POTENTIAL ECONOMIC AND ENERGY SUPPLY IMPACTS OF PROPOSALS TO MODIFY FEDERAL ENVIRONMENTAL LAWS APPLICABLE TO THE U.S. OIL AND GAS EXPLORATION AND PRODUCTION INDUSTRY

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January 2009

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EXECUTIVE SUMMARY

In the last several years, a number of environmental organizations have pushed for greater federal environmental oversight over U.S. oil and gas exploration and production (E&P) operations. These organizations generally allege that a number of "loopholes" in federal U.S. statutes and regulations allow U.S. oil and gas producers to circumvent environmental requirements imposed on other industries. Moreover, ongoing federal regulatory initiatives may also impact domestic E&P operations. Finally, recent new activities in emerging shale gas basins in the United States are resulting in oil and gas development in areas of the country not previously accustomed to oil and gas operations; causing some concern among local residents about the potential environmental implications associated with such development.

The U.S. oil and gas industry is quite concerned that this set of regulatory proposals, if implemented, could have adverse impacts on the economics of domestic oil and gas E&P operations, and thus on domestic oil and gas supplies, prices, and other economic considerations. Similarly, the Department of Energy has strong interests in ensuring that U.S. energy supplies are not unnecessarily constrained and that environmental protection approaches make technical, environmental and economic sense. In this regard, this "white paper" compiles and documents the results of previous economic impact studies prepared for industry and government that examined many of the recommendations made by various environmental organizations; updates this previous work to be consistent with current energy market outlooks, costs, and industry trends; and characterizes the potential cumulative impact of these initiatives on domestic U.S. oil and gas supplies and on the related economic benefits that these supplies help facilitate.[1]

Of these environmental group recommendations, this white paper focuses on the following:

- Requiring oil and gas E&P operations to report to the Toxic Release Inventory (TRI).
- Subjecting hydraulic fracturing of oil and gas wells by the E&P industry to Underground Injection Control (UIC) program requirements, despite language excluding this in the Energy Policy Act of 2005.
- Requiring that all wastes associated with oil and gas exploration and production be addressed under Resource Conservation and Recovery Act (RCRA) cradle-to-grave hazardous waste provisions. This includes requiring that the underground injection of produced water and other materials associated with enhancing oil and gas production meet the standards of Class I injection.
- Requiring storm water permits for all oil and gas E&P operations, rescinding Section 323 of the Energy Policy Act of 2005.
- Requiring aggregation of the emissions of oil and gas E&P activities under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, and requiring the U.S. Environmental Protection Agency (EPA) to review and update clean air regulations related to oil and gas E&P.
- The implementation of new Spill Prevention, Control, and Countermeasure (SPCC) requirements issued by EPA to "provide increased clarity," as well as to better "tailor" requirements to oil and gas industry operations.

[1] This assessment focuses on potential economic and energy supply impacts and does not address environmental risk, the scope and adequacy of existing state and federal regulations applicable to oil and gas E&P, or other factors considered in the establishment of prior regulatory determinations that resulted in federal exemptions or requirements tailored to oil and gas E&P operations.

The combination of initiatives assumed in this assessment, if implemented, represents a stringent set of potential federal requirements, but would not necessarily be a "worst case" scenario from the perspective of the domestic E&P industry. For purposes of this assessment, the compliance requirements providing the basis for this assessment have been labeled a "Stringent Federal Scenario."

For purposes of this assessment, several fundamental considerations were explicitly addressed for each proposed federal environmental initiative considered:

1. What additional compliance requirements could be implemented to address each of the environmental group proposals?
2. What types of "facilities" (equipment, processes, sites, etc.) could be subject to each new requirement?
3. How many/what portion of the "facilities" might be subject to each new requirement?
4. What types of compliance options would apply to each type of "facility"?
5. What precisely will operators have/choose to do to comply?
6. What will be the incremental costs associated with compliance?
7. What information exists that can be used as a basis for the above?

The impact of the potential increased compliance costs associated with the proposed initiatives was examined in terms of their impact of future oil and gas supplies from three sources:

- Currently producing oil and gas wells.
- Potential future supplies of unconventional natural gas resources.
- Potential future crude oil supplies from carbon dioxide enhanced oil recovery (CO_2-EOR).

The previous economic impact studies used as the basis of this white paper were prepared in different years (ranging from 1985 to 2008), and were based on different assumptions regarding industry activity and existing environmental compliance approaches at that time. Moreover, in some cases, state and federal regulatory requirements have changed since these original assessments were performed. Accordingly, the results of this assessment, representing the cumulative impacts associated with all of compliance initiatives considered, should be interpreted as an indication of the overall order of magnitude of potential impacts, rather than an exact prediction of impacts associated with the Stringent Federal Scenario as defined in this analysis.

Moreover, for different categories of resources, the potential impacts are reported in different ways. This is a result of both the nature of the different resource categories considered, as well as the characteristics of the analytical approaches and models used to assess the impacts for each category. Specifically, in this assessment results related to currently producing oil and gas wells are reported as first year impacts, those related to unconventional natural gas resources are reported as reduced industry activity over 25 years, and those related to CO_2-EOR are reported as potential reduced volumes of economically recoverable resources and associated CO_2 storage capacity.

The energy supply and economic impacts associated with each category of domestic resource is summarized in the paragraphs below.

Currently producing oil and gas wells. Given the potential incremental federal compliance requirements considered under the "Stringent Federal Scenario," the energy supply and related economic impacts on currently producing oil and gas wells were evaluated assuming crude oil prices of $50 per barrel and wellhead natural gas prices of $6.00 per Mcf. These are summarized as follows (all impacts are reported in 2007 dollars):

- The U.S. industry could spend nearly $10 billion annual complying with the new requirements, representing a significant investment that could otherwise be spent on developing U.S. oil and gas resources. In fact, at average drilling costs and reserve additions per well in 2006, this diversion of $10 billion represents the investment that could otherwise be used to drill over 5,800 wells, with corresponding reserve additions of on the order of 645 million barrels of oil equivalent (BOE) in just one year.
- Shut in crude oil production in the first year of compliance could amount to over 183,000 barrels per day, or 7% of U.S. Lower-48 onshore oil production. Shut in natural gas production could amount to 245 Bcf annually, amounting to 1.5% of U.S. Lower-48 onshore natural gas production.
- 57% of producing onshore oil wells in the United States could be shut in, as could 35% of producing onshore gas wells.

Potential future supplies of unconventional natural gas resources. For unconventional natural gas, the energy supply and related economic impacts associated with these proposed initiatives were assessed assuming wellhead natural gas prices averaging $6.00 and $9.00 per Mcf. Impacts are characterized in terms of their cumulative effect over the next 25 years. Overall, these impacts could be summarized as follows:

- From 42 to 53 Tcf of otherwise economic unconventional natural gas production could not be developed, a 12% to 18% reduction.
- Overall well drilling for unconventional gas could be reduced by 35% to 50%.
- Even for those resources that would be developed, industry would spend from $39 to $75 billion to comply with the increased requirements over 25 years.
- At average drilling costs and reserve additions per well over this time period, this diverted investment could help to drill from 33,000 to 76,000 unconventional gas wells over the next 25 years, which could result in reserve additions corresponding to 50 to 90 Tcf.

Potential future crude oil supplies from carbon dioxide enhanced oil recovery (CO_2-EOR). The impacts associated with the incremental compliance costs of the "Stringent Federal Scenario" on CO_2-EOR were assessed assuming crude oil prices of $50 per barrel. Depending on future costs for CO_2 and the risk industry would be willing to accept to pursue future CO_2-EOR projects, the impacts are summarized as follows:

- Lost reserves potential from CO_2-EOR could range from 5 to 9 billion barrels, depending on the assumed cost of CO_2 (13% to 30% reduction in reserves potential).
- Approximately 103 to 173 otherwise economic EOR prospects would become uneconomic, representing 12% to 30% of total prospective projects; a large and diverse set of future potential economic CO_2 sequestration sites.
- The reservoirs where reserves potential is lost represent 1,600 to 2,600 million metric tons (tonnes) of potential CO_2 storage capacity.[2] For reference, total U.S. CO_2 emissions in 2006 were about 6,000 million tonnes.

[2] Represented in terms of the amount of CO_2 that would need to be originally acquired (not recycled) to achieve the oil recovery potential for EOR

MAIN REPORT

BACKGROUND

For the last several years, the Natural Resources Defense Council (NRDC), along with a number of other environmental organizations such as the Oil and Gas Accountability Project (OGAP) and Rocky Mountain Clean Air Action, have been pursuing an aggressive campaign pushing for greater federal environmental oversight over U.S. oil and gas exploration and production (E&P) operations. In October 2007, the NRDC issued a report, entitled *Drilling Down: Protecting Western Communities from the Health and Environmental Effects of Oil and Gas Production*, which alleges that a number of "loopholes" in federal U.S. statutes and regulations allow U.S. oil and gas producers to circumvent environmental requirements imposed on other industries.[3] This report continues the trend of these environmental groups' contentions that oil and gas E&P operations benefit from such "loopholes."[4] These "loopholes" generally refer to special provisions for the oil and gas E&P industry under federal U.S. statutes such as the Safe Drinking Water Act (SDWA), Clean Water Act (CWA), Clean Air Act (CAA), Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, or Superfund), Resource Conservation and Recovery Act (RCRA), and the "public right-to-know" provisions of the Emergency Planning and Community Right-to-Know Act (EPCRA).

In addition, on July 2, 2008, Earthjustice, on behalf of a coalition of environmental groups including NRDC, announced its intent to sue the U.S. Environmental Protection Agency (EPA) over its "…nationwide failure to keep families and communities safe from air pollution produced by oil and gas drilling."[5] Earthjustice's letter of intent states that EPA has violated the Clean Air Act by failing to review and update three sets of clean air regulations related to oil and gas drilling: (1) New Source Performance Standards (NSPS) to ensure that sources of air pollution use the latest technology to reduce any pollutants that endanger public health and welfare, applicable to both production and natural gas processing operations; (2) Maximum Achievable Control Technology (MACT) standards, that ensure that industry reduce toxic air emissions, applicable to production, transmission, and storage operations; and (3) Residual Risk standards.

Moreover, ongoing federal regulatory initiatives may also impact domestic oil and gas E&P operations. These include Spill Prevention, Control, and Countermeasure (SPCC) requirements promulgated by EPA in 2002, 2006 and 2008 to "provide increased clarity," as well as to better "tailor" requirements to oil and gas industry operations,[6] and possible new federal effluent limitation guidelines (ELGs) to address water produced in association with methane production from coal seams (also referred to as coal seam or coalbed natural gas).[7]

Finally, recent new activities in emerging shale gas basins in the United States, such as the Marcellus shale in Pennsylvania and New York and the Haynesville shale in Arkansas, are resulting in oil and gas development in areas of the country not previously accustomed to oil and gas operations, causing some anxiety and concern among local residents about the potential environmental implications associated with such development.[8]

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[3] http://www.nrdc.org/land/use/down/contents.asp
[4] See, for example, http://www.earthworksaction.org/oil_and_gas.cfm
[5] "Groups Target EPA For Not Safeguarding Rocky Mountain West: Outdated standards, air pollution from drilling endanger communities, climate," Press Release issued July 2, 2008 (http://www.earthjustice.org/news/press/2008/groups-target-epa-for-not-safeguarding-rocky-mountain-west.html)
[6] http://www.epa.gov/OEM/content/spcc/index.htm
[7] http://www.epa.gov/guide/304m/2008/cbm-icr-200808.html
[8] See, for example, http://www.triplepundit.com/pages/shale-gas-energ.php

The domestic oil and gas industry is quite concerned that this set of regulatory proposals, if implemented, could have adverse impacts on the economics of U.S. oil and gas E&P operations, and thus on domestic oil and gas supplies, prices, and other economic considerations.[9]

STUDY OBJECTIVE

The objective of this "white paper" is to compile and document the results of previous economic impact studies that examined many of the recommendations made by these various environmental organizations, and to update this previous work to be consistent with current energy market outlooks, costs, and industry trends. Additionally, based on this previous work, this white paper characterizes the cumulative impact of these initiatives, if enacted, on potential domestic U.S. oil and natural gas supplies and on the related economic benefits that these supplies help facilitate.

REGULATORY INITIATIVES CONSIDERED

Of the dozen recommendations made by various environmental groups to close "loopholes" in U.S. federal environmental statutes, along with recommendations made by the Earthjustice announcement of its intent to sue, these initiatives were explicitly considered in this assessment:

- Requiring oil and gas E&P companies to report to the Toxic Release Inventory (TRI).
- Subjecting all hydraulic fracturing of oil and gas wells by the E&P industry to the requirements of the Underground Injection Control (UIC) program under the SDWA, despite language excluding this in the Energy Policy Act of 2005 (Pubic Law 109-58).[10]
- Requiring that all wastes associated with oil and gas exploration and production be addressed under RCRA cradle-to-grave hazardous waste provisions. This would include requiring that the underground injection of water associated with oil and gas E&P to meet the RCRA definition of hazardous waste and the standards of Class I injection.
- Requiring storm water permits for all oil and gas E&P operations, rescinding Section 323 of the Energy Policy Act of 2005 (EPAct).
- Requiring aggregation of the emissions of oil and gas E&P activities under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, and requiring EPA to review and update clean air regulations related to oil and gas E&P.

Also considered in this "cumulative" regulatory impact assessment is implementation of new Spill Prevention, Control, and Countermeasure (SPCC) requirements issued by EPA to "provide increased clarity," as well as to better "tailor" requirements to oil and gas industry operations.[11]

The combination of compliance requirements assumed in this assessment represent a stringent set of potential federal requirements, though would not necessarily be a "worst case" scenario

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[9] See, for example, IPAA Testimony to the House Oversight and Government Reform Committee in October 2007 (http://ipaa.org/issues/testimony/IPAATestimony-HouseOversiteGovtReform10-31-2007.pdf)

[10] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109

[11] The federal SPCC rule was first promulgated in 1973 and became effective on January 10, 1974. EPA issued a final rule amending the SPCC regulations in July 2002, becoming effective August 16, 2002. On December 12, 2005, EPA proposed further amendments to the 2002 rule. This analysis was based on the proposed rule proposed by EPA as of December 2005. Subsequent revisions not fully reflected in this analysis were promulgated by EPA in 2006 and 2008. (See http://www.epa.gov/emergencies/content/spcc/index.htm)

from the perspective of the domestic E&P industry. For purposes of this assessment, the compliance requirements providing the basis for this assessment have been labeled a "Stringent Federal Scenario."

