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TESTIMONY

Alternative Fuel Provisions in HR 909

The Roadmap for America's Energy Future

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The Roadmap for America's Energy Future[2]

Before the Committee on Energy and Commerce
Subcommittee on Energy and Power
United States House of Representatives

June 3, 2011

Chairman and distinguished Members: Thank you for inviting me to further elaborate on the testimony that I gave to this subcommittee on May 5 of this year. Today I will provide you with my understanding of the policy implications of sections of HR 909 dealing with oil shale and coal liquefaction, namely sections 141 and 151 through 153.

In my written statement for the May 5 hearing, I reviewed the strategic importance and value of alternative fuels. In that review, I emphasized that achieving the potential economic and national security benefits offered by alternative fuels requires that domestic production of alternative fuels must be an appreciable fraction of domestic demand for liquid fuels. Alternative fuels derived from oil shale and coal have the potential to meet that important criterion; each has the potential to displace millions of barrels of daily crude oil imports.

Oil Shale

The largest high-grade deposits of oil shale in the world are located in the United States, primarily in western Colorado and eastern Utah in an area known as the Green River Formation. This recoverable portion of this resource is enormous. When we did the research for our 2005 report on oil shale, we estimated recoverable resources at between 500 billion and 1.1 trillion barrels of oil.[3] To put this estimate in perspective, the mid-point—800 billion barrels—is more than triple the crude oil reserves of Saudi Arabia. Since our work, the U.S. Geological Survey has published a new assessment suggesting an upwards revision of our estimate.

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[2] This testimony is available for free download at http://www.rand.org/pubs/testimonies/CT363/.
[3] *Oil Shale Development in the United States: Prospects and Policy Issues*, Santa Monica, CA: RAND MG-414-NETL, 2005.

The Challenges of Oil Shale Development: Before reviewing the provisions of Section 141, I would like to provide a little background on the U.S. oil shale resource. First, extracting oil from the Green River oil shale resource is technically complex. This is because the hydrocarbon material in oil shale is not liquid but solid. To obtain a useful product, the oil shale must be heated to 650 Fahrenheit or higher, which causes the solid material to undergo a chemical change that yields a liquid product. That is a fairly high temperature, for example, temperatures below 212 Fahrenheit are sufficient for extracting petroleum from deposits of heavy oil and oil sands. At present a number of firms are making investments in research directed at developing technologies that economically produce liquid fuels from oil shale. However, to my knowledge, none of these firms has gathered enough technical information adequate to support a decision to invest hundreds of millions, and more likely billions, of dollars in first-of-a-kind commercial oil shale production facilities.

Second, about 80 percent of this oil shale resource base lies under federal lands. At crude oil prices of $100 per barrel, the value of the oil that might be recovered from federally owned land is over $60 trillion. The public wealth embedded in our oil shale lands is staggering. Many, if not most, of the potential lease tracts in Colorado contain over 2 million barrels of oil per surface acre. A single commercial lease tract of 5760 acres will generally hold over 6 billion barrels. The public value of a single lease is clearly in the tens of billions of dollars, considering lease bonus payments, royalties, and taxes on profits. But realizing this public value and the broader economic and national security benefits of oil shale development requires commercially viable technology. So both industry and the public have a strong stake in successful technology development.

The third aspect that I want to mention is the geographic concentration of this vast resource. Most of the high value resources lie within in a very small area (roughly 30 by 35 miles) within Colorado's Piceance Basin and within a small portion of the nearby Uinta Basin within Utah. This means that oil shale leasing decisions made by the federal government may have a profound impact on the residents in the northwestern quarter of Colorado and the Northeastern quarter of Utah. In particular, large-scale development of oil shale will cause federal lands to be diverted from their current uses. In the absence environmental and economic mitigation measures, unprecedented in scope and scale, such development would almost certainly have adverse ecological impacts, and would likely be accompanied by socioeconomic impacts that could be particularly severe, especially in the northwest quarter of Colorado.

There could also be broader environmental impacts. The Green River Formation is part of the Colorado River Basin. Much of the oil shale resource is comingled with various salts. It is obviously important that oil shale extraction does not result in contaminating important underground and surface waters.

