015 DPP 2009	Obama 2012-2017 Comp. Strategy (March 2010)	Obama 2012-2017 Comp. Strategy (December 2010)	Obama 2012-2017 Final Program (2012)
North Atlantic	1	Not Scoped	Not Scoped	0
Mid Atlantic	3	Scoped	Not Scoped	0
South Atlantic	1	Scoped	Not Scoped	0
Washington/Oregon	0	Not Scoped	Not Scoped	0
Northern California	1	Not Scoped	Not Scoped	0
Central California	0	Not Scoped	Not Scoped	0
Southern California	2	Not Scoped	Not Scoped	0
Western Gulf	5	Scoped	Scoped	5
Central Gulf	6	Scoped	Scoped	5
Eastern Gulf	3	Fully Scoped	Moratorium Area Not Scoped	2*
Beaufort Sea	2	Scoped	Scoped	1
Chukchi Sea	3	Scoped	Scoped	1
Cook Inlet	2	Scoped	Scoped	1
North Aleutian Basin	2	Withdrawn	Withdrawn	0
Total	31			15

* Not in the moratorium areas

Source: DOI

While it remains critical to balance environmental preservation and energy extraction, Interior's current approach falls short of striking such a balance. Operating in the wake of a serious industry failure, DOI has essentially locked the nation into a Gulf-centric approach to offshore development that unnecessarily constrains access to potentially promising resources elsewhere. This should be revised through a two-step process that allows for greater access while promoting the highest levels of environmental protection and giving greater input to coastal states.

Step One

Congress should require the Department of Interior to develop a revised Five Year Plan covering the period 2015 to 2020. In order to determine the areas made available in such a plan, eligible coastal state legislatures should have the opportunity to opt into the program. Eligibility should extend to any coastal state with an approved Coastal Zone Management Plan in place. States that opt in should have their portion of their OCS planning areas—as determined by State Administrative Boundaries—included for at least one lease sale in the revised 2015–2020 Five Year Plan.

Step Two

The Council remains convinced that OCS access should be guided to a greater degree by an oversight process that measures companies' environmental performance. To this end, Interior should establish a set of safety performance metrics for the industry that cover a range of indicators, including spills, discharges of chemicals and other materials, and inspection violations. Individual companies that fall below a specified minimum performance rating should be ineligible to bid on new leases until they regain compliance.

There are two additional issues that will arise from this approach that must be noted here. First, opponents of offshore development will suggest that opening new areas to development within the 2015 to 2020 timeframe is too soon. From a practical standpoint, however, we note that this timeframe will provide Interior two full years in advance of the plan to work through the necessary environmental impact statements for development in new areas being incorporated into the plan. Furthermore, if deemed appropriate, leasing in controversial areas could easily be set for a date later in the 2015–2020 period in order to provide Interior with adequate review time.

Second, areas of the Mid-Atlantic most likely to receive state-level support, particularly off the coast of Virginia, currently experience a high level of military traffic, which some have said would be compromised by drilling activity in the area. The members of the Council are uniquely qualified to comment on this issue. In fact, it is not a new concern, and it is not unique to the Mid-Atlantic region. In 2008 and 2009, the Council evaluated the issue in great detail with respect to the Eastern Gulf of Mexico.⁵⁵ In the case of Virginia—as in the case of the Eastern Gulf—energy development simply requires a high level of coordination between the career professionals at the Departments of Defense and Interior. Indeed, this coordination is already supported by an existing memorandum of understanding between DOI and DOD, and it is clearly built into the underlying statutory framework covering offshore oil and gas development, most notably the Outer Continental Shelf Lands Act of 1953 (OCSLA).

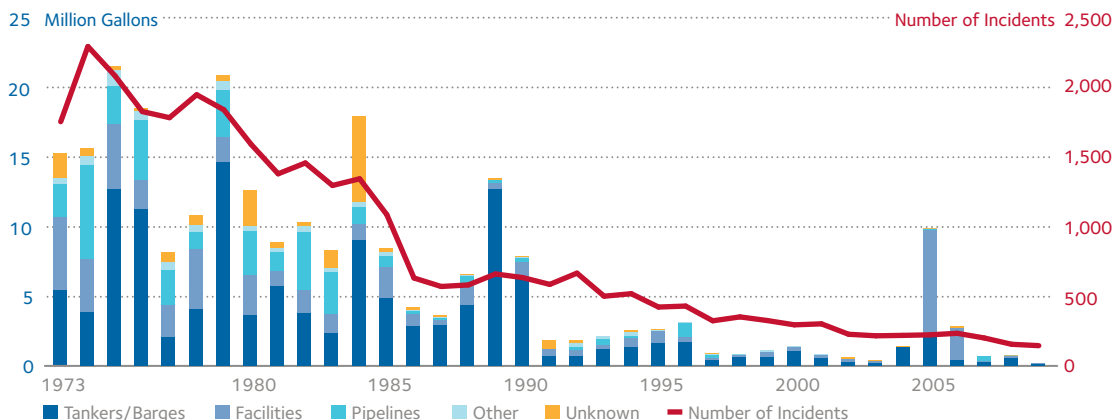
Section 12 of OCSLA specifically states, “the United States reserves and retains the right to designate by and through the Secretary of Defense, with the approval of the President, as areas restricted from exploration and operation that part of the outer Continental Shelf needed for national defense.” Section 5 of the Act, which deals with administration of leasing on the Outer Continental Shelf, states that “cancellation [of leasing] may occur at any time, if the Secretary determines, after a hearing, that continued activity pursuant to such lease or permit would probably cause serious harm or damage to ... the national security or defense.” Our proposal here in no way removes or modifies this authority.

Finally, the fact is that the industry can produce oil from offshore regions in a safe manner. The *Deepwater Horizon* disaster has largely overshadowed two decades of remarkable progress in reducing oil spills due to offshore development. According to the Department of Interior, the offshore oil and gas industry produced 10.2 billion barrels of oil between 1985 and 2007 with a spill rate of just .001 percent.⁵⁶ In fact, between 1990 and 1999, nearly two-thirds of the oil that entered North American coastal waters came from natural seeps, with only 5 percent coming from oil extraction and transportation.⁵⁷

The turbulent 2005 Atlantic hurricane season—when Hurricanes Katrina and Rita tore through the Gulf of Mexico—was in some ways a demonstration of the industry’s capabilities. Approximately 75 percent of the 4,000 federal OCS oil and gas facilities in the Gulf of Mexico were subjected to 175 mile-per-hour winds and other hurricane conditions. Despite serious damage to 168 platforms, 55 rigs, and more than 560 pipeline segments, the U.S. Coast Guard and Department of Interior reported no major oil spills in federal OCS waters.⁵⁸

FIGURE 42

U.S. Annual Volume and Number of Oil Spills from Selected Sources, 1973–2009



Source: USCG

55 SAFE, “Eastern Gulf of Mexico Oil and Gas Exploration and Military Readiness,” (2010), available at http://www.secureenergy.org/sites/default/files/1103_FinalEasternGulfPaper.pdf

56 SAFE Analysis; DOI, MMS, “Spills: Statistics and summaries,” available at <http://www.boemre.gov/incidents/spills1964-1995.htm>

57 CRS, “Oil spills in U.S. coastal waters: background, governance, and issues for Congress,” August 2007, at 30

58 The Coast Guard defines “major spills” as those in excess of 2,400 barrels.

COROLLARY RECOMMENDATION

Extend Outer Continental Shelf revenue sharing to all coastal states.

Industry development of federal resources in the Outer Continental Shelf generates significant revenue for the U.S. treasury. Adjusted for inflation, OCS oil and natural gas development has produced a total of \$450 billion in auction (bonus bid), rental, and royalty revenues since 1953, making it a significant source of federal revenue.⁵⁹

Coastal states have not historically shared in federal OCS revenues. The OCS Lands Act allotted states 27 percent of federal revenue from leases within 3 nautical miles of their seaward boundaries, but these revenues were equal to less than 4 percent of total federal OCS revenues in FY 2011.⁶⁰ In general, this approach to revenue allotment has been based on the notion that oil beneath federal waters is the property of the entire United States and that, therefore, revenues should generally benefit all taxpayers. This delineation between federal and coastal state jurisdiction did not become entrenched in U.S. law until 1953 with the passage of the Submerged Lands Act, which settled nearly

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Federal Revenues from Offshore Oil and Gas Activity

The federal government derives significant revenue from the development of OCS oil and gas resources. In general, these revenue streams fall into three specific categories: bonus bids, lease rental payments, and production royalties.

Bonus Bid Revenues are generated as part of the initial leasing process, which is essentially an auction. Individual companies submit sealed bids for eligible lease tracts as part of a particular sale, and the lease is awarded to the highest bidder as long as the bid meets a minimum 'fair value' threshold. Companies are required to submit one-fifth of any bid for a lease tract up front at the time of the bid and pay the remaining four-fifths balance and their first year rental payment after acquiring a lease.

Lease Rental Payments begin once a lease is awarded. Payments are set on a per-acre basis and are determined by water depth and lease vintage. Current primary lease terms range from five to ten years depending on water depth with three-year extensions available in some cases where activity is underway at the date of expiry. Rental rates range from as low as \$7 to as high as \$44 per acre.

Production Royalties must be paid to Interior when leases on federal lands begin to produce oil and/or natural gas. The amount paid is defined by a percentage applied to the fair-market value of the commodity produced. Though the applied royalty rate has varied over time based on policy goals and industry activity, the current royalty rate for all OCS leases is 18.75 percent.

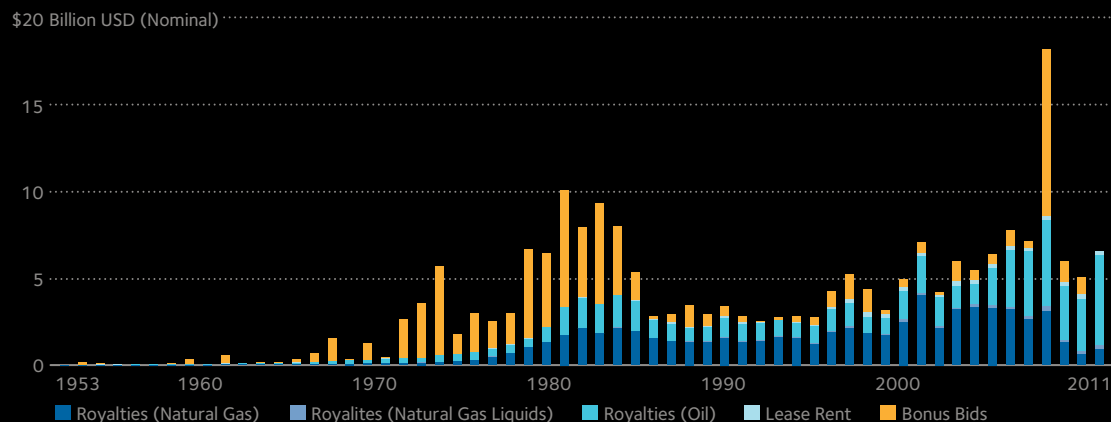
Though the aggregate total of federal OCS revenues over time is quite large, annual sums can vary widely depending on market conditions. Bonus bids are a function of the level of industry interest in the areas offered for lease, which is generally correlated with oil prices and lease prospectiveness. Rental revenues are a function of the number and type of tracts under lease and the rental rate. Royalties are typically a function of the level of production, the royalty rate, and the oil price.

59 SAFE analysis based on data from: DOI, Office of Natural Resource Revenue (ONRR)

60 Id.

FIGURE 43

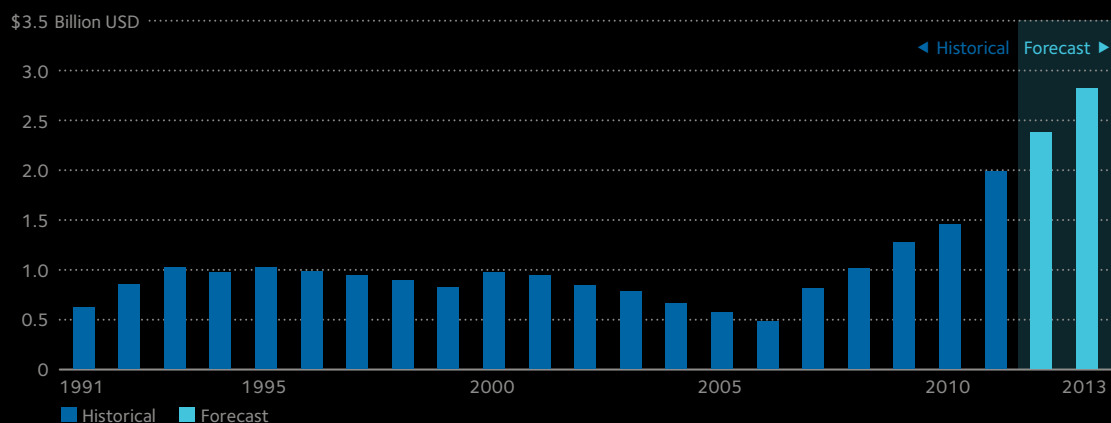
Federal Royalties Collected from Outer Continental Shelf Activities



Source: DOI, ONRR

FIGURE 44

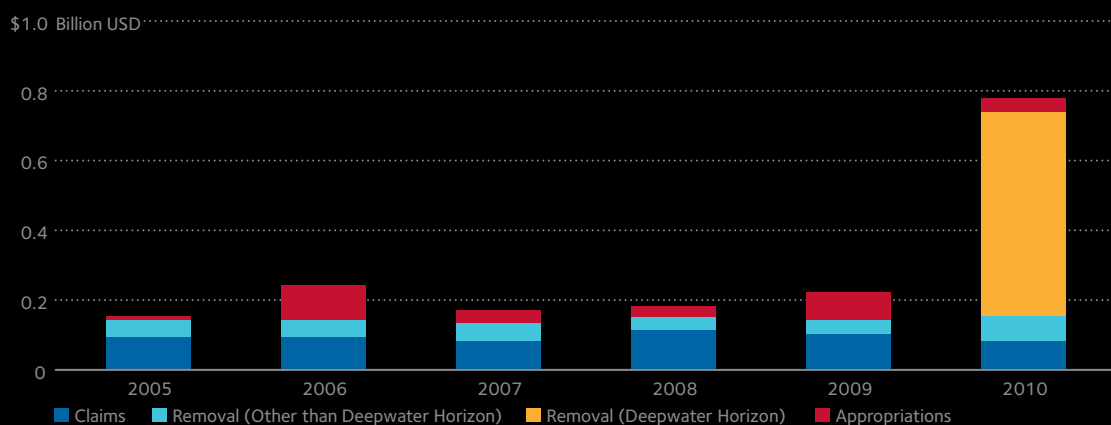
Oil Spill Liability Trust Fund, Year-End Balance



Source: Government Printing Office, Budget of the President, FY 1993-2013

FIGURE 45

Oil Spill Liability Trust Fund Expenditures



Source: USCG

a decade of wrangling between the federal government and the states of California, Texas, and Louisiana over OCS jurisdiction.⁶¹

The Gulf of Mexico Energy Security Act of 2006 represented the first significant shift in federal policy regarding revenue sharing since 1953. Specifically, GOMESA stipulated that 37.5 percent of all royalty, rent, and bonus revenues from Gulf of Mexico leases developed after 2016 be apportioned according to a formula to the states of Texas, Louisiana, Alabama, and Mississippi. In doing so, GOMESA recognized that offshore development has meaningful impacts on coastal state infrastructure and ecology, and that states should be granted a share of development revenues to deal with these issues.

Revenue sharing could represent a significant incentive for states to support OCS development in frontier areas like the Alaskan, Atlantic, and Pacific OCS. It is certainly the case that the offshore industry can bring capital investment, direct and indirect jobs, increased tax revenue, and other economic benefits to states where significant activity takes place. However many of these benefits are fairly uncertain in nature, and some coastal states are unlikely to be supportive of offshore development in the absence of clear benefits that can be compared to expected costs.

In order to provide clear incentives for coastal states to opt into future OCS development plans, revenue sharing should be extended to all coastal states that participate in OCS development. Given the existence of the agreed upon disbursement share and formula approach set forward in GOMESA, it would be reasonable to extend this formula to other OCS regions, with participating states deriving a share of all revenues generated by leases included in a revised 2015–2020 Five Year Plan and going forward. Where multiple participating coastal states border an OCS region under active development, individual apportionments should be determined by distance from the lease; this is consistent with the approach set forth by GOMESA.

COROLLARY RECOMMENDATION

Revise the liability limits and financial responsibility requirements set forth in the Oil Pollution Act of 1990 to reflect current economic and financial realities.

The United States suffered the worst oil tanker accident in its history in 1989, when a single-hulled tanker known as the Exxon Valdez ran aground on Bligh Reef in Prince William Sound, Alaska. The spill resulted in the discharge of between 260,000 and 750,000 barrels of crude oil.⁶² The number and gravity of safety violations were so high that the accident resulted in a series of legislative reforms, most notably the Oil Pollution Act of 1990 (OPA).⁶³

Among its most important provisions, OPA set forward liability limits for spills associated with a range of oil- and gas-related activities. The liability limit for onshore facilities was set at \$350 million. The limit for deepwater ports was initially also set at \$350 million, but the law allowed presidential discretion to lower the limit, and it currently sits at \$87 million. Vessel liability limits vary depending on the type of ship and its size, and range from \$1,000 per gross ton to \$3,200 per gross ton, which places the absolute limit for a medium-sized, double-hulled very large crude carrier (VLCC) at roughly \$200 million. Finally, for offshore facilities, such as drilling rigs, OPA set unlimited liability related to clean-up costs and a \$75 million limit with respect to natural resource damages and indirect economic costs of an offshore spill.⁶⁴

61 National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, "Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling," 2011, at 58

62 Jonathan L. Ramseur, "Oil Spills in U.S. Coastal Waters: Background and Governance," CRS, September 2, 2010

63 Id., at 10–12

64 Jonathan L. Ramseur, "Liability and Compensation Issues Raised by the 2010 Gulf Oil Spill," CRS, March 11, 2011

In order to ensure that operators would be capable of managing a significant portion of their liability limit, OPA also stipulated that offshore facilities and vessels be able to demonstrate financial responsibility through insurance coverage or sufficiently deep financial statements.⁶⁵ For vessels, the financial responsibility requirements were matched directly to the liability limits. An oil tanker operating in U.S. waters must demonstrate that it can meet its maximum liability limit in the event of a spill. Because offshore facilities have separate liability limits for oil spill removal and indirect costs, financial responsibility requirements are somewhat unique and vary based on an assessment of “worst case discharge.”⁶⁶ A facility with a worst case discharge of between 1,000 and 35,000 barrels of oil must demonstrate financial responsibility of \$35 million. A facility with a worst case discharge of 105,000 barrels must demonstrate financial responsibility of \$150 million.⁶⁷

Finally, OPA created the Oil Spill Liability Trust Fund, administered by the U.S. Coast Guard and designed to provide a federal backstop against oil spill costs and economic damages that exceeded a responsible party’s willingness or ability to pay.⁶⁸ The Act stipulated that the Fund be supported by a 5 cent per barrel tax on domestic and imported oil. Though the tax was allowed to lapse between 1994 and 2005, the Energy Policy Act of 2005 restored it effective April of 2006, and the Energy Improvement and Extension Act of 2008 extended it to 2016 at a rate of 8 cents per barrel and 2017 at a rate of 9 cents per barrel.⁶⁹ According to its most recent annual report, the Coast Guard expects the Fund to average \$2.4 billion in FY 2012.⁷⁰ The fund’s ability to make payments is limited to \$1 billion per incident.⁷¹

The *Deepwater Horizon* incident revealed a number of potential shortfalls associated with the current system for managing the financial and economic risk associated with low-probability, high-impact accidents in the federal OCS. For example, BP has gone well beyond its statutory requirements in terms of financial compensation associated with indirect natural resource and economic costs. While its liability limit for indirect costs associated with the Macondo incident was ostensibly \$75 million, BP has reportedly already paid claims totaling \$8.1 billion.⁷² These payments are in addition to the company’s \$14 billion in clean-up costs, for which it is subject to unlimited liability.⁷³ Though the Oil Spill Liability Trust Fund made an estimated \$600 million in payments in FY 2010 associated with the Gulf oil spill, BP fully reimbursed the Fund for these outlays.⁷⁴

BP confronted the spill at a time when its annual operations were generating nearly \$30 billion in cash.

It is worth noting that BP was arguably among a small handful of companies capable of so thoroughly and comprehensively meeting a wide range of financial obligations arising from the Gulf spill. As one of the largest oil companies in the world, BP confronted the spill at a time when its annual operations were generating nearly \$30 billion in cash, its global resource base exceeded 60 billion barrels of oil equivalent, and annual production exceeded 4.0 mbd

of oil equivalent.⁷⁵ Even still, to secure its ability to comfortably meet spill responsibilities, BP initiated an ambitious program of asset disposals which has netted the company \$26.5 billion in additional cash since 2010.⁷⁶ Had the *Deepwater Horizon* incident occurred under the primary responsibility of a significantly smaller, less financially robust company, Gulf restoration efforts could have been substantially more difficult and come at the direct expense of American taxpayers.

65 Id., at 6–7

66 30 CFR, 253–254

67 Id.

68 U.S. Coast Guard, Oil Pollution Act Liability Limits in 2011: FY 201 Report to Congress, May 3, 2012, at 2

69 U.S. Coast Guard, National Pollution Funds Center, at http://www.uscg.mil/npfc/About_NPFC/osltf.asp

70 U.S. Coast Guard, Oil Pollution Act Liability Limits in 2011: FY 201 Report to Congress, May 3, 2012, at 11

71 Ramseur, 2011

72 BP, plc., BP’s Financial Commitment: The Gulf Response, at <http://www.bpgulfupdate.com/go/doc/4699/1332115/>

73 Id.

74 Ramseur, 2011, at 11

75 BP, plc., 2010 Results and Investor Update, at 18 and 33

76 Jonathan Russell, “BP offloads \$2.5 billion in assets to pay for spill,” The Telegraph, August 14, 2012

The oil and natural gas industry has done much to increase its preparedness for future offshore oil spills since the *Deepwater Horizon* oil spill. The formation of entities such as the Marine Well Containment Company (MWCC), the Helix Energy Solutions Group (HESG), and the Subsea Well Response Project (SWRP) should give regulators and political leaders greater confidence that the industry is prepared to quickly and successfully deal with a subsea blowout at a variety of depths, in a variety of locations, and at high flow rates.⁷⁷ However, the statutory framework dealing with liability and financial responsibility remains insufficient, with numerous components of the code remaining unchanged since 1990. A wide range of governmental, non-governmental, and academic entities have argued that the current system requires updating.⁷⁸

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The oil spill liability and financial responsibility limits set forth in OPA must be revised, specifically with respect to offshore facilities and indirect costs associated with a spill. The current figure of \$75 million is not only too low, it also in no way reflects the varied levels of risk associated with operations conducted at different water depths or in different OCS environments. First, the maximum liability and financial responsibility requirements should be made equal to each other to ensure that only companies fully capable of meeting their obligations operate in the federal OCS. Second, liability levels for indirect spill costs should be increased and structured to reflect project risk. Such a framework could be informed by a range of factors, including water depth, drilling depth, and type of equipment used.

The Council makes this recommendation cognizant of concerns raised by some in industry that the insurance market is not capable of offering sufficient coverage or that higher liability and responsibility limits will disadvantage independent oil and gas companies at the expense of larger, international oil companies. On the first point, it is important to note that large global insurers have come forward with product offerings in the wake of Macondo. For example, in September of 2010, insurer Munich Re announced its willingness to provide up to \$2 billion in coverage related to “clean-up and removal costs, impairment of natural resources and property damage, as well as loss of earnings in sectors such as fishing or tourism.”⁷⁹

On the second point, it is clearly the case that the U.S. independent oil and gas companies are a critical stakeholder in offshore oil and gas operations. These companies currently account for 45 percent of U.S. offshore oil production, and policy that unduly burdens or effectively excludes such companies from future OCS development would have a negative impact on U.S. energy security. However, the industry has numerous options for ensuring that higher liability and financial responsibility requirements—particularly those associated with deep and ultra deepwater operations—do not become a financially restrictive requirement. In addition to traditional private insurance coverage, the concept of pooled financial risk among a number of operators stands out as an attractive possibility. Similar to the concept of shared responsibility exemplified by the MWCC, HESG, and SWRP, industry should strongly consider developing a shared liability fund seeded by offshore operators and capable of meeting financial claims associated with an incident similar to the *Deepwater Horizon* oil spill.