OVERVIEW OF ANALYTICAL APPROACH

For purposes of conducting the economic and energy impact assessment in this white paper, several fundamental considerations were explicitly addressed for each of the initiatives considered. These were:

1. What additional compliance requirements could be implemented to address each of the environmental group proposals?
2. What types of "facilities" (equipment, processes, sites, etc.) could be subject to each new requirement?
3. How many/what portion of the "facilities" might be subject to each new requirement?
4. What types of compliance options would apply to each type of "facility"?
5. What precisely will operators have/choose to do to comply?
6. What will be the incremental costs associated with compliance?
7. What information exists that can be used as a basis for the above?

It is important to note that the proposals put forth by various environmental groups generally do not make specific recommendations, other than calling on the federal EPA to regulate specific industry activities and/or "waste" streams. Therefore, the assumptions concerning compliance actions made in this document do not necessarily represent any particular set of requirements proposed by EPA, any other state or federal agency, or any specific association, institution, or company.

To accomplish the above-stated objectives, a number of tasks were performed. First, the results from a significant body of prior work examining the cost, economic and energy supply impacts of most of the environmental group proposals were compiled and documented.[12] Previous impact analyses were updated consistent with current market activity and trends to make the findings on potential future compliance costs from these previous analyses comparable and consistent with current costs, industry trends, and energy market outlooks. This involved updating all costs to reflect recent conditions (e.g., oil and gas fields costs have increased dramatically the last few years), present levels of industry activity (e.g., drilling levels have increased significantly in response to recent high oil and gas prices), and future market outlooks (accounting for major market drivers from recent, historically high oil and gas prices, along with the policy push to reduce emissions of greenhouse gases).

Discussions of each of the individual regulatory initiatives/issue areas considered in this assessment are provided in Appendix A. These discussions include a summary of each issue and an overview of the sources, assumptions, and methodology for estimating potential future compliance costs which could be associated with the recommendations by the environmental groups (again, referred to in this analysis as the "Stringent Federal Scenario").

Next, the impact of the potential increased compliance costs was examined in terms of their impact on future oil and gas supplies from three categories of resources. Moreover, for different categories of resources, the potential impacts are reported in different ways. This is a result of both the nature of the different resource categories considered, as well as the characteristics of the analytical approaches and models used for each category. The approach and impacts considered for each of the categories of resources are summarized in the following.

[12] This body of work is summarized in the bibliography in Appendix D.

1. **Currently producing oil and gas wells.** For currently producing oil and gas wells, impacts were characterized in terms of the impacts on production in the first year that compliance requirements associated with the initiatives are assumed to be implemented. Impacts are represented in terms of the number of wells and volume of production shut in due to increased compliance requirements in the first year, the total cost of compliance associated with producing wells not shut in (since some wells are shut in, they would not incur incremental compliance costs), and the lost royalties and tax revenues that would otherwise have been associated with wells shut in. The approach used for assessing the impact of the potential increased compliance costs on currently producing oil and gas wells is summarized in Appendix B.

2. **Potential future supplies of unconventional natural gas resources**. For unconventional natural gas (coalbed methane, gas shales, and tight gas sands), impacts are represented as the reduction in wells drilled and the associated gas production that would have otherwise occurred over the next 25 years if these compliance requirements are not implemented. The total cost of compliance associated with wells drilled over the next 25 years (wells that are not drilled do not incur incremental compliance costs), and the lost royalties and tax revenues that would otherwise be associated with the production over this time period, are also estimated. The approach used for assessing the impact of the potential increased compliance costs on future supplies of unconventional natural gas is summarized in Energy Information Administration (EIA) documentation of its Unconventional Gas Resources Supply Model (UGRSS) (developed originally by Advanced Resources), as part of its National Energy Modeling System (NEMS).[13]

3. **Carbon dioxide enhanced oil recovery.** The approach used for assessing the impacts of the potential increased compliance costs on potential future supplies from carbon dioxide enhanced oil recovery (CO_2-EOR) builds upon a series of studies performed by Advanced Resources for DOE, the most recent published in September 2008.[14] This work builds on previous analyses of currently practiced CO_2-EOR technology, as reported in "*Storing CO_2 with Enhanced Oil Recovery*"[15] and a series of "*Ten Basin-Oriented Reports*" [16]. For this category of domestic resource, the impacts are characterized in terms of lost economic reserves potential, the number of otherwise economic EOR prospects could become uneconomic, and the potential CO_2 storage capacity associated with the reservoirs where CO_2-EOR reserves potential is lost. The approach used for assessing the impacts of the potential increased compliance costs on potential future supplies from CO_2-EOR is summarized in Appendix C.

[13] http://tonto.eia.doe.gov/ftproot/modeldoc/m063(2005).pdf

[14] Advanced Resources International, *Storing CO2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology,* Report DOE/NETL-2009/1350 prepared for the U.S. Department of Energy, National Energy Technology Laboratory, January 9, 2009 (http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20Next%20Generation%20CO2-EOR.pdf)

[15] Advanced Resources International, "*Storing CO2 with Enhanced Oil Recovery*" report prepared for U.S. DOE/NETL, Office of Systems, Analyses and Planning, DOE/NETL-402/1312/02-07-08, February 7, 2008. http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf

[16] The Advanced Resources completed series of ten "basin studies" were the first to comprehensively address CO_2 storage capacity from combining CO_2 storage and CO_2-EOR. These ten "basin studies" covered 22 of the oil producing states plus offshore Louisiana and included 1,581 large (>50 MMBbls OOIP) oil reservoirs, accounting for two thirds of U.S. oil production. These reports are available on the U.S. Department of Energy's web site at: http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html.

Finally, for both currently producing wells and unconventional gas resource potential, estimates were made of the total number of wells that could be drilled, and the reserves potential associated with those wells, if the amount of money spent to comply with the potential requirements was otherwise expended on resource development.

POTENTIAL ECONOMIC AND ENERGY SUPPLY IMPACTS – CURRENTLY PRODUCING WELLS

Of the list of regulatory initiatives discussed above, the specific requirements assumed to apply to currently producing oil and gas wells include TRI reporting, complying with RCRA hazardous waste provisions for produced water and other associated E&P wastes, requirements for Area Source aggregation of E&P emissions under NESHAP, new requirements for engines and tanks under NESHAP, and new SPCC requirements.

The largest cost set of potential requirements is associated with the management of other associated E&P wastes under RCRA's cradle-to-grave hazardous waste provisions. In general, these provisions could apply to produced water, drilling wastes and other associated wastes produced in association with oil and gas E&P operations. This particular item refers to "other associated wastes" (not including drilling wastes and produced waters) that represent a wide range of small volume waste streams that primarily include:

- Completion Fluids – All fluids from initial well completion activities, including any initial acid stimulation or hydraulic fracturing.
- Workover/Stimulation Fluids – All fluids from subsequent workover and stimulation operations.
- Tank Bottoms/Oily Sludges – Tank sediment and water, produced sand and other tank bottoms.
- Dehydration/Sweetening Wastes – Includes glycol-based compounds, glycol filters, molecular sieves, amines, amine filter, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media and other wastes associated with the dehydration and sweetening of natural gas.

Based on a 1995 American Petroleum Institute (API) survey,[17] other associated wastes represent only about 0.11% of E&P wastes nationwide. The method for estimating costs for disposing of such wastes, for purposes of this study, assumed that 15% of such wastes would test as RCRA hazardous wastes based on analyses conducted of E&P waste streams in Louisiana.[18]

The second largest cost item is associated with compliance with potential new SPCC requirements. For existing producing wells, these costs represent one-time costs that would be incurred to bring existing facilities into compliance.

The third largest category of costs would involve requiring underground injection of produced water to comply with RCRA's hazardous waste provisions (i.e., standards for Class I injection). For this category of costs, producing oil wells were assumed to bear the full costs associated with produced water disposal (including the small proportion produced from gas wells); with 10% of produced water volumes assumed to test as hazardous under RCRA criteria.

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[17] American Petroleum Institute, *1995 Survey of Oil and Gas Exploration and Production Waste Management Practices in the United States*, May 2000

[18] Louisiana Department of Natural Resources. Office of Conservation, Public information database; "Analytical Results, Chemical Constituents of E&P Waste Shipments Disposed at Commercial E&P Waste Facilities in Louisiana, 1997 and 1998"

Given the above set of regulatory requirements, estimated annual incremental compliance costs are $24,570 per producing oil well and $22,938 per producing gas well (2007 dollars).[19] This is broken down by compliance requirement in Table 1.

TABLE 1
AGGREGATE PER WELL COMPLIANCE COSTS BY KEY REGULATORY REQUIREMENT APPLICABLE TO CURRENTLY PRODUCING WELLS UNDER THE "STRINGENT FEDERAL SCENARIO"
(2007 $)

	Producing oil wells **(\$/well/year)**	**Producing gas wells** **(\$/well/ year)**
TRI reporting [(1)]	$318	$171
Manage other associated E&P wastes under RCRA hazardous waste provisions	$10,452	$10,452
Area Source aggregation of E&P emissions under NESHAP	$0	$575
Impose new requirements for engines and tanks under NESHAP[(2)]	$4,783	$2,174
Comply w/ new SPCC requirements	$ 9,018	$9,566
TOTAL	**$24,570**	**$22,938**
Manage produced water under RCRA hazardous waste provisions **($/barrel of water produced)**	**$0.08**	

[(1)] Initial investment costs to comply with TRI requirements assumed to be amortized over 5 years and as such are different than the estimates shown in Appendix A. For oil, this amounts to $477/5 + $222 = $318. For gas, this amounts to $258/5+$119 = $171..
[(2)] Initial investment costs to comply with NESHAP requirements for new engines assumed to be amortized over 5 years and as such are different than the estimates shown in Appendix A. For oil, this amounts to ($1537+$6456/5) + $1317+$1867 = $4783. For gas, this amounts to $1537/5+$1867 = $2174.

Source: Advanced Resources International.[20]

[19] Unless otherwise indicated, all costs, revenues, and other financial information in this assessment is reported in 2007 dollars.
[20] See subsequent sections of this report for more detailed information and references. Rather than being a fundamentally new analysis, this report builds on and extrapolates the results of prior analyses prepared for industry or government agencies such as the U.S. Department of Energy and EPA.

The process of adding the incremental costs for compliance results in costs exceeding revenues for certain categories of low productivity or "marginal" wells. The number of wells and amount of production for these rate categories was assumed to be shut-in, since wells in the category, on average, would no longer be profitable to produce.

Given these incremental compliance costs, the energy supply and related economic impacts associated with these requirements, assuming crude oil prices of $50 per barrel and wellhead natural gas prices of $6.00 per Mcf, are summarized as follows (again, all impacts are reported in 2007 dollars; note that these impacts represent those only for the first year after which these requirements go into effect):

- The U.S. industry could spend nearly $10 billion complying with the new requirements. As a point of perspective, the U.S. industry spent about $15 billion on exploration activity in 2006.[21] This represents a significant investment that, if not diverted to meet new compliance requirements, could otherwise be spent on developing U.S. oil and gas resources. In fact, at average drilling costs and reserve additions per well in 2006, the $10 billion could otherwise be used to drill over 5,800 wells, with corresponding reserve additions of nearly 645 million barrels of oil equivalent (BOE).
- Shut in crude oil production would amount over 183,000 barrels per day, or 7% of U.S. Lower-48 onshore oil production. Shut in natural gas production would amount to 245 Bcf annually, amounting to 1.5% of U.S. Lower-48 onshore natural gas production.
- 57% of all producing onshore oil wells in the U.S. would be shut in, as would 35% of all producing onshore gas wells.
- Public and private royalty holders would lose over $600 million in revenues from the lost production. State governments would lose $285 million in revenues from state severance taxes, and over $500 million in revenues from state income taxes, while the federal government would lose as much as $4 billion in federal income tax receipts at the standard U.S. corporate tax rate.[22]

These results are presented in detail by state in Table 2.

POTENTIAL ECONOMIC AND ENERGY SUPPLY IMPACTS – UNCONVENTIONAL NATURAL GAS

Of the list of regulatory initiatives discussed above, the specific requirements assumed to apply to new unconventional natural gas development and production include TRI reporting, subjecting all hydraulic fracturing to federal UIC program requirements, requiring storm water permits for all new oil and gas E&P industry activities, managing drilling and other associated wastes under RCRA hazardous waste provisions, implementing requirements for Area Source aggregation of E&P emissions under NESHAP, implementing new requirements for engines and tanks under NESHAP, and complying with new SPCC requirements.

[21] http://www.eia.doe.gov/emeu/perfpro/t_tab08.html
[22] Not taking into consideration the effect of potential tax incentives, alternative minimum tax, etc.

Table 2
SUMMARY OF IMPACTS OF INCREASED COMPLIANCE COSTS ON CURRENTLY PRODUCING OIL AND GAS WELLS UNDER THE "STRINGENT FEDERAL SCENARIO"
(2007 $)

STATE	Annual Volume of Shut In Oil Production (MBOE)	Annual Volume of Shut In Gas Production (MMcfe)	Number of Shut in Wells: Oil	Number of Shut in Wells: Gas	Incremental Industry Compliance Expenditures (MM $/yr)	Foregone Royalties (Public and Private) (M $/yr)	Foregone State Severance Taxes (M $/yr)	Foregone State Income Taxes (MM $/yr)	Foregone Federal Income Taxes (MM $/yr)
Alabama	54	542	90	295	$88	$742	$594	$7	$30
Arkansas	3	19	821	486	$54	$32	$25	$7	$43
Arizona	0	0	2	0	$1	$1	$1	$0	$0
California	2,953	818	8,577	614	$1,017	$19,072	$1,526	$94	$278
Colorado	1,152	7,622	2,091	3,556	$553	$12,918	$7,751	$35	$227
Florida	2	0	4	1	$1	$10	$6	$0	$1
Illinois	2,079		3,879		$39	$12,996	$0	$6	$37
Indiana	173		552		$15	$1,078	$86	$2	$5
Kansas	6,451	10,278	33,806	7,116	$688	$48,029	$30,739	$32	$248
Kentucky	626	11,608	4,174	5,770	$172	$12,620	$7,067	$12	$69
Louisiana	3,235	8,420	14,110	8,928	$286	$26,531	$26,531	$31	$104
Maryland		11		5	$0	$8	$8	$0	$0
Michigan	668	1,611	2,062	592	$250	$5,381	$2,583	$5	$88
Mississippi	155	232	283	112	$67	$1,141	$548	$4	$23
Missouri	55		283		$1	$345	$166	$0	$0
Montana	811	4,175	1,992	2,127	$118	$8,197	$5,902	$13	$54
Nebraska	93	55	243	22	$26	$623	$149	$2	$7
Nevada	2		8		$1	$14	$1	$0	$1
New York	133	6,948	2,678	5,602	$20	$6,045	$0	$4	$59
New Mexico	3,997	10,346	7,486	5,187	$805	$32,739	$22,263	$82	$297
North Dakota	91	97	257	82	$85	$639	$460	$6	$25
Ohio	2,615	32,816	10,049	22,904	$46	$40,957	$21,625	$16	$94
Oklahoma	4,726	18,340	20,779	9,881	$1,104	$43,295	$24,245	$74	$359
Oregon	0	4	0	1	$0	$3	$2	$0	$0
Pennsylvania	775	43,624	6,363	25,452	$93	$37,562	$19,833	$26	$150
South Dakota	3	62	8	23	$4	$66	$25	$0	$2
Tennessee	9		127		$2	$56	$21	$0	$1
Texas	34,524	36,008	76,914	18,548	$3,128	$242,781	$89,343	$0	$1,543
Utah	331	663	566	389	$153	$2,563	$615	$0	$53
Virginia	2	1,193	8	526	$103	$909	$345	$0	$38
West Virginia	448	40,242	2,819	25,826	$309	$32,981	$13,192	$47	$135
Wyoming	817	8,838	3,241	6,157	$701	$11,738	$9,390	$0	$264
Total for States	**66,983**	**244,572**	**204,272**	**150,202**	**$9,930**	**$602,071**	**$285,042**	**$505**	**$4,235**
	(Bbl/day	**(Bcf/day)**							
Total Daily Shut in Production Rate	**183,514**	**670**							

Source: Advanced Resources International. Marginal wells are particularly burdened by increased environmental compliance costs which can increase the potential for such wells to become uneconomic (shown above as "shut-in production") .