The production and use of oil shale causes emissions of greenhouse gases. As compared to the production and use of conventional petroleum, estimates of lifecycle greenhouse gas emissions range from a slight decrease to roughly a 50 percent increase. Without legislation that would place a cost on emitting greenhouse gases, early oil shale production plants would likely fall in the upper half of this range.

Finally, and perhaps most importantly, without proper planning at the federal, state, and local levels, provisions taken to put in place the initial round of commercial oil shale production facilities, if not done properly, could end up precluding the development of oil shale to a level commensurate with its potential economic and national security value to the nation. This problem derives from the fact that a U.S. based oil shale industry would operate in a geographically concentrated area. Issues of concern include impacts on air and water quality, provisions taken to meet demands for water, and the large amount of required infrastructure, including roads, pipelines, power plants and transmission lines, reservoirs, and housing and public services industries.

Section 141 Oil Shale Provisions

Section 141(a). Findings

Two of the findings in this section are problematic. Section 141(a)(1) refers to a Department of Energy estimate that "oil shale resources located on Federal lands hold 2 trillion undiscovered technically recoverable barrels of oil." My knowledge of the resource base suggests that this statement is erroneous. I suggest that the committee contact either the Department of Energy or the U.S. Geological survey to verify the validity of this finding.

Section 141(a)(5) makes the claim that "Oil shale is one of the best resources available for advancing American technology and creating American jobs." I have no knowledge of any research that supports this claim. Oil shale has a potentially important role in advancing our energy security and furthering economic progress. I see no reason to promote oil shale as above other promising areas for advancing technology and creating jobs.

Section 141(b) Additional Research and Development Lease Sales

In January 2009, the Bureau of Land Management (BLM) published a notice soliciting industry nominations for second round of R&D lease sales. This solicitation was cancelled by the incoming administration. A new solicitation was published in November 2009. Three nominations were received and all three were selected for in-depth review. The review process is still underway.

Section 141(b) calls for a third offering of small lease tracts, specifying that the offering should be based on the terms offered in the cancelled January 2009 solicitation and should occur within 180 days after enactment of the Act.

The periodic offering of small lease tracts for research and development (R&D) is a sound concept. Successful R&D would yield extraction processes with improved economic and environmental performance and would increase the number of firms competing for commercial oil shale leases. These outcomes could yield substantial public benefits. The policy issue is the public cost of providing industry access to these small lease tracts.

In terms of public costs, both the January and November offerings of 2009 did not contain the provisions of the initial offering, dated June 9, 2005, that were most unfavorable with regard to protecting the public interest, namely, (1) a preference right to lease nearly 5000 acres of federal lands adjoining the R&D lease site, and (2) awarding a single entity multiple R&D lease sites, and consequently, multiple preference rights for much larger leases.

As compared with the January 2009 offer, the November 2009 offering contains due diligence and other requirements that give more authority to the government. Compliance with these diligence provisions will likely cause the leaseholder to incur additional expenditures and may force the leaseholder to relinquish the lease. Both offerings offer preference rights to lease up to 640 acres of contiguous oil shale bearing lands, again with the November offering being more protective of the government interest at the expense of the leaseholder. However, it is my judgment that these differences are fairly minor. The fact that BLM received three credible responses to its November 2009 solicitation supports this conclusion. Overall, legislating that BLM must follow the provisions of the January 2009 offering in a future R&D lease offering is unlikely to have a noticeable impact on the pace of oil shale development.

Section 141(c) Application of Regulations

Establishing the commercial viability and obtaining the information required to design and build a first-of-a-kind commercial oil shale production facility requires very large investments. Private firms will not undertake the substantial technical and financial risks associated with preparing for, building, and operating a commercial facility unless they are amply rewarded in the event that they are successful. On November 18, 2008, the Department of the Interior published final rules on the leasing of oil shale lands for commercial production. Overall the royalty and management provisions of these rules provided a strong motivation to private firms interested in developing oil shale. On February 15, 2011, the Department of the Interior announced that it would conduct a review of these rules “and, if necessary, update them based on the latest research and technologies, to account for expected water demands in the arid West and to ensure they provide a fair return to taxpayers.”