COROLLARY RECOMMENDATION

Increase funding for the Department of Interior to offer competitive pay in order to engage with operators on equal footing.

As the offshore oil and natural gas industry has grown in complexity, the need for a sophisticated regulator with a thorough understanding of current technologies has become increasingly apparent. In

77 See, e.g., MWCC Interim System Overview at http://marinewellcontainment.com/interim_system.php; and HESG Spill Containment at: <http://www.helixesg.com/HFRS/>

78 See, e.g., Nicolas Loris, Jack Spencer, and Dr. James Carafanao, “Oil Spill Liability, A Plan for Reform,” The Heritage Foundation, August 2, 2010; National Petroleum Council, Offshore Operations Subgroup, “Safe and Sustainable Offshore Operations,” background paper for Prudent Development: Realizing the Potential of North America’s Abundant Natural Gas and Oil Resources, September 15, 2011; and Jonathan L. Ramseur, “Liability and Compensation Issues Raised by the 2010 Gulf Oil Spill,” CRS, March 11, 2011

79 Munich Re, at http://www.munichre.com/en/media_relations/press_releases/2010/2010_09_12_press_release.aspx

the aftermath of the Deepwater Horizon incident, the Department of Interior was criticized not only for inadequate procedures, organizational structure, and inspection levels, but also for failing to secure senior petroleum engineers and other scientists with a firm understanding of trends and technologies in the offshore industry.⁸⁰

While Interior's previous shortcomings had roots in a number of issues, one particular area of concern focused on Interior's inability to offer competitive compensation levels to its staff, particularly vis-à-vis the oil and natural gas industry. According to the Bureau of Labor Statistics, the median annual salary for a petroleum engineer in the United States was \$135,260 in 2011.⁸¹ The median for geoscientists was \$129,450. These salaries are beyond the scope of the federal government's General Schedule (GS) pay system, which applies to non-executive level federal employees.⁸² In other words, the median petroleum engineer in the private sector earned substantially more than the federal government was capable of paying even the most senior non-executive employees. Generally speaking, the higher salaries offered by the private sector historically ensured that it secured the best talent in the industry.

In 2011, Congress took action designed to at least partially address this issue. The fiscal year (FY) 2012 Omnibus Appropriations bill provided Interior with the flexibility to establish higher minimum rates of pay for its petroleum engineers, geophysicists, and geologists stationed in the Gulf of Mexico.⁸³ As a result, the Bureau of Safety and Environmental Enforcement and the Bureau of Ocean Energy Management were able to offer selected non-executive employees special pay rates up to 25 percent higher than the base salary levels specified by their existing GS rate.⁸⁴ Interior was given the flexibility to make decisions about base pay increases through the end of FY 2013, and selected employees were guaranteed that their increased rate of pay would remain in effect going forward.⁸⁵

It is important that federal regulators be given the ability to increase their scope and capabilities, particularly if new areas of the OCS are to be made available for development. The Department of Interior must have the budget and flexibility to attract and retain the same quality of engineering talent as the industry does, and it must be able to do so wherever and whenever development is occurring. With an eye fostering the establishment of the most sophisticated regulatory entity possible, Congress should permanently expand Interior's increased pay authority to all regions of the OCS and adequately fund the agency's personnel requirements. Moreover, any increases in employee pay should be in addition to adjusted salary, not base pay. One shortcoming of the current fix is that, by offering increases to base pay only, employees in areas with higher locality-based salary adjustments—such as Houston—were effectively ineligible for a pay increase.

COROLLARY RECOMMENDATION

Facilitate limited development of the Arctic National Wildlife Refuge using extended reach drilling and strict surface occupancy restrictions.

The United States possesses significant reserves in onshore federal lands which are also not available for production. The Energy Policy and Conservation Act of 2000 directed the Department of Interior to conduct a comprehensive review of all onshore oil and gas resources and to identify the impediments to their development. In 2008, a multi-agency process that integrated analyses from

80 See, e.g., "Leslie Eaton, Stephen Power, and Russell Gold, "Inspectors Adrift in Rig-Safety Push, Outgunned by Industry and Outmatched by Job, Agency Lags," Wall Street Journal, December 3, 2010; and Matthew Daly, "Obama Should Increase Offshore Drilling Inspectors, Surprise Inspections: Interior Department IG Report," December 7, 2010

81 U.S. Bureau of Labor Statistics, Industries at a Glance: Oil and Gas Extraction

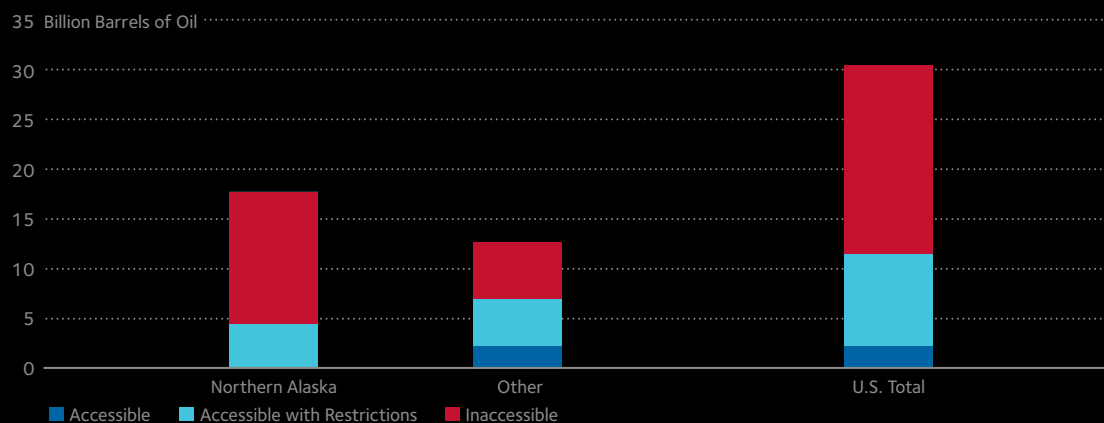
82 U.S. Office of Personnel Management, General Schedule Locality Pay Tables, 2011

83 Consolidated Appropriations Act of 2012, P.L. 112-74, Section 121, Part (c)

84 See, BOEM fact sheet, available at http://www.boem.gov/uploadedFiles/BOEM/About_BOEM/Jobs/FAQs_BOEM-PayTables.pdf

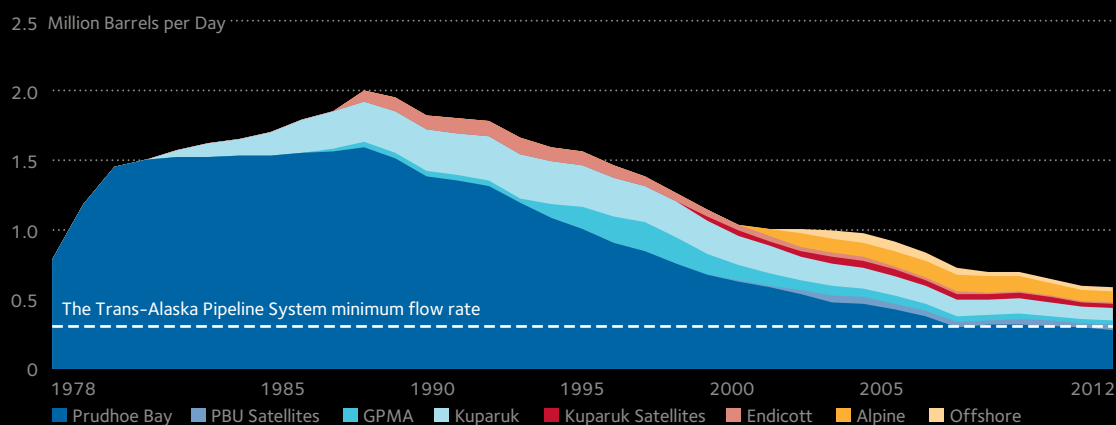
85 DOI, available at http://www.boem.gov/uploadedFiles/BOEM/About_BOEM/Jobs/FAQs_BOEM-PayTables.pdf

Oil Resources on U.S. Federal Lands



Source: DOI

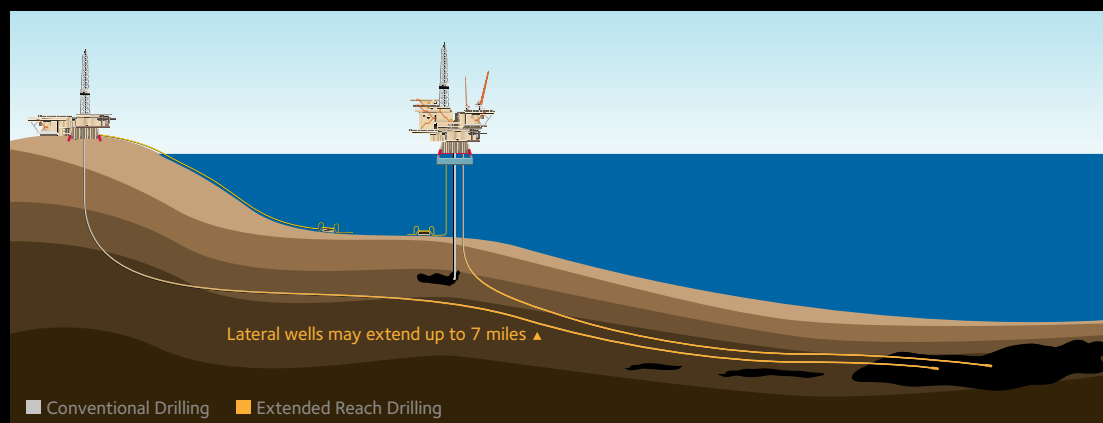
Alaska North Slope Crude Production



Note: Data is for Fiscal Year.

Source: Alaska Department of Revenue

Extended Reach Drilling



Source: SAFE analysis

FIGURE 46

FIGURE 47

FIGURE 48

the Departments of Interior, Energy, and Agriculture, as well as the Environmental Protection Agency, produced an inventory of the entire onshore United States.⁸⁶ The study estimated total UTRR beneath federal lands to be approximately 30.1 billion barrels of oil and 230.1 trillion cubic feet of natural gas.⁸⁷ Of these totals, 62 percent of the oil and 41 percent of natural gas resources were fully inaccessible due to regulatory restrictions.⁸⁸

Many of the reserves surveyed by the federal government coincide with ecosystems and natural geological structures of tremendous scientific and national importance. Nonetheless, certain onshore areas likely possess large quantities of conventional resources. In particular, of all the areas surveyed, Northern Alaska is notable for possessing extremely large resources in a relatively confined space. While off-limits lands in the Northern Alaska Study Area represent just 11 percent of the fully inaccessible federal territory, these lands hold more than two-thirds of the inaccessible onshore UTRR oil resources (13.3 billion barrels).⁸⁹

Historically, crude oil production from the accessible areas of Alaska's North Slope (ANS) has played an important role in overall U.S. output. Production began in the late 1970s and peaked in 1988 at more than 2.0 mbd, much of this from the mammoth Prudhoe Bay oil field, which had estimated oil in place of at least 25 billion barrels and has yielded cumulative production of approximately 14 billion barrels.⁹⁰ As Prudhoe Bay has gone into natural decline, and potential replacement resources have been held off-limits, total ANS crude oil production has quickly trended downward. In fact, production fell below 600,000 b/d in State Fiscal Year 2012, a level many view as uncomfortably close to the minimal operational threshold for the Trans-Alaska Pipeline, which is estimated to be roughly 300,000 b/d.⁹¹

Opening limited areas of Northern Alaska to oil and natural gas production could reverse this trend. Specifically, of the 13.3 billion barrels of technically recoverable federally restricted oil in the Northern Alaska Survey Area, 7.7 billion barrels fall within the federal portion of the 1002 Area of the Arctic National Wildlife Refuge (ANWR).⁹² An additional 2.7 billion barrels are on state and native lands within ANWR's 1002 Area.⁹³ While the full Refuge covers approximately 19 million acres, including 9 million acres designated as wilderness, the 1002 area covers just 1.5 million acres of coastal plain—or approximately 8 percent of the Refuge.⁹⁴ This land was set aside in the Alaska National Interest Lands Conservation Act of 1980 for the expressed purpose of further resource evaluation, including oil and gas potential.⁹⁵ It is considered highly prospective due to its proximity to other significant hydrocarbon discoveries.

After decades of debate, federal protections that restrict industry development in ANWR are unlikely to be abandoned in their entirety. The cultural, environmental, and political significance of these lands are such that, even in the current energy security environment, strong opposition remains entrenched. However, recent developments may provide an opportunity for industry to leverage technology to access oil resources with a minimal footprint.

Specifically, long-range extended reach drilling (ERD) is an increasingly common technology being deployed by industry to access hydrocarbon reservoirs in remote or environmentally sensitive areas around the world. The longest such well drilled to date, measuring more than 7 miles, was completed by ExxonMobil on Russia's Sakhalin Island in 2011.⁹⁶ ERD technology was also used by BP to develop

86 U.S. Departments of Interior, Agriculture, and Energy, "Phase III Inventory: Onshore United States," 2008

87 Id., at 114

88 Id.

89 Id., at 117

90 DOE, NETL, "Alaska North Slope oil and gas: a promising future or an area in decline?" August 2007, Fig. 3.1 and Table 3.1

91 Alaska Department of Revenue, Tax Division, "Crude Oil Production History," available at <http://www.tax.alaska.gov/sourcesbook/AlaskaProduction.pdf>

92 DOE, EIA, "Analysis of Crude Oil Production in the Arctic National Wildlife Refuge," 2008, at 1

93 Id.

94 DOE, EIA, "Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, Updated Assessment," Part 1, available at http://www.eia.gov/pub/oil_gas/petroleum/analysis_publications/arctic_national_wildlife_refuge/html/overview.html

95 Id.

96 ExxonMobil, "Sakhalin-1 Project Drills World's Longest Extended Reach Well," Friday, January 28, 2011

Poole Harbor in the UK, an ecologically sensitive and archeologically important area, from a disguised onshore drilling pad.⁹⁷ Though ERD wells have typically been used to develop reservoirs in shallow coastal waters, there has been increasing interest in using this approach to access a portion of ANWR in recent years. By some estimates, an extended-reach drilling program initiated from non-federal lands adjacent to ANWR could provide access to approximately 30 percent of the resource potential and leave no above-ground footprint within the Refuge itself.⁹⁸

In fact, there is some precedent for deploying ERD technology in Alaska's North Slope. In early 2010, ExxonMobil drilled and cased its first development well on the Point Thompson project in Alaskan State lands approximately 60 miles east of Prudhoe Bay and directly adjacent to the 1002 Area of ANWR. The Point Thompson project features an onshore drilling pad with extended reach directional wells that extend 1.5 miles offshore into the Beaufort Sea.⁹⁹ First production is expected in 2016 from a reservoir containing 8 tcf of natural gas and 200 million barrels of condensate. (It is worth noting that production timelines have been subject to slippage due to repeated permitting delays. The Army Corps of Engineers, the lead federal regulatory agency for the Point Thompson project Environmental Impact Statement, issued a critical Record of Decision and construction permit in October 2012 after more than a year of delay.¹⁰⁰)

In order to facilitate limited ANWR development using ERD without changing current approaches to prohibiting surface disturbance within the federally-protected sections of the Refuge, the Department of Interior could structure leases to prohibit surface activity. Federal onshore leasing regulations stipulate a range of access categories. The most straightforward federal lands categories are either fully accessible (Leasing, Standard Lease Terms) or fully inaccessible (No Leasing). However, there are a number of incremental variations between these two ends of the spectrum, including access to lands that allows leasing and development of sub-surface resources but without surface occupancy (Leasing, No Surface Occupancy). The Bureau of Land Management describes these as "lands that can be leased, but ground-disturbing oil and natural gas exploration and development activities are prohibited." The agency further notes that, "at least some of the resources [on these lands] can be accessed by directional drilling from nearby lands where surface occupancy is allowed."¹⁰¹

In many cases, the development of a No Surface Occupancy land tract is accomplished by setting aside a portion of the protected area and designating it an Extended Drilling Zone. However, in the case of ANWR, this is unlikely to be a workable approach. Instead, the federal government should initiate a program in cooperation with the State of Alaska to use state lands and waters adjacent to ANWR as Extended Drilling Zones.

The Council is sensitive to the notion that restricting surface activity within ANWR is not, on its own, a blanket guarantee that development will leave local ecosystems—and the Refuge itself—undisturbed. Therefore, leasing under the approach described above should proceed in an extremely limited fashion, primarily through a pilot project. Cooperation between Interior and the State of Alaska should begin with a single lease sale in 2014. Within two years of initial production, Interior should produce a report detailing any successes and failures of the project, and whether to move forward with additional ERD leasing from lands adjacent to the 1002 Area.

97 BP, plc., Asset Portfolio, "Wytch Farm," available at http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_wytch_farm.pdf

98 SAFE analysis based on data from: BLM, Phase Three Inventory, at 121; and CRS, Arctic National Wildlife Refuge: A Primer for the 112th Congress, at 1-3 and 21

99 ExxonMobil, "ExxonMobil Reaches Target Depth at First Point Thompson Well," available at <http://news.exxonmobil.com/press-release/exxonmobil-reaches-target-depth-first-point-thomson-well>

100 CNBC, "Corps issues permit for Alaska's Point Thompson," October 26, 2012

101 BLM et al., at 111

PRIMARY RECOMMENDATION

Establish a federal Energy Security Trust Fund seeded with revenues from new Outer Continental Shelf and Alaskan Production.

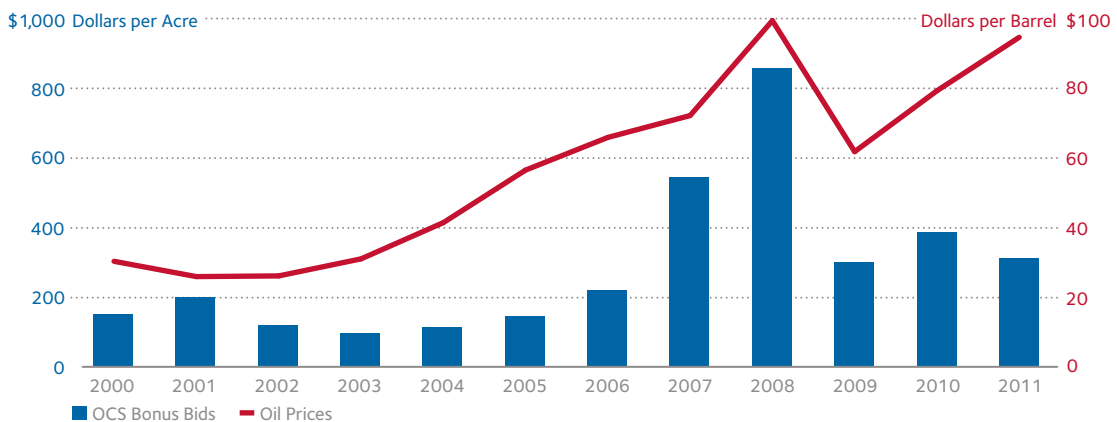
Expanded development of the federal oil and natural gas resources has the potential to make important contributions to U.S. energy security, specifically by reducing the need for crude oil imports and mitigating their effect on the U.S. trade deficit. It is important, however, to remain focused on the longer-term goal of significantly reducing the role of oil in the U.S. economy, particularly in the transportation sector. In furtherance of this goal, a portion of the revenues from any new energy development proposed by the Council should be directed into a federal Energy Security Trust Fund managed by the Department of Energy. The Fund's purpose should be strictly limited to supporting R&D programs related to oil displacement in the transportation sector.

As discussed in *Part I* of this report, commercialization of advanced-technology vehicles powered by electricity and natural gas represents a critical long-term objective with respect to U.S. energy security. The federal government has a role to play in supporting development of these technologies through R&D directed toward specific drivetrain components—such as batteries and CNG storage tanks—as well as targeted efforts focused on developing a more comprehensive approach to deployment at the community level. Federal programs such as these will require increased budget outlays at a time when new spending is being appropriately scrutinized, and budgetary offsets are effectively required.

Development of oil and natural gas resources in currently inaccessible federal territory has the potential to generate substantial income for the federal government in the form of income taxes as well as bonus, lease rental, and production royalty revenues. A 2008 study from ICF International estimated that cumulative additional federal revenues through 2030 would total \$8.1 billion from the Atlantic OCS, \$11.7 billion from the Pacific OCS, and \$8.1 billion from the East Gulf of Mexico.¹⁰² Potential revenues from ANWR development alone totaled an additional \$60 billion. Of course, such estimates are highly sensitive to oil prices. ICF's study assumed that oil prices averaged roughly \$57 per barrel in inflation-adjusted terms between 2012 and 2030.¹⁰³ A 2009 study from Advanced Resources International (ARI) assumed oil prices averaged \$111 per barrel—a level more in line with current expectations—and estimated total government revenues from development of the same OCS regions

FIGURES 49

Oil Prices and OCS Bonus Bids



Note: Data reflects bonuses collected for leased tracts only.

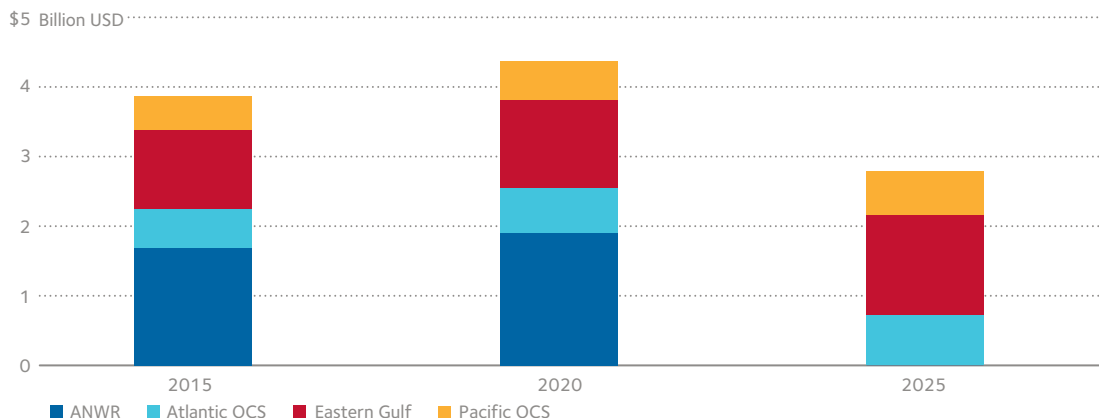
Source: DOI, BOEM; and SAFE analysis

¹⁰² ICF International, "Strengthening Our Economy: The Untapped U.S. Oil and Gas Resources," Tables 32, 36, and 36, 2008

¹⁰³ ICF's analysis was based on AEO 2008

Projected Lease Sale Revenue by Region (Assuming Immediate Availability)

FIGURES 50



Source: Wood Mackenzie, 2011

would reach nearly \$60 billion by 2025.¹⁰⁴ The ARI study did not include an assessment of economic benefits from ANWR.

It is important to note that federal royalty revenues are derived from three separate streams: bonus bids, lease payments, and production royalties. Each of these streams has the potential to generate significant revenue during the course of an individual project. However, the timing of the individual streams is typically varied, with bonus bids accounting for the earliest revenue and production royalties occurring at the time of first production, which may be a period of several years after the initial lease sale. Therefore, bonus bids are likely to play an important role in supporting the initial seeding of the Energy Security Trust Fund.

Bonus bids can be especially difficult to forecast—particularly in frontier areas—because they depend on a range of variables, including economic conditions, oil prices, the global oil outlook, expectations about geology, and individual company goals. However, a handful of recent estimates suggest that the expected revenues from lease sales in the Atlantic, Pacific, and Eastern Gulf OCS regions could be substantial. For example, a 2011 study from Wood Mackenzie estimated that annual federal bonus revenue in undeveloped regions of the OCS and ANWR would be \$3.8 billion in 2015 and \$4.3 billion in 2020.¹⁰⁵ For context, the average sale in the Gulf of Mexico OCS planning areas since 2000 has totaled nearly 1.8 million acres fetching \$299 per acre, giving a ‘typical’ high-bid sum of \$532.6 million per sale.¹⁰⁶ Were sales in other OCS regions to track closely to these figures, annual bonus revenue could average more than \$3 billion based on a rate of two sales per region.

Assuming a revised Five Year Plan is put into place covering the period from 2015 to 2020, and that the plan includes lease sales in frontier OCS regions currently unavailable for development, 50 percent of the federal share of all royalty revenue from new regions should be placed into the Energy Security Trust Fund. The maximum threshold for Fund receipts should be \$500 million annually. DOE should produce an annual report to Congress on the Fund’s programs and their level of effectiveness in supporting technologies that will directly displace petroleum consumption in the transportation sector.