Table 2 (Continued)
SUMMARY OF IMPACTS OF INCREASED COMPLIANCE COSTS ON CURRENTLY PRODUCING OIL AND GAS WELLS UNDER THE "STRINGENT FEDERAL SCENARIO"

	Total Annual Volume of Production in the State		Annual Volume of Shut In Production		% of Total Production Shut in		Total Number of Producing Wells		Number of Shut in Wells		% of Total Wells Shut in	
	(OIL)	(GAS)	(OIL)	(GAS)	(OIL)	(GAS)	(OIL)	(GAS)	(OIL)	(GAS)	(OIL)	(GAS)
STATE	**(MBOE)**	**(MMcfe)**	**(MBOE)**	**(MMcfe)**								
Alabama	7,173	306,144	54	542	0.71%	0.18%	484	4,063	90	295	19%	7%
Arkansas	6,031	193,942	3	19	8.39%	0.52%	1,666	4,697	821	486	49%	10%
Arizona	55	611	0	0	0.20%	0.00%	23		2	0	9%	0%
California	223,449	308,730	2,953	818	1.28%	0.26%	47,197	3,692	8,577	614	18%	17%
Colorado	23,390	1,214,396	1,152	7,622	5.05%	0.63%	4,655	28,536	2,091	3,556	45%	12%
Florida	2,360	2,845	2	0	0.06%	0.01%	59	5	4	1	7%	20%
Illinois	10,323	170	2,079		7.73%		5,460		3,879		71%	
Indiana	1,731	2,921	173		9.99%		1,173		552		47%	
Kansas	35,651	372,029	6,451	10,278	19.07%	2.76%	45,530	24,543	33,806	7,116	74%	29%
Kentucky	2,340	95,320	626	11,608	24.70%	12.18%	4,778	12,617	4,174	5,770	87%	46%
Louisiana	73,483	1,378,238	3,235	8,420	4.29%	0.61%	18,635	17,102	14,110	8,928	76%	52%
Maryland	0	48		11		0.00%		7		5	0%	71%
Michigan	5,093	370,958	668	1,611	12.03%	0.43%	3,656	9,780	2,062	592	56%	6%
Mississippi	17,356	212,081	155	232	0.20%	0.11%	1,778	1,566	283	112	16%	7%
Missouri	87	0	55		0.00%		304		283		93%	
Montana	36,262	114,037	811	4,175	2.47%	3.66%	4,199	6,207	1,992	2,127	47%	34%
Nebraska	2,313	1,217	93	55	3.85%	4.54%	1,213	117	243	22	20%	19%
Nevada	426	5	2		0.49%		69		8		12%	
New York	319	55,980	133	6,948	67.75%	12.41%	2,909	6,217	2,678	5,602	92%	90%
New Mexico	59,818	1,619,528	3,997	10,346	6.59%	0.64%	15,456	4,063	7,486	5,187	48%	128%
North Dakota	39,911	62,786	91	97	0.25%	0.15%	484	36,202	257	82	53%	0%
Ohio	5,422	86,315	2,615	32,816	0.00%	0.00%	10,557	27,178	10,049	22,904	95%	84%
Oklahoma	62,841	1,688,985	4,726	18,340	7.61%	1.09%	31,016	47,021	20,779	9,881	67%	21%
Oregon	0	621		4		0.63%				1	0%	0%
Pennsylvania	3,626	158,355	775	43,624	0.00%	0.00%	6,674	35,796	6,363	25,452	95%	71%
South Dakota	1,394	10,616	3	62	0.22%	0.58%	82	135	8	23	10%	17%
Tennessee	192	1,793	9		0.00%	0.00%	205		127		62%	
Texas	397,220	6,267,366	34,524	36,008	3.66%	0.57%	136,738	104,983	76,914	18,548	56%	18%
Utah	17,910	356,038	331	663	0.51%	0.19%	2,574	5,259	566	389	22%	7%
Virginia	7	103,027	2	1,193	0.00%	0.00%	8	5,020	8	526	100%	10%
West Virginia	1,749	225,530	448	40,242	28.66%	17.84%	3,137	38,932	2,819	25,826	90%	66%
Wyoming	52,904	2,111,766	817	8,838	1.58%	0.42%	10,712	28,675	3,241	6,157	30%	21%
Total for States	**1,090,836**	**17,322,398**	**66,983**	**244,572**	**6.89%**	**1.52%**	**355,537**	**418,758**	**204,272**	**150,202**	**57%**	**36%**
			(Bbl/day	**(Bcf/day)**								
Total Daily Shut in Production			**183,514**	**670**								

The potential requirement representing the single largest cost item considered for initial compliance costs for new unconventional gas wells is potential new requirements for hydraulic fracturing. This represents over 65% of the total of all cost elements.

The potential requirement representing the single largest operating and maintenance (O&M) cost item is that associated with the management of "other associated wastes" under RCRA hazardous waste provisions. This represents 80% of the total of all cost elements.

A potentially important cost item not considered for unconventional natural gas is that related to the management of produced water. This includes both managing waters produced in association with unconventional gas production under RCRA hazardous waste provisions[23], as well as water produced in association with coalbed methane production that could be subject to new federal effluent limitation guidelines (ELGs). The analytical structure for unconventional gas used in this assessment did not include an accounting for water produced in association with unconventional gas production, so these potential requirements could not be explicitly assessed.

Given this assumed set of regulatory requirements, estimated incremental investment costs to comply are estimated to be $152,843 per well, on average, for all new unconventional gas wells. In addition, estimated incremental annual operating costs are estimated to total, on average, $13,013 per well. This is broken down by requirement in Table 3.

Given these incremental compliance costs, the energy supply and related economic impacts associated with these requirements were assessed assuming wellhead natural gas prices averaging $6.00 and $9,00 per Mcf. Impacts are characterized in terms of their cumulative effect over the next 25 years. Overall, these impacts could be summarized as follows, with the range associated with assumptions about future natural gas prices:

- From 42 to 53 Tcf of otherwise economic unconventional natural gas production would not be developed, a 12% to 18% reduction.
- Overall well drilling for unconventional gas over the 25 year period could be reduced by 35% to 50%.
- Even for those resources that would be developed, industry could spend from $39 to $75 billion to comply with the increased requirements
- At average drilling costs and reserve additions per well over this time period, this diverted investment could help to drill from 33,000 to 76,000 wells over the next 25 years, which could result in reserve additions corresponding to 50 to 90 Tcf.
- Royalties of nearly $50 billion over 25 years that would otherwise be collected would not be paid. Since a large portion of U.S. unconventional gas potential exists under federal lands, much of this could otherwise be revenues accruing to the federal government.

These results are summarized in Table 4.

[23] Oil and gas wastes that could potentially test or be characterized as hazardous under RCRA and CERCLA regulations do not necessarily pose an environmental or health risk when properly managed. See http://www.epa.gov/osw/nonhaz/industrial/special/oil/index.htm

Table 3
AGGREGATE PER WELL COMPLIANCE COSTS BY KEY REGULATORY REQUIREMENT APPLICABLE TO UNCONVENTIONAL NATURAL GAS UNDER THE "STRINGENT FEDERAL SCENARIO"
(2007 $)

	Incremental initial investment costs (New wells only)	**Incremental annual O&M costs (New wells only)**
	($/well)	**($/well)**
TRI reporting	$258	$119
Regulate hydraulic fracturing to UIC program requirements	$100,505	$0
Require storm water permits for all O&G industry activities	$26,452	$0
Include drilling wastes from O&G E&P under RCRA hazardous waste provisions	$14,526[1]	$0
Manage other associated E&P wastes under RCRA hazardous waste provisions	$0	$10,452
Area Source aggregation of E&P emissions under NESHAP	$0	$575
Impose new requirements for engines and tanks under NESHAP	$1,537	$1,867
Comply w/ new SPCC requirements	$9,566	$0
TOTAL	**$152,843**	**$13,013**

[1] This represents the average costs for unconventional gas wells, specifically considering the depths of such wells. Consequently, it does not precisely match values shown in Appendix A.
Source: Advanced Resources International.

Table 4
SUMMARY OF 25-YEAR IMPACTS OF INCREASED COMPLIANCE COSTS ON FUTURE U.S. UNCONVENTIONAL NATURAL GAS POTENTIAL UNDER THE "STRINGENT FEDERAL SCENARIO" (2007 $)

		Tight Gas		Coalbed Methane		Shale Gas		Total Unconventional	
Category	Units	$6/Mcf	$9/Mcf	$6/Mcf	$9/Mcf	$6/Mcf	$9/Mcf	$6/Mcf	$9/Mcf
Total Production - Base Case	**Tcf**	186,739	210,940	38,020	44,273	71,908	109,021	296,667	364,234
Reduction in Cum. Production	**Tcf**	25,839	19,308	10,851	11,623	16,168	11,031	52,858	41,962
% Reduction		14%	9%	29%	26%	22%	10%	18%	12%
Foregone Reserve Additions	**Tcf**	23,105	32,644	1,808	6,910	24,707	50,312	49,620	89,866
Total Drilling - Base Case	**Wells**	150,646	193,058	42,461	61,175	35,563	87,890	228,669	342,122
Reduction in Well Drilling	**Wells**	60,053	46,045	34,827	35,263	19,139	39,540	114,019	120,848
% Reduction		40%	24%	82%	58%	54%	45%	50%	35%
Compliance Costs	**Million $**	$31,575	$51,240	$1,674	$7,297	$5,725	$16,852	$38,974	$75,389
Foregone Royalties	**Million $**	$29,069	$21,722	$8,138	$13,076	$12,126	$12,409	$49,333	$47,207

Source: Advanced Resources International.

POTENTIAL ECONOMIC AND ENERGY SUPPLY IMPACTS – CO_2-EOR

Of the regulatory initiatives discussed above, the specific requirements assumed to apply to CO_2-EOR include TRI reporting, subjecting all CO_2 injection wells to federal UIC program requirements for Class I injection , requiring storm water permits for all O&G industry activities, managing drilling wastes and other associated E&P wastes under RCRA hazardous waste provisions, Area Source aggregation of E&P emissions under NESHAP, new requirements for engines and tanks under NESHAP, and new SPCC requirements.

The potential requirement representing the single largest cost item considered is that associated with potential new requirements that could subject CO_2 injection wells used for CO_2-EOR to federal UIC program requirements for Class I injection of "hazardous" waste. While CO_2 itself is not considered a hazardous substance, the injected CO_2 stream may contain hazardous substances such as mercury, or the constituents of the CO_2 stream could react with groundwater to produce a listed hazardous substances such as sulfuric acid. Moreover, CO_2 mixed with water forms carbonic acid, which can corrode well materials and piping. Corrosivity, along with ignitability, reactivity, or toxicity, is a characteristic that can define an injectant as hazardous under RCRA.

For purposes of this assessment, new compliance costs for CO_2-EOR projects are assumed to be associated with incremental capital costs for new well drilling, for newly converted wells, for existing producers, and for existing injectors. In addition, incremental annual O&M costs are also assumed to be incurred, which, for purposes of this assessment, were assigned to existing and new producers.

Given this assumed set of regulatory requirements, average estimated incremental costs to comply with the proposed requirement in the Stringent Federal Scenario considered in this assessment, for each category of cost, are broken down by requirement in Table 5.

Table 5
AGGREGATE PER WELL COMPLIANCE COSTS BY KEY REGULATORY REQUIREMENTS APPLICABLE TO CO_2-EOR UNDER THE "STRINGENT FEDERAL SCENARIO"
(2007 $)

	Incremental Capital Costs -- New Well Drilling (2007 $/well)	Incremental Capital Costs -- Newly Converted Wells (2007 $/well)	Other Incremental Capital Costs -- Existing Producers (2007 $/well)	Other Incremental Capital Costs -- Existing Injectors (2007 $/well)	Incremental Annual O&M Costs (Producers) (2007 $/well)
TRI reporting	$477	$477	$477	$0	$222
Conform injectors to Class I requirements	$692,694	$1,176,137	$0	$0	$60,626
Require stormwater permits for all O&G industry activities	$26,452	$26,452	$26,452	$26,452	$0
Include drilling wastes associated with O&G E&P under RCRA hazardous waste provisions	$14,198	$0	$0	$0	$0
Manage other associated E&P wastes under RCRA hazardous waste provisions	$0	$0	$0	$0	$10,452
Impose new requirements for engines and tanks under NESHAP	$7,996	$7,996	$7,996	$7,996	$3,184
Comply w/ new SPCC provisions	$9,018	$9,018	$9,018	$0	$0
TOTAL	**$750,835**	**$1,220,080**	**$43,943**	**$34,448**	**$74,484**

Source: Advanced Resources International.