Section 141(c) would require that the final commercial leasing rules published in 2008 by the Bureau of Land Management apply to all commercial leasing of federally-owned lands for the purpose of oil shale extraction and production.

I have carefully examined the commercial leasing rules published in 2008 and find them to be seriously deficient. Basically the oil shale leasing rules were modeled on existing rules for coal and oil leasing. The rules do not take into account the geographic concentration of the oil shale resource base, the fundamental uncertainties regarding the economic, environmental, and technical performance of oil shale production technologies, and the national energy security benefits of being able to produce eventually a few million barrels per day of fuel (gasoline, diesel, and jet) derived from oil shale.

The problem of managing our federal oil shale lands so that we can have strategically significant and sustainable commercial development is much akin to the problem of managing a major port. In both cases, there exists very high-value real estate that is geographically concentrated. Both cases require a large supporting infrastructure and a trained workforce. And in both cases the public has a major stake. For major ports, the need for coordination, planning, and centralized decision making has been recognized and implemented through port authorities. I suggest that a governance mechanism that has some of the key governance elements of a port authority is required to undertake the coordination, planning, and sustained regulatory compliance that are essential to the development of a dynamic oil shale industry in the United States.

My major concern is that the oil shale management rules published in 2008 completely ignore the need for strategic planning. Instead, the rules set up a first come, first served approach. While this approach may yield early production and offer an attractive financial investment for a few firms, it is unlikely to allow oil shale production beyond a few hundred thousand barrels per day, if that.

A second concern is the royalty. Oil shale on federally managed lands belongs to all of us. Therefore, the royalty calculation should be based on optimizing the public benefit, taking into account not only the direct benefits to the national treasury, but also the broad national economic and national security benefits associated with greater domestic fuels production as well as environmental and socioeconomic costs. The analytic methodology used to set the royalty rates associated with the 2008 leasing rules does not take into account any of these issues.

Moving Forward with Oil Shale

There are also a few areas where Congress may need to assert its will for the purpose of assuring that the nation is moving forward in realizing the full opportunity that oil shale offers. The critical step is obtaining early production experience. Until we understand the performance of the process options, it is not productive to engage in establishing a detailed regulatory structure for a large multimillion barrel per day commercial industry. I suggest the following for consideration by the Committee.

1) Require that the Department of Energy, the Department of the Interior, and the Environmental Protection Agency cooperatively develop and publish a federal plan for promoting the construction and operation of a limited number of pioneer commercial plants.
That plan should be based on an analysis of the benefits and costs of potential incentives designed to attract America’s top high technology firms to invest in a first-of-a-kind production plant. Incentives that should be examined include not just land access and royalty arrangements, but also investment subsidies, price floors, loan guarantees, and revenue sharing.

2) Require that the Department of the Interior develop, publish, and implement a 15-year schedule for offering small R&D lease tracts. Giving industry advance notice of future offerings will promote better planning, a better industrial response, and less speculation.

3) Require that the Department of the Interior and the Department of Energy, in consultation with the Environmental Protection Agency prepare plans for conducting critical environmental and

ecological research, including an assessment, and possibly a large scale demonstration, of carbon management options in the vicinity of the Green River Formation.

Coal-to-Liquids

The United States leads the world with recoverable coal reserves estimated at nearly 270 billion tons.[4] These recoverable reserves are broadly distributed, with at least 16 states having sufficient reserves to support commercial coal-to-liquids production. It takes slightly less than a half ton of coal to produce a barrel of liquid transportation fuels. Consequently, a domestic industry producing one million barrels per day would require the mining of about 180 million tons of coal per year. As I discuss later, a highly promising approach to using coal to produce liquid fuels is to use a combination of coal and biomass. A thirty percent (by energy) biomass to coal blend would reduce the amount of coal required by roughly the same percentage. In this case, the amount of coal needed to produce one million barrels per day would be about 130 million tons per year.