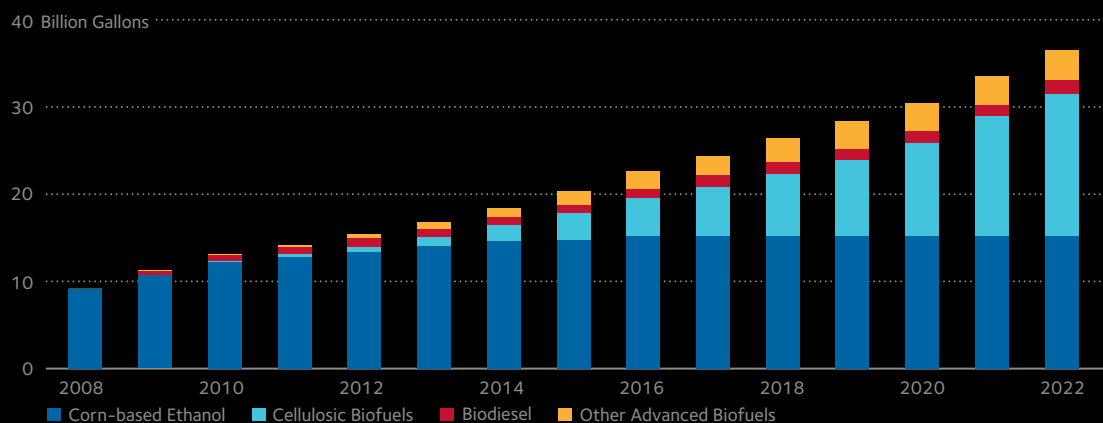
¹⁰⁴ Advanced Resources International (ARI), “Outer Continental Shelf Moratoria Areas: Impact of Various Assumptions on Oil and Natural Gas Production Potential,” at 15, 2009

¹⁰⁵ Wood Mackenzie, “U.S. Supply Forecast and Potential Jobs and Economic Impacts,” 2011, at 43

¹⁰⁶ SAFE analysis based on data from: DOI, BOEM

FIGURES 51

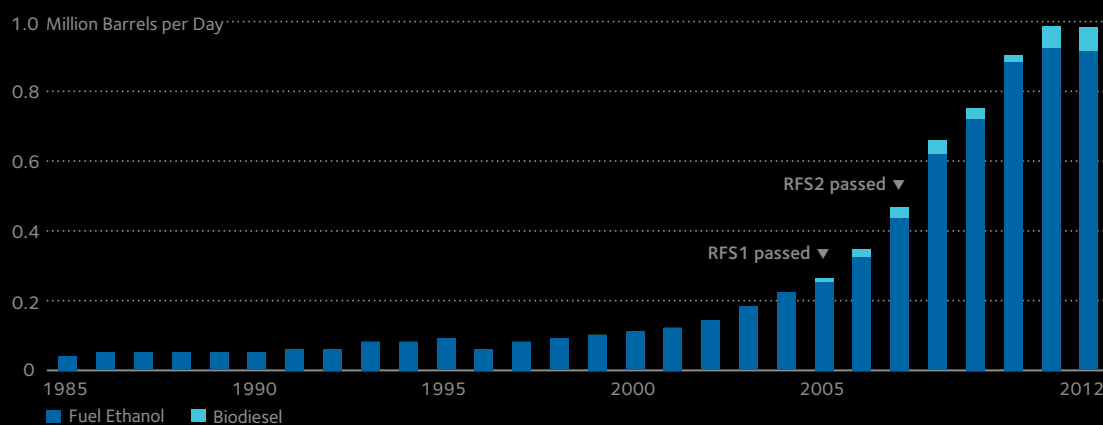
U.S. Renewable Fuel Standard



Source: EPA

FIGURES 52

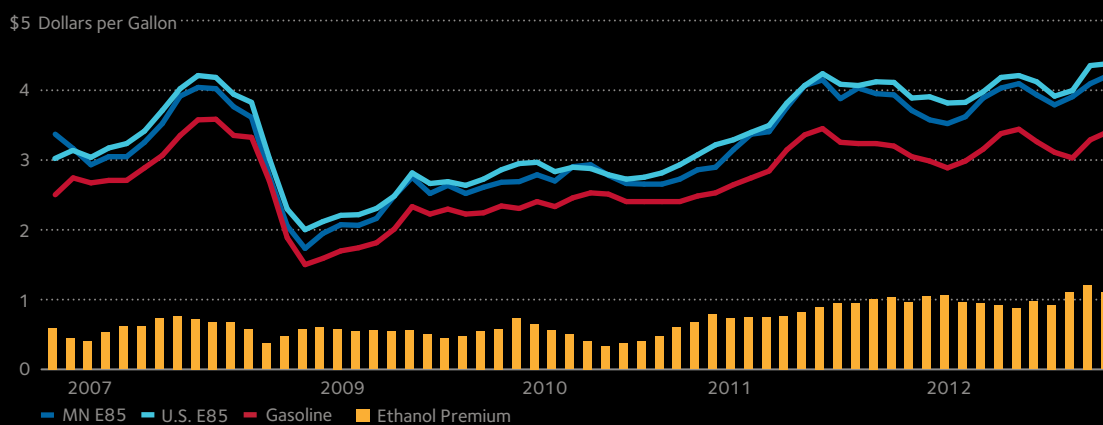
U.S. Biofuels Production, 1985-2012



Source: DOE, EIA

FIGURES 53

Gasoline and Ethanol Prices



Note: Prices are adjusted for energy content.

Source: DOE, EIA; and E85Prices.com

Unconventional Resources

While access to conventional resources is currently unavailable, federal lands and waters can still help increase domestic energy supplies in the near and medium term, it is also important to continue to support innovation in the development of unconventional and non-petroleum liquid fuels over the long term. While many such fuels are generally uneconomic or technologically-challenging to produce today, they could ultimately provide significant increases in the availability of domestic fuels. Federal policy should support ongoing research and development for the fuels of tomorrow while also allowing federal agencies to procure any alternative fuels that meet their operational needs.

PRIMARY RECOMMENDATION

Increase funding for research and development related to advanced biofuels.

While gasoline consumption in light-duty vehicles typically accounts for more than 60 percent of U.S. transportation-related oil demand, other fuels and modes of transportation also represent significant sources of consumption. In particular, demand for diesel fuel in heavy-duty trucks and commercial airplanes represented more than 25 percent of U.S. transportation-related oil demand in 2010.¹⁰⁷ Demand from class-7 and class-8 trucks totaled 2.4 million barrels per day while commercial aviation demand totaled 1.1 mbd.¹⁰⁸

Though cost and availability are clearly constraints to widespread adoption, numerous alternatives to petroleum-fuels are currently being developed or deployed in the light-duty vehicle market. In fact, today's drivers can already choose between vehicles powered by electricity, natural gas, highly-concentrated blends of biofuels, and even hydrogen. Outside of light-duty vehicles, however, alternative fuel and drivetrain options become somewhat more limited. Options for heavy-duty trucks have historically been limited primarily to natural gas fuels—including both compressed natural gas and liquefied natural gas. Meanwhile, there have historically been few practical alternatives to jet fuel available in the commercial aviation sector.

More recently, non-petroleum liquid fuels have received considerable attention as an alternative for both heavy-duty trucks and commercial airplanes. In particular, synthetic diesel fuels derived from biomass, so-called advanced biofuels, could offer aviation and trucking applications many of the benefits of petroleum fuels—ease of transport, access to existing infrastructure, and high energy density—while eliminating some of the critical drawbacks of oil combustion, including lifecycle greenhouse gas emissions. Moreover, displacement of oil demand in the U.S. economy with domestically produced advanced biofuels would provide the country and national economy with important benefits, including reduced oil imports and a corresponding improvement in the trade deficit.

Through existing technologies, biofuels can be derived from several different feedstocks and take on a number of different chemical compositions. U.S. policy to date has focused on ethanol derived from corn, which is an alcohol-based fuel that differs in important ways from traditional petroleum fuels. Perhaps most importantly, fuels with high concentrations of alcohol-based biofuels are incompatible with the nation's existing petroleum transportation and distribution network and require modifications to vehicle components, such as the fuel line. In addition, while ethanol can be considered energy-dense relative to other alternative fuels, it contains only approximately 70 percent of the potential energy of gasoline.¹⁰⁹ In comparison, a number of processes for producing advanced biofuels result in a liquid fuel that is the molecular equivalent of diesel fuel.¹¹⁰

¹⁰⁷ ORNL, TEDB, Edition 31, Tables 1.15 and 1.16

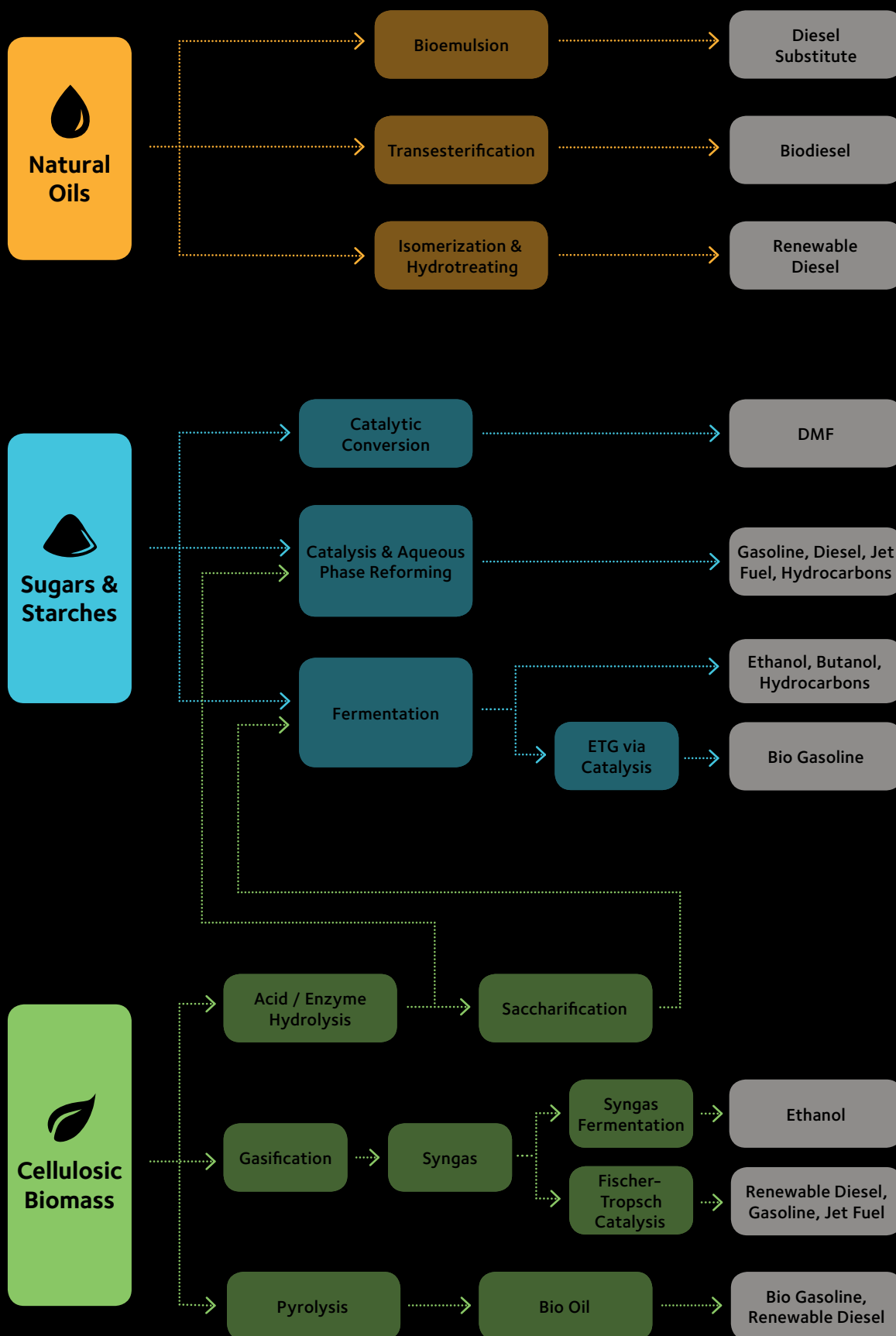
¹⁰⁸ Id.

¹⁰⁹ DOE, EIA, *AEO 2012*, Appendix G

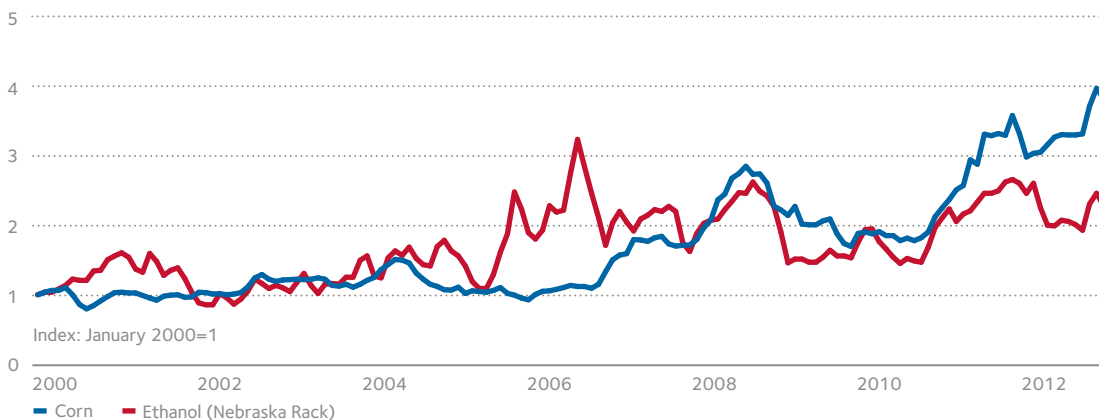
¹¹⁰ See, e.g., DOE, Report on the First Quadrennial Technology Review, September 2011, at 58

FIGURE 54

Pathways To Renewable Fuels



Indexed U.S. Corn and Ethanol Prices



Source: USDA; and Nebraska Ethanol Board

The most important existing public policy supporting domestic biofuels production is the Renewable Fuels Standard (RFS), which was first enacted as part of the Energy Policy Act of 2005 and then modified in the Energy Independence and Security Act of 2007 (EISA).¹¹¹ EISA set annual production guidelines for four biofuel types: corn-based ethanol, cellulosic ethanol, biodiesel, and advanced biofuels. By 2022, the RFS requires annual U.S. production of these four fuels to total 36 billion gallons.¹¹² Corn-based ethanol effectively dominates the requirements, accounting for nearly two-thirds of the program's aggregate volumes. Nonetheless, the RFS does require significant advanced biofuel production, totaling more than 3 billion gallons annually by 2020.¹¹³

Policy and technology have driven the majority of global biofuel investment to date toward ethanol produced from corn and sugar cane. These crops are fermented to produce ethanol, most notably in the United States and Brazil. U.S. ethanol production surpassed 900,000 barrels per day in 2011, while production in Brazil is currently estimated at 444,000 b/d.¹¹⁴ Ethanol production in these two countries alone accounts for more than 70 percent of global biofuels production today.¹¹⁵ The cost of producing ethanol varies significantly from year-to-year based on two critical determining factors: energy costs and crop costs. In the United States, this has meant that the viability of the ethanol industry is determined in large part by the prices of corn and natural gas, in addition to the price of the dominant liquid fuel in the marketplace, gasoline. As the fuels which essentially define the market, gasoline and diesel are critical price benchmarks for all biofuels, and their prices almost always track each other closely.

While low natural gas prices and high oil prices have created favorable economic drivers for ethanol in recent years, high corn prices have created an increasingly challenging outlook. Food-for-fuel debates aside, the dependence of the U.S. ethanol industry to corn as a feedstock exposes the production chain to uncontrollable events, such as 2012's Midwestern drought. In fact, when adjusted for energy content, fuels blended with 85 percent ethanol (E85) are currently significantly more expensive than gasoline in most regions of the United States, and production in 2012 will decline for the first time since 1996.¹¹⁶ Tight corn supplies and high prices have been the critical drivers behind these trends.

Production of biofuels from feedstocks that have less inherent volatility would have obvious benefits, as would the commercialization of biofuels that are closely aligned with the molecular structure of traditional hydrocarbons. Generally speaking, advanced biofuels are those that meet one or both of these criteria. That is, they either rely on a non-food crop feedstock, or they are a traditional

111 EPA, Renewable Fuels: Regulations and Standards, available at: <http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm>

112 Id.

113 Id.

114 DOE, EIA, Short Term Energy Outlook, November 2012; and IEA, *MTOMR 2012*, at 90

115 SAFE analysis based on data from: IEA, *MTOMR 2012*

116 SAFE analysis based on data from: DOE, EIA, Short Term Energy Outlook, November 2012 and *Monthly Energy Review*, October 2012

hydrocarbon substitute. While these fuels make up an extremely small portion of global biofuels production to date—roughly 50,000 barrels per day in 2011—their output is expected to increase by a factor of more than six by 2017 based on an analysis of currently announced projects.¹¹⁷

There is a role for the federal government in supporting the accelerated development of advanced biofuels, particularly in terms of identifying low-cost pathways to deploy hydrocarbon substitutes from non-food crop feedstocks. The Plants Engineered to Replace Oil (PETRO) program at ARPA-E awarded \$36.3 million to 10 such projects in 2011, and DOE's Office of Energy Efficiency and Renewable Energy was appropriated more than \$90 million in FY 2010 for R&D related to advanced biofuel feedstocks and conversion processes. While these funds are significant, they should be increased by a factor of two between 2013 and 2015, and funding for ethanol R&D should be phased out. Indeed, in its most recent *Quadrennial Technology Review (QTR)* released in September of 2011, the Department of Energy stressed that future research and development funding priorities would be directed toward advanced biofuels, further noting that ethanol is “neither a total drop-in fuel nor ideal for the heavy-duty vehicle market, and because [ethanol] already has substantial investment from the private sector.”¹¹⁸ This prioritization of R&D for advanced biofuels is wholly appropriate in terms of the federal government's role, and it is consistent with the energy security needs of the country.

Finally, while some observers have called for significant modifications to the RFS to benefit advanced biofuels, further investment uncertainty—particularly in favor of unproved technologies—is not desirable at this time. Instead, any federal policies focused on advanced biofuels that extend beyond research and development should prioritize a handful of key issues.

First, the cellulosic biofuel producer tax credit should be amended to apply to other advanced biofuels, most notably those derived from algae. Such fuels have unique properties distinguishing them from all other biofuel feedstocks currently in use. The per-acre productivity is orders of magnitude greater than field crops, and the inputs—waste or salt water, sunlight, and carbon dioxide—are abundant, dependably inexpensive, and not subject to price volatility. The algae itself can be genetically engineered to optimize yield and production is possible in a range of climate and weather regimes. Algal biofuels also avoid land use conflicts with other agricultural products, and can be produced with or without sunlight. Furthermore, through existing commercial technology, it is possible to produce all three major distillates as fungible, drop-in replacements, in addition to a range of petrochemicals.

Second, Congressional extension of financial support for biofuels over a period several years would be considerably more useful than credits requiring annual reauthorization. The current cellulosic biofuels tax credit expires in December 2012. This credit should not only be renewed, but it and other biofuels tax credits should be extended on 3–5 year time frames to enable project developers sufficient time to develop business plans and seek investors, and to give investors greater confidence that incentives will remain in place for an appropriate period of time.

PRIMARY RECOMMENDATION

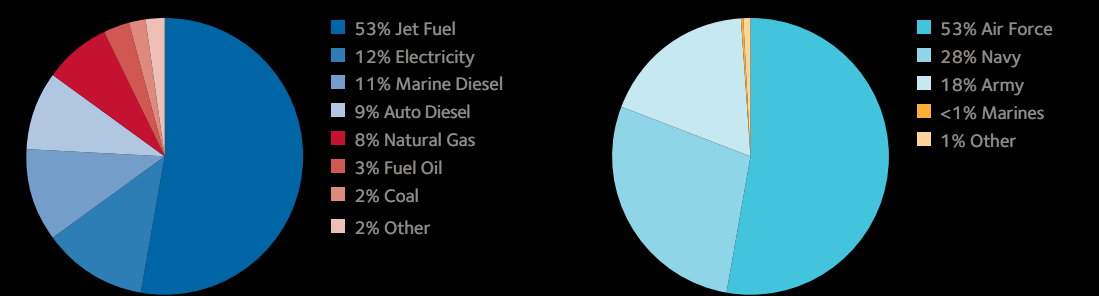
Allow the Department of Defense the flexibility to purchase advanced fuels and technologies.

The Department of Defense (DOD) can play a key role in supporting the development of alternative fuels and advanced energy technologies. This role is justified from at least two perspectives. First, DOD faces what amount to unique incentives in evaluating the cost effectiveness of many technologies. Energy systems that reduce exposure to enemy combatants, for example, can be justified even at high cost levels, because they save American lives. Second, DOD can serve as a technology incubator and

117 SAFE analysis based on data from: Biofuels Digest, Advanced Biofuels and Bio-Based Materials Database

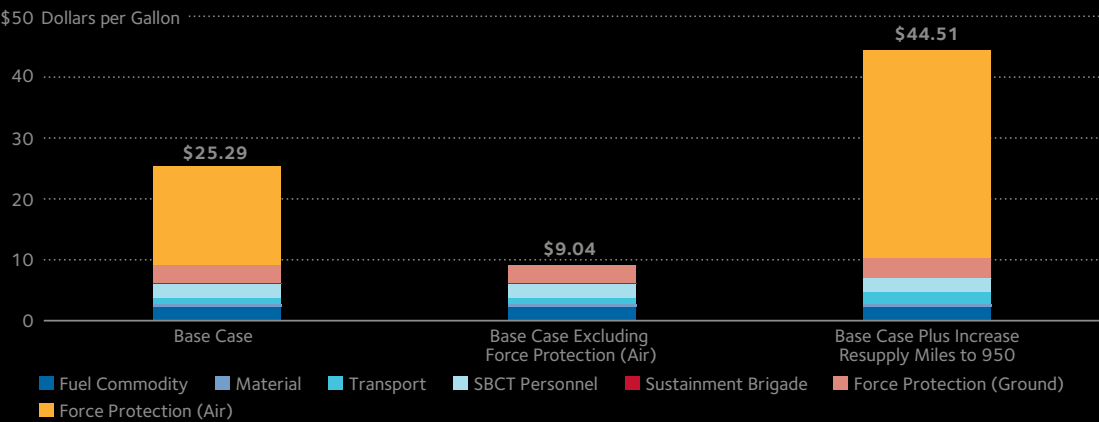
118 DOE, Report on the First Quadrennial Technology Review, September 2011, at 61

DOD Energy Consumption by Fuel Type and Service Branch



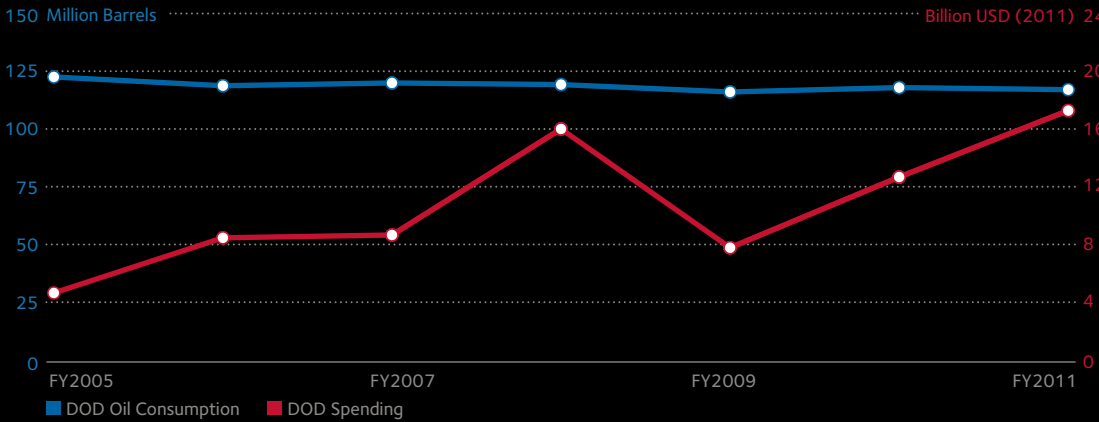
Source: DOD

Fully Burdened Cost of Fuel



Source: Deloitte

DOD Oil Consumption and Spending



Source: CRS

FIGURE 56 & 57

FIGURE 58

FIGURE 59

accelerator given its significant purchasing power. This role must be carefully analyzed and consistently evaluated, however, to ensure that the Department is supporting development of technologies that meet clear, long-term national security needs.