Given these incremental compliance costs, the energy supply, economic, and potentially related environmental impacts associated with these requirements were assessed assuming average crude oil prices, over the long term (in real 2007 dollars), of $50 per barrel. The impacts of increased requirements under the "Stringent Federal Scenario" for CO_2-EOR were considered for two potential costs of CO_2. The two CO_2 cost scenarios considered were:

- A "Business as Usual" set of conditions for CO_2 costs, which assumes the future looks much as it does today; that is, no requirements are mandated for controlling CO_2 emissions besides voluntary actions by industry. In this case, CO_2 prices are comparable to those in the current market – with a delivered CO_2 cost equivalent to, on average, about 5% of the oil price. At an oil price of $50 per barrel, this would about to a CO_2 cost of $47.25 per metric ton (tonne), or $2.50 per Mcf. Under this scenario, operators would pay a price for CO_2 comparable to that paid by CO_2 flood operators today.
- A "Carbon-Constrained" set of conditions for CO_2 costs that assumes increasingly strict requirements are implemented for limiting CO_2 emissions, particularly for new sources. In this case, the price for delivered CO_2 is assumed to amount to about 2% of the oil price, on average. At an oil price of $50 per barrel, this would amount to a CO_2 cost of $18.90 per tonne, or $1.00 per Mcf. The assumption here is that a regulatory program for limiting CO_2 emissions would encourage CO_2 producers/emitters to sell their CO_2 at lower costs, since the supply of CO_2 (from industrial emissions) would tend to be larger than the demand for its application in CO_2-EOR projects.

The assessment also considered two potential rates of return that new CO_2-EOR projects would have to meet to be considered economically viable. These two hurdle rates represent two views as to the amount of risk developers/operators would be willing to take to pursue new CO_2-EOR projects. The two hurdle rates of return considered were 15% and 25%, real.

The impacts associated with the incremental compliance costs under the "Stringent Federal Scenario" on CO_2-EOR could be summarized as follows, depending on future costs for CO_2, and the risk industry is willing to accept to pursue future CO_2-EOR projects:

- Lost reserves potential from CO_2-EOR would range from 5-9 billion barrels (13% to 30% reduction in total potential reserves potential) (Table 6). The largest proportional impacts are in the Gulf Coast, West Texas, and Appalachia.
- Approximately 103 to 173 otherwise economic EOR prospects would become uneconomic, representing 12% to 30% if total prospective projects; a very large and diverse set of future potentially economic CO_2 storage/sequestration sites (Table 7).
- The reservoirs where reserves potential is lost represent 1,600 to 2,600 million metric tonnes of potential CO_2 storage capacity (Table 8). For reference, total U.S. CO_2 emissions in 2006 were about 6,000 million metric tonnes

TABLE 6
SUMMARY OF IMPACTS OF INCREASED COMPLIANCE COSTS ON FUTURE U.S. CO_2-EOR OIL RECOVERY POTENTIAL UNDER THE "STRINGENT FEDERAL SCENARIO"
(2007 $)

Oil Recovery Potential (Billion Barrels)
15% Hurdle Rate of Return

	CO_2 Cost - $1.00 per Mcf				CO_2 Cost - $2.50 per Mcf			
Basin/Area	Current Requirements	Stringent Federal Scenario	Difference	% Difference	Current Requirements	Stringent Federal Scenario	Difference	% Difference
1. Alaska	9.27	7.67	1.60	17.3%	7.28	7.18	0.10	1.4%
2. California	5.43	5.37	0.06	1.2%	4.97	4.65	0.32	6.5%
3. Gulf Coast (AL, FL, MS, LA)	2.27	1.22	1.05	46.1%	0.73	0.12	0.61	83.8%
4. Mid-Continent (OK, AR, KS, NE)	5.55	5.17	0.38	6.8%	5.07	4.57	0.50	9.9%
5. Illinois/Michigan	0.65	0.51	0.14	21.7%	0.54	0.34	0.20	37.6%
6. Permian (W TX, NM)	7.59	6.27	1.32	17.4%	4.56	0.12	4.44	97.4%
7. Rockies (CO,UT,WY)	1.85	1.65	0.20	11.0%	1.31	1.12	0.19	14.3%
8. Texas, East/Central	8.26	7.30	0.96	11.6%	7.26	6.14	1.12	15.4%
9. Williston (MT, ND, SD)	0.47	0.45	0.02	5.3%	0.39	0.32	0.07	18.3%
10. Louisiana Offshore	4.11	4.02	0.09	2.3%	1.03	0.41	0.63	60.8%
11. Appalachia (WV, OH, KY, PA)	0.07	0.01	0.06	84.7%	0.02	0.01	0.01	46.8%
TOTAL	45.53	39.64	5.89	**12.9%**	33.16	24.97	8.19	**24.7%**

Oil Recovery Potential (Billion Barrels)
25% Hurdle Rate of Return

	CO_2 Cost - $1.00 per Mcf				CO_2 Cost - $2.50 per Mcf			
Basin/Area	Current Requirements	Stringent Federal Scenario	Difference	% Difference	Current Requirements	Stringent Federal Scenario	Difference	% Difference
1. Alaska	7.67	7.18	0.49	6.4%	0.29	0.29	0.00	0.0%
2. California	5.19	4.98	0.20	3.9%	4.10	3.59	0.50	12.3%
3. Gulf Coast (AL, FL, MS, LA)	1.82	0.48	1.34	73.8%	0.25	0.01	0.24	95.8%
4. Mid-Continent (OK, AR, KS, NE)	5.36	3.75	1.61	30.0%	4.24	1.88	2.36	55.6%
5. Illinois/Michigan	0.59	0.35	0.24	40.5%	0.48	0.09	0.39	81.7%
6. Permian (W TX, NM)	6.74	4.21	2.53	37.6%	0.11	-0.05	0.16	149.7%
7. Rockies (CO,UT,WY)	1.58	1.35	0.24	15.1%	0.99	0.75	0.24	24.6%
8. Texas, East/Central	7.80	6.47	1.32	17.0%	6.19	5.21	0.98	15.9%
9. Williston (MT, ND, SD)	0.39	0.38	0.02	4.6%	0.31	0.21	0.10	32.5%
10. Louisiana Offshore	2.46	1.53	0.93	37.9%	0.00	0.00	0.00	
11. Appalachia (WV, OH, KY, PA)	0.02	0.01	0.01	46.8%	0.01	0.01	0.00	0.0%
TOTAL	39.61	30.68	8.93	**22.6%**	16.98	11.99	4.99	**29.4%**

Source: Advanced Resources International.

TABLE 7
SUMMARY OF IMPACTS OF INCREASED COMPLIANCE COSTS ON THE FUTURE NUMBER OF CO_2-EOR PROJECTS IN THE U.S UNDER THE "STRINGENT FEDERAL SCENARIO"

Number of EOR Projects
15% Hurdle Rate of Return

	CO_2 Cost - \$1.00 per Mcf				CO_2 Cost - \$2.50 per Mcf			
Basin/Area	Current Requirements	Stringent Federal Scenario	Difference	% Difference	Current Requirements	Stringent Federal Scenario	Difference	% Difference
1. Alaska	11	5	6	54.5%	3	2	1	33.3%
2. California	75	73	2	2.7%	66	61	5	7.6%
3. Gulf Coast (AL, FL, MS, LA)	68	38	30	44.1%	23	5	18	78.3%
4. Mid-Continent (OK, AR, KS, NE)	83	77	6	7.2%	77	63	14	18.2%
5. Illinois/Michigan	50	22	28	56.0%	43	16	27	62.8%
6. Permian (W TX, NM)	105	78	27	25.7%	65	3	62	95.4%
7. Rockies (CO,UT,WY)	67	58	9	13.4%	42	32	10	23.8%
8. Texas, East/Central	125	105	20	16.0%	96	76	20	20.8%
9. Williston (MT, ND, SD)	18	17	1	5.6%	17	14	3	17.6%
10. Louisiana Offshore	75	71	4	5.3%	19	7	12	63.2%
11. Appalachia (WV, OH, KY, PA)	5	1	4	80.0%	2	1	1	50.0%
	682	545	137	**20.1%**	453	280	173	**38.2%**

Number of EOR Projects
25% Hurdle Rate of Return

	CO_2 Cost - \$1.00 per Mcf				CO_2 Cost - \$2.50 per Mcf			
Basin/Area	Current Requirements	Stringent Federal Scenario	Difference	% Difference	Current Requirements	Stringent Federal Scenario	Difference	% Difference
1. Alaska	5	2	3	60.0%	1	1	0	0.0%
2. California	69	67	2	2.9%	52	46	6	11.5%
3. Gulf Coast (AL, FL, MS, LA)	55	13	42	76.4%	10	2	8	80.0%
4. Mid-Continent (OK, AR, KS, NE)	80	57	23	28.8%	66	33	33	50.0%
5. Illinois/Michigan	41	17	24	58.5%	29	3	26	89.7%
6. Permian (W TX, NM)	86	56	30	34.9%	3	1	2	66.7%
7. Rockies (CO,UT,WY)	54	44	10	18.5%	28	21	7	25.0%
8. Texas, East/Central	106	87	19	17.9%	76	58	18	23.7%
9. Williston (MT, ND, SD)	17	16	1	5.9%	13	10	3	23.1%
10. Louisiana Offshore	42	24	18	42.9%	0	0	0	
11. Appalachia (WV, OH, KY, PA)	2	1	1	50.0%	1	1	0	0.0%
	557	384	173	**31.1%**	279	176	103	**36.9%**

Source: Advanced Resources International.

TABLE 8
SUMMARY OF IMPACTS OF INCREASED COMPLIANCE COSTS ON FUTURE CO_2 DEMAND IN CO_2-EOR PROJECTS UNDER THE "STRINGENT FEDERAL SCENARIO"

CO_2 Demand for EOR Projects (Million Metric Tons)

15% Hurdle Rate of Return

	CO_2 Cost - \$1.00 per Mcf				**CO_2 Cost - \$2.50 per Mcf**			
Basin/Area	**Current Requirements**	**Stringent Federal Scenario**	**Difference**	**% Difference**	**Current Requirements**	**Stringent Federal Scenario**	**Difference**	**% Difference**
1. Alaska	2,029	1,689	340.31	16.8%	1,586	1,564	22.13	1.4%
2. California	1,375	1,361	14.68	1.1%	1,241	1,119	121.84	9.8%
3. Gulf Coast (AL, FL, MS, LA)	701	357	344.11	49.1%	204	30	174.00	85.3%
4. Mid-Continent (OK, AR, KS, NE)	1,431	1,331	100.16	7.0%	1,297	1,158	138.09	10.7%
5. Illinois/Michigan	140	107	33.45	23.8%	126	78	48.96	38.7%
6. Permian (W TX, NM)	2,896	2,473	423.03	14.6%	1,887	1,044	843.65	44.7%
7. Rockies (CO,UT,WY)	563	502	60.66	10.8%	390	341	49.46	12.7%
8. Texas, East/Central	1,950	1,679	271.69	13.9%	1,645	1,349	296.26	18.0%
9. Williston (MT, ND, SD)	125	119	5.97	4.8%	105	87	17.73	16.9%
10. Louisiana Offshore	1,454	1,420	33.97	2.3%	331	125	205.33	62.1%
11. Appalachia (WV, OH, KY, PA)	15	2	13.18	86.4%	3	2	1.06	33.8%
	12,680	11,039	1,641	**12.9%**	8,815	6,897	1,918	**21.8%**

CO_2 Demand for EOR Projects (Million Metric Tons)

25% Hurdle Rate of Return

	CO_2 Cost - \$1.00 per Mcf				**CO_2 Cost - \$2.50 per Mcf**			
Basin/Area	**Current Requirements**	**Stringent Federal Scenario**	**Difference**	**% Difference**	**Current Requirements**	**Stringent Federal Scenario**	**Difference**	**% Difference**
1. Alaska	1,689	1,564	125	7.4%	63	63	0	0.0%
2. California	1,313	1,252	60	4.6%	961	814	146	15.2%
3. Gulf Coast (AL, FL, MS, LA)	550	134	415	75.6%	64	2	62	97.5%
4. Mid-Continent (OK, AR, KS, NE)	1,381	947	434	31.4%	1,052	428	624	59.3%
5. Illinois/Michigan	125	79	46	36.5%	111	22	89	80.5%
6. Permian (W TX, NM)	2,596	1,838	758	29.2%	931	507	424	45.5%
7. Rockies (CO,UT,WY)	480	411	69	14.4%	302	237	65	21.6%
8. Texas, East/Central	1,802	1,438	364	20.2%	1,357	1,108	249	18.3%
9. Williston (MT, ND, SD)	105	103	2	1.6%	84	59	26	30.6%
10. Louisiana Offshore	838	513	325	38.8%	0	0	0	
11. Appalachia (WV, OH, KY, PA)	3	2	1	33.8%	2	2	0	0.0%
	10,881	8,281	2,599	**23.9%**	4,927	3,241	1,686	**34.2%**

Source: Advanced Resources International.

APPENDICES

APPENDIX A
SUMMARIES OF INDIVIDUAL INITIATIVES/ISSUES CONSIDERED IN THIS ASSESSMENT
"ENSURE THE PUBLIC'S RIGHT-TO-KNOW"

Background

Environmental groups have proposed the need to require oil and gas E&P companies to report to the Toxic Release Inventory (TRI) to provide information to the public regarding chemicals that may pose a risk to the health of local communities.

The oil and gas industry has responded that the TRI was created by Congress to obtain information on chemical releases from the manufacturing sector of the economy, where concentrated operations at facilities pose a potential risk if releases occur.[24] Oil and gas E&P operations are scattered throughout the country in mostly rural areas and individually are generally believed to not pose much risk. While EPA has the authority to expand the scope of the TRI reporting requirements, to date it has not added oil and natural gas E&P operations because they have concluded that there is no compelling reason to create a new reporting burden for this industry sector that provides no real additional information.[25] Moreover, the E&P industry already makes extensive reports on its releases under various federal and state laws.

Inclusion of E&P in the TRI program would require submittal of annual reports of the amounts of toxic chemicals that a facility uses and "releases" into the environment, either routinely or as a result of accidents, and the amounts of wastes that undergo recycling, energy recovery, and treatment. To report such "releases" for E&P would require extensive monitoring, testing and reporting of numerous product and waste streams at oil and gas operations, including produced water injection facilities (for both saltwater disposal and enhanced oil recovery).

Estimate of Potential Compliance Costs

Previous assessments of the potential impact of TRI reporting requirements assumed that such requirements would be met under an EPA-established federal program. The estimated compliance costs for this scenario were derived from the total industry compliance costs estimated by Dames & Moore in a 1995 report on this issue.[26] Dames & Moore determined that 53 chemicals specific to the E&P industry could be subject to a programmatic chemical list for reporting. For cost evaluation purposes, they developed a number of chemical sub-lists to group chemicals which may require reporting. The study estimated compliance costs by developing nationwide and state-by-state estimates of E&P "generic units" which would be subject to reporting, and developed a cost estimate for reporting on each generic unit. The aggregate cost the E&P industry would incur from reporting was estimated as the product of the number of generic units and the reporting cost per generic unit. Reporting costs consisted primarily of the labor costs associated with monitoring and reporting and the costs associated with analytical testing of various waste streams.