Presently, mining in the United States produces about 1.1 billion tons of coal per year. Nearly all of this production is directed at the generation of electric power. Coal's future in power generation will depend on whether the United States adopts measures to control greenhouse gas emissions. If such measures are implemented, it is very likely that the level of coal mining will decrease, with potential adverse economic impacts in traditional coal mining areas. Using coal to make liquid fuels, especially when combined with biomass, provides not only the economic and national security benefits associated with reducing dependence on imported oil, but also a new market for coal that could counter the adverse local and regional economic impacts of reduced demand for coal in power generation.

Commercially-proven technology is available to produce gasoline, diesel fuel, jet fuel, marine fuels, and home heating oil from coal. One set of approaches utilizes the Fischer-Tropsch method first developed in Germany in the 1930s and since then greatly improved through commercial experience in South Africa, Malaysia, and Qatar. The second proven approach is the coal-to-gasoline method demonstrated by Mobil Oil (now ExxonMobil) in New Zealand. Both methods start by gasifying coal by reacting it with steam at elevated pressures. The final products are "drop-in" substitutes for their conventional counterparts. For some applications, the coal-derived products are clearly superior to their conventional counterparts. For example, for all coal-derived fuels, sulfur levels are near zero, providing important environmental advantages when they are used in gasoline and diesel-powered vehicles equipped with catalytic converters. And the middle

[4] This portion of the testimony draws on *Producing Liquid Fuels from Coal: Prospects and Policy Issues*, Bartis, Camm and Ortiz, Santa Monica, Calif.: RAND Corporation, MG-754-AF/NETL.

distillates produced from the Fischer-Tropsch method have a very high cetane number (a measure relevant to fuel performance in compression ignition engines) causing them to carry a further premium as a blendstock with conventional diesel fuel.

The Challenges of Producing Liquid Fuels From Coal: From publicly available information, the production of liquid fuels from coal appears to be economic when crude oil prices exceed $70 per barrel. World oil prices have exceeded that level for some time now, but we see very little progress in CTL commercial development. While a number of commercial coal-to-liquid fuel projects have been announced in the United States, only a single facility, located in Wyoming, has begun construction. From our research, the most important factor impeding private sector investment is uncertainty regarding the future course of world oil prices. Many investors expect oil prices to remain high over the financial lifetime of a coal-to-liquid plant. However, all investors are concerned that a drop in oil prices would bring severe adverse consequences, namely, extremely low rates of return or project bankruptcy.

The most important factor impeding federal support for coal-to-liquids production is the conflict between , on the one hand, the economic and national security benefits from coal-derived fuels and, on the other hand, the need for the federal government to take measures to reduce greenhouse-gas emissions.

Without management of greenhouse gas emissions, liquid fuels produced from coal will have lifecycle greenhouse gas emissions that are about twice that of their conventional petroleum counterparts. This problem has been studied by RAND and others, including the National Academy and researchers at Princeton University, MIT, and the National Energy Technology Laboratory. The consensus of these groups is that capture and sequestration of greenhouse gas emissions from coal-to-liquid production plants is inexpensive. Further, with capture and sequestration, lifecycle greenhouse emissions can be comparable to those of their petroleum-derived counterparts. By comparable, I mean within 10 percent. The crude oil breakeven price estimate of $70 per barrel that I quoted includes provisions for capturing carbon dioxide and preparing it for transport to a location where it would be sequestered.

These same researchers also agree that using a combination of coal and biomass can result in lifecycle greenhouse gas emissions that are significantly less than those of petroleum-derived fuels and certain renewable fuels. For this to be the case, greenhouse gases generated at the production facility need to be captured and sequestered and the biomass needs to be produced in a sustainable manner. For example, if these measures are taken, a 25/75 biomass/coal feed should allow alternative fuel production at lifecycle greenhouse gas emissions that are 35 percent of those generated by the production and use of conventional petroleum derived fuels.

Taking these measures, however, does require additional expense and involves additional risks. Gasifying mixtures of coal and biomass is generally viewed as low risk. Nonetheless, there is very little commercial experience in gasifying such mixtures, and there is the possibility that problems might arise, albeit correctable at a cost, during the initial operating period of a commercial production facility.