The Department Defense is a significant consumer of energy across multiple platforms. In FY 2011, stationary facilities accounted for approximately 25 percent of DOD energy consumption, while mobility fuel accounted for 75 percent.¹¹⁹ Across the entire department, petroleum fuels accounted for approximately three-fourths of energy demand, with jet fuel alone representing more than half of Defense energy use in FY 2011.¹²⁰ Consistent with this notion, the Air Force was far and away the Department's largest petroleum fuel consumer, accounting for more than half of the petroleum consumed by the entire DOD. The Navy was a distant second, accounting for 28 percent of the total.¹²¹

As global oil prices have increased over the past decade, DOD spending on petroleum fuels has increased significantly. Between 1999 and 2003, Defense spending on mobility fuels averaged \$3.75 billion. Even in 2003 and 2004, as operations in Iraq led to a 20 percent increase in fuel demand relative to pre-war levels, spending did not top \$6 billion.¹²² However, surging oil prices in 2007–2008 drove DOD spending on petroleum fuels to \$16 billion—a level that was surpassed in FY 2011, when spending reached \$17.5

billion.¹²³ Though this figure represented just 2.5 percent of total defense outlays, it represented 6 percent of operational expenses, and petroleum fuel costs have been the fastest-rising DOD budget item since the early 1990s.¹²⁴ While the operational effect of high fuel prices is arguably negligible in the short term, the nine billion additional dollars spent on fuel by DOD in FY 2011 compared to FY 2006 is foregone capital that surely could have been invested in a variety of more productive ways.

The Department of Defense's dependence on oil and rising expenditures on petroleum fuels justify a long-term effort to promote fuel diversification.

While the budget-level figures for DOD fuel consumption reveal important trends, it is also important to consider the impact of fuel consumption and prices on the military's cost-benefit analysis for energy technologies. For typical consumers, investment in energy technology—particularly with regard to efficiency or alternative fuels—is generally based on an assessment of economic value. In this regard, DOD faces important operational factors that arguably differentiate it from typical consumers.

The military's use of fuel in operational scenarios subjects it to several layers of external costs that must be included in its assessment of what fuel actually costs. For example, the total cost of delivering diesel fuel to operate power generators at forward operating bases in Afghanistan is certainly more than the base cost of the commodity. This total cost is often referred to as the fully-burdened cost of fuel. A 2007 study from the Department of Defense placed this cost for the military at approximately \$25 per gallon, including the cost of the fuel as well as the cost of shipping and protecting the fuel in a combat zone.¹²⁵ For longer supply lines, the fully-burdened cost can rise as high as \$45 per gallon. This fuel price alone allows DOD to consider a larger range of more expensive alternatives than typical consumers—such as generators operated by distributed energy sources—strictly from an economic perspective. Of course, economics is often not the military's sole, or even primary, justification for adopting various energy technologies. Minimizing the length of fuel supply lines in combat zones reduces risks to American troops and saves lives.

These operational factors provide a basic justification for the Department of Defense to acquire energy technologies that reduce its costs or personnel risks, even if those technologies would not

119 SAFE analysis based on data from: DOD, Annual Energy Management Report, FY 2011

120 SAFE analysis based on data from: DOD

121 Moshe Schwartz, Katherine Blakeley, and Ronald O'Rourke, "Department of Defense Energy Initiatives: Background and Issues for Congress," CRS, August 10, 2012

122 LMI, Transforming the Way DOD Looks at Energy, 2007

123 Schwartz, at 8

124 Id., at 8–9

125 Steve Siegel, "Sustain the Mission Project Energy Costing Methodology," May 23, 2007

necessarily be cost-effective in the private market. The litmus test for DOD energy technology acquisitions in this respect is whether such technologies allow DOD to better carry out its mission.

A separate question is whether it is appropriate for the Department of Defense to serve as a national energy technology incubator for alternative fuels and systems that do not necessarily enhance operational effectiveness in the near term, and in fact may have little or no applicability to DOD's core mission. Advocates of electric vehicles, biofuels, liquids derived from coal, and numerous others have all looked to DOD's significant purchasing power as an opportunity to help drive production scale in their respective industries, thereby driving down costs and increasing market competitiveness. As a policy matter, this approach should be viewed with considerable caution.

It is true that the Department of Defense's dependence on oil and rising expenditures on petroleum fuels justify a long-term effort to promote fuel diversification. But efforts at diversification must prioritize fuels that will in some way enhance DOD capabilities or reduce costs, either tactical or non-tactical. In this regard, investments in highly-efficient or advanced technology vehicles, such as those powered by electricity, can be viewed as entirely appropriate. The Department of Defense operated 192,353 non-tactical cars and trucks in FY 2011, which consumed a reported 74.8 million gallons of petroleum fuels.¹²⁶ Replacing these vehicles with more cost-effective platforms could yield important budget savings over time.

Furthermore, widespread commercialization of advanced vehicle technologies that utilize little or no petroleum is clearly in the long-term interest of the U.S. military. Several reports by well-respected analysts have documented the impact of U.S. oil dependence on the military, which expends enormous personnel and financial resources to effectively guarantee the free-flow of oil. A 2009 study by the RAND Corporation placed the cost of this burden at between \$67.5 billion and \$83 billion annually.¹²⁷

In this context, policymakers should seek to provide the Department of Defense with as much flexibility in purchasing fuels as possible, particularly with respect to advanced liquid fuels of all types. The Defense Logistics Agency is currently able to purchase ethanol at prices that exceed the price of conventional fuels. This exemption should be extended to advanced biofuels and any other future alternatives. To mitigate the risk of imprudent investments, the exemption should be modified for all fuels to apply only when the supplier submits a credible plan for achieving competitive pricing during the term of the contract.

Finally, the Department of Defense should be given the flexibility to participate in public-private fuel-purchasing consortia at the national or regional level. When combined, DOD and commercial U.S. airlines represent the large majority of jet fuel purchases, specifically jet A-1. With DOD transition to a jet A-1 standard, a purchasing consortium could provide significant long-term certainty to advanced biofuels producers, scaling up the supply chain and driving down costs. This kind of industry 'best-value' approach is not workable today, as current procurement policy requires that DOD issue a request for proposal (RFP) and separate source selection.

¹²⁶ ORNL, TEDB, Edition 31, Table 7.7; and DOD, Annual Energy Management Report, FY 2011, at 27

¹²⁷ RAND Corporation, "Imported Oil and National Security," at 60-62, 2009





PART III

Reforming and Streamlining Regulatory Structures

Reforming and Streamlining Regulatory Structures

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The energy sector operates in a tightly regulated environment under the influence of numerous government agencies. This regulation can sometimes stifle progress. The government should take advantage of opportunities to reform or eliminate overly-stringent and complex rules to the immediate and long-term benefit of U.S. energy production, consumption, and security. Importantly, in a time of constrained budgets, these benefits can be realized without requiring substantial federal outlays.

The United States has experienced a revolution in domestic oil and natural gas production over the past decade due to the combined application of horizontal drilling and hydraulic fracturing in what were previously inaccessible shale formations. As production has surged, however, so too has debate surrounding the fracturing process. Specifically, there is widespread disagreement regarding an acceptable regulatory framework to address environmental concerns. This is intertwined with a rising debate over the potential export of U.S. liquefied natural gas (LNG)—discussed in more detail in *Part IV*.

Of some concern is that an inability to reach consensus and establish an acceptable level of regulatory certainty regarding hydraulic fracturing threatens the realization of a wide array of substantial economic and energy security benefits, including job creation and trade deficit reduction. And while a development of such magnitude must most certainly be evaluated carefully, an overly lengthy, complex, or burdensome review process can pose an unnecessary impediment to progress.

The debate over hydraulic fracturing is just one of the most prominent energy-related regulatory issues of the day, but it is illustrative of a broader point: every significant energy technology and major energy project, including renewables, is subject to a degree of regulation. And stakeholders

representing nearly all energy technologies have cited regulatory uncertainty or undue burdens as important drivers of cost increases and slower growth.

The federal government must ensure that its approach to regulation of the energy industry is clear, consistent, and rational, and serves as a framework to promote our energy goals instead of an obstacle to achieving them.

The government's role—or lack thereof—should be clear. Enhancing certainty, transparency, and stability in the process of permitting and monitoring all major energy development activities is an important starting point, whether for offshore oil production and wind-powered electricity generation, or onshore natural gas production using hydraulic fracturing and horizontal drilling technologies. Even the infrastructure required to transport

this energy to end-use markets, which is an equally critical piece of the supply chain, faces regulatory uncertainty. As such, the United States would benefit from a clearer, more streamlined regulatory review process for a wide variety of energy-production and distribution technologies, particularly for projects of regional significance.

Reform in these areas will strengthen the nation's ability to facilitate projects that help to improve energy security. Other objectives, such as safety, are also critical, and can likewise be achieved without unnecessarily onerous regulation, but instead through a rigorous approach to oversight based on best-practices and performance-based evaluation. Such an approach will also help foster a more certain operating and investment climate for the broader energy industry.

Reforms to promote the more efficient use of oil and the wider use of alternative fuel vehicles (AFVs) remain essential to common-sense regulatory processes that strengthen, rather than hinder, improvements in the nation's energy security. Ultimately, this requires a transition from a miles-per-gallon metric to a gallons-per-mile metric which provides consumers with clearer information about the relative efficiency of different vehicles and also enables a clear comparison of oil consumption across all vehicles. Regulatory reforms will also aid the adoption of AFVs in the medium- and heavy-duty fleet by both commercial customers and the federal government.

Finally, recent severe weather events have reminded of the extent to which the nation relies on, and often takes for granted, its energy infrastructure. The federal government should encourage states to undertake regular reviews of the resiliency of their energy infrastructure to severe weather and offer incentives to implement improvements and upgrades.

As the country increasingly produces traditional fuels in new ways, deploys advanced or alternative fuels that did not exist decades ago, and works to achieve broad national goals such as enhanced energy security and environmental sustainability, the federal government must ensure that its approach to regulation of the energy industry is clear, consistent, and rational, and serves as a framework to promote our energy goals instead of an obstacle to achieving them.

Policy Recommendations

PRIMARY RECOMMENDATION

Improve the federal permitting process for major energy projects by streamlining authority, promoting transparency, and reducing frivolous litigation.

The application process for federal energy permits is too often wrought with unnecessary delays, frivolous litigation, and a lack of coordination. It is not only often difficult and cumbersome to obtain a permit, but there are multiple pathways for detractors to oppose a project, creating a regulatory and litigation obstacle course that serves to the detriment of national energy security. The U.S. regulatory process should not unduly dissuade private sector investment through inefficiency and lack of transparency.

In an economy with a dynamic energy sector, we must enhance certainty in the process by which all projects are reviewed. This will provide companies with better information regarding both the cost and timing of obtaining approval. While the process should be analytically-rigorous and require industry to meet high standards, special attention should be paid to ensure it is fair and not unnecessarily burdensome. Its goal should be to identify and overcome problems whenever possible and require significant adaptations or cancellations only when the problems cannot be overcome. The regulator's purpose should be to ensure that projects proceed in a safe and responsible manner.

The federal permitting process affects all types of energy-related projects, from wind farms and hydraulic fracturing operations to the construction of pipelines for oil, refined product, and natural gas. The cost related to delays and cancellations is substantial. This has the potential to undermine U.S. economic growth, energy security, and job creation. And while a wholesale review of the current approach to permitting energy projects might be warranted over the long term, a handful of common-sense reforms can substantially improve the process in the near term.

Interagency Coordination

Infrastructure projects often require the approval of multiple federal agencies in addition to state and local governments. As part of their approval process, agencies often have to comply with the National Environmental Policy Act (NEPA), the Endangered Species Act, and other environmental laws in addition to meeting their own primary statutory obligations. Although the Council for Environmental Quality (CEQ) issues the guidelines and rules for performing the environmental impact statements required by NEPA, they do not stringently manage the process for any particular project. The lack of a central coordinating agency means that there is no timeline for the completion of all federal approvals required for a project. A single agency can often delay a project no matter how small its concerns or how large the project. In the absence of political accountability, this process can extend interminably.

In order to improve the process, the Office of Information and Regulatory Affairs (OIRA) at the Office of Management and Budget (OMB) should be responsible for overseeing and expediting the permitting of major energy projects. While CEQ has primary responsibility for establishing NEPA's substantive guidelines, the energy sector has expressed a longstanding concern about the process and CEQ's role in it. Granting OMB—an agency that is less likely to be viewed as having a stake in the substantive outcome of reviews—responsibility for ensuring that the process is advancing expeditiously will allow CEQ to focus on more substantive issues. These responsibilities would be a logical extension of OIRA's current purview to review and approve most federal regulations. Characterization of major energy projects should be based on the amount of upfront investment and amount of energy produced or transported.

Federal projects with an initial investment exceeding \$100 million that meet one of the following criteria should be subject to this revised process:

1. Nameplate generating capacity of at least 300 megawatts of electricity; or
2. Nameplate generating capacity of at least 150 megawatts of renewable electricity; or
3. Transmit electricity at greater than 500 kilovolts; or
4. Produce more than 25,000 barrels of oil equivalent per day; or
5. Transport via pipeline more than 200,000 barrels of oil equivalent per day of oil, natural gas, or refined products.

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In its expanded role, OIRA would not advocate for any particular outcome, but would ensure that the permitting process for major energy projects is completed in accordance with an established timeline. A process similar to this proposal was established by President Obama when he assigned a White House staff member the responsibility of coordinating the review of Shell Oil's proposal to drill for oil off the northern coast of Alaska,¹ a process that was widely regarded as a success.²

After an eligible project is submitted to the appropriate lead agency or agencies for review and approval, OIRA would establish a project timeline that includes intermediate milestones and a firm deadline for project approvals based on input from agencies with an interest in the project and CEQ. The final project approval should not exceed 30 months, with shorter timelines for smaller projects. The lead agency would be responsible for bringing together all agencies with an interest in the project, monitoring compliance with project milestones, and reporting the progress to OIRA. Critically, it would also be required to maintain contact with the project developer to ensure that issues related to the process are readily identified and that information needed from the developer is acquired in a timely manner.

Under current practice, some aspects of an environmental review may be evaluated by multiple agencies. The Council therefore also recommends that the lead agency coordinate the preparation of all elements of the review and approval process, identify those areas where there is duplication, and direct agencies to work together to eliminate it. Agencies should also be directed to use environmental reviews prepared by state or local governments when they are available and meet the agency's standards. In the event that agencies cannot agree on a timely pathway that eliminates duplication, OIRA should resolve any disputes.

In order to ensure that the process is not delayed by agencies' failure to complete their portion of an environmental assessment in a timely manner, agencies that miss milestones in the process without prior OIRA approval should have to request an extension from OIRA as soon as it is apparent that the milestone will be missed. Moreover, requests for extensions of interim deadlines should be made by the Secretary, Administrator, or other head of the agency seeking the extension, and the right to make the request to OIRA should not be delegated. Requiring the agency head to personally make the request imposes a degree of political accountability on the agency. Likewise, final project approvals may be delayed for good cause, but the decision to extend deadlines must be made public.

Transparency

To ensure transparency in the permitting process, every qualified project should be tracked on an OIRA-administered website. After OIRA establishes the timeline for a project's federal review, the project docket would be posted to the website along with the final deadline and all interim deadlines for the agencies participating in the process. OIRA would then update the status of the review until it is complete. While this would constitute nothing more than an informational tool, it will promote transparency in the process and identify genuine bottlenecks. If certain agencies or steps in the

1 Executive Order 13580, Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska, The White House, July 12, 2011

2 John M. Broder and Clifford Krauss, "New and Frozen Frontier Awaits Offshore Oil Drilling," New York Times, May 23, 2012

process appear to be recurring bottlenecks, policymakers would have clear evidence of where problems exist so that they may be corrected. A website called the “Federal Infrastructure Projects Permitting Dashboard” has been created to track certain high priority projects as mandated in Executive Order 13604.³ The website shows the timeline for approval and gives information about the project.⁴ This is a good model that should be used for all major energy projects as defined above.

Litigation

Even after being approved, the issuance of project permits may be further delayed by legal challenges, often times brought under the Clean Air Act, the Clean Water Act, the Endangered Species Act, and NEPA. NEPA’s requirement that federal agencies prepare an environmental impact statement for “all major Federal actions significantly affecting the quality of the human environment,” is vague and is used as a mechanism for project opponents to bring forth lawsuits to delay or stop projects.

While the broad scope of possible challenges under NEPA is problematic in its own right, it is exacerbated by a six-year statute of limitations that introduces far too much uncertainty into the process of obtaining definitive federal government approval for large energy projects. The Council recommends that the statute of limitations, which relates only to the timeframe within which a suit can be filed in court, be shortened to one year for major energy projects. Doing so will reduce project uncertainty while still guaranteeing generous access to the courts. The Council also recommends limiting litigants’ right to challenge decisions under NEPA to issues that they raise during the administrative process, ensuring that issues of true importance are found early in the process and not reserved for later use as a means to delay a project through frivolous litigation.

PRIMARY RECOMMENDATION

In order to increase public confidence in the hydraulic fracturing process, states should participate in the State Review of Oil and Natural Gas Regulations (STRONGER) review process. STRONGER should increase its scope to develop best practices for hydraulic fracturing.

The Council is concerned that any erosion in public confidence regarding environmental contamination from hydraulic fracturing will lead regulators to restrict access to the resource. New York,⁵ Maryland,⁶ and municipalities in Pennsylvania⁷ have either decided to not allow hydraulic fracturing while studying potential impacts or have banned it outright. The Council believes, however, that public confidence can be enhanced if the states actively review and improve their regulatory programs and adopt best practices to ensure that the local environment is protected and substandard producers are held accountable for their shortcomings.

Hydraulic fracturing has dramatically changed the American energy landscape by giving industry the ability to produce oil and natural gas from previously inaccessible geological formations, most notably shale. Although hydraulic fracturing has been used to some degree since the 1950s, the past half-decade has seen a dramatic increase in its use. Today, natural gas produced from shale deposits accounts for nearly 40 percent of domestic gas output, and shale oil production has been the primary driver behind recent growth in U.S. liquids output.⁸ The rise in domestic production of both oil and

3 Executive Order 13604, Improving Performance of Federal Permitting and Review of Infrastructure Projects, The White House, March 22, 2012

4 See, permits.performance.gov

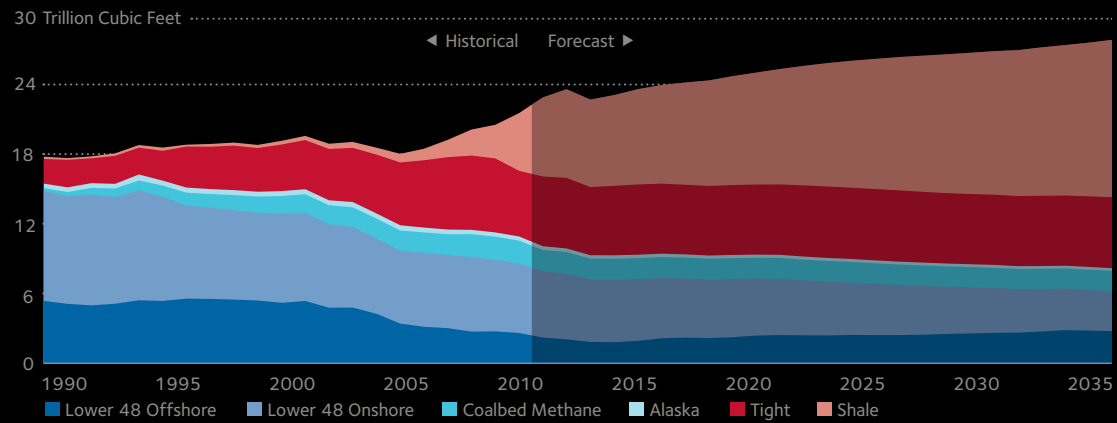
5 Mireya Navarro, “New York State Plans Health Review as it Weighs Gas Drilling,” *New York Times*, September 20, 2012

6 “Governor O’Malley Announces Study of Marcellus Shale Drilling,” Office of Governor Martin O’Malley, June 6, 2011

7 ACT 13 became law in Pennsylvania on February 14, 2012 and prohibited local bans on hydraulic fracturing. However, this portion of the law was deemed unconstitutional in commonwealth court and existing bans were stayed pending appellate review. Sarah Fletcher, “Municipal Restrictions on Hydraulic Fracturing: A New Test for Federalism,” *IHS Unconventional Energy Blog*, November 1, 2012

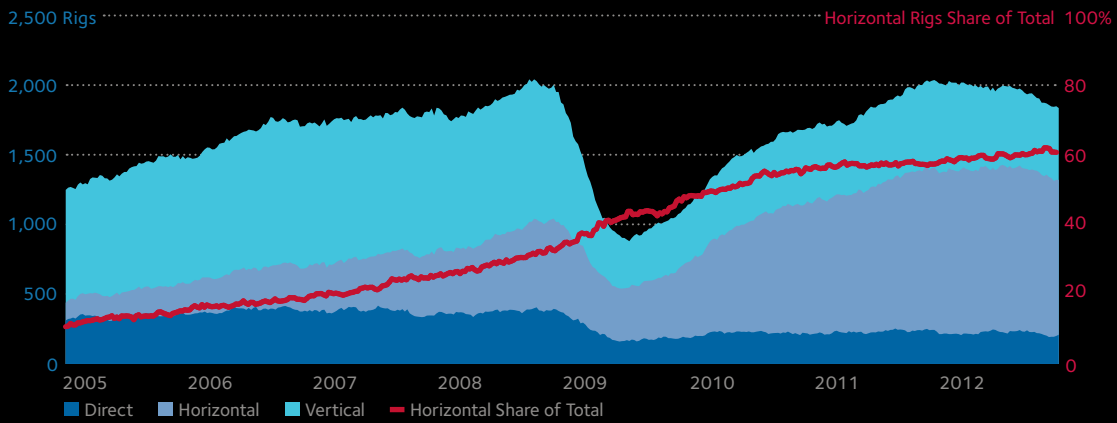
8 SAFE analysis based on data from: Adam Sieminski, “Prospects for U.S. Oil and Natural Gas,” July 20, 2012; and DOE, EIA, *Monthly Energy Review*, September 2012

U.S. Natural Gas Production



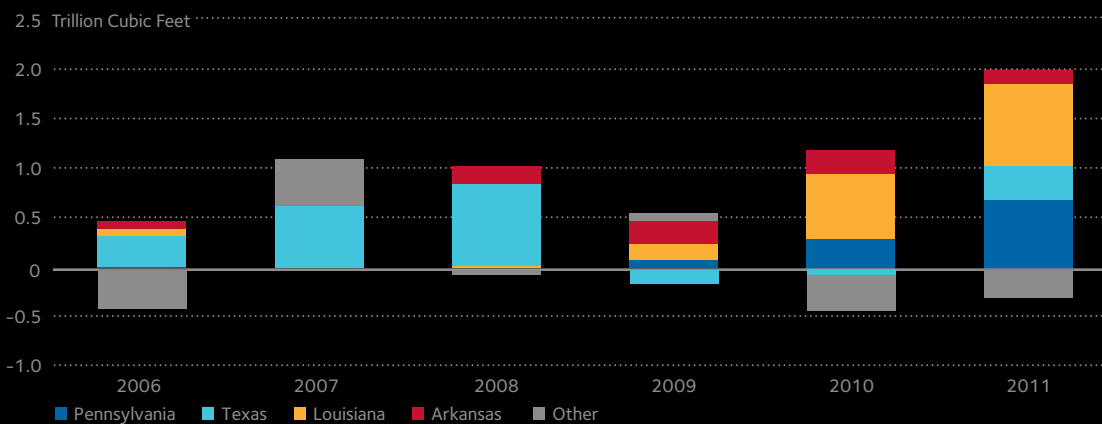
Source: DOE, EIA

North American Rig Count By Type



Source: Baker Hughes

Change in U.S. Natural Gas Production, 2006-2011



Source: DOE, EIA

FIGURE 60

FIGURE 61

FIGURE 62

natural gas has also been an important factor in the creation of a wealth of high paying jobs. North Dakota's low unemployment rate is widely attributed to revitalized oil industry activity in the Bakken formation.⁹ However, while horizontal drilling and hydraulic fracturing have allowed the United States to dramatically increase domestic energy supplies, the rapid proliferation of these drilling and completion technologies has raised a number of questions and concerns regarding safety, particularly with respect to the protection of water resources.