For this assessment, the total nationwide compliance costs estimated by Dames & Moore in 1995 were divided by the number of wells to estimate a unit ("per well") capital and annual cost. The expected difference in reporting requirements and costs to be borne by gas and oil

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24 H. R. Rep. No. 99-962 at 281 (1986), *reprinted in* 1986 U.S.C.C.A.N. 3276, 3374.
[25] 61 Fed. Reg. 33588, 33592 (June 27, 1996).
[26] Dames & Moore, "Evaluation of Impacts to the Oil and Gas Exploration and Production Industry from Imposition of SARA 313 Reporting by Regulation," November 1995

operations is accounted for by allocating 35% of the cost to gas wells and 65% of the cost to oil wells. The estimated unit compliance costs are summarized in Table A-1.

Table A-1
Estimated Compliance Costs for E&P Reporting
Under the Toxic Release Inventory (TRI) Program
<u>Compliance Cost Calculations</u>[27]

<u>Oil:</u>

= (estimated total capital cost of compliance for E&P industry / total # producing wells, onshore and offshore)(% oil production)

= ($240 million / 884,842 wells)(0.65)

= $176 per new and existing oil well, Capital Cost (apply to onshore and offshore wells) **(1998 $)**

= $477 per new and existing oil well, Capital Cost (apply to onshore and offshore wells) **(2007 $)**

<u>Gas:</u>

= (estimated total capital cost of compliance for E&P industry / total # producing wells)(% gas production)

= ($240 million / 884,842 wells)(0.35)

= $95 per new and existing gas well, Capital Cost (apply to onshore and offshore wells) **(1998 $)**

= $258 per new and existing gas well, Capital Cost (apply to onshore and offshore wells) **(2007 $)**

<u>Oil:</u>

= (estimated total annual cost of compliance for E&P industry / total # producing wells)(% oil production)

= ($112 million/884,842 wells)(0.65)

= $82 per new and existing oil well per year, Annual Cost (apply to onshore and offshore wells) **(1998 $)**

= $222 per new and existing oil well per year, Annual Cost (apply to onshore and offshore wells) **(2007 $)**

<u>Gas:</u>

= ($112 million/ 884,842 wells)(0.35)

= $44 per new and existing oil well per year, Annual Cost (apply to onshore and offshore wells) **(1998 $)**

= $119 per new and existing oil well per year, Annual Cost (apply to onshore and offshore wells) **(2007 $)**

<u>Key Data and Assumptions</u>

Total number of producing oil and gas wells (onshore & offshore)	884,842 (a)
% onshore production: oil	65%
% onshore production: gas	35%
Total capital cost of compliance for E&P industry ("First-Year" cost)	$237.8 million (b)
Total annual cost of compliance for E&P industry	$110.6 million(b)

(a) API, 1999, "Basic Petroleum Data Book". (b) Dames & Moore, "Evaluation of Impacts to the Oil and Gas Exploration and Production Industry, from Imposition of SARA 313 Reporting by Regulation," Final Report, Nov. 3, 1995. *Costs reported are in 1998 dollars*.

[27] ICF Consulting, *Oil and Gas Environmental Program Metrics: 2000 Analysis and Results*, report prepared for the U.S. Department of Energy, Office of Natural Gas and Petroleum Technology, under DOE Contract No. DE-AC01-95FE62467, August 2000

"SUBJECT HYDRAULIC FRACTURING TO FEDERAL UIC PROGRAM REQUIREMENTS"

Background

Some environmental groups propose to subject all hydraulic fracturing of oil and gas wells by the E&P industry to the requirements of the federal UIC program under SDWA, despite language excluding this in EPAct. On September 29, 2008, Congresswoman Diana DeGette (CO) introduced a bill (H.R. 7231) in the U.S. House of Representatives that would reinstate basic federal standards for hydraulic fracturing under the SDWA and enable EPA to regulate underground injection under the SDWA.

Prior to 1997, EPA had not considered regulating hydraulic fracturing because it believed that this well stimulation process did not fall under UIC program purview or the jurisdiction of SDWA. In 1994, the Legal Environmental Assistance Foundation (LEAF) challenged that interpretation, claiming that the State of Alabama should regulate hydraulic fracturing for coalbed methane development as underground injection.[28] LEAF petitioned EPA to withdraw Alabama's SDWA Section 1425 UIC program. EPA rejected LEAF's petition, and LEAF litigated. In 1997, the 11th Circuit Court of Appeals ruled that hydraulic fracturing of coalbeds in Alabama should be regulated under the SDWA as underground injection (LEAF v. EPA, 118 F. 3d 1467). The State was required to modify its UIC program, and in December 1999, EPA approved this revision.

In 2004, EPA conducted a study to assess the potential for contamination of underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids by coalbed methane (CBM) wells.[29] EPA concluded that the injection of hydraulic fracturing fluids by CBM wells posed little or no threat to USDWs and additional studies were not justified. EPA retained the right, however, to conduct additional studies in the future. As a precautionary measure, EPA also entered into a Memorandum of Agreement with companies that conduct hydraulic fracturing of CBM wells to eliminate use of diesel fuel in fracturing fluids.[30]

The Energy Policy Act of 2005 excluded hydraulic fracturing from SDWA jurisdiction. No other state has been required to regulate the practice under the UIC Program.

Estimate of Potential Compliance Costs

The environmental groups' recommendation extends far beyond coalbed methane, intending to overturn the exclusion in EPAct and to regulate hydraulic fracturing for all applications under UIC program jurisdiction. The estimated compliance costs to comply with requirements consistent with the environmental groups' recommendations are presented in Table A-2. These estimates, based on a 1999 assessment for DOE, assume that the regulation of hydraulic fracturing as underground injection is applied to all hydraulically fractured wells nationwide, including fractured tight gas, Devonian shale and coalbed methane.[31] These include the costs of obtaining a permit, conducting an Area of Review (AOR) assessment, performing in-situ stress analysis from acoustic log or pump-in/fall off tests, conducting 3-D fracture simulation, monitoring, mapping fractures, or conducting other post-frac analysis, and, for some wells, performing state-of-the-art downhole fracture imaging (e.g. microseismic or downhole tiltmeter). The costs also include additional cementing to ensure isolation of the target zone prior to fracturing.

[28] 118 F.3d 1467 (11th Cir. 1997)
[29] http://www.epa.gov/ogwdw/uic/wells_coalbedmethanestudy.html
[30] http://www.epa.gov/ogwdw/uic/pdfs/moa_uic_hyd-fract.pdf
[31] Memo from Robin Petrusak, ICF Consulting to Nancy Johnson, U.S. Department of Energy, entitled "Documentation of Estimated Potential Cost of Compliance for Toxic Release Inventory (TRI) Reporting and Hydraulic Fracturing," August 19, 1999

Table A-2
Estimated Compliance Costs for Regulation of Hydraulic Fracturing
Compliance Cost Calculations[32]

The estimates below assume that the regulation of hydraulic fracturing as underground injection is applied to all hydraulically fractured wells nationwide, including fractured oil wells, tight gas, Devonian shale and coalbed methane.

Action	Estimated Cost	% Wells	Total Est. Cost	Comments
Obtain permit	60 hr/well x $75/hr = $4,500/well	1.00	$4,500	
Area of Review	$2,800/per AOR	1.00	$2,800	Assumes all wells will require AOR, but no corrective action if potential problems are found; assumes no drill or frac if potential problems found.
In-situ stress analysis from acoustic log or pump-in/fall off tests	$15,000/frac/well $5,000/frac/well	X 0.30 X 0.30	$4,500+$1,500= $6,000	Assumes 40% of wells already determine stress gradient
3-D Fracture Simulation	$10,000/frac	0.75	$7,500	Assumes 3-D model used for frac design in 25% of wells
Monitor, map fracture, or other post- frac analysis	$10,000/frac	0.60	$6,000	Assumes some frac monitoring or post-frac analysis already in 40% of fracs
State of art downhole fracture imaging e.g. microseismic or downhole tiltmeter	$375,000	0.10	$37,500	Assumes that state-of-art downhole fracture imaging requiring observation wells may be required in 10% of fractured wells
		Total Incremental Hydraulic Fracturing Cost	= $64,300	
Average incremental cost for additional cementing to ensure isolation of the target zone prior to fracture	$10,000	0.30	$3,000	
		Total Incremental Completion Cost	= $3,000	
Total Incremental Cost for New Well Receiving Hydraulic Fracture Treatment (1999 $) Fracture Treatment (2007 $)			= $67,300 = $100,505	

[32] Memo from Robin Petrusak, ICF Consulting to Nancy Johnson, U.S. Department of Energy, entitled "Documentation of Estimated Potential Cost of Compliance for Toxic Release Inventory (TRI) Reporting and Hydraulic Fracturing," August 19, 1999

Key Data and Assumptions

1. Estimated cost to obtain a permit = $75.00/hour. Estimated Total Permit Cost = 60 hours x $75 hour = $4,500/well (a)
2. Cost to use Acoustic Logs to obtain in-situ stress profile = approx. $3,000-$10,000/well, depending upon depth of well; for this analysis, $5,000 was used.
3. Cost to calibrate acoustic log stresses w/ stress profile obtained from pump-in/falloff tests (performed on one out of six wells) = $15,000/well was used (b)
4. Approx. Cost for 3-D Fracture Simulation by service company or consulting company = $8,000/well - $25,000/well; some quotes $100/hour or $600/day- $800/day; also $500/well (not 3-D) to $20,000/well (b). Used $10,000 per frac.
5. Approx. cost for surface tiltmeter survey & hydraulic fracture mapping = $1,500/stage (tiltmeter); $3,500/well - $25,000/well depending on the fracture treatment and complexity of the analysis (c)
6. Average nationwide cost to cement squeeze casing on an active well identified to pose a threat of vertical migration of injection fluids = $19,600/well (d). Used $10,000/well applied to 50% of wells.
7. Incremental costs to drill and complete a new oil and gas well with the three levels of aquifer protection of a conventional Class II injection well: slimhole = $34,200/well; tubingless construction = $12,300/well; packerless construction = $1,500/well (d). Used $10,000/well applied to 30% of wells.
8. GRI Hydraulic Fracture Survey response, fracture treatment design & monitoring: (e) Use 2-D model for fracture treatment design = 36% respondents Use 3-D models for fracture treatment design = 43% " Do not use models for fracture treatment design = 21% "" Calc. in-situ stress gradients from open hole log data = 27% " Use in-situ stress test to determine stress gradients = 11% " Determine stress gradient in interval to be treated = 84% " Determine stress gradient in bounding intervals = 39% " Conduct some type of post-frac analysis on all wells = 65% "
9. Cost for state-of-the-art downhole fracture imaging & monitoring technology requiring drilling of observation wells = $375,000 (k) Applied in 10% of fractured wells (f)

(a) Gas Research Institute, "Evaluating the Benefits of Tight Gas Sands Research – A Statistical Approach," GRI Topical Report, December 1992, No. 5091-221-2129, Gas Research Institute, Chicago, IL. (b) ICF, communication quotes with some smaller companies offering fracture simulation, fracture treatment design services. (c) Communication with Michael Stock of Pinnacle Technologies regarding approximate cost of hydraulic fracture mapping & tiltmeter survey, October 1998. (d) S.A. Holditch & Associates, Interim Economic Evaluations of Revisions to Class II Underground Injection Control Regulations prepared for American Petroleum Institute, October 1994. (e) Gas Research Institute, Results of 1995 Hydraulic Fracturing Survey and a Comparison of 1995 Industry Practices vs. 1990 Industry Practices, survey conducted by S.A. Holditch & Associates for Gas Research Institute, 1995. (f) Personal communication between Jim Collins and Richard Keck, January 25, 1999; estimate of costs for downhole fracture imaging technology, approximately $500,000 for observation well depth greater than 5000 ft and $250,000 for observation well depth less than 5,000 ft.

"REQUIRE E&P MATERIALS MEETING RCRA'S HAZARDOUS WASTE DEFINITION TO INJECT IN CLASS I WELLS"

PRODUCED WATER AND OTHER INJECTANTS

Background

In addition to increasing daily fines for violations by the oil and gas industry to equal those for other industries, environmental groups propose that the underground injection of materials associated with oil and gas production that meet the RCRA definition of hazardous waste meet the standards of Class I injection.

Wastes generated during the exploration, development, and production of crude oil, natural gas, and geothermal energy are categorized by EPA as "special wastes" and are exempt from federal hazardous waste regulations under RCRA. On July 6, 1988, EPA issued its *Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes*,[33] which stated that EPA believed that regulation of oil and gas E&P wastes under RCRA Subtitle C (as hazardous waste) is not warranted. Instead, EPA implemented a three-pronged strategy to address the issues posed by these wastes by improving federal programs under existing authorities in Subtitle D of RCRA (for non-hazardous wastes), the CAA, and SDWA; working with states to encourage changes and improvements in their regulations and enforcement; and working with Congress to develop any additional statutory authorities that may be required.

On March 22, 1993, EPA issued a "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy" (58 FR 15284)[34], which clarifies the regulatory status of wastes generated by the crude oil reclamation industry, service companies, gas plants and feeder pipelines, and crude oil pipelines. Similarly, in October 2002, EPA issued the publication "Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations,"[35] which provides an understanding of the exemption of certain oil and gas E&P wastes from regulation as hazardous wastes under RCRA Subtitle C. The document includes background on the E&P exemption, basic rules for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of E&P waste mixtures, and clarifications of several misunderstandings about the exemption.

In addition, the term "hazardous substance" is defined in CERCLA section 101(14) to include substances listed under four other environmental statutes (as well as those designated under CERCLA section 102(a)). Similar to RCRA, the definition excludes "petroleum, including crude oil or any fraction thereof," unless specifically listed or designated under CERCLA. EPA interprets CERCLA section 101(14) to exclude crude oil and fractions of crude oil - including the hazardous substances, such as benzene, that are indigenous in those petroleum substances - from the definition of hazardous substance.