About 30 to 40 million tons of carbon dioxide are produced and distributed each year for the purpose of improving the recovery of crude oil contained in U.S. oilfields. Presently, this carbon dioxide is obtained from natural underground deposits. Decades of experience suggest that carbon dioxide used in enhance oil recovery will stay underground. Since carbon dioxide is the predominant greenhouse gas emitted during the production of coal-derived liquids, there should be no problem regarding the sequestration of carbon dioxide so long as the facility is located within a few hundred miles of a suitable oil field, so as to avoid high transport costs. For each barrel of coal-derived liquids, using captured carbon dioxide for enhanced oil recovery will yield about two additional barrels of crude oil.

But for coal-to-liquid production facilities that are not within reasonable range of oil fields, the only approach for sequestration is a dedicated geological repository. Unfortunately, there is no experience in permitting, licensing and operating a commercial sequestration facility in the United States. This lack of experience poses a severe barrier to siting low-greenhouse gas coal-to-liquid facilities in certain traditional coal-producing areas, such as West Virginia and Kentucky. One possible approach could be to use the emissions captured from a coal-to-liquids plant in planned government-sponsored demonstrations of the geologic sequestration of greenhouse gases.

Section 151 Development and Operation of Facilities

Section 151 would provide the Secretary of Defense with the authority to develop, construct and operate a qualified coal-to-liquid facility.
The Department of Defense consumes about 340,000 barrels per day of liquid fuels, nearly all of which is used in aircraft, ships, combat vehicles and combat support systems. That level of consumption makes the Defense Department the largest fuel purchaser in the United States. Nevertheless, that level of use remains a small percent of total national petroleum consumption and an even smaller percent of global oil demand. In January the RAND Corporation published its

findings on a congressionally mandated study of alternative fuels for military applications.[5] A principal finding of that study is that while certain alternative fuels (including coal-derived fuels) are no less able than conventional fuels to meet the Defense Department's needs, such fuels offer no particular tactical or operational benefit over their petroleum-derived counterparts. Consequently, we found that Defense Department goals for alternative fuels should be based on potential national benefits.

Unlike ongoing Department of Defense efforts directed at seed oils, Department of Defense efforts directed at coal-derived fuels, especially coal-biomass mixtures and management of greenhouse gases could yield major national benefits. The key policy issue raised by Section 151 is whether having the Department of Defense engage in coal-to-liquids fuels production is an efficient application of federal funds. In the course of our examination of alternative fuels activities in the Department of Defense, we found limited expertise on the production of those fuels that constitute the great bulk of the Department's use. The only exceptions are those specialty fuels with unique military applications, such as fuels for missiles and torpedoes. In the United States, the centers of excellence in fuel production rest within integrated oil companies and refining companies. As such, these firms are in a much stronger position to assess technical alternatives and make investment decisions.

If Congress is interested in using the purchasing power of the Defense Department to promote early commercial experience in production of coal-derived liquids, I suggest providing the Department with the authority to make long-term agreements (i.e., up to 20 years) with alternative fuel producers that would

- Have the Department commit to purchase alternative fuels that meet military specifications at a specified floor price
- Require the alternative fuels producer to sell alternative fuels that meet military specifications to the Department according to a specified formula that would basically set a ceiling price.

This arrangement places a collar on the prices of some fraction of the fuels that would be produced by a coal-to-liquids plant. In return for guaranteeing a minimum sale price to the benefit of the producer in the event that world oil prices are low, the Department would be guaranteed a maximum purchase price that would be lower than world oil prices in the event that world oil prices pass a specified threshold.

[5] *Alternative Fuels for Military Applications*, Bartis and Van Bibber, Santa Monica, Calif.: RAND Corporation, MG969-OSD, 2011.

This arrangement would have the added benefit of promoting the use of coal-derived liquids in applications where they have the greatest value. In particular, most military applications involve the use of high sulfur jet fuel in turbine engines. These applications place no value on the high cetane number and near-zero sulfur levels of coal-derived diesel fuels.