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Producers use hydraulic fracturing to develop oil and natural gas from deep, low-permeability unconventional formations. To extract oil and natural gas from these reservoirs, hydraulic fracturing over-pressurizes the source rock creating multiple fractures in which hydrocarbons can accumulate and flow to the well. To fracture a well, producers typically use fluids (like water under high pressure) along with viscosity-enhancing chemical agents (surfactants). In addition, producers typically inject a proppant, or propping agent (usually sand), into the well to keep the fractures from closing when pressure is reduced. Instead of using traditional vertical wells, hydraulic fracturing and resource recovery take place via horizontal wells, which increase exposure of the well bore to the hydrocarbon-producing zone. It is estimated that close to 2.5 million fracture treatments have been carried out globally in the past half century.¹⁰

Fresh water and proppants typically account for 98 to 99.5 percent of the fluids used during the hydraulic fracturing process with chemical additives making up the balance.¹¹ Still, hydraulic fracturing of an individual well can consume several million gallons of fluid, meaning that even if chemicals constitute just 0.5 percent of the volume of the fluids, a job that consumes 5 million gallons of fluid includes 25,000 gallons of chemicals.¹² Both the volume of hydraulic fracturing fluid required and the number of times each well is stimulated are a function of the geology and hydrology of the well location.

Although some of the fluid used in hydraulic fracturing remains in the shale, depending on the formation, 30 to 70 percent flows back out of the well and is contained at the drill site until the

operator disposes of it, generally either through recycling or the use of disposal wells.¹³ The use of chemicals in large volumes and repeated injection of fluid at high pressure into a well (which puts stress on the well casing) are significant differences from the typical processes that characterize conventional oil and natural gas development.

One way to help alleviate some of the public concern with hydraulic fracturing would be to establish best practices that are implemented and enforced by the states.

To date, most of the public criticism of hydraulic fracturing has focused on the chemical additives used during the

process. Critics of the practice have voiced concern that such chemicals could migrate into drinking water wells and reservoirs or could contaminate surface water sources during transportation, mixing, and temporary on-site storage. Some of the chemicals used for hydraulic fracturing are toxic, and some are known carcinogens.¹⁴ Starting in 2011, several producers began voluntarily disclosing non-proprietary chemicals used in hydraulic fracturing on an industry-funded website.¹⁵ In addition, some states now require full disclosure of all chemicals, including those considered proprietary.¹⁶

Industry supporters have noted that shale oil and natural gas wells are drilled thousands of feet below drinking water reservoirs, meaning that the actual process of hydraulic fracturing is far removed from

9 Federal Reserve Bank of Minneapolis, "Data on Demographic, Economic and Financial Activity in the Bakken," June 20, 2012

10 Carl Montgomery and Michael Smith, "Hydraulic Fracturing – History of an Enduring Technology," *Journal of Petroleum Technology*, December 2010

11 DOE, "Modern Shale Gas Development in the United States: A Primer," 2009, at 62

12 Bryan Walsh, "Could Shale Gas Power the World," *Time Magazine*, March 31, 2011

13 DOE, "Modern Shale Gas Development in the United States: A Primer," 2009, at 66–69

14 United States House of Representatives Committee on Energy and Commerce Minority Staff, "Chemicals Used in Hydraulic Fracturing," April 2011, at 8

15 <http://fracfocus.org/>

16 Brandon Murrill and Adam Vann, "Hydraulic Fracturing: Chemical Disclosure Requirements," CRS, June 19, 2012, at 14

drinking water supplies. However, the possibility of improper well completion, including cementing procedures for the well casing, has raised fears that human error associated with natural gas drilling could contaminate drinking water in other ways. For example, a 2011 study conducted by researchers from Duke University study found evidence of methane from shale deposits in drinking water near active drilling sites and implied that leaky well casings were a likely source.¹⁷

While concerns about groundwater contamination focus on drilling risks below the ground, challenges exist above ground as well. In April 2011, a blowout at a shale gas well in Pennsylvania spewed fracturing fluid above ground for more than 12 hours.¹⁸ The on-site storage, transport, and disposal of chemicals and produced water raise additional concerns about surface water. The fracturing fluid is usually mixed onsite, meaning that the undiluted chemicals are transported to and stored at the hydraulic fracturing site. The water that is produced from the well (wastewater) is also temporarily stored at the site, generally in open pits. In many cases, particularly in Pennsylvania, wastewater is transported over the road to water treatment facilities, and a handful of accidents involving trucks carrying wastewater from shale development have resulted in spills that damaged surrounding ecosystems.¹⁹ Recent press reports have also suggested that some of the wastewater treatment facilities receiving wastewater from shale drilling are not equipped to properly treat the fluids before releasing them.²⁰ In April 2011, state authorities in Pennsylvania requested that the industry voluntarily begin shipping recycled water to more sophisticated treatment facilities.²¹ Some states have already mandated that drinking water wells within a certain distance be tested before any drilling occurs. For example, in Pennsylvania baseline water quality measurements are made on wells within 2,500 feet of the drill site.²²

These and other contamination issues may occur at just a small percentage of the thousands of fracturing jobs that take place each year, but they have nonetheless made local populations more skeptical of the industry. The fact is that public perception of hydraulic fracturing has grown increasingly divided over the past several years, and this has placed a critical source of future U.S. energy supply at risk. With every new account of water contamination, anecdotal or not, proven or unproven, confidence in the industry is diminished. Pressure from local citizens and environmental groups has resulted in hydraulic fracturing bans in some states and several municipalities since 2008.²³

One way to help alleviate some of the public concern with the practice would be to establish best practices that are implemented and enforced by the states. States have been regulating oil and natural gas exploration and production processes for more than a century. And although certain aspects of oil and natural gas production are subject to portions of federal environmental laws, federal regulators have delegated primary enforcement authority to state regulators in most states. When enforcement authority is delegated to a state, it must enforce the federal law at least as stringently as the Environmental Protection Agency (EPA) would. States also have the option to implement standards more stringent than the federal regulations or to implement their own regulations regarding aspects of exploration and production outside of established federal jurisdiction. Because the widespread use of hydraulic fracturing is relatively new, some states are reevaluating their regulations to ensure that they adequately protect public health and the environment. Other states are experiencing an uptick in drilling and production activity due to hydraulic fracturing and are just now learning how to monitor and manage this new development.

In 1999, EPA and the Interstate Oil and Gas Compact Commission created the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) to review states' programs to regulate

17 Stephen Osborne, Avner Vengosh, Nathaniel Warner, and Robert Jackson, "Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Sciences*, Volume 108: 8172-8176, 2011

18 Edward McAllister, "Driller Halts Pennsylvania Fracking After Blowout," *Reuters*, April 21, 2011

19 See, e.g. "Tanker spills fracking wastewater in Pa. Creek", *AP*, September 27, 2012

20 Ian Urbina, "Wastewater Recycling No Cure-all in Gas Process," *New York Times*, March 1, 2011

21 Robbie Brown, "Gas Drillers Asked to Change Method of Waste disposal," *New York Times*, April 19, 2011

22 Marcellus Shale Coalition, "MSC Releases Recommended Practice for Pre-Drill Water Sampling," August 28, 2012

23 <http://www.fracktracker.org/maps/ny-moratoria/>; and Sarah Fletcher, "Municipal Restrictions on Hydraulic Fracturing: A New Test for Federalism," *IHS Unconventional Energy Blog*, November 1, 2012

oil and natural gas production activities.²⁴ STRONGER has a nine member voting board comprised of representatives of the oil and natural gas industry, state regulators, and environmental non-governmental organizations. STRONGER's primary goal is to prepare guidelines for state oil and natural gas regulatory programs. STRONGER currently operates with minimal funding from a Department of Energy grant and additional funds from the American Petroleum Institute.

STRONGER is well-respected in the energy community. An interim report by the Shale Gas Production Subcommittee of the Secretary of Energy Advisory Board (SEAB), for instance, lauded STRONGER for its peer-review work with states.²⁵ SEAB recommended that more states seek STRONGER review of their regulatory programs and that its budget be enlarged.²⁶ In addition, the National Petroleum Council recommended that "STRONGER should be bolstered and increase the scope of its activities," recommending that "[a]ll states with natural gas and oil production should actively participate in STRONGER and use its recommendations to continuously improve regulation." It also recommended that the federal government provide STRONGER additional funding.²⁷

The Council believes that STRONGER's work, reputation, and representation of diverse stakeholders make it the appropriate organization to develop best practices for hydraulic fracturing. STRONGER's current guidelines represent a strong starting point for a consensus, and its ongoing engagement with the state regulatory agencies demonstrates a robust understanding of state processes and existence of effective working relationships. To broaden its scope and perform more state reviews, STRONGER would require additional funding, some of which would likely come from the public sector.

As STRONGER continues to refine its guidelines for hydraulic fracturing, and establishes best practices for the industry, the Council believes that several important practices should be included. None of these practices would meaningfully increase costs or production time, but would build acceptance of the industry by reassuring the public that it is operating safely and responsibly. Most of them are already included in the recommendations of the Appalachian Shale Recommended Practices Group, a consortium of the largest producers in the region.²⁸ The Council's recommended best practices are:

- Test surface and well water within a reasonable distance from the drilling site before drilling to establish a baseline for water quality in the area and perform follow up testing after the hydraulic-fracturing process is complete;
- Disclose all chemicals in hydraulic-fracturing fluid to the state regulator and make them public to the greatest extent possible. Provide all medical and emergency personnel access to the composition of the fluid in case of an emergency;
- Adequately contain all wastewater (including recovered fracturing fluid) at the drilling site to prevent contamination of surface water;
- Ensure that all well casings and cement are appropriate for the pressure and number of fracture cycles to be used; and
- Report any mishaps or accidents at drill sites related to drilling or hydraulic fracturing to both the public and the regulatory agency in an established time frame.

Through the implementation of these best practices, the Council believes that public confidence in—and, ultimately, support for—this important extraction technique will help ensure that America continues to reap the national security and economic benefits of developing its domestic energy resources.

24 State Review of Oil and Natural Gas Environmental Regulations, Who We Are, available at <http://www.strongerinc.org/who-we-are>

25 Secretary of Energy Advisory Board, Shale Gas Production Subcommittee 90-Day Report, August 18, 2011.

26 Id.

27 National Petroleum Council. Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources. 2011.

28 Appalachian Shale Recommended Practices Group, "Recommended Standards and Practices," April 2012

PRIMARY RECOMMENDATION

The government should use fuel consumption, measured in gallons per 100 miles of travel, to report fuel economy on vehicle labels and calculate compliance with fuel-economy standards.

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Tremendous improvements in fuel efficiency have been made in recent years. President Bush signed the Energy Independence and Security Act of 2007 (EISA), which required automakers to achieve an average fleet fuel economy of 35 miles per gallon by 2020,²⁹ and the Obama administration accelerated the standards by four years.³⁰ The Obama Administration then issued new standards for light-duty vehicles produced through 2025, which are expected to save 2.5 million barrels of oil per day by 2040, and issued the first ever standards for medium- and heavy-duty vehicles, as directed by EISA.³¹ The Council emphasizes the importance of EPA and the National Highway Traffic Safety Administration (NHTSA) continuing to increase the standards to the extent that doing so is cost-effective during the next phase of rulemaking for medium- and heavy-duty vehicles, and when they undertake the midstream review for the 2017 to 2025 light-duty vehicle standards.

Since automobile manufacturers and consumers first began calculating how much fuel vehicles consume, fuel consumption has been measured in terms of miles per gallon (MPG), which represents the number of miles that a vehicle can travel while consuming one gallon of fuel. The MPG metric served as an effective surrogate for operating costs, which made sense when the nation relied on a single fuel—gasoline—whose price was highly volatile. The MPG metric allows consumers to compare the relative efficiency of vehicles, and thus their relative operating costs, while isolating the effects of fuel-price volatility.

The use of the MPG metric has two shortcomings, however. First is the so-called MPG illusion, the systematic misperception of fuel savings created by evaluating vehicle performance using miles per gallon. Specifically, most consumers incorrectly believe that the amount of gasoline consumed by an automobile decreases as a linear function of its MPG. This misconception causes consumers to underestimate the value of replacing the least fuel efficient vehicles and overstate the value of replacing relatively efficient cars with even more efficient ones. This can lead to confusion over the information provided to consumers, such as the mileage ratings on the vehicle's fuel-economy label or its advertisements. In developing the fuel-economy label, EPA and NHTSA recognized this problem and required that new labels include gallons consumed per 100 miles of travel (GPM) in addition to MPG, though the GPM is displayed much less prominently than MPG on the fuel economy label of a passenger car or light-duty truck.^{32,33}

In designing the labels, the agencies recognized that there was value in continuing to use a system that consumers understood, but that it also was important to introduce consumers to a better system over time. Consistent with that approach, the agencies should switch the GPM and MPG figures on the current labels. Then, after a five-period, the agencies should remove the MPG figure.

Improving vehicle efficiency has long been recognized as a critical measure in improving U.S. energy security. The technological advances made to increase efficiency are generally permanent in that

²⁹ Energy Independence and Security Act of 2007 (EISA), Public Law No. 110-140, 121 Stat. 1492 at §102(2a)

³⁰ Environmental Protection Agency (EPA), Department of Transportation, National Highway Traffic Safety Administration (NHTSA), "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," 75 Fed. Reg. 25,324, May 7, 2010

³¹ EPA, NHTSA, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," 77 Fed. Reg. 62,624, 62,769, October 15, 2012, ("2017-2025 LDV GHG Emissions and Fuel Economy Rule"); and EPA, NHTSA, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," 76 Fed. Reg. 57,103, September 15, 2011, (MD/HD FE Rule)

³² EPA, NHTSA, "Revisions and Additions to Motor Vehicle Fuel Economy Label; Final Rule," 76 Fed. Reg. 39,478, July 6, 2011

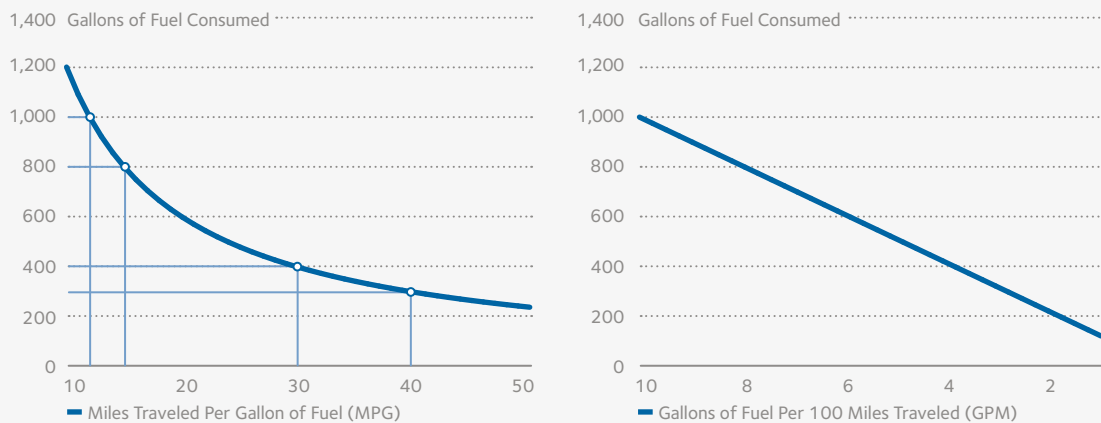
³³ It is interesting to note that in calculating the vehicle ratings reflecting relative fuel economy that are displayed on a slider bar on the labels, rating each vehicle on a scale from 1 to 10, the vehicle ratings are calculated on a GPM basis, and not an MPG basis, because they more accurately reflect fuel consumption and relative fuel costs.

Focusing on the MPG Illusion

The MPG illusion refers to the common misconception that the amount of gasoline a car consumes decreases as a linear function of its MPG rating. This misconception undervalues the fuel savings achieved by improving the efficiency of inefficient vehicles, even by a small amount, and overvalues the benefits of increasing the efficiency of vehicles that are already among the most efficient on the road. For instance, one might easily assume that greater fuel savings would be achieved by replacing a car that gets 30 MPG with one that achieves 40 MPG instead of replacing a car that achieves 12 MPG with one that achieves 14 MPG. Yet, as can be seen in Figures 63 and 64, replacing the 12 MPG car would save more oil than replacing the 30 MPG car, with the savings being 42 gallons greater per year if the vehicles traveled 12,000 annually and even larger if the vehicles traveled farther.

FIGURES 63
& 64

Fuel Consumption by Measurement Type



Source: SAFE analysis

A GPM scale offers obvious improvements to MPG. In contrast to the non-linear relationship between vehicle MPG and fuel consumed depicted in Figure 63, there is a linear relationship between vehicle GPM and fuel consumed as depicted in Figure 64. When fuel consumption is measured in GPM, a reduction of GPM by any specific amount saves the same amount of fuel no matter the initial fuel efficiency.

While MPG may help consumers measure the relative efficiency of different vehicles, GPM makes it easier to understand how much fuel a vehicle is consuming, and how much fuel costs can be reduced by increasing vehicle efficiency. It also makes it easier to calculate the reduced fuel costs from driving a more efficient car, further promoting consumers' purchase of more efficient vehicles.

once an improvement that results in higher fuel efficiency becomes cost-effective, it is likely to be incorporated into all new vehicles. Moreover, to the extent that the benefits of increasing oil supply accrue to consumers of oil globally—more than 80 percent of whom are outside the United States—the benefits of increased vehicle efficiency accrue entirely domestically.

The second shortcoming of the MPG metric is that it is not designed to account for alternative fuel vehicles (AFVs). To calculate fuel economy across vehicles that rely on an increasingly diverse portfolio of fuels, NHTSA now relies on an alternative fuel vehicle’s miles per gallon *equivalent* (MPGe) as a representation of fuel economy.³⁴ That metric, however, is not a measure of relative cost-effectiveness, relative oil consumption, or relative emissions. It is, instead, a measure of relative energy efficiency, measuring the performance of AFVs in terms of miles traveled per 115,000 British Thermal Units (Btus) of energy—the energy content of a gallon of gasoline.³⁵ That metric is neither particularly meaningful to consumers nor consistent with the original intent of the fuel economy program, which was to encourage the reduced use of petroleum in the economy.³⁶ Setting aside the fact that few consumers understand the meaning of “miles per Btu of energy,” the metric fails to account for the most important contribution that most alternative fuels provide to the nation—reducing the oil consumption and oil intensity of the U.S. economy.

Therefore, the Council recommends that fuel consumption be calculated on the basis of GPM (or per 100 miles), which accounts for the fact that some vehicle technologies do not use oil.³⁷ Using this revised method of calculating fuel economy is warranted because using non-petroleum based fuels uniquely improves our nation’s energy security. Nearly every fuel used in the United States other than those derived from crude oil, including the fuels used to generate electricity, is produced in North America. Their production supports American jobs and decreases the trade deficit when used as a transportation fuel, either directly or to generate electricity to power plug-in electric vehicles (PEVs). Most importantly, however, many of their prices are less volatile than the price of oil. It was, in fact, concern about our consumption of oil that led to the first fuel-economy standards, which were required by the Energy Policy and Conservation Act of 1975.

Calculating Fuel Economy

Vehicle	Fuel Economy	Fuel Consumption	
	Miles Per Gallon Equivalent (MPGe)	Gallons of gasoline equivalent per 100 miles (GPM _e)	Gallons of gasoline per 100 miles
1	18	5.6	5.6
2	22	4.5	4.5
3	25	4.0	4.0
4	27	3.7	3.7
5	35	2.9	2.9
6	40	2.5	2.5
7	45	2.2	2.2
8 (NGV)	35	2.9	0.0
9 (EV)	99	1.0	0.0
10 (PHEV)	73	1.4	0.0
Average	41.9	3.1	2.5

Source: SAFE Analysis

34 EPA, NHTSA, 2017–2025 LDV GHG Emissions and Fuel Economy Rule at 62,651

35 DOE, “Electric and Hybrid Vehicle Research, Development, and Demonstration Program; Petroleum-Equivalent Fuel Economy Calculation,” 65 Fed. Reg. 36,986, 36,990, June 12, 2000

36 While advocating establishment of the CAFE requirements, President Ford also advocated deferring tightening of automobile emission standards for five years so that automakers could focus on improving fuel economy by 40 percent over that time period. President Ford’s Address Before a Joint Session of the Congress Reporting on the State of the Union, January 15, 1975

37 The statute governing the calculation of corporate fuel economy currently incentivizes the use of alternative fuel vehicles by dividing their actual fuel economy by 0.15 for the purpose of calculating fuel economy for purposes of compliance. Though this already gives a substantial incentive to automakers to produce alternative fuel vehicles, the Council believes that the system would be improved if the calculations were performed in a manner supported by the underlying energy situation and not by an artificial and arbitrary construct.

FIGURE 65

The table on page 99 demonstrates the calculation of fuel economy using three different metrics: 1) MPGe, 2) gallons of gasoline equivalent consumed per 100 miles, and 3) gallons of gasoline consumed per 100 miles traveled. If the metric of “gallons of gasoline per 100 miles” is used, the total average fuel consumption would be lower than if it were measured in gallons of gasoline equivalent of fuel, because it accounts for the fact that PEVs, natural gas vehicles (NGVs), and fuel cell vehicles (FCVs) do not consume oil. Using this calculation is therefore more consistent with the original intent of the statute in that it emphasizes the goal of reducing petroleum consumption.

The Council recognizes that the current calculation, which is based on a vehicle’s MPGe, is required by statute at this point in time.³⁸ We nevertheless encourage NHTSA to evaluate the consequences of calculating fuel economy based on a gallons-per-mile metric and share its conclusions with Congress.

PRIMARY RECOMMENDATION

The National Highway Traffic Safety Administration and the Environmental Protection Agency should amend the medium- and heavy-duty fuel economy and greenhouse gas emission rules to offer additional incentives for natural gas vehicles.

In 2011, EPA and NHTSA issued the first ever fuel-economy and greenhouse-gas (GHG) emission standards for medium- and heavy-duty vehicles.³⁹ The rules, which were mandated by the Energy Independence and Security Act of 2007, are forecast to save 530 million barrels of oil over the life of the vehicles sold during the model years 2014 to 2018.⁴⁰

The agencies designed the rules so that fuel economy was calculated as a direct function of greenhouse gas emissions.⁴¹ In doing so, they effectively established a single standard for GHG emissions and fuel economy. Because electric vehicles have no tailpipe emissions, they are treated favorably under the rules.⁴² NGVs also receive favorable treatment because natural gas has lower carbon content than gasoline or diesel and therefore NGVs have lower GHG emissions.⁴³ The agencies, however, declined to create additional incentives for NGVs beyond the benefit they would receive by virtue of their more favorable GHG profile.⁴⁴

The Council disagrees with the assessment made by NHTSA and EPA. Natural gas is becoming an increasingly important part of the U.S. energy mix and its role in transportation as an alternative to oil is crucial to strengthening the nation’s energy security. It is well positioned to displace oil in the medium- and heavy-duty vehicle segment in particular, which is the second largest fuel-consuming segment of the economy behind light-duty vehicles.⁴⁵ This is a result of several characteristics, including having the storage space required for large CNG fuel tanks to support sufficient range. These vehicles are also typically deployed in fleets which can use centralized refueling centers or as long-haul trucks that typically travel and refuel along defined corridors.

In 2010, a year before issuance of the medium- and heavy-duty rule, the EPA declined to offer incentives for NGVs in the GHG emissions rule, though they sought comments on whether additional incentives were appropriate.⁴⁶ By the time it issued the final light-duty vehicle rule in 2012, a year

38 49 USC §32905(c)

39 EPA, NHTSA, MD/HD FE Rule

40 Id., at 57,106; and EISA 2007, Pub. Law 110-140, 121 Stat. 1492, Sec. 102

41 Id. at 57,124

42 Id. at 57,123

43 Id. at 57,124

44 Id.

45 ORNL, TEDB, Edition 31, Tables 1.14 and 1.17

46 EPA, NHTSA, “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards,” 76 Fed. Reg. 74,854, 75,013, December 1, 2011

after the final medium- and heavy-duty vehicle rule, EPA had changed its approach. In the 2012 final light-duty rule, EPA gave NGVs an incentive⁴⁷ because they “share some of the market barriers faced by [EVs, PHEVs, and FCVs]; for example, higher vehicle cost, lower vehicle range, the need for new refueling infrastructure, and consumer acceptance.”⁴⁸ Moreover, EPA concluded that “CNG investments have the potential to facilitate the introduction of hydrogen FCVs in several respects.”⁴⁹

The Council believes that the new policy adopted in the light-duty vehicle rule, issued after the 2011 medium- and heavy-duty rule, should be extended to medium and heavy-duty NGVs. Due to the role that medium and heavy-duty NGVs can play in reducing petroleum consumption, the suitability of natural gas to power segments of medium- and heavy-duty vehicles, and the reasons given by the agencies for additional incentives in the light-duty rule, the Council recommends that in undertaking phase two of the medium- and heavy-duty fuel economy and greenhouse gas emission regulations, the regulators should offer heavier NGVs an incentive of similar value to that provided to NGVs in the light-duty rule.