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[33] U.S. Environmental Protection Agency, *Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes*, July 6, 1988 (53 FR 25466) http://www.epa.gov/epaoswer/other/oil/index.htm

[34] http://yosemite.epa.gov/osw/rcra.nsf/ea6e50dc6214725285256bf00063269d/db142875d20a60758525670f006bed66!OpenDocument

[35] http://yosemite.epa.gov/osw/rcra.nsf/ea6e50dc6214725285256bf00063269d/f76099033f806868852574b4005f5587!OpenDocument

Currently, a waste is considered toxic if an extract obtained from a sample of the waste using the TCLP contains any of 25 organic constituents listed in the regulation in concentrations at or above specified levels. Wastes that exhibit the RCRA toxicity characteristic are automatically RCRA hazardous wastes and, therefore, CERCLA hazardous substances.

The Emergency Planning and Community Right-to-Know Act (EPCRA) section 304 release reporting requirements apply to CERCLA hazardous substances and EPCRA extremely hazardous substances (EHSs). Of the EHSs defined under EPCRA section 302; over a third are also CERCLA hazardous substances. Aside from this overlap of listed substances, CERCLA and EPCRA also have closely related notification requirements when releases of CERCLA hazardous substances occur.

Consistent with the regulatory determination, and prior to it, Congress amended the SDWA in 1980 to provide greater flexibility to states that had operational programs to manage the use of produced water to enhance oil and natural gas recovery. The structure of the SDWA and its subsequent regulations for Class II wells proved so burdensome that states were unwilling to seek primacy under the SDWA to run the federal program. The law was changed to allow states to show that their programs provided comparable levels of protection rather than meet the specific federal program requirements. Without these changes, industry associations have asserted that enhanced oil recovery would have been crippled. Today, wells used for both the injection of water and CO_2 for enhanced recovery are regulated as Class II wells.

Estimate of Potential Compliance Costs

Prior to the release of its regulatory determination and its earlier Report to Congress,[36] EPA conducted a detailed assessment of the potential economic consequences of regulating oil and gas wastes under RCRA's Subtitle C program for hazardous wastes, published as supporting material to the Report to Congress.[37] In this assessment, a scenario was considered where produced water testing hazardous would be subject to pollution control requirements consistent with Subtitle C of RCRA. In the case of produced water, water with hazardous characteristics was assumed to be injected into Class I wells, except where the water was used for enhanced oil recovery (this was referred to as the "Subtitle C-1 Scenario"). Assumptions were made concerning the cost differences between Class I and Class II injection (the Baseline Scenario), and costs were allocated based on the proportion of produced water reinjected for enhanced oil recovery versus that injected for disposal.

No specific information was available to specify what proportion of the produced water stream would test hazardous under RCRA criteria, so two scenarios were considered, where 10% and 70% respectively, was considered hazardous. The estimated compliance costs per barrel of produced water are summarized by region in Table A-3.

[36] U.S. Environmental Protection Agency, *Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, EPA530-SW-88-003, Volumes 1-3, December 1987

[37] Eastern Research Group, *Technical Support Document to Chapter VI of the Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Volume 1 of 2, prepared for the U.S. Environmental Protection Agency, January 1988

Table A-3
Estimated Compliance Costs for Reinjection of Produced Water Testing as Hazardous[38]

	Disposal Costs ($ per barrel of H_2O)			
	1998 $		2007 $	
	% Hazardous		% Hazardous	
	10%	70%	10%	70%
Appalachia	$0.15	$1.05	$0.41	$2.85
Gulf	$0.07	$0.48	$0.19	$1.30
Midwest	$0.01	$0.05	$0.03	$0.14
Plains	$0.04	$0.31	$0.11	$0.84
TX/OK	$0.03	$0.19	$0.08	$0.52
Northern Mountain	$0.02	$0.15	$0.05	$0.41
Southern Mountain	$0.02	$0.11	$0.05	$0.30
West Coast	$0.03	$0.23	$0.08	$0.62
Alaska	$0.04	$0.25	$0.11	$0.68
Lower-48	$0.03	$0.24	$0.08	$0.65

Based on the average water:oil ratio in the U.S. of 10.2 to 1 (barrels of water per barrel of oil produced), this would amount to, on average, an incremental cost of $0.32 per barrel of oil for the 10% hazardous case, and an incremental cost of $6.61 per barrel of oil for the 70% hazardous case (in 2007 dollars).

For coalbed methane, for example, costs for a basin such as the Powder River Basin, where it is estimated that 1.73 barrels of water are produced for every thousand cubic feet (Mcf) of natural gas, this would amount to, on average, an incremental cost of $0.09 per Mcf of coalbed methane produced for the 10% hazardous case, and an incremental cost of $0.71 per Mcf for the 70% hazardous case (in 2007 dollars).

While CO_2 itself is not a hazardous substance, the CO_2 stream may contain other substances such as mercury that are hazardous substances, or the constituents of the CO_2 stream could react with groundwater to produce listed hazardous substances such as sulfuric acid. Moreover, water and/or CO_2 produced and injected in association with CO_2-EOR projects could test hazardous, since the combination of water and CO_2 can be corrosive. CO_2 mixed with water forms carbonic acid, which can corrode well materials and piping. Corrosivity, along with ignitability, reactivity, or toxicity, is a characteristic that can define a waste stream or injectant as hazardous.

In this assessment, CO_2 injection wells, rather than being Class II as currently permitted, were assumed to be constructed as Class I wells, and well costs would thus increase substantially. The possible increase in costs are presented in Table A-4, with the range represented by assumptions of 10% and 70%, respectively, of the injected stream testing as hazardous.

For purposes of this assessment, for the reinjection of produced water, it is assumed that 10% of the volume of produced water injected would test as hazardous, and require injection into

[38] Eastern Research Group, *Technical Support Document to Chapter VI of the Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Volume 1 of 2, prepared for the U.S. Environmental Protection Agency, January 1988

Class I wells. For the injection of CO_2, again for purposes of this assessment, it is assumed that 70% of new CO_2 injection wells would be drilled and operated as Class I injection wells.

Table A-4
Estimated Compliance Costs for CO_2-EOR Injection Wells where Injected Fluids (CO_2 and/or Water) Could Test as Hazardous[39]

Class II and Class I Well Drilling Costs Assumptions for EOR (All costs in $1,000)

	Class II EOR				Class I EOR			
	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost
Appalachia	$80.0	$16.0	$15.0	$4.5	$297.0	NA	$76.0	$31.0
Gulf	$320.0	$22.0	$21.3	$6.8	$800.0	NA	$76.6	$42.9
Midwest	$109.0	$15.0	$22.0	$6.4	$329.0	NA	$79.0	$33.0
Plains	$105.0	$17.0	$21.7	$6.7	$276.0	NA	$91.2	$38.0
TX/OK	$260.0	$19.8	$23.3	$7.8	$584.5	NA	$94.3	$44.2
Northern Mtn	$440.0	$17.8	$22.2	$7.1	$654.0	NA	$89.6	$41.9
Southern Mtn	$381.0	$19.0	$22.2	$7.1	$700.0	NA	$85.5	$42.0
West Coast	$158.0	$19.0	$34.4	$10.5	$442.0	NA	$97.3	$42.5
Alaska	$1,551.0	$80.0	$76.2	$25.0	$3,810.0	NA	$310.0	$170.0

	Differences (1988)				Differences (2007)			
	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost
Appalachia	$217.0	$281.0	$61.0	$26.5	$665.8	$862.1	$165.4	$71.9
Gulf	$480.0	$778.0	$55.3	$36.1	$1,472.7	$2,387.0	$150.0	$97.9
Midwest	$220.0	$314.0	$57.0	$26.6	$675.0	$963.4	$154.6	$72.1
Plains	$171.0	$259.0	$69.5	$31.3	$524.6	$794.6	$188.5	$84.9
TX/OK	$324.5	$564.7	$71.0	$36.4	$995.6	$1,732.5	$192.5	$98.7
Northern Mtn	$214.0	$636.2	$67.4	$34.8	$656.6	$1,951.9	$182.8	$94.4
Southern Mtn	$319.0	$681.0	$63.3	$34.9	$978.7	$2,089.4	$171.7	$94.6
West Coast	$284.0	$423.0	$62.9	$32.0	$871.3	$1,297.8	$170.6	$86.8
Alaska	$2,259.0	$3,730.0	$233.8	$145.0	$6,930.8	$11,443.9	$634.1	$393.2

	Differences (10% Hazardous)				Differences (70% Hazardous)			
	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost	New Well Cost	Converted Well Cost	Facility Cost	Annual O&M Cost
Appalachia	$66.6	$86.2	$16.5	$7.2	$466.0	$603.5	$115.8	$50.3
Gulf	$147.3	$238.7	$15.0	$9.8	$1,030.9	$1,670.9	$105.0	$68.5
Midwest	$67.5	$96.3	$15.5	$7.2	$472.5	$674.4	$108.2	$50.5
Plains	$52.5	$79.5	$18.8	$8.5	$367.2	$556.2	$131.9	$59.4
TX/OK	$99.6	$173.3	$19.3	$9.9	$696.9	$1,212.8	$134.8	$69.1
Northern Mtn	$65.7	$195.2	$18.3	$9.4	$459.6	$1,366.3	$128.0	$66.1
Southern Mtn	$97.9	$208.9	$17.2	$9.5	$685.1	$1,462.5	$120.2	$66.3
West Coast	$87.1	$129.8	$17.1	$8.7	$609.9	$908.5	$119.4	$60.7
Alaska	$693.1	$1,144.4	$63.4	$39.3	$4,851.5	$8,010.7	$443.8	$275.3

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[39] Eastern Research Group, *Technical Support Document to Chapter VI of the Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Volume 1 of 2, prepared for the U.S. Environmental Protection Agency, January 1988. The regions in these tables correspond to the regions defined in the Eastern Research Group report for EPA, while the regions in Tables 6, 7and 8 are the regions defined in the series of DOE reports serving as the basis for the analyses of CO_2-EOR recovery potential.

"REQUIRE STORM WATER PERMITS FOR ALL OIL AND GAS INDUSTRY ACTIVITIES"[40]

Background

The 1987 Water Quality Act (WQA) added section 402(*l*)(2) to the CWA specifying that EPA and States shall not require National Pollution Discharge Elimination System (NPDES) permits for uncontaminated storm water discharges from oil and gas E&P facilities. In the early 1990s, EPA adopted regulations for Phase I, to include industrial runoff, runoff from municipal storm sewers serving 100,000 or more, and construction activities greater than 5 acres. EPA developed several model general permits to cover these categories. Because most oil and gas sites do not disturb more than 5 acres, few oil and gas sites were covered under these permits.

In 1999, EPA published proposed regulations for Phase II, as stipulated in the CWA, to cover smaller separate municipal storm sewers and construction sites that disturb from 1 to 5 acres. Most onshore oil and gas well sites disturb from 1-5 acres (including the lease road and well pad) and therefore, based on EPA's determination, could be subject to Phase II requirements.

On March 10, 2003, EPA issued a decision (Federal Register, Vol. 68, No. 46, pp. 11325-11330) where the determination of the applicability of the storm water discharge permit requirements on oil and gas operations was deferred to March 10, 2005, because EPA concluded that it had not adequately performed economic impact analyses related to this industry sector. An important issue under consideration and subject to some debate at the time, was whether site construction and site preparation activities prior to oil and gas exploration (i.e., drilling) was considered to be part of the exemption for oil and gas facilities.

Section 323 of EPAct added a new paragraph (24) to section 502 of the CWA to define the term "oil and gas exploration, production, processing, or treatment operations or transmission facilities" to mean "all field activities or operations associated with exploration, production, processing, or treatment operations or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities." This term is used in section 402(l)(2) of the CWA to identify oil and gas activities for which the EPA shall not require NPDES permit coverage for certain storm water discharges. The effect of this statutory change makes construction activities at oil and gas sites eligible for the exemption.

On June 12, 2006, EPA published a final rule to address the new provision added by EPAct, which effectively exempted from NPDES permit requirements storm water discharges of sediment from construction activities associated with oil and gas facilities unless the relevant facility had a discharge of storm water resulting in a discharge of a reportable quantity of oil or hazardous substances. 40 CFR § 122.26(a)(2)(ii) (citing 122.26(c)(1)(iii)(C)).

Shortly thereafter, NRDC petitioned the Ninth Circuit Court of Appeals (Ninth Circuit) for direct review of EPA's action. On May 23, 2008, the Ninth Circuit Court of Appeals issued an opinion in *Natural Resources Defense Council v. United States Environmental Protection Agency*, 526 F.3d 591 (9th Cir. 2008) vacating EPA's 2006 oil and gas construction storm water regulation. On July 21, 2008, EPA filed a petition for rehearing in this case. On November 3, 2008, the Ninth Circuit Court of Appeals issued its order denying EPA's request for rehearing of this Court decision.

Now that the 2006 rule has been vacated, the effective requirements are the regulations in place prior to the 2006 rule plus the additional EPAct clarification of the activities included in the CWA 402(l)(2) exemptions.

[40] http://cfpub.epa.gov/npdes/stormwater/oilgas.cfm

Nonetheless, environmental groups are essentially proposing that the legislative action in the EPAct also be rescinded.

Estimate of Potential Compliance Costs

In 2004, as a response to the March 2003 decision, DOE developed a quantitative assessment of the potential economic impacts of storm water discharge requirements on the domestic oil and gas industry.[41] The economic impacts were assessed as they relate to three aspects of oil and gas operations:

- The increased costs that industry must bear to comply with the proposed requirements, including the impacts on "construction" sites associated with oil and gas drilling, gas gathering, and natural gas and liquids transportation operations.
- The project delays that could result and the impact of these delays on the productivity of the nation's rig fleet, on the delay in revenues received from oil and gas production, and from other increased costs attributable to project delays.
- The wells that would not be drilled because of permitting delays associated with the new requirements, the production lost from this foregone drilling, and the economic impacts associated with this lost production.

Critical Assumptions and Uncertainties. Estimates of the potential economic impacts of the new storm water discharge requirements on the oil and natural gas industry were developed based on several critical assumptions and uncertainties:

- Future levels of domestic drilling (production and injection wells), and the "construction" sites associated with these wells that are between 1 and 5 acres in size and thus could potentially be subject to the new requirements.
- The estimated number of "construction" projects of 1 to 5 acres in size that could fall under the proposed requirements that would be associated with natural gas gathering and gas and liquids transportation operations.
- The portion of these sites that would in fact be subject to the new requirements:
    - In some states, existing regulations already meet or exceed the proposed federal requirements; thus sites in these states would not incur incremental costs.
    - Some sites may be eligible for waivers based on prevailing climatic and environmental conditions related to potential erosion and pollutant loading.
- The portion of sites that could be required to conduct endangered species and/or archeological or historic reviews (as required under the Endangered Species Act (ESA) and the National Historical Preservation Act (NHPA)).
- Where potential concerns are identified, the portion of sites undergoing endangered species or historic reviews that would require consultation with appropriate oversight agencies to determine how potential impacts could be mitigated.
- The costs associated with complying with these requirements, for impacted sites.