Section 152. Definitions Relating to Coal-to-Liquid Fuel and Facilities

I would advise the Congress to further consider the environmental impact of harvesting peat resources before including peat as an acceptable feedstock for coal-to-liquids production facilities. Peat is generally found in sensitive ecosystems and the energy content per acre is fairly low. For the same amount of energy, harvesting peat would disturb much more land than would mining coal.

Section 153. Repeal

Section 153 would repeal Section 526 of the Energy Independence and Security Act of 2007.

Section 526 prohibits federal agencies from entering into a contract for procurement of an alternative fuel or a fuel from an unconventional petroleum source unless the contract specifies that the lifecycle greenhouse gas emissions of that fuel are less than the equivalent product produced from conventional petroleum. The only exception would be for alternative fuels purchased for the purposes of research and fuel testing.

As enacted, Section 526 places severe restraints on the government's ability to purchase fuels. It would prohibit the government from purchasing any mobility fuel that might be derived in part or whole from coal, oil shale, oil sands, or biofuels without a certification from the fuel supplier regarding lifecycle greenhouse gas emissions. To my knowledge, Section 526 has not been applied to biofuels, even though biofuels can have lifecycle greenhouse gas emissions that are higher than the equivalent product produced from conventional petroleum.

Since passage of Section 526, the main concern has been whether the law prohibits government purchases of fuels that might be derived in part from Canadian oil sands. If this were the case, the government would be unable to purchase fuels from growing number of commercial fuel vendors. With less competition, it is reasonable to expect that the government would incur increased costs. Additionally, the Defense Department may find it difficult or very costly to purchase aviation fuel in South Africa or Qatar, where alternative fuels from coal and natural gas are routinely blended with conventional fuels.

To remedy this problem, Congress in 2010 passed legislation (Public Law 111-314, Sec 30210) that provides an exception to the fuel purchase prohibitions of Section 526. That exemption *apparently* allows government purchases of commercially available fuels that might in part be derived from alternative fuels so long as three conditions hold. The language of Section 30210 is unclear, so my interpretation of Public Law 111-314 as providing a remedy to the more onerous provisions of Section 526 may be incorrect.

Repeal of Section 526 would remove any confusion regarding the exemptions to constraints on government purchases of mobility fuels. It would also allow agencies to continue their current practice of purchasing biofuels, such as corn-derived alcohol fuels and biodiesel, without regard to lifecycle greenhouse gas emissions. Finally, it would allow federal procurement of alternative fuels such as coal-derived liquids, natural gas-derived liquids, and fuels produced from oil shale without regard to lifecycle greenhouse gas emissions.

The primary policy issue raised by repeal of Section 526 is whether it is in national interest to allow government agencies to promote the production of alternative fuels that have lifecycle greenhouse gas emissions that are significantly higher than their petroleum counterparts. For example, repeal of Section 526 would open the door to a government procurement of coal-derived liquids produced without managing greenhouse gas emissions.

If Congress is concerned with the limitations and continued uncertainties associated with the implementation of Section 526, I suggest consideration of legislation that would clarify the meaning of Section 30210 of Public Law 111-314 so that the government is not prohibited from purchasing commercial fuels derived in part from alternative fuels or oil sands. Congress should also clarify whether Section 526 prohibitions apply to biofuels.

If the intent of Congress is to promote the early production of alternative fuels with greenhouse gas emissions that are comparable or better than those of their petroleum counterparts, I suggest consideration of an amendment to Section 526 that would allow the government to target purchases of alternative fuels derived from fossil fuel resources (such as coal, natural gas, or oil shale) if 90 percent of greenhouse gases produced during the alternative fuel production process are captured and sequestered or if lifecycle greenhouse gas emissions that are no more than five percent above the lifecycle greenhouse gas emissions of their petroleum counterparts. This suggested amendment would still require management of greenhouse gas emissions, but it would significantly reduce the costs of building and operating pioneer alternative fuels facilities that are based on coal, stranded natural gas resources in Alaska, and possibly oil shale.

In closing, I thank the Subcommittee once again inviting me to testify. I hope the foregoing analysis of policy issues is useful to your important deliberations.