PRIMARY RECOMMENDATION

Encourage federal government adoption of alternative fuel vehicles.

As one of the largest purchasers of vehicles and fuel in the nation, with a presence that extends throughout the economy, the federal government is well situated to be a significant participant in the market for alternative fuel vehicles. Greater federal adoption of advanced technology vehicles would generate important data and lessons regarding vehicle use and help scale the industry supply—which is critical to continue to reduce costs for typical consumers—while ultimately saving agency funds and American taxpayers' money.

Executive Order (E.O.) No. 13423, issued by President Bush in 2007, directed agencies with 20 or more vehicles to reduce their fleet fuel consumption by 2 percentage points annually from 2005 to 2015 (a 20 percent reduction).⁵⁰ It also directed agencies to purchase plug-in hybrid electric vehicles when commercially available at a cost comparable to other vehicles.⁵¹ Executive Order No. 13514, issued by President Obama, imposes additional requirements on agencies to reduce greenhouse gas emissions from the federal fleet by 2 percent annually until 2020 and extends the requirement in E.O. 13423 to reduce fuel consumption by 2 percent annually through 2020 as well.⁵² It left the PHEV purchase requirement in E.O. 13423 intact and advised agencies to reduce the use of fossil fuels by deploying “low greenhouse-gas emitting vehicles, including alternative fuel vehicles.”⁵³

The federal government can play a critical role in terms of driving scale throughout the AFV production supply chain. By placing large orders that replace significant portions of regional federal fleets, the government can contribute to an accelerated pace of technological advancement and cost reduction in AFV drivetrain components, such as batteries, electric motors, and natural gas storage tanks. Large fleet purchases will also give stakeholders throughout the AFV supply chain the long-term stability needed to justify significant investments in labor and equipment.

Despite the existence of executive orders that direct agencies to purchase efficient and advanced vehicles, agencies often choose to meet the requirements by purchasing vehicles with the lowest

47 EPA, NHTSA, “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards,” 77 Fed. Reg. 199 at 62,652, October 15, 2012, (LDV FE/GHG Emissions Rule). This incentive complements the incentives for NGVs required by law in the light-duty fuel economy rule. See, 49 USC § 32,905

48 EPA, NHTSA, LDV FE/GHG Emissions Rule at 62,816

49 Id.

50 Federal Register, Vol. 72, No. 17, Executive Order 13423 of January 24, 2007, Strengthening Federal Environmental, Energy, and Transportation Management, at 3919

51 Id., at 3919–2920

52 Federal Register, Vol. 74, No. 194, Executive Order 13514 of October 5, 2009, Federal Leadership in Environmental, Energy, and Economic Performance, at 52117–52118

53 Id., at 52118 and 52124–52126

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Agency	Cars	Buses	Light Trucks	Medium-Duty Trucks	Heavy-Duty Trucks
USPS	10	0	190	0	5
Army	20	0	35	10	5
DHS	15	0	35	5	5
Air Force	15	0	25	5	10
USDA	15	0	25	5	0
DOJ	20	0	20	0	0
Navy	15	0	15	0	5
DOI	15	0	15	0	5
DOE	5	0	10	0	0
Marine Corps	5	0	10	0	0
Other	25	0	50	0	5

FIGURE 67

80 Thousand Units

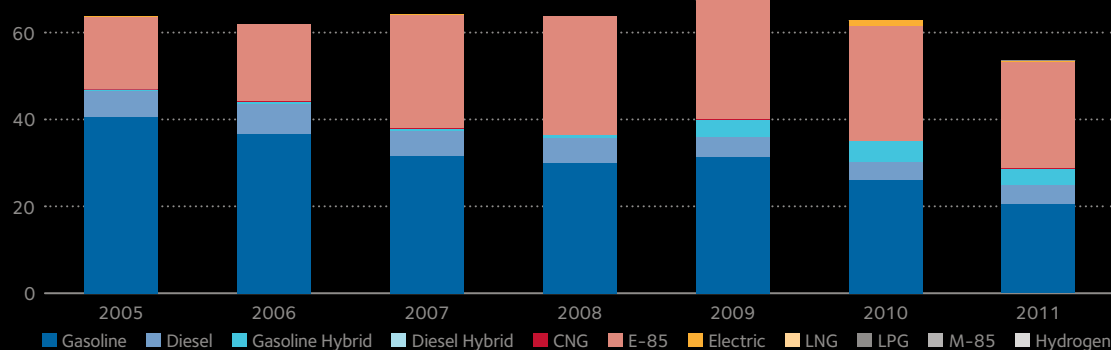
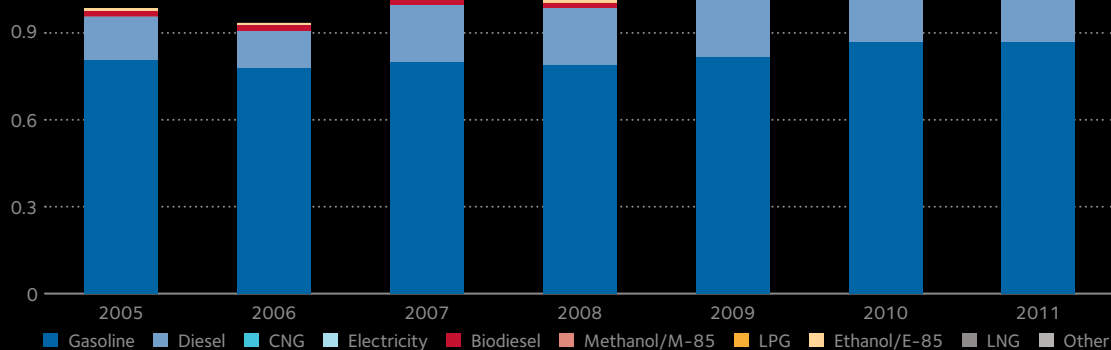


FIGURE 68

1.2 Million Barrels per Day Gasoline Equivalent



Source: ORNL

capital cost. Too often, this has meant purchasing flex-fuel vehicles that—though capable of running on E85—operate on traditional petroleum fuels due to a lack of refueling infrastructure.⁵⁴ This accomplishes very little in terms of improving U.S. energy security and only benefits an already mature technology.

There are several things the federal government could do to improve the uptake of plug-in electric vehicles and natural gas vehicles within the federal fleet. First, Congress could establish a program at the General Services Administration (GSA) that would cover the incremental costs of AFVs and any associated infrastructure purchased by federal agencies. Directly appropriating funds for that purpose would allow agencies to procure AFVs without taking scarce funds away from their core missions. Such a program would have the added benefit of allowing Congress and the public to easily monitor the rate at which these vehicles are incorporated into the federal fleet.

Second, either by Executive Order or Congressional Action, federal agencies could be required to more carefully evaluate commercial leasing options. Today, most agencies interested in leasing do so through the GSA, which purchases the vehicles and then leases them to agencies. For conventional vehicles, this approach has been generally successful, as it leverages GSA's bulk-purchasing power to capture savings for the agencies. However, GSA has been unwilling to carry the burden of higher AFV purchase costs, particularly for PEVs, and it has expressed concerns regarding the uncertainty of the residual value of PEVs. GSA, therefore, requires agencies to cover the incremental costs of PEVs as part of the lease term, an approach that essentially negates the benefits of leasing.

Agencies should be encouraged to lease PEVs directly from automotive dealerships when it makes economic sense. Today, commercially-available PEV leases are more attractive than GSA leases. While there is nothing statutorily preventing agencies from utilizing commercial leases, most government fleet managers default to GSA for leasing as a matter of practice. Therefore, agency fleet managers should be required to perform a basic business-case analysis that compares the lease costs offered by GSA with those offered by commercial leasing entities.

United States Postal Service

The U.S. Postal Service (USPS) is currently facing significant funding issues. Most recently, USPS reported a \$15.9 billion loss in FY 2012.⁵⁵ The largest portions of the shortfall were unrelated to current operational issues, with more than \$11 billion generated by mandatory pre-funding of retiree health benefits, and an additional \$2.4 billion coming from long-term workers compensation payments. Yet, even without these expenses, losses in 2012 would have amounted to approximately \$2.5 billion.⁵⁶

A well-managed switch to plug-in vehicles could reduce operating costs substantially at a time when savings are badly needed. As of 2011, USPS had 210,318 vehicles in operation, including 192,000 light trucks, and fuel costs in FY 2012 topped \$520 million.⁵⁷ According to a 2009 report by the USPS Office of the Inspector General (IG), the average daily mail-delivery vehicle driving distance is 18 miles, making many of these vehicles well-suited for right-sized EV batteries or smaller PHEV batteries.⁵⁸ In fact, more than 90 percent of Postal delivery vehicles travel less than 40 miles per day on highly-predictable routes.

The current USPS vehicle fleet contains a large number of older vehicles—25 percent have been in service for 20 years or more—and maintenance costs have become a significant burden.⁵⁹ USPS spent roughly \$900 million on vehicle maintenance in FY 2012, including parts and labor, implying

54 See, e.g. GAO, 11-386, *United States Postal Service, Strategy Needed to Address Aging Delivery Fleet*, May 2011, at 17-19

55 U.S. Postal Service (USPS), "Postal Service \$15.9 Billion Loss Highlights Urgent Need for Legislative Reform in Congressional Lame Duck Session," November 15, 2012

56 *Id.*

57 ORNL, TEDB, Edition 31, Table 7.7

58 USPS, Office of the Inspector General (OIG), *Electrification of Delivery Vehicles*, at 8

59 *Id.*, at 9

an average cost per vehicle of more than \$4,000.⁶⁰ In fact, these figures understate the issue to a large degree. Postal Service policy currently emphasizes maintaining conventional vehicles as long as possible—a strategy known as fix until fail—including to the point of vehicle reconstruction at a cost that can exceed \$10,000 per unit.⁶¹ In addition to generating large savings in fuel spending, substituting PEVs for conventional vehicles would result in sharply lower maintenance costs for items such as brake pads and tires, not to mention fluid replacement, engine servicing, and transmission repair and replacement.⁶²

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To assess the potential return on investment of electric vehicles for USPS, the IG report presented a ten-year cash flow analysis for the purchase of 3,000 electric vehicles at a cost of \$40,000 per unit. This figure represents a significant incremental cost compared to a conventional alternative, which the IG assumed to be \$19,000.⁶³ Additional costs incorporated in the analysis included the purchase and installation of infrastructure, employee training, and battery replacement. Primary savings were derived from lower fuel and maintenance expenditures.

According to the IG, the post office typically requires a 3 year payback on capital and a minimum 30 percent rate of return.⁶⁴ In its base case, the IG report found that an EV investment by USPS would fall short of these goals. However, the report also looked at additional scenarios, including enhanced revenue from vehicle-to-grid (V2G) applications and participation in a DOE-sponsored demonstration program. These scenarios found that USPS could achieve a two-year payback and 63 percent return if the vehicles were subsidized at \$15,500 per truck through participation in a DOE-sponsored demonstration program and earned \$2,000 per truck annually in supplementary V2G revenue.⁶⁵

It is also important to note that the IG report did not explore potential cost savings from battery right-sizing. The incremental cost of electric vehicles could be significantly reduced by eliminating unused battery capacity. While the IG analysis assumed average daily vehicle travel to be roughly 18 miles, a \$40,000 EV would almost certainly provide range closer to the industry average of 70 to 100 miles. Given the predictable and relatively short nature of USPS delivery routes, battery capacity could effectively be cut in half, reducing costs by \$5,000 to \$8,000 while still meeting operational needs. This would substantially offset the need for additional funds.

The federal government should help offset the incremental cost of a limited number of PEV purchases by USPS for the period 2013–2016. This could be managed through direct appropriations or through a demonstration project focused on the potential applications of V2G technologies. An emphasis should be placed on driving advancements and learning that will benefit the broader industry, with particular focus on the feasibility of battery right-sizing and best applications of V2G. Such a program would have the dual benefits of allowing USPS to achieve significant operational savings while also helping to scale the PEV supply chain. At the end of this four-year period, the Inspector General should be required to produce an analysis of the program and make recommendations on the need for a possible second phase.

60 SAFE analysis based on published reports

61 SAFE conversations with federal government officials

62 Commercial fleets deploying EVs and PHEVs have reported significantly extended life on both brake pads and tires, yielding greater than expected maintenance savings. See, e.g., Electrification Coalition, "It's Electrifying: PG&E on How Electrification is Saving its Fleet Money Today," available at <http://fleetanswers.com/content/its-electrifying-positive-returns-pev-deployment>

63 USPS, OIG, Electrification of Delivery Vehicles, at 14

64 Id., at 4

65 Id.

PRIMARY RECOMMENDATION

Establish a grant program at the Department of Energy to fund state initiatives to upgrade critical infrastructure which would reduce the risk of severe weather-related energy sector service interruptions.

On several occasions in recent years, the energy sector has been unable to maintain electrical service and meet regional fuel demands in the wake of natural disasters, most often hurricanes or major snowstorms.⁶⁶ The transportation fuels sector is particularly vulnerable to storms that make landfall in the Gulf Coast, because transport and refining facilities are more heavily concentrated there than elsewhere in the nation.⁶⁷ But as we have seen from Hurricane Sandy, other regions of the nation are also susceptible to supply interruptions as the result of severe weather.

The impacts of large storms extend far beyond the damage they do to energy-related infrastructure, often resulting in injuries, the loss of life, and devastating property damage. Because our electric distribution infrastructure is among the more fragile parts of our nation's critical infrastructure, it is subject to service interruptions in areas far beyond the center of a storm.

When the electrical grid fails, not only does a community lose power, it also often loses the ability to obtain fuel through the traditional distribution infrastructure which itself relies on electricity to move products through pipelines, and pump it from bulk storage tanks into tanker trucks, and from underground tanks at gasoline stations into vehicles. Fuel shortages may not have as dire of an impact on a community as the physical damage from the storm or loss of electricity to homes and businesses, but it does limit the mobility on which our daily lives and our economy depends. Maintaining the availability of transportation fuel also is critical to supporting first responders as well as energy response service providers, facilitating other recovery efforts, restoring a sense of normalcy, and beginning the process of economic recovery.

While the grid is a giant interconnected system, the distribution system—its most vulnerable part—is designed to meet local needs. As a general matter, the reliability of the electrical distribution system is the responsibility of utilities that deliver power to local business and residences.⁶⁸ The distribution activities of these utilities typically are regulated by state public utility commissions and are not subject to federal regulation.⁶⁹ The federal government has authority over the reliability standards applicable to the bulk power market, exercised generally through the Federal Energy Regulatory Commission's authority to ensure the reliability of the bulk power system.⁷⁰ However, in large-scale power outages, much of the damage often occurs to state-regulated distribution level facilities outside the scope of federal jurisdiction.⁷¹

Policies to enhance the resilience of the distribution system in the wake of severe weather, therefore, should be developed at the state level and tailored to meet local needs. As a critical first step, state emergency planners should work with utilities to identify the parts of the local distribution system that are most susceptible to storm damage, upgrades that might enhance distribution grid resiliency and reduce the likelihood of service interruptions, and preparations that might facilitate their repair after a storm. They should use weather crises simulations to help identify vulnerabilities and enhance preparedness.

66 Los Angeles Times, "After Sandy, 75 Dead, Millions Without Power, Gas Precious," November 2, 2012; DOE, Office of Electricity Delivery and Energy Reliability, "A Review of Power Outages and Restoration Following the June 2012 Derecho," August, 2012; and New York Times, "The Troubling Connecticut Power Failure," November 3, 2011.

67 DOE, Office of Electricity Delivery and Energy Reliability, "Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons," at 1, August, 2010.

68 See, Section 215 of the Federal Power Act, codified at 16 U.S.C. § 8240(a)(1); Federal Energy Regulatory Commission, "Report on Transmission Facility Outages During the Northeast Snowstorm of October 29–30, 2011, Causes and Recommendations," at 8, 2012.

69 Id.

70 Id.

71 Id.

The Council expects that state regulators would allow inclusion of investments to enhance system reliability in the utility's rate base, allowing it to recover its costs. There may be some instances, however, where investments that emergency planners feel are appropriate do not meet with regulators' approval, perhaps because they are deemed too expensive or focused on events that are too unlikely to warrant investment, or are investments that should be made by parties other than utilities subject to state regulation. State emergency planners that identify such investments as part of their planning processes should be eligible to apply for federal grants described below.

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Despite its complexity, the fuel delivery system is less fragile than the grid, in substantial part because it does not require real-time production of fuel and incorporates capacity to store fuel at nearly every place along the value chain from the refineries where it is produced, to the pipelines and fuel terminals through which it is transported, to the retail outlets from which it is sold. While all of these parts of the system are susceptible to storm damage, they are more likely to be affected by electricity outages. Unlike utilities, however, which have strong incentives to limit power loss during a storm and get the electricity back on quickly, many of the parties along the petroleum product distribution chain are individual entities that may lack the same incentives to put emergency backup systems in place because of their substantial expense and the infrequency with which they may be used. For example, a gasoline retailer or a fuel terminal operator might lack an incentive to install backup generation, because it loses power only infrequently and cannot increase the price of fuel during shortages to compensate for the costs incurred to ensure fuel availability during power outages. Moreover, even if such a business has backup power, if other parts of the network lack power, they may not be able to help move fuel through the system to retail customers.

State emergency plans should focus on maintaining the operability of facilities that are best situated to serve the community, recognizing that a facility's value to the community may be far greater than the cost required to enhance its reliability. State emergency planners, therefore,

should identify those facilities whose operation is most important to the community, and then identify what, if any, incentives are required to upgrade the facilities to the appropriate level of preparedness. Florida, for instance, which has perhaps more first-hand experience with hurricanes than any other state, requires fuel terminals and gasoline stations near interstate highways or state-designated evacuation routes to be wired to accept power from portable generators and requires owners of multiple gasoline stations to have portable generators in or near the state.⁷² This level of preparedness may or may not be sufficient, as there still may be a shortage of generators, fuel, or open

When the electrical grid fails, not only does a community lose power, it also often loses the ability to obtain fuel through the traditional distribution infrastructure which itself relies on electricity to move products through pipeline, and pump it from bulk storage tanks into tanker trucks, and from underground tanks at gasoline stations into vehicles.

road to transport generators to places where they are needed. Louisiana has similar requirements for newly constructed or rebuilt gasoline stations.⁷³ Of course, there are likely different needs in different states, and a state's emergency planners are often the best judges of what will enhance the reliability of energy systems in their own communities.

To reduce the risk of service interruptions of critical energy-related infrastructure due to severe weather, the Congress should establish a grant program at the Department of Energy to which states can apply for funds to enhance the resiliency of their energy infrastructure. Grants should be available to states that develop comprehensive plans specifically to minimize the interruption of energy services, which, among other things, identify measures that could reduce the risk of service interruptions due

72 Fla. Stat. § 526.143

73 La Rev Stat § 30:2195.12

to severe weather and the ability to recover more quickly after storms. Grants should also be available to assist states in the planning process. Running simulations of severe weather events that can help all relevant parties identify and understand system weaknesses and develop responses could be an important part of preparedness, and should be run on a regular basis as many important response and oversight positions turn over with some regularity. States, however, should undertake whatever planning process works best for the state. Priority in awarding grants should be given to states that supplement federal funds and take additional measures to enhance system reliability, such as creating legal requirements for measures to enhance the resiliency of critical infrastructure, as Florida did with gasoline stations.

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States could use federal grant funds to upgrade infrastructure, especially in instances where the property owners lack incentives to make upgrades which could provide substantial public benefits. Primary emphasis should be given to maintaining power, particularly through the availability of backup generators, at critical energy infrastructure, such as fuel terminals and gasoline stations, and appropriate points in the distribution system. Because maintaining service on interstate product pipelines is a national priority, and the beneficiary communities might be far from where outages occur, Congress should consider either requiring interstate product pipelines to maintain sufficient backup power generation to enable pipeline operators to restore power within a specified period of time, or establishing tax credits for the purchase and installation of such equipment.





PART IV

Global Developments with Long-Term Implications for U.S. Energy Security

Global Developments with Long-Term Implications for U.S. Energy Security

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II O

Over the past decade, there have been incredible shifts in the energy landscape both globally and domestically, including many that few market observers predicted. Economic growth, an expanding middle class, and increased demand for mobility in emerging markets like China and India resulted in greater-than-expected increases in oil global consumption. These increases placed significant strain on global oil producers to expand supplies and have been a major factor in supporting the high and volatile oil prices witnessed since 2003. Forecasts suggest that continued growth in emerging market oil demand will be a key component in relatively high global oil prices going forward.

It is hardly surprising that sustained high oil prices triggered greater investment in the upstream oil and natural gas sector, but the technological revolution in hydrocarbon development that erupted in the United States beginning in 2005 has been a true game changer. Driven by supportive commodity prices and innovations in drilling and completion techniques, the U.S. oil and natural gas industry has unlocked perhaps a century's worth of domestic natural gas supplies and at least 30 billion barrels of new oil resources.¹ The energy debate in the United States has shifted from one focused squarely on resource scarcity and rising current account imbalances to one in which greater self-sufficiency in energy supplies is treated as a given, and questions regarding the best use of new energy supplies are front and center.

Further shifts in global and domestic energy markets will undoubtedly occur in the coming decades. And the shifts of tomorrow, like the shifts of today, will both afford opportunities and pose threats to American economic prosperity and national security. Undoubtedly, some elements of change in energy markets will always be beyond the ability of forecasters to fully anticipate. Yet there is clearly a selection

Future shifts in energy markets both domestically and globally will afford opportunities and pose threats to American economic prosperity and national security.

of important developments already on the horizon that policymakers would be wise to watch closely in the coming months and years. In fact, some are natural extensions of changes already underway.

The boom in U.S. oil and natural gas production has raised several critical questions with respect to global energy markets. Flush with domestic natural gas supplies, many analysts now wonder how rapidly the United States will enter

the global natural gas market as an exporter. While several studies have attempted to quantify the domestic and international price effects of such a development, few have pondered the geopolitical impacts that could result from greater supply-side natural gas competition—particularly as they might relate to established suppliers like Russia.

1 SAFE analysis based on data from: DOE, EIA; and Potential Gas Committee

If successfully applied abroad, the hydraulic fracturing and horizontal drilling technologies that have unlocked new resources in the United States could have profound implications for international oil prices and the global energy market. Investment in the United States by foreign oil and natural gas producers has increased dramatically in recent years, suggesting that the transfers of technology and know-how that could make meaningful production growth possible in multiple other global regions are already underway. However, success remains far from certain and impediments currently abound.

There are perhaps no developments that could impact oil prices more than a sudden decline in demand growth or a surge in production of low-cost oil supplies. Both developments are within the realm of the possible—though perhaps not the probable. Amid signs of economic uncertainty in China, some observers have begun to question a key pillar in the case for buoyant global oil prices—fuel demand in China. Major changes in China's economy would be expected to affect oil consumption which could have broad ramifications for the global oil market.

Meanwhile, a surge in oil production from Iraq, where output recently reached levels last seen prior to the first Gulf War, would likely lower oil prices by displacing investment in the world's most expensive oil supplies. Growth in Iraqi oil production may also soon raise questions and tensions within OPEC, as it works to incorporate new production growth into the quota system at a time of rising output from non-OPEC countries.

In the pages that follow, these four developments are addressed in turn: the geopolitical impact of U.S. liquefied natural gas (LNG) exports, the likelihood of U.S. technology ushering in unconventional production growth in other global regions, the outlook for Chinese oil demand growth under three different scenarios, and prospects for the Iraqi oil sector with potential effects on OPEC. Each of these developments could have profound impacts on the global energy system, and by extension, major implications for U.S. energy security. Moreover, they are likely to have significant effects on global energy markets regardless of exactly what direction they take. Therefore, we examine these issues through the lens of their implications for American policymakers, suggesting guidelines for action where appropriate.