[41] Advanced Resources International, Inc., "Estimated Economic Impacts of Proposed Storm Water Discharge Requirements on the Oil and Natural Gas Industry (Final)," memo to the U.S. Department of Energy/Office of Fossil Energy, dated December 7, 2004 (http://www.fe.doe.gov/programs/oilgas/environment/publications/storm_water_summ120704.pdf)

- The “unscheduled” delays that would result because of the processes imposed by complying with the new requirements, and the estimated economic implications associated with these delays.
- The portion of wells that would not be drilled because of delays and/or extra costs imposed by the new requirements that would make development unfeasible or undesirable, and the lost production and resulting economic impacts associated with wells not drilled.

Compliance Scenarios. Two scenarios were defined in the 2004 analysis to represent the potential range of impacts that could result from these new requirements:

- The *Base Case* was based on citable, mostly conservative assumptions, based on published data, on estimates or assumptions derived from EPA’s own economic analyses performed in 2002, and on the current requirements for storm water discharges. This scenario essentially assumed routine permitting processes, adequately staffed regulatory agencies, waivers and exclusions would be available; and that abuse of the system to cause project delays would be minimal.
- The *Higher Impact Scenario* assumes that permitting processes are cumbersome and lengthy, regulatory agencies overseeing the process are inadequately staffed, some additional requirements get implemented, waivers and exclusions are difficult to obtain, and environmental groups and discontented landowners use the permitting and project review process to delay and/or stop drilling on some leases.

Estimated Compliance Costs. The estimated costs associated with compliance, for the two scenarios considered in this assessment, were assumed as follows:

- Incremental compliance costs would be incurred by activities associated with developing the information and meeting the requirements for filing a Notice of Intent (NOI), which would be required for each site subject to the new requirements. This would include activities to ensure that a Storm Water Pollution Prevention Plan (SWPPP) is completed, BMPs are installed according to SWPPP, periodic inspections are conducted, and the site is stabilized prior to filing a Notice of Termination (NOT). This analysis assumes that this will require approximately 72 person-hours, amounting to \$6,000 per well. This applies to both the Base Case and the Higher Impact scenario.
- In the Base Case, 36 person-hours are assumed to be required for the endangered species review, amounting to \$3,000 per site. For the consultation, 160 person-hours, amounting to \$13,333 per site, are assumed to be required under Base Case conditions. Under the Higher Impact scenario, it is assumed that the consultation process takes twice as long, amounting to 320 person-hours and \$26,667.
- 48 person-hours are assumed to be required to conduct the historic review, amounting to \$4,000 per site. For consultation, 320 hours, amounting to \$26,667 per site, are assumed. These are assumed to be applicable in the Higher Impact scenario only.

If the Higher Impact Scenario was considered, these incremental costs could be as much as \$66,334 per new well drilled, in 2004 dollars. However, for purposes of this assessment, the Base Case set of conditions was assumed. This amounts to total incremental costs per new well drilled of \$22,333, in 2004 dollars. In 2007 dollars, these costs would amount to \$26,452.

"INCLUDE ALL TOXIC WASTES ASSOCIATED WITH OIL AND GAS EXPLORATION AND PRODUCTION UNDER RCRA'S CRADLE-TO-GRAVE HAZARDOUS WASTE PROVISIONS"

DRILLING WASTES AND OTHER ASSOCIATED WASTES

Background

Similar to that described above for injected CO_2 and produced water, environmental groups propose that other wastes associated with oil and gas E&P be addressed under RCRA's cradle-to-grave hazardous waste provisions. In addition to produced waters and CO_2, this would apply to drilling wastes and other associated wastes produced in association with oil and gas operations.

Estimate of Potential Compliance Costs

As described above, prior to the release of its regulatory determination and its earlier Report to Congress,[42] EPA conducted a detailed assessment of the potential economic consequences of regulating oil and gas wastes under RCRA's Subtitle C program for hazardous wastes, published as supporting material to the Report to Congress.[43] Like that described for produced water, a scenario was considered where drilling wastes testing hazardous would be subject to pollution control requirements consistent with Subtitle C of RCRA. Under this scenario, drilling wastes with hazardous characteristics were assumed to be disposed in a pit equipped with a synthetic composite liner with leachate collection (SCLC) facility, employing site management and groundwater monitoring practices consistent with RCRA subtitle C disposal operations.

No specific information was available to specify what proportion of drilling wastes would test hazardous under RCRA criteria; so two scenarios were considered, where 10% and 70% respectively, was considered hazardous. The estimated compliance costs per well drilled are summarized by region in Table A-5.

For this assessment, it is assumed that 10% of the volume of drilling wastes would be subject to pollution control requirements consistent with RCRA Subtitle C.

Other associated wastes include a wide range of small volume waste streams that are associated with exploration and production of oil and natural gas. These wastes are often grouped under the term "other associated wastes" as the third category of wastes (along with produced water and drilling wastes) that are exempt from regulation as hazardous wastes under RCRA. Four categories of wastes that together comprise the majority of these other associated wastes:

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[42] U.S. Environmental Protection Agency, *Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, EPA530-SW-88-003, Volumes 1-3, December 1987

[43] Eastern Research Group, *Technical Support Document to Chapter VI of the Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Volume 1 of 2, prepared for the U.S. Environmental Protection Agency, January 1988

Table A-5
ESTIMATED COMPLIANCE COSTS FOR DISPOSAL OF DRILLING WASTES TESTING AS HAZARDOUS[44]

	Disposal Costs ($ per well)			
	Percent hazardous			
	1998 Dollars		2007 Dollars	
	10%	70%	10%	70%
Appalachia	$3,334	$23,335	$9,042	$63,284
Gulf	$6,265	$43,858	$16,990	$118,941
Midwest	$4,124	$28,866	$11,184	$78,283
Plains	$4,631	$32,416	$12,559	$87,911
TX/OK	$3,765	$26,356	$10,211	$71,476
Northern Mtn	$7,779	$54,450	$21,096	$147,666
Southern Mtn	$6,978	$48,844	$18,924	$132,463
West Coast	$3,602	$2,555,216	$9,768	$6,929,643
Alaska	$6,555	$45,883	$17,777	$124,433
Lower-48	**$4,661**	**$32,624**	**$12,640**	**$88,475**

- Completion Fluids – Fluids from initial well completion activities, including any initial acid stimulation or hydraulic fracturing.
- Workover/Stimulation Fluids – fluids from workover and stimulation operations.
- Tank Bottoms/Oily Sludges – Tank sediment and water, produced sand and tank bottoms.
- Dehydration/Sweetening Wastes – Includes glycol-based compounds, glycol filters, molecular sieves, amines, amine filter, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media and other wastes associated with the dehydration and sweetening of natural gas.

Based on the 1995 API survey,[45] associated wastes represent only about 0.11% of E&P wastes nationwide. For this assessment, 15% of such wastes were assumed to test as RCRA hazardous based on analyses conducted of E&P waste streams in Louisiana.[46]

The method for estimating costs for disposing of such wastes is summarized in Table A-6.

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[44] Eastern Research Group, *Technical Support Document to Chapter VI of the Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Volume 1 of 2, prepared for the U.S. Environmental Protection Agency, January 1988

[45] American Petroleum Institute, *1995 Survey of Oil and Gas Exploration and Production Waste Management Practices in the United States*, May 2000

[46] Louisiana Department of Natural Resources, Office of Conservation, Public information database; "Analytical Results, Chemical Constituents of E&P Waste Shipments Disposed at Commercial E&P Waste Facilities in Louisiana, 1997 and 1998"

Table A-6
ESTIMATED COMPLIANCE COSTS FOR DISPOSAL OF OTHER ASSOCIATED E&P WASTES TESTING AS HAZARDOUS
Compliance Cost Calculations[47]

All associated wastes were tested prior to disposal. Wastes that tested hazardous were disposed of at a hazardous waste disposal facility.

Estimated costs determined as follows:

={(Total volume of liquid associated wastes)(% candidate waste for disposal @ commercial E&P waste facility) [(% test hazardous)(avg. test + transport + dispose cost for hazardous waste) + (% test non hazardous)(avg. test + transport + dispose cost for non-hazardous waste)]+(Total volume of solid associated waste)(% candidate waste for disposal @ commercial E&P waste facility) [(% test hazardous)(avg. test + transport + dispose cost for hazardous waste) + (% test non-hazardous)(avg. test + transport + dispose cost for non-hazardous waste)]}/(total annual well completions)

={(18.3 million bbl/year)(0.28)[(0.15)($48.17/bbl)+(0.85)($17.72/bbl)] + (6.2 million bbl/year)(0.28)[(0.65)($48.17/bbl)+(0.35)($17.72/bbl)]}/(20,322 oil and gas well completions)

= $8,824 per new oil and gas well; Operating Cost (2004 dollars)
= $10,452 per new oil and gas well; Operating Cost (2007 dollars)

Key Data and Assumptions

Volume of liquid associated wastes generated annually	18.3 million barrels/year (a)
Volume of tank bottoms/oily sludge associated wastes generated annually	2.2 million barrels/year (a)
Estimated volume of produced sand, contaminated soil, and other oily debris generated annually	4 million barrels/year (b)
% associated wastes recycled or reclaimed	19 % (a)
% associated wastes disposed in commercial E&P waste facility	15% (a)
% associated wastes disposed by injection	38% (a)
Average associated waste disposal cost at E&P waste facility	$9.97/bbl (c)
Estimated disposal cost at hazardous waste facility	$40.42/bbl (c)
Transport cost (assume 100-mile transport distance; $0.03/bbl/mile)	$3.32/bbl(d)
Estimated waste testing cost (from LA $500/sample & 1 sample per 24 – 125 bbl shipment)	$4.43/bbl (e)
# onshore well completions in 2003	20,322 wells (f)
% associated liquid wastes (waste water, workover, & completion fluids) testing hazardous in LA survey	15 % (g)
% oily sludges, solids, tank bottoms testing hazardous in LA survey	65% (g)

(a) American Petroleum Institute, "1995 Survey of Oil and Gas Exploration and Production Waste Management Practices in the United States," publication pending. (b) American Petroleum Institute, 1987, "1985 Production Waste Survey." (c) Argonne National Laboratory, "Costs for Offsite Disposal of Non-hazardous Oil Field Wastes, Salt Caverns versus Other Disposal Methods," April 1997. (d) ICF Consulting. Edwin Hardy personal communication with oil field waste hauling companies to survey typical hauling cost, 1998. Average cost is $0.03/bbl/mile. (e) ICF Consulting. Personal communication with Pierre Catrou of Louisiana Office of Conservation. "Waste testing cost in Louisiana is approximately $500/sample and a single sample is taken from each 24 bbl to 125 bbl shipment. Most associated waste shipments are 5 bbl to 25 bbl," 1998. (f) American Petroleum Institute, "Basic Petroleum Data Book," 2004. (g) Louisiana Department of Natural Resources. Office of Conservation, Public information database; "Analytical Results, Chemical Constituents of E&P Waste Shipments Disposed at Commercial E&P Waste Facilities in Louisiana, 1997 and 1998."

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[47] ICF Consulting, *2004 Petroleum Environmental Program Metrics: Environmental Issues and Cost Analysis* (Draft Report), prepared for the U.S. Department of Energy, Office of Fossil Energy, under DOE Contract No. DE-AT01-01FE67197, February 2005

"RECONSIDER REGULATORY REQUIREMENTS ON AIR EMISSIONS FROM E&P ACTIVITIES UNDER NESHAPS PROGRAM"

Background

In *Drilling Down*, NRDC proposes to require aggregation of the emissions of oil and gas E&P operation under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program. The NESHAP program establishes controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells.

In addition, the Earthjustice suit charges that, in violation of the Clean Air Act, EPA has failed to review and update three sets of clean air regulations related to oil and gas E&P operations:

- New Source Performance Standards (NSPS) that ensure that sources of air pollution use the latest technology to reduce any pollutants that endanger public health and welfare, such as hydrogen sulfide (H_2S). Under the Clean Air Act, EPA must review and update NSPS every eight years.
- Maximum Achievable Control Technology (MACT) standards, which are designed to ensure that industry reduces toxic air emissions -- such as benzene -- using the most effective technology available. Under the Clean Air Act, the EPA must review and update MACT standards every eight years.
- "Residual Risk" standards, which are designed to ensure that industry reduces toxic air emissions to safeguard public health. Residual Risk standards are typically stronger than MACT standards. Under the Clean Air Act, the EPA must establish Residual Risk standards within eight years of promulgating MACT standards. It has been nine years since standards related to oil and gas drilling were established.

Final MACT rules have been promulgated in the last five years for oil and gas production facilities and for natural gas transmission and storage facilities that are defined as major sources. A major source is defined as any stationary source or group of stationary sources located within a contiguous area and under common control with the potential to emit 10 tons per year or more of any hazardous air pollutant (HAP), or 25 tons per year or more of any combination of HAPs. To determine whether a gas production facility is a major source, HAP emissions from combustion turbines, reciprocating internal combustion engines, glycol dehydrators, and tanks that have the potential for flash emissions are aggregated. For oil and gas facilities, these rules apply to turbines, process heaters, and reciprocating internal combustion engines, which may affect oil and gas operations; although most oil and gas operations are not defined as major sources.

With regard to the NRDC recommendations in *Drilling Down*, industry's response is that when Congress passed the 1990 Clean Air Act Amendments, it specifically prohibited aggregation of oil and gas E&P sites under the HAPs title because these sites operate as separate facilities and are frequently under different ownership. EPA has taken action to regulate the principle source of concern at E&P sites – glycol dehydrators emitting benzene. Thus, again according to industry, there is no compelling basis to broaden regulation of air emissions from oil and gas E&P operations by requiring emissions from such facilities to be aggregated.[48]

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[48] See, for example, IPAA Testimony to the House Oversight and Government Reform Committee in October 2007 (http://ipaa.org/issues/testimony/IPAATestimony-HouseOversiteGovtReform10-31-2007.pdf)

Estimate of Potential Compliance Costs

With regard to both the recommendations in *Drilling Down* and the charges in the Earthjustice legal action, it is difficult to forecast what possible future requirements may be considered for oil and gas operations. In *Drilling Down*, NRDC claims that the oil and gas industry has many options available to control its toxic air emissions and actually stands to benefit from readily available, cost-effective technologies. The basis for their claim is an article in the *Journal of Petroleum Technology,* which discussed 25 cost-effective ways to reduce methane emissions (with, perhaps, proportional reductions in VOC and HAPs emissions as well) at small to mid-size oil and gas operations.[49] They report that EPA's Natural Gas STAR Program has identified more than 89 different control options available to industry that involve the recovery of methane and the reduction of air pollution, ranging from basic inspection and preventive maintenance to equipment upgrades, heightened monitoring, and even process changes.[50]

Industry has already made significant strides to voluntarily address this category of emissions, without the need for additional regulatory requirements. According to EPA, private company partners in the production sector have reported approximately 53.7 Bcf of methane emissions reductions in 2006—and a total of 346.7 Bcf (or nearly 40 million metric tonnes of carbon equivalent (MMTCE)) since 1990.[51] However, EPA estimates that only a portion of the facilities in the U.S. can economically achieve additional methane emission reductions, even when the added benefits from incremental recovery of methane are taken into consideration.[52] EPA estimates that U.S. methane emissions in 2005 will be 36.5 MMTCE. At average natural gas prices characteristic of that for the last three years, EPA estimates that from 14 to 16 MMTCE of methane emissions would be economic to reduce, amounting to 40% to 45% of total methane emissions from the oil and gas sector, and it is technically possible to reduce only about half of the total methane emissions.