Analysis

II.2

DEVELOPMENT I

What are the economic and geopolitical implications of the United States exporting liquefied natural gas?

A rapid increase in U.S. natural gas production has given rise to a complex debate over what to do with it. Specifically, there is a very real possibility that the United States could soon export substantial quantities of LNG. The decision that policymakers make on the question of LNG exports will have very significant—though not always clear—impacts on the U.S. economy, our strategic interests, and the overall geopolitical landscape.

Less than a decade ago, amid declining levels of domestic production, the United States was contemplating the risks of significant increases in LNG imports shipped from the Middle East, North Africa, and Russia. There was a concern that facilitating LNG imports would risk linking the North American natural gas market with an emerging global gas market, a prospect that seemed to present many of the same risks posed by American oil dependence. Given ongoing speculation that large foreign natural gas producers, many of whom also were large oil producers, might seek to create a natural gas cartel, numerous observers asked whether linking the markets could once again result in a situation similar to the global oil market.²

In the past, the substantial cost of building the infrastructure required to liquefy, export, and ship natural gas has forestalled both the development of a single global market and the United States' participation in the LNG trade in either the Pacific or Atlantic basins. Yet in recent years, LNG has come to play an increasingly significant role in the energy economies of a number of countries worldwide, particularly in East Asia. Having risen by approximately 121 percent in the past decade, LNG today represents more than 30 percent of the total natural gas traded between nations.³ The United States, however, has been able to meet its demand by relying on domestic production supplemented by limited pipeline imports from other North American suppliers and only very small quantities of imported LNG. LNG prices in Europe and Asia, where most trade is occurring, are to some extent correlated with each other, and are higher than North American prices. As the United States has not imported LNG in meaningful quantities, it has been effectively insulated from global price volatility in LNG markets.⁴

Market factors, however, could change the United States' role in the global LNG market. With dramatically increased natural gas production and low domestic prices—\$4.01 per million Btu (MMBtu) in 2011—there are U.S. natural gas producers who would like to see U.S. exports.⁵ With significantly higher prices in Japan, Germany, and the United Kingdom (\$14.73, \$10.69, and \$9.03 per MMBtu respectively), many potential consumers have also indicated a desire for U.S. exports.⁶ Although increased exports, rather than increased imports, may emerge as the catalyst of future links between the North American and global natural gas markets, the costs and benefits of the United States' active participation are still being weighed. The emergence of a functional U.S.

2 See, e.g., Michael Economides, "The Coming Natural Gas Cartel," *Foreign Policy*, March 28, 2006; Monika Ehrman, "Competition is a Sin: An Evaluation of the Formation and Effects of a Natural Gas OPEC," 27 *Energy Law Journal* 175, 2006

3 BP, plc., *Statistical Review 2012*, at 28; BP, plc., *Statistical Review 2003*, at 28

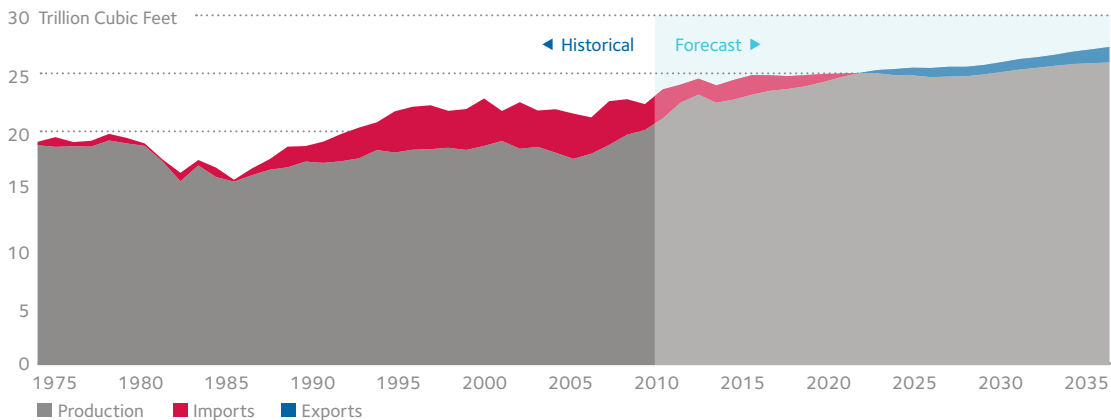
4 DOE, EIA, *AER 2010*, Table 6.3, at 197

5 BP, plc., *Statistical Review 2012*, at 27

6 *Id.*

U.S. Natural Gas Production, Imports, and Exports

FIGURE 69



Source: DOE, EIA

natural gas export industry could bring our relatively low domestic natural gas prices into greater alignment with higher international prices. Moreover, greater integration into an increasingly global market might expose the United States to not only higher prices, but also to price volatility. If realized, both could be detrimental to U.S. energy security. However, increased LNG exports would also have positive macroeconomic consequences, including improving the trade balance and strengthening the U.S. dollar.

Exports on the Horizon

Most market observers expect that the United States will begin exporting natural gas, and the Department of Energy currently forecasts that the country will become a net exporter sometime between 2020 and 2023, depending on resource recovery.⁷ The Oxford Institute for Energy Studies estimates that U.S. LNG exports could exceed 12 billion cubic feet per day (bcf/d) by 2020—equivalent to approximately 37 percent of the current global trade in LNG of about 32bcf/d, or 14 percent of total forecast inter-regional natural gas trade in 2020.⁸ While that would reflect an aggressive export strategy, it seems entirely reasonable that the United States could easily export 6 bcf/d, still equal to approximately 9 percent of forecast U.S. natural gas demand of 70 bcf/d in 2020.⁹

Significant U.S. LNG exports will have important geopolitical ramifications as it competes against Australian, Southeast Asian, Russian, Middle Eastern, and African LNG on the global market, forcing existing producers to find new markets, at home or abroad, or perhaps decrease production as declines in natural gas revenues risk exacerbating regional instability. Equally important is the prospect of strong growth in LNG trade and an emerging U.S. role in global natural gas markets shifting markets away from a pricing system historically linked to global oil prices. Such a shift would enable consumers in Europe and Asia to enjoy lower natural gas prices as oil and natural gas prices decouple, without pushing up U.S. natural gas prices significantly.

Importantly, these geopolitical implications are likely to occur even if the United States decides against exporting significant quantities of LNG. If the United States restricts exports, increased production of domestic shale gas likely will supplant imports from Canada in satisfying domestic demand, prompting Canada to export LNG to markets outside of North America with similar effects.

7 DOE, EIA, *AEO 2012, Natural Gas Supply, Disposition, and Prices*

8 James Henderson, "The Potential Impact of North American LNG Export," Oxford Institute for Energy Studies, 2012; BP, plc., *Statistical Review 2012*, at 28; and IEA, *WEO 2012*, at 147

9 IEA, *WEO 2012*, at 128

FIGURE 70

Geopolitical LNG Dynamics

Region	Economic implications	Geopolitical implications
Asia	North American LNG exports to Asia compete with long-term contracted LNG for incremental supply. Australian, Russian, North American, and South East Asian LNG supplies Asia, displacing Middle Eastern and West African LNG to Europe.	Limited. Potential exists to use energy flows to strengthen the role of the United States in Asia.
Middle East	Existing projects deliver cargos as planned, but there are limits to further expansion of LNG capacity. Instead, additional natural gas production is directed to supplying Middle East power demand (displacing oil for export).	Limited. The Middle Eastern country with perhaps the greatest potential for new natural gas development is Iran, which shares a resource base with Qatar, but sanctions currently prevent Iran from developing its resources. Qatar's revenue stream is secure on long-term contracts, and it is the only Middle Eastern country that relies on natural gas, rather than oil, for its export revenue.
West Africa	West Africa has been relatively swift to embrace spot pricing of LNG. As such, it will experience a sharper fall in revenues than the Middle East, where a larger share of natural gas production is under long-term contract. However, LNG projects in West Africa have been developed by international oil and natural gas companies, which will bear the brunt of decreased revenues.	Limited. West Africa does not rely heavily on natural gas exports for its revenues, and energy conflict in Nigeria is focused primarily on dispersed oil production facilities, rather than large, concentrated LNG liquefaction plants.
Europe	U.S. LNG exports will free West African and Middle Eastern LNG that would previously have gone to Asia to go to Europe, where it will compete with Russian and North African (mostly Algerian) exports for European market share. This will help to reduce natural gas prices in Europe and will likely speed the shift away from long-term, price-stabilized contracts and towards traded market pricing. Lower natural gas prices may help Europe to recover economically and regain competitiveness.	A wider range of import options will help reduce European prices. This will aid economic recovery in Europe and help reduce its dependence on Russia, strengthening the trans-Atlantic alliance.
Russia	Russia's export revenues from natural gas are being squeezed by rising domestic consumption, insufficient and inefficient investment in production, and rising import prices for the natural gas it buys from Central Asia. Falling European prices, and potentially falling demand for its natural gas, could prevent Russia from raising the energy revenue that it needs to balance its budget and meet the social commitments that help ensure political stability.	The political consequences of slower or declining economic growth in Russia could be serious. If Russia is unable to meet its budget commitments, the government's political legitimacy could be damaged, perhaps leading Russia to adopt aggressive domestic and international policies to deflect popular scrutiny away from weak economic conditions. This could be particularly damaging for U.S. interests given Russia's close relations with Iran and Syria.
North Africa	Falling European prices and greater competition for supplies into Europe would also hurt North Africa, particularly Algeria, which relies on natural gas exports to Europe for a large portion of its export revenues. Like Russia, Algeria requires high prices to balance its budget.	Like Russia, Algeria is at risk of social and political instability if the government is unable to meet its budgetary commitments. Given continued regional conflicts and uncertainty in the aftermath of the Arab spring, it is unclear what the consequences of rising social tensions in Algeria might be.

Source: Roubini Global Economics

Implications for Policymakers

Low-cost U.S. natural gas is already affecting natural gas market dynamics across the globe. Exports of North American LNG appear likely to have even more significant consequences, both economically and geopolitically. At home, a fierce debate has developed over the propriety of exporting substantial volumes of LNG and the effects it could have on the U.S. economy.

In the short term, after approving the first application to export natural gas to a nation with which the United States do not have a free trade agreement, DOE has subsequently delayed any decisions regarding other pending applications until the completion of an economic analysis report. This report has been specifically commissioned to examine the economic impacts of U.S. LNG exports using a global natural gas market model.

The Council recognizes the importance of studying this issue further and plans to release a report analyzing the geopolitical and economic effects of U.S. LNG exports in 2013.

DEVELOPMENT II

What are the barriers preventing other countries from exploiting their unconventional oil resources using hydraulic fracturing and horizontal drilling techniques?

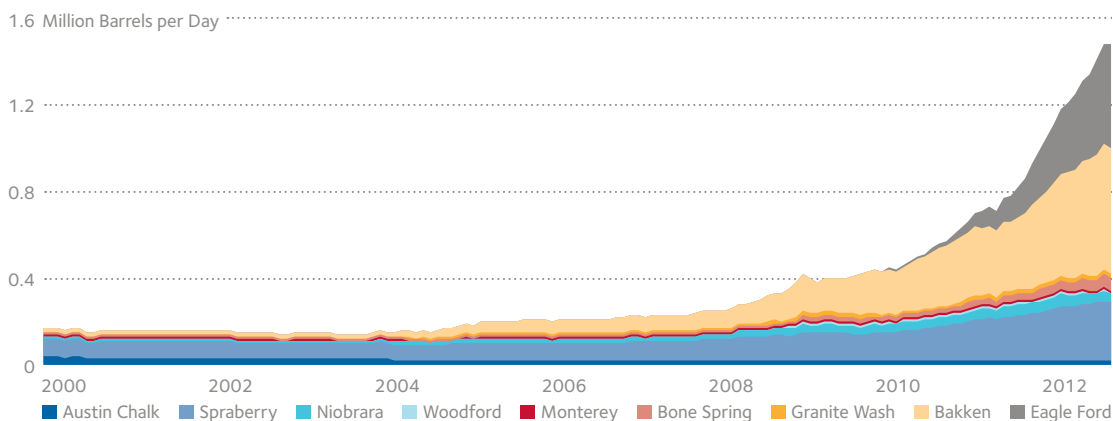
As discussed in detail in *Part II*, a modern boom in oil production is underway in the United States. While mature oil-producing regions like the Permian basin in Texas remain an important part of the picture, large quantities of light sweet crude oil held in unconventional deposits in North Dakota, Colorado, and elsewhere are now also being developed using hydraulic fracturing and horizontal drilling techniques. These resources are collectively referred to as light tight oil (LTO) and are produced from shales (such as the Bakken and Eagle Ford) in addition to tight sands, low-permeability carbonates, chinks, and other similar geological formations. As a whole, the lower-48 onshore United States appears to be positioned for a sustained period of growth based largely on the development of these resources. The extent to which hydraulic fracturing and horizontal drilling techniques can be applied to extract oil in other nations, and particularly in other major oil-consuming nations, remains uncertain. However, companies have hinted at good prospects in several nations including China, Argentina, Australia, Poland, and Russia.¹⁰

Prospects for the Application of U.S. Drilling Technology

Contrasting the characteristics of the current U.S. oil boom with previous booms is demonstrative of the potential (or lack thereof) associated with know-how and technology transfer. The critical limiting factors for the deepwater offshore oil boom of the 1990s and 2000s, for example, were capital and new, advanced technology. Each drilling prospect was different and the solutions were highly individualized. As such, technology and continued innovation became the most important determinants of success, and Western international oil companies (IOCs) were able to achieve an early lead as a result.

On the other hand, the massive growth in Russian oil production in the decade from 1996, when oil production increased by more than 50 percent (+3.4 mbd), was not driven by technological innovation.¹¹ Instead, this growth was made possible by applying a relatively straightforward set of established technologies (known colloquially as the “West Texas Toolkit”) in Western Siberia. This required investments in labor and production capital, but no new technological innovation.¹²

U.S. Tight Oil Production by Play



Source: DOE, EIA

FIGURE 71

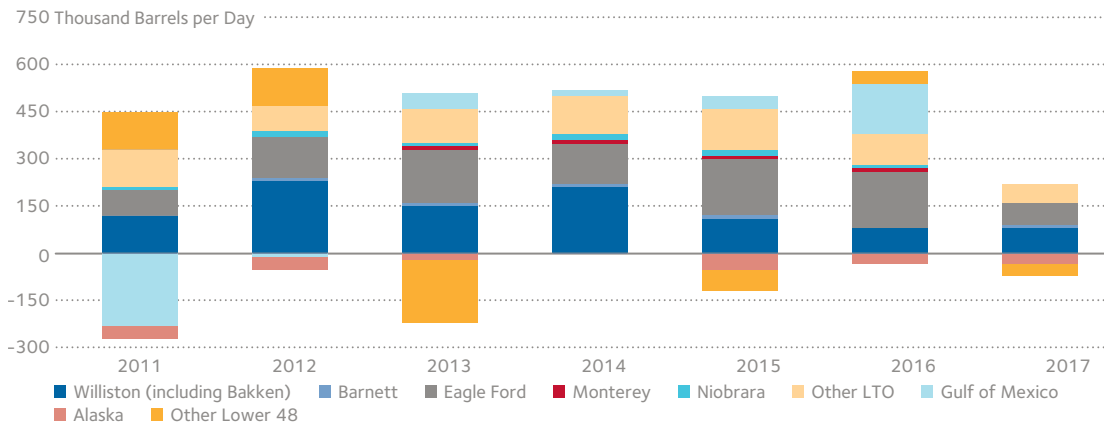
¹⁰ IEA, *MTOMR 2012*, October 2012, at 58

¹¹ BP, plc., *Statistical Review 2012*, online statistical supplement, “Oil Production”

¹² While these technologies have been used very successfully around the world, their impact was most striking in Western Siberia, where the end of the Soviet Union led to a sudden influx of new technology. These technologies include particularly directional drilling, hydraulic fracturing and more sophisticated stimulation through reinjection, water injection and management of pressure and flow dynamics across the field. Russian production expansion since 2005 has been driven primarily by new prospects coming online, most notably Sakhalin, rather than application of new technology to existing prospects.

FIGURE 72

Forecast Change in U.S. Crude Production



The current domestic oil boom falls into the second category. LTO production technology is relatively straightforward, and rather than relying on substantial new innovation, it instead requires continued application of a standard set of established technologies—namely horizontal drilling and hydraulic fracturing.¹³ As such, foreign countries seeking to develop their LTO resources are not beholden to the latest technological expertise of Western IOCs and can instead access this technology directly, whether through practical experience of investing in LTO development in North America or through service companies. Barclays Capital has estimated that global spending on exploration and production will be \$614 billion in 2012, with the bulk spent outside of North America (\$451 billion).¹⁴ Hydraulic fracturing and horizontal drilling, core technologies for LTO as well as shale gas, have been among the main drivers of recent increases in spending and can be expected to remain as such in coming years. Many maturing oil producers (Russia, Oman among others) have emerged as major buyers of these technologies as they seek to maintain their production levels.

Non-Technological Impediments

Whether the U.S. LTO boom is repeated elsewhere remains uncertain in the short to medium term. This is primarily attributable to differences in operating environments. With respect to LTO production specifically, the United States is uniquely situated to exploit these unconventional resources because it has: an extensive pipeline network; a large, established drilling rig fleet; a large pool of skilled labor; strong property rights extending to the subsoil that incentivize landowners to support energy production; and a sufficiently stable and consistent approach to environmental regulation. Other countries, which lack at least one of these features, could find LTO development costs to be substantially higher. For example, the International Energy Agency (IEA) estimates that drilling and producing natural gas from a typical onshore shale gas well in the United States would cost \$4 to \$8 million depending on drilling depth and pressure, whereas a similar well in Poland would cost \$10 to \$12 million, because Poland's drilling and oil services industries are much less developed.¹⁵ The differences in LTO costs would be expected to be similar.

Though it is by no means clear that these obstacles will be overcome, there are reasons to believe that they could be. First, in both Europe and China, LTO offers the possibility of increasing domestic oil supplies in a reasonably short timeframe, thus lessening dependence on imports and improving trade balances (as the United States has done). This should prompt these nations to address any existing regulatory and capital bottlenecks. Second, the cost of LTO wells overseas will fall as the size of the capital stock (rigs and other supporting infrastructure) increases.

¹³ Though techniques such as infill drilling and pad drilling can improve operational efficiency and reduce cost.

¹⁴ Barclays Capital, "Global E&P Capital Spending Update: Higher Int'l Spending to Offset Modest Reduction in North American Budgets," May 18, 2012

¹⁵ IEA, Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas, 2012, at 53

Finally, costs will also fall as exploration efforts accelerate and the understanding of local geology improves.

Geopolitical Implications

Fundamentally, growth in LTO production, whether in the United States or overseas, can affect the global price of oil in two ways. First, the marginal cost of U.S. LTO production is less than the peak marginal cost in the global oil cost curve (i.e. the cost of the most expensive barrel currently produced). Therefore, increasing U.S. LTO production means that more oil can be produced at a given price, thereby constraining future oil price increases, and perhaps even putting downward pressure on oil prices in a low-demand environment.

OPEC is the only market participant likely to consider reducing its production to compensate; however, its incentive and ability to do so will be weakened the greater the quantity of LTO production, because OPEC will be increasingly incentivized to maintain export volumes rather than reduce production to prop up prices. Complicating this response, however, is the fact that many OPEC members are finding that they need high revenues to support rising demand for domestic public services, and they face a tension between trying to increase revenues by raising production or by trying to maintain high price levels. This strengthens the competitiveness of LTO and likely makes OPEC loath to attempt to undercut LTO development by temporarily increasing production to reduce price. Finally, because once established in a particular location, LTO projects have relatively short lead times and can increase production quite quickly, LTO production could recover quickly from a temporary OPEC-induced decrease in prices.¹⁶

Second, a global increase in LTO production would help to constrain price volatility, as production in the United States, Europe, and most of Asia, is considered less susceptible to disruption. Also, because resource development is likely to be located in some major oil-importing economies, the real share of oil consumed in these markets that is potentially at risk of physical disruption will be reduced, as will transportation costs. Furthermore, as referenced above, LTO production is highly flexible in the sense that it can be increased and decreased relatively rapidly. This flexibility could significantly reduce the tendency of the global oil market to undershoot and overshoot for extended periods when demand or other supply levels shift.

Implications for Policymakers

The international impact of the U.S. LTO boom will primarily be associated with the potential it has for decreasing reliance on imported energy in major consuming nations. Increasing LTO production, both in the United States and abroad, will help mitigate oil price volatility, to some extent. It also has the potential to constrain growth in prices.

Besides maintaining a robust regulatory environment to promote domestic LTO production, policymakers must focus on encouraging the development of the necessary physical and regulatory infrastructure necessary to facilitate LTO production in Europe and Asia. This is likely to include a number of components, some general, others more specific to particular nations or regions (such as property rights). Examples might include a dialogue with Europe about the environmental implications of LTO production, discussions with Asian and Middle Eastern policymakers about the negative long-term impact of diverting national oil companies' expenditures to support social and other spending programs, and diplomatic support for American-made technology and know-how.

¹⁶ By contrast, a temporary decrease in oil prices in the 1990s had a major impact on deepwater development because projects take many years to plan and deliver, and short-term changes in prices caused companies to change their planning assumptions and cancel or postpone investments.

DEVELOPMENT III

What if there is a significant slowdown in the growth of the Chinese economy?

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To a large extent, developments in the global oil market during the past decade have been driven by rising levels of oil demand in emerging market economies. A burgeoning middle class, rising rates of vehicle ownership, and increased industrial demand for petroleum have transformed the world's developing economies into the engine of oil demand growth. Between 2000 and 2011, consumption of petroleum fuels outside of the Organization for Economic Cooperation and Development (OECD) increased by 13.7 million barrels per day.¹⁷ Demand within OECD member states actually declined over the same period.¹⁸

No country was more central to this story than China. Between 2001 and 2011, demand for petroleum fuels in China increased by 4.9 mbd, adding the oil demand equivalent of another Japan to the global market.¹⁹ Today, China is the world's second largest consumer of oil, trailing only the United States, and simple population fundamentals suggest that this will not endure. In its most recent long-term forecasts, the International Energy Agency suggests that primary oil demand in China will surpass that of the United States by 2035, but a sooner crossover point is surely possible.

Demand for mobility has been the primary driver behind the Chinese oil demand juggernaut. The number of registered motor vehicles on the road in China reached 78 million units in 2010, nearly six times the 13.4 million on the road in 2000—a rate of growth that accounted for almost one fifth of the global total over that period.²⁰ Passenger car sales in China exceeded U.S. sales in 2010 and 2011, driving a five-fold increase in the number of vehicles per 1,000 people, which now stands at roughly 60, and making China the world's largest vehicle market.²¹ In the United States, by contrast, there are almost 800 vehicles per 1,000 people.²² And while rising mobility in passenger applications has driven sizeable growth in gasoline consumption, demand for middle distillates (which would include diesel fuel for road transport as well as domestic aviation) has increased by an astounding 120 percent since 2001—growth of 2.0 mbd.²³ China has also plowed resources into building its strategic reserves.²⁴

Likely Outlook

While few estimates suggest that the breakneck speed of China's oil demand growth in the 2000s will continue, neither a significant slowdown in oil consumption nor overall economic growth should be expected. Perhaps more importantly, even if a sharp economic slowdown were to occur, the decline in China's overall economic growth rate would likely not be met with a corresponding slowdown in oil demand growth. This finding has important implications for the global oil market in general, and U.S. policymakers in particular.

The analysis that follows presents three potential economic scenarios for China during the period from 2013 to 2016: a *hard landing*, where growth collapses and global capital markets contract; a *slow grind*, where growth slows sharply but consumption holds up; and a *muddle through*, where extensive stimulus and bank bailouts defer some of the vulnerabilities building up in China's domestic economy, prompting a more gradual rebalancing.