Additional controls were previously considered for engines, heaters, boilers, turbines, incinerators, and other combustion devices at major sources. In addition, EPA originally considered comparable controls on area sources to those promulgated for major sources. As part of its assessment process, EPA estimated the incremental compliance costs associated with additional controls on area sources. Based on the total compliance costs for gas E&P facilities estimated in this assessment, divided by the number of producing gas wells at the time the study was conducted, an estimated annual compliance cost per producing gas well was developed, assuming that emissions controls on area sources are adopted as originally proposed by EPA, as follows: [53]

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[49] Fernandez, R. et al., "Cost-effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," *Journal of Petroleum Technology* (June 2005)

[50] Environmental Protection Agency, "Natural Gas STAR Program: Recommended Technologies and Practices," http://www.epa.gov/gasstar/techprac.htm

[51] http://www.epa.gov/gasstar/accomplish.htm#six

[52] Environmental Protection Agency, "Addendum to the U.S. Methane Emissions 1990-2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions," 2001 http://www.epa.gov/methane/reports/2001update.pdf

[53] ICF Consulting, *Oil and Gas Environmental Program Metrics: 2000 Analysis and Results*, report prepared for the U.S. Department of Energy, Office of Natural Gas and Petroleum Technology, under DOE Contract No. DE-AC01-95FE62467, August 2000

= (total cost of risk based alternative to 2010)/(# active gas wells)/(# years)

= ($12,000,000) / (311,338 gas wells)/(10 years)

= $385 per new and existing gas well per year (1999 dollars)

= $575 per new and existing gas well per year (2007 dollars)

This is based on total annual compliance costs of the original EPA proposal of $12 million,[54] applied over a 10 year period to an estimated 311,338 producing gas wells.[55]

Finally, additional controls could be imposed for other emission sources, such as engines and tanks, and to reduce particulate emissions from these facilities. Early DOE work examined possible controls to address regional haze; these could be applicable in this regard if new requirements are implemented based on EPA's review. Potential incremental costs for these controls are summarized in Table A-7.

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[54] ICFR, Technical Support Document, "Proposed NESHAP: Oil & Natural Gas Production and Natural Gas Transmission and Storage;" also, ICF Resources, "DOE Regulatory E&P Air Model," April 1998.
[55] American Petroleum Institute, "Basic Petroleum Data Book," 1999

Table A-7
Estimated Compliance Costs for Additional New Regulatory Requirements on Air Emissions for Oil and Gas Exploration and Production Facilities

<u>Assumed Regulatory Requirements</u>

- All engines > 150 hp used in E&P operations are subject to BART to reduce particulate emissions.
- All new wells in Western producing states incur a cost for wind erosion and dust control measures.
- VRU and other controls on VOC are required on black oil tanks at production facilities in the West. Apply to approx. 25% of most productive oil wells)

Incremental Compliance Cost Calculations

<u>Best Available Retrofit Technology on Engines</u>:

= (# engines >500 hp){[(% engines >150 hp, 4 stroke)(1 - % engines, 4 stroke w/catalytic control)(cost to add cat. control)] + [(0.67)(% engines >150 hp, 2 stroke)(cost plasma ignition)] + [(0.33)(% engines > 150 hp. 2 stroke)(equipment cost clean burn modification + installation cost clean burn modifications)]}/# oil and gas wells

= (9512 engines)[0.43)(1-0.21)($39,000/engine) + (0.67)(0.37)($70,400/engine) + (0.33)(0.37)($324,000/engine + $194,000/engine)]/868,582 wells

= $1,029 per existing oil and gas well, Capital Cost (1999 dollars)
= **$1,537** per existing oil and gas well, Capital Cost (2007 dollars)
(Assumes engines associated with new E&P operations are already in compliance)

<u>Particulate Control Measures (dust, well blowouts, smoke, etc):</u>

= (average annual O&M. cost)(Cost of control measures as estimated % of operating cost)

= ($25,000/well)(0.05)

= $1,250 per new and existing well, Annual Cost (1999 dollars)
= **$1,867** per new and existing well, Annual Cost (2007 dollars)
(Apply to Western States and Louisiana)

<u>Black Oil Tank Emission Control:</u>

= (est. installation cost, VRU)/ (average # wells per tank battery)

= ($17,300/tank battery)/(4 oil wells/tank battery)

= $ 4,325 per new and existing oil well, Capital Cost (1999 dollars)
= **$ 6,459** per new and existing oil well, Capital Cost (2007 dollars)
(Apply to Western States excluding CA)

<u>Annual Cost for Black Oil Tank Emission Control</u>

= (est. typical O&M cost, VRU less approx. value of methane recovered)/ (average # wells per tank battery)

= ($3530/tank battery)/(4 wells/tank battery)

= $ 882 per new and existing oil well, Annual Cost (1999 dollars)
= $ 1,317 per new and existing oil well, Annual Cost (2007 dollars)
(Apply to Western States excluding CA)

Key Data and Assumptions

Estimated number of engines >150 hp	11,600 (a)
Estimated number of engines affected >500 hp [(# engines > 150 hp)(% engines > 500 hp)(% engines in LA & western US)] – (# engines controlled under ICCR)	6,585 (a)
Estimated number of engines affected >150 hp [(# engines > 150 hp)(% engines in LA & western U.S.)] - (# engines controlled under ICCR)	9,512 (a)
% engines >150 hp that are >500 hp	71% (a)
% engines located in Louisiana and western U.S.	87% (a)
% engines >150 that are 4-stroke, rich burn	43% (a)
% engines >150 hp, 4-stroke rich burn with catalytic controls	21% (a)
% engines >150 hp that are 2-stroke, lean burn	37% (a)
% engines >150 hp that are already clean burning	20% (a)
Cost of adding non-selective catalytic controls to 4-stroke, rich burn engines	$39,000 (b)
Cost of plasma ignition system for 2-stroke, lean burn engines	$70,400 (b)
Equipment cost for clean burn modifications for 2-stroke, lean burn engines	$324,000 (b)
Installation cost for clean burn modifications for 2-stroke, lean burn engines	$194,000 (b)
Estimated number of engines likely to be controlled under ICCR	580 (a)
Est. Capital cost to install smaller sized VRU on oil tank	$17,300 (c)
Est. O&M Cost, smaller size VRU less est. savings from value of methane recovered	$3530 (c)
Est. # of Black oil tanks in near Class I airsheds that might be required to install VRU	44,367 (d) (e)
Est. cost for dust, erosion control on two acre construction or drill site	$2,500 (f)

(a) American Petroleum Institute, "Comments on Potential Impact of Proposed Regional Haze Rule; Industry Survey Preliminary Data, 1997. (b) Gas Research Institute, "Retrofit NO_x Control Technologies for Natural Gas Prime Movers," 1994. (c) EPA, "Installing Vapor Recovery Units on Crude Oil Storage, Lessons Learned from Natural Gas Star Partners", EPA 430-B-97-032, October 1997. (d) Entropy Ltd., "Aboveground Storage Tank Survey", prepared for API, April 1989. (e) ICF Consulting estimate. (f) EPA, "Economic Analysis of Proposed Storm Water Phase II Rule" 1997.

COMPLY WITH NEW PROPOSED FEDERAL SPCC REQUIREMENTS

Background

The federal Spill Prevention, Control, and Countermeasure (SPCC) rule was first promulgated in 1973 and became effective on January 10, 1974.[56] After three attempts to revise the SPCC rule in the 1990s, EPA issued a final rule amending the SPCC regulations in July 2002. The 2002 SPCC rule established requirements for non-transportation-related facilities with total above-ground oil storage capacity (in tanks or other oil-filled containers) greater than 1,320 gallons or with buried oil storage tank capacity greater than 42,000 gallons. The 2002 SPCC rule revisions became effective August 16, 2002, but EPA subsequently amended the rule in 2002, 2003, and 2004 to extend the compliance deadline. On December 12, 2005, EPA proposed further amendments to the 2002 rule, and then on February 10, 2006, extended the compliance date to October 31, 2007 for facilities to revise and implement their SPCC plans. On December 5, 2008, the Federal Register published EPA's final rule to amend the SPCC rule in order to provide increased clarity, to tailor requirements to particular industry sectors, and to streamline certain requirements for those facility owners or operators subject to the rule. The rule is effective February 3, 2009. In January 2009, EPA amended the dates by which facilities must prepare or amend Spill Prevention, Control, and Countermeasure (SPCC) Plans, and implement those Plans, extending the deadline to November 20, 2009 except for certain qualified farm and production facilities which must comply by November 20, 2013.[57]

This analysis was based on the proposed rule proposed by EPA as of December 2005.[58]

In the 2002 SPCC rule, several relatively minor language changes dramatically altered, from the perspective of industry, the scope of the SPCC requirements. These include:

- The inclusion of the word "use" in Section 112.1(b).
- The change applicability from "tanks" to "containers" that "use" or store oil and have a maximum capacity of 55 gallons or more.
- The change in the term "loading rack" to cover "loading and unloading areas."
- The inclusion of produced water storage tanks as vessels containing oil.

These changes will bring a number of other types of facilities and/or pieces of equipment at oil and natural gas exploration and production (E&P) facilities under the jurisdiction of the rule, beyond the storage "tanks" originally perceived by industry to be the primary focus.[59] New types of facilities/equipment falling under the rule's jurisdiction include:

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[56] *(38FR 34164)*

[57] http://www.epa.gov/oilspill/index.htm

[58] (See http://www.epa.gov/emergencies/content/spcc/index.htm)

[59] EPA asserts that the 1974 rule was always meant to apply to oil-filled equipment, and that the use of the terms "container" and "use" in the language of the 2002 rule is a clarification of the original intent of the 1974 rule. This is evident from "Appendix C, Summary of Revised SPCC Rule Provisions" in EPA's *SPCC Guidance for Regional Inspectors* published November 28, 2005. In the discussion of minimum container size in the 2002 rule (section 112.1 (d) (5) EPA states that in the 1974 rule "…all containers, regardless of size, were considered to be subject to SPCC provisions." Again, in the discussion of oil-filled equipment in the 2002 rule (section 112.2) EPA states that the language in the 2002 rule is a "clarification on the application of the rule to this type of equipment."

- Produced water treatment facilities and associated tanks which contain relatively small volumes of oil.
- Process vessels such as separators, heater treaters, compressors, pump jacks, etc.
- Flow and gathering lines/ process and facility piping.
- Emergency and temporary containers used in drilling and production operations, such as blowdown tanks, emergency tanks and pits, frac tanks, etc.
- Truck loading areas at oil and gas production facilities.

In addition, the revisions in the 2002 rule will impose incremental compliance costs associated with drilling, workover, and service rigs. While these increased requirements may lead to increases in the costs associated with providing these services that use this equipment, those increased costs and their associated impacts were not considered in this assessment.

General Logic for Determining New Facilities Subject to 2002 Rule[60]

As described above, the 2002 changes to the SPCC rule result in a number of additional types of facilities and/or pieces of equipment being included under the jurisdiction of the rule, beyond the storage "tanks" originally perceived. However, not all facilities/equipment will need to take action to comply. For example:

- Some do not meet the size threshold.
  - For facilities that have a total storage capacity of less than 10,000 gallons, the operator is allowed to "self certify" their SPCC plan. *In this analysis, we are assuming that a negligible portion of oil and gas facilities would have a total storage capacity less than 10,000 gallons (238 barrels). Moreover, there is negligible benefit to operators as the only thing that is waived by the December. 12, 2005 proposal is the PE certification. The operator is still required to meet all other requirements and is not allowed to deviate from those requirements. Consequently, this provision of the December 12, 2005 proposed rulemaking would have minimal effect on oil and gas operations.*
  - No individual tank or piece of equipment stores more than 1,320 gallons.
- Some already are in compliance.
- Some are located such that they pose no threat to "navigable waters" (Given EPA's 2005 interpretation of "navigable waters", few operators were assumed to be able to claim that they do not pose a threat to "navigable waters.")[61]

For facilities/equipment not in compliance, several choices can be made:

- Some will build new secondary containment around those parts of their facilities not in compliance.

[60] For a more complete description of this methodology, see Advanced Resources International, Incorporated, *Assessment of the Potential Costs and Energy Impacts of Spill Prevention, Control, and Countermeasure Requirements for U.S. Oil and Natural Gas Production*, Report Prepared for the U.S. Department of Energy Office of Fossil Energy, August 17, 2006 (http://www.fossil.energy.gov/programs/oilgas/publications/environment_otherpubs/SPCC_Impact_Exploration_and_Production_8.pdf).

[61] In November 2008 and December 2006 EPA issued two separate final rules to amend the Spill Prevention, Control, and Countermeasure (SPCC) rule at 40 CFR Part 112. Also, in November 2008, the Agency issued a direct final rule to revise the definition of "navigable waters" in the SPCC rule to comply with a court decision, but it is premature at this time to consider this potential impact. For additional information see http://www.epa.gov/emergencies/content/spcc/index.htm.

- For some, this will be "impractical," and they will instead choose to implement an inspection and maintenance (I&M) program, develop a contingency plan, and provide a written commitment to have the resources and trained personnel necessary for mitigation should a spill occur.

For facilities/equipment not in compliance:

- Some may be incorporated under an existing (upgraded) SPCC plan.
- Most will not be able to be incorporated into an existing facility's plan, and will require a new SPCC plan. (Given the significant changes to the 2002 rule proposed, it is assumed that most facilities will develop a new plan.)

Therefore, this analysis assumes that facilities/equipment will need to pursue