17 BP, plc., *Statistical Review 2012*, at 9, plus online statistical supplement, "Oil Consumption"

18 Id.

19 Id.

20 ORNL, TEDB, Edition 31, Figure 3.1

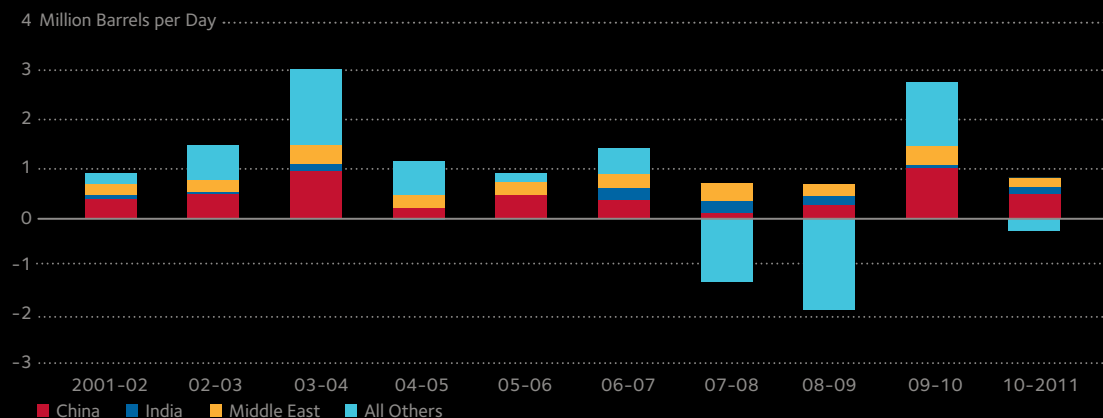
21 Id.

22 Id.

23 BP, plc., *Statistical Review 2012*, at 13

24 See, e.g., Reuters, "China has 24.38 mln T strategic oil reserve capacity," January 20, 2011; and Energy Tribune, "China's Strategic Petroleum Reserves Become an Oil Game Changer," August 28, 2012

Annual Change in Global Oil Demand

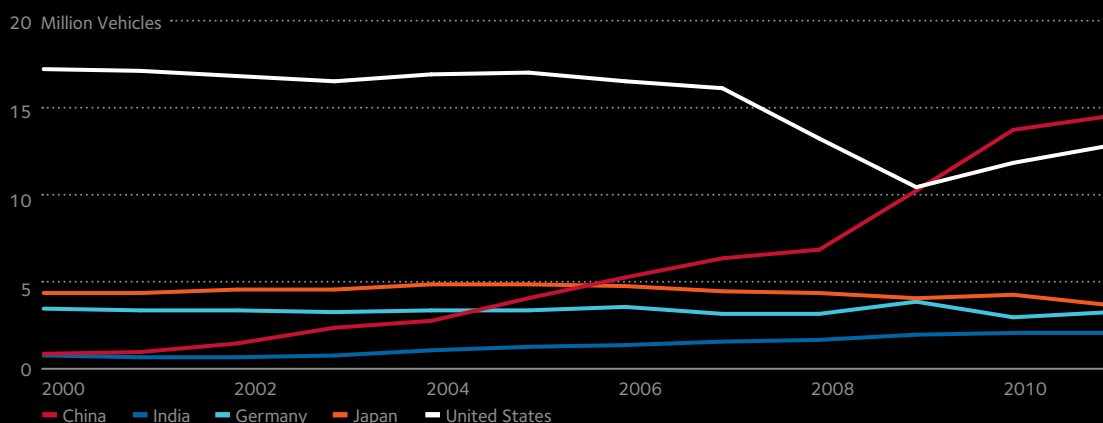


Source: BP, plc., *Statistical Review of World Energy 2012*

FIGURE 73

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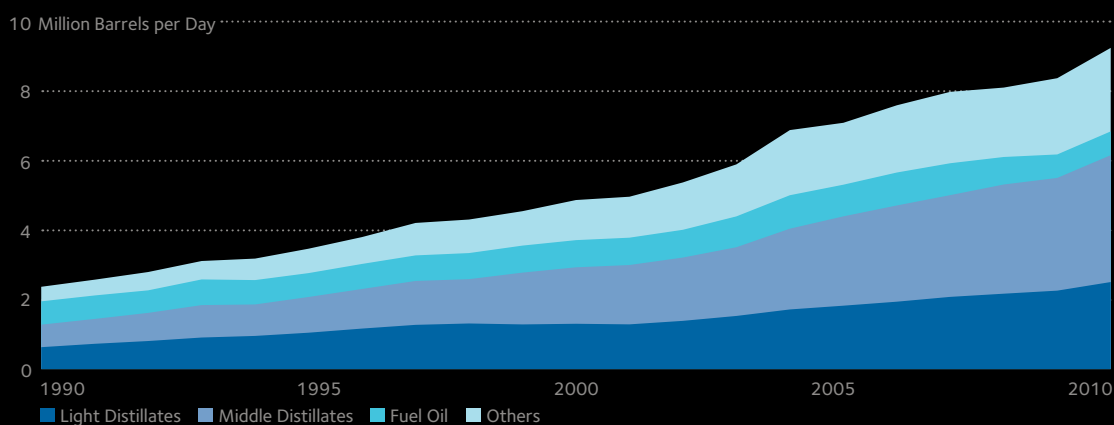
Passenger Vehicle Sales, 2000-2011



Source: IEA; Ward's Automotive; China Association of Automobile Manufacturers; Japan Automobile Manufacturers Association; German Association of the Automotive Industry; and Society of Indian Automobile Manufacturers

FIGURE 74

Chinese Oil Demand, 1990-2011

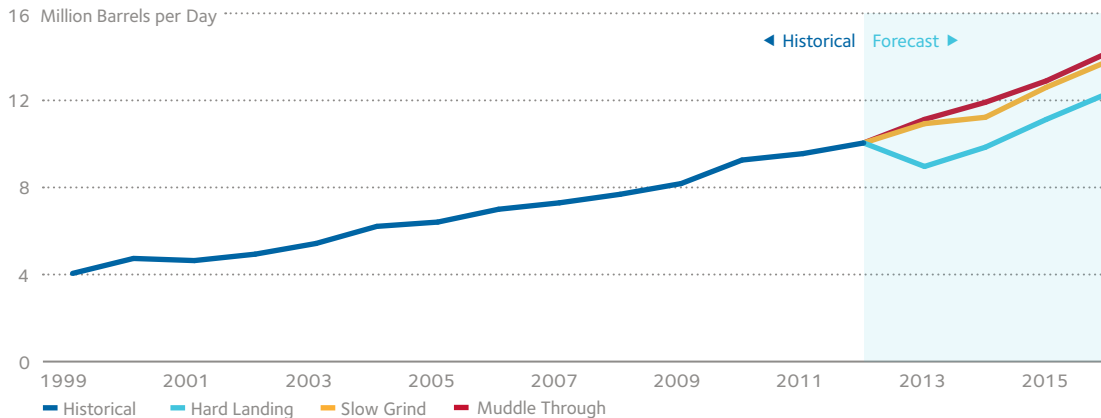


Source: BP, plc., *Statistical Review of World Energy 2012*

FIGURE 75

FIGURE 76

Forecast Chinese Oil Consumption



Source: Roubini Global Economics; and Haver

A sharp economic slowdown in China—the world’s largest exporter and second largest economy—could detract up to a full percentage point of global GDP. However, it is not just the rate of China’s growth, but also the drivers of that growth, which have global economic resonance. China’s traditional growth model has been driven by exports (low-cost production and a weak currency), fixed investment, high corporate and household savings rates, and a very low consumer spending contribution to GDP. By contrast, oil demand is driven largely by the transportation sector and will therefore correlate more closely with consumer spending than the other factors impacting growth. Thus, while a massive investment collapse fueling a sharp economic downturn would dampen consumption to some degree, structural shifts and demographics imply that consumption will outperform the broader economy.

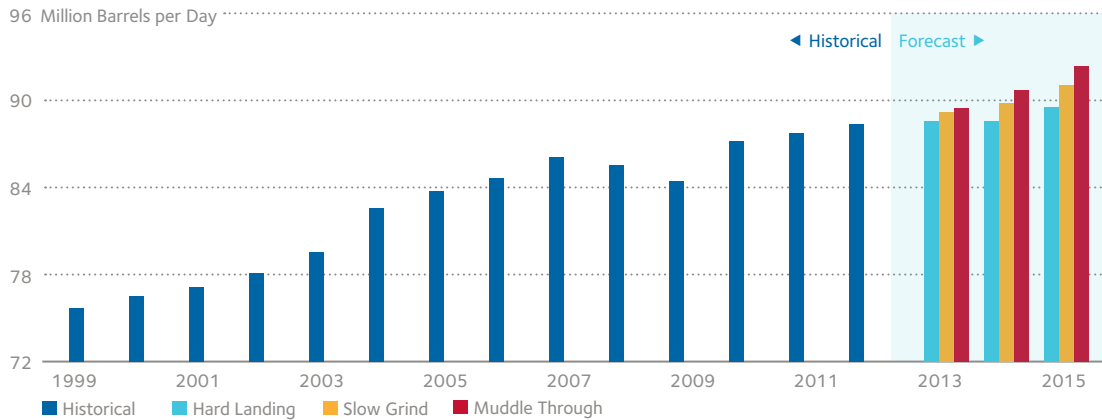
The baseline scenario (*slow grind*) shows Chinese GDP growth slowing to 4 to 6 percent as investment stagnates. In this scenario, restrictive government policy, rising borrowing costs, and overcapacity drive down the price of property and land which results in the default of land developers and local governments. In this scenario, Beijing refuses to grasp the extent of the problem and provides these local governments only a partial bailout. This puts pressure on the banking system as a whole, and limits the scope for effective central-government stimulus as investment falls. China’s slowdown will therefore have the greatest effect on commodities used heavily in fixed investment and the manufacture of capital goods, such as iron ore, steel, and copper.

Demand for mobility has been the primary driver behind Chinese oil demand. The number of registered motor vehicles on the road in China reached 78 million units in 2010, nearly six times the 13.4 million on the road in 2000.

Although oil demand growth will slow initially, it will likely remain robust, outperforming other commodities and maintaining the 7.2 percent annual growth rate it averaged from 2005 to 2011.²⁵ Nevertheless, the global market reaction to China’s investment slowdown—which would have precipitated the overall slowdown in economic growth—will likely exert initial downward pressure on crude oil prices. This decline would probably be short-lived, however, as China capitalized on lower prices by increasing imports to build its strategic reserves. Moreover, OPEC would likely seek to limit the fall in price by reducing production. One further implication of the slow grind scenario is that persistent oil demand will keep Chinese companies focused on overseas opportunities in resource-rich countries to acquire technological capabilities.

Forecast Global Oil Consumption

FIGURE 77



In the upside scenario (*muddle through*), China continues its gradual transition from investment- and export-backed growth to consumption-driven growth, maintaining an average growth rate of 6 to 8 percent and oil demand growth of 8.2 percent. Chinese demand for other commodities also remains reasonably robust due to a more moderate decline in investment. Market risk sentiment is also lower in this scenario, helping other emerging economies maintain stronger economic and oil demand growth than in the baseline scenario.

In the downside scenario (*hard landing*), Chinese economic growth declines to below 3 percent for two years. The impetus for such a deep cut is a sharp decline in real estate and land values. With defaults severely compromising banking sector equity, the national government would have to direct fiscal resources to banks and local governments (rather than towards stimulus). Oil demand growth falls to an average of 5.2 percent through 2016 in this scenario. The slump in Chinese growth reinforces weak global growth, which combined with weaker oil demand growth exerts downward pressure on oil prices. In this near-recessionary global economic environment, oil prices would likely fall below the cost of production, prompting a reduction in supply from OPEC and non-OPEC countries.

In the hard landing scenario, China is likely to withdraw capital from international markets to help address its domestic challenges. As such a large investor in oil production activities abroad, this could significantly undermine their efforts to cultivate global production by increasing project costs, potentially cause investment delays, and also underinvestment more generally. This could see global production capacity strained more heavily than it otherwise would have been once Chinese and other emerging market demand recovers. A temporary decline in oil prices might also affect domestic activities—particularly those for which the marginal costs of production are highest—by delaying some investments in productive capacity in the short term.

Implications for Policymakers

Although a temporary decline in Chinese oil demand growth—and subsequent fall in global oil prices—could occur, decreases in Chinese economic growth within the realm of legitimate possibilities will likely be insufficient to cause a significant, long-term structural shift in global oil demand growth. More generally, oil demand growth in emerging markets is expected to remain robust, supporting oil prices in the medium term. Policymakers should therefore be careful not to interpret any short-term price easing due to slower growth in China and other emerging markets as a reason to reduce efforts to either develop new energy resources domestically or lower the oil intensity of the transportation sector and broader economy. Collaborative efforts with foreign governments to achieve these same outcomes abroad should also be maintained.

DEVELOPMENT IV

How will increasing oil production in Iraq affect OPEC's ability to manage its production? If Iraq is not perceived as a team player, how will other OPEC members respond?

I2.2

Over the past decade, the geographical structure of the global oil industry has been dominated by a handful of key trends. First, non-OPEC conventional production in mature basins like the North Sea has peaked and entered decline. Second, access to the largest, lowest-cost conventional reserves within OPEC has been restricted due to political instability, geopolitical tension, and the presence of national oil companies. Finally, as a result of these two dominant themes, a significant portion of recent global supply growth has been derived from unconventional projects outside of OPEC, including U.S. tight oil, global deepwater, Canadian oil sands, and biofuels. The importance of these resources in the global oil cost curve has been a dominant factor behind escalating oil prices since 2003.

One country has the potential to buck these trends, driving substantial increases in the production of low-cost, conventional crude oil and significantly affecting global oil prices. That country is Iraq. As of year-end 2011, Iraq's proved reserves of oil totaled 143.1 billion barrels, placing it behind only Iran and Saudi Arabia in terms of conventional reserve base.²⁶ The IEA recently noted that the cost of developing these reserves will be "very low by international standards," placing operating costs at just \$2 to \$3 per barrel.²⁷

Potential and Uncertainty

As home to some of the few remaining relatively untapped and low cost oil fields, Iraq represents arguably the largest medium-term potential upside to global crude oil production. The Iraqi government initially set a goal of growing production to 12 mbd by 2017, a goal which would require the most significant increase in production capacity by any country in the history of the global oil industry.²⁸ More recently, the IEA has projected that Iraqi oil production could increase up to 6.5 mbd by 2020 from its current level of 3.0 mbd.²⁹ For context, U.S. crude production in 2012 averaged 6.2 mbd through July.³⁰

Although there are certainly reasons to be optimistic about Iraq's prospects, achieving such high production growth is still far from certain, and many challenges remain. In the short term, political and institutional challenges are certainly substantial and on-going instability possible. These challenges range from delays in finalizing legislation to establish a regime for managing natural resources, to infrastructure construction (e.g. pipelines and roads) and issues associated with the payment of foreign partners—on whose investment and expertise production heavily relies. For example, there are a series of issues related to the production of oil in the semi-autonomous Kurdish north, where contracts signed with the Kurdistan Regional Government (KRG) are deemed illegal by federal authorities.³¹ If there is persistent failure to establish a revenue sharing agreement with the KRG, investment across Iraq could suffer as foreign partners are forced to choose sides. If there is a more extensive settlement, other Iraqi regions, most notably Basra, could also push for greater autonomy over the collection and spending of oil revenues, which could be a further source of political gridlock and delay.

Iraq's Calculus

In the immediate future, Iraq's focus will be on increasing production as rapidly as possible to fund its reconstruction and develop the necessary foundations for a modern economy. According to

26 BP, plc., *Statistical Review 2012*, at 6

27 IEA, *Iraq Energy Outlook*, October 2012, at 54 (operating costs are expenses occurring during day-to-day production activities)

28 New York Times, *Oil Output Soars as Iraq Retools, Easing Shaky Markets*, June 2, 2012

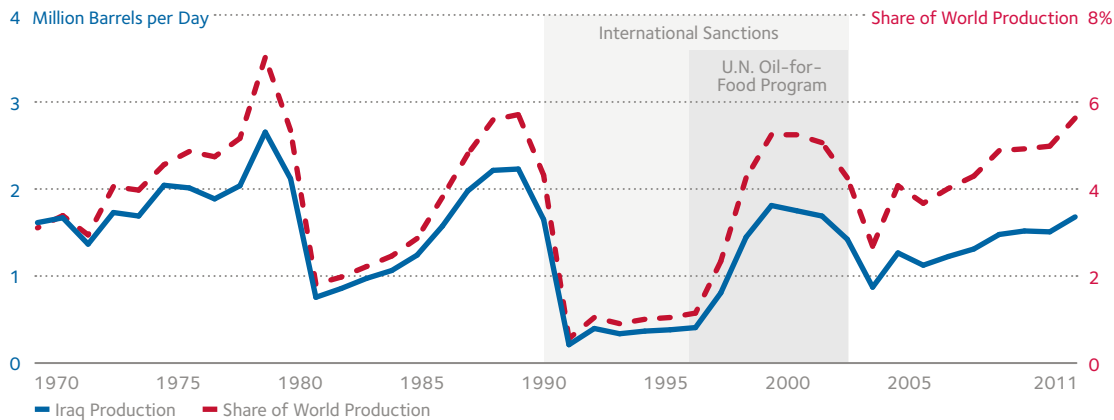
29 IEA, *Iraq Energy Outlook*, October 2012, Table 2.3, at 59

30 DOE, EIA, *Crude Oil Production*

31 In October 2012, the KRG sold oil on the international market in independent export deals further challenging Baghdad's claim to full control of Iraqi oil.

Iraq Oil Production History

FIGURE 78



Source: IEA

International Monetary Fund estimates, Iraq currently requires an oil price of more than \$110 per barrel to balance its fiscal budget, and 95 percent of government revenues are attributable to oil sales.³² It therefore currently has a desire to increase both prices and exports. The implementation of ambitious infrastructure spending goals would strengthen this desire further.

Nevertheless, as production does begin to rise, and particularly if global market prices begin to moderate due to weak global demand, Iraq will begin to face the same political calculation that confronts its fellow OPEC members—namely, how much oil they should produce in order to help maintain global prices at a level that does not undermine global demand but still enables them to satisfy their revenue requirements. Given the disconnect that exists between Iraq's ambition and its ability, in the short term it may initially follow the path of least resistance, preferring a higher price and lower production. However, continued political and economic challenges may prompt Iraq to ultimately develop resources more slowly in the medium term than forecasts might suggest as well.

Iraq and OPEC

If Iraq overcomes the many hurdles described above and achieves sufficient growth in installed capacity, it could be in a position to hold production in reserve reasonably soon. This would reduce the burden today borne almost exclusively by Saudi Arabia as the holder of the global market's spare capacity and could become increasingly valuable given the rapid rise in consumption being observed both in Saudi Arabia and other major global exporters. However, Iraq is unlikely to invest extensively in capacity it will not use in the short-term. Such reserves would more likely be a part of medium- or long-term goals as Iraq seeks to develop its own power base within OPEC and the Middle East region more broadly.

Nonetheless, if sharp production increases from Iraq do occur, they could significantly strain OPEC cohesion, primarily by undermining the influence of both Saudi Arabia and Iran, OPEC's largest producers.^{33,34,35} So far, Iraq has not threatened OPEC's overall production targets, because declines in output from Iran (due to sanctions) and Libya (due to civil war) have required offsetting increases in production.³⁶ However, this is now changing as Libyan production has rapidly returned to pre-war levels.

32 IMF, World Economic and Financial Surveys, Middle East and Central Asia Regional Economic Outlook Update, November 2012, Table 6, at 93; and IEA, Iraq Energy Outlook, October 2012, at 387

33 IEA, Iraq Energy Outlook, October 2012, Table 4.1, at 114

34 Iraqi oil production growth could have a particularly significant effect if easing global growth moderates oil demand growth in the coming years.

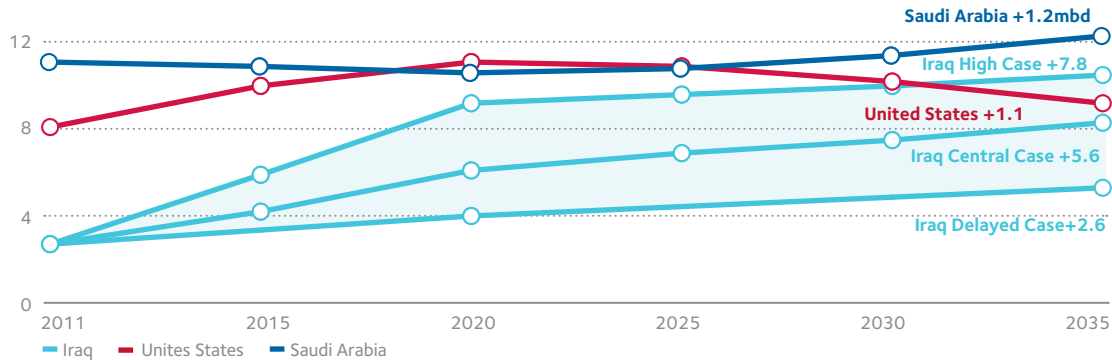
35 Other nations whose budgets rely heavily on oil revenues (and high oil prices), such as Russia and Algeria, are also likely to be affected in the case of a sharp increase in Iraqi output. This could undermine social stability in these nations.

36 As part of a compromise between Saudi Arabia and members of OPEC who have advocated for the group to limit production increases to influence market prices, including Iran, Iraq was re-included in OPEC's global target in 2012, and members pledged not to produce above a total 32 mbd. (Members have avoided setting formal country targets since cuts were made to from then-current levels of production in 2008.) The inclusion of Iraq was somewhat informal, in line with the recent vagueness of OPEC quota announcements, but it did set an implicit cap on Iraqi output—at least to the extent that the global quota is observed.

FIGURE 79

Iraq Oil Production Forecast

16 Million Barrels per Day (mbd)



Source: IEA

Further increases in Iraqi production are likely to test OPEC's quota and, by consequence, the cartel's ability to balance global oil prices.³⁷

It is in Iraq's interest to defer its quota allocation for as long as possible while it scales up output, given that OPEC has tended to assign quotas or output cuts based on current production. However, Iran and other members who struggle to increase production will prefer to lock Iraq into a country-specific quota earlier and are likely to encourage slower output growth. By contrast, Saudi Arabia may be more comfortable with Iraq having a higher quota given its concerns about high oil prices dampening global demand. Long comfortable with relatively lower prices than its peers, Saudi Arabia has sought to avoid depressing demand and prompting a rush to alternatives. Saudi Arabia would likely be comfortable with modest increases from Iraq, but not significantly more, which could force the Gulf Cooperation Council to reduce output until sufficient demand returns. The extent to which Saudi Arabia supports production growth in Iraq could be greatly influenced by the degree to which the Saudis believe Iraq is on course to emerge as a producer willing to maintain spare capacity.

A lack of new Iraqi oil supplies could act to tighten the global oil market considerably, which would result in an increase in price and price volatility.

Finally, if complemented by the effective development of the nation's natural gas resources (estimated at 126.7 trillion cubic feet), Iraq will be able to diversify its domestic energy mix to consume less oil in, for example, power generation.³⁸ To achieve this, Iraq must reduce the quantity of natural gas that it currently wastes by flaring and invest in additional infrastructure.³⁹ This would have the added benefit of increasing the quantity of oil available for export.

Implications for Policymakers

Iraq has aspirations to play a leading role in the Middle East region. As such, over the long term it is likely to strike a balance between a desire to maximize production and a desire to maximize prices. Iraq's medium-term goals are almost certainly to achieve higher levels of production at a relatively lower price (one which they can easily sustain thanks to their low marginal costs of production). However, with political dynamics and a lack of infrastructure potentially constraining their ability to increase production capacity in the short term, Iraq may choose to align itself with Iran and other OPEC members who want to maintain higher prices.

³⁷ Members have avoided setting formal country targets since cuts were made to from then-current levels of production in 2008.

³⁸ BP, plc., *Statistical Review 2012*, at 6

³⁹ IEA, *Iraq Energy Outlook*, October 2012, at 122–124

Perhaps the greatest threat to U.S. interests is Iraq failing to achieve a moderate level of growth in oil production. This would pose a significant obstacle to broader economic growth in Iraq and could potentially undermine political stability. In the worst case, it might result in security problems that could be destabilizing to the region. In addition, the lack of new Iraqi oil supplies could act to tighten the global oil market considerably, which would result in an increase in price and price volatility. By contrast, it is highly unlikely that Iraqi production growth would be sufficiently large and increase quickly enough to result in price decreases that would endanger U.S. light tight oil production.

Policymakers should therefore strive to shape Iraq's understanding of its own self-interest towards sustained long-term production increases. This requires recognizing the myriad of challenges that Iraq still faces and assisting Iraqi policymakers as they lead a transition from stabilization to consolidation and economic growth. Policymakers could also work with their European and Asian counterparts to encourage Iraq to increase the transparency associated with its investment and royalty regime, as well as to regularize the legal standing of operations in the Kurdish region to facilitate ongoing investment by U.S. and foreign oil companies.

Credits and Acknowledgements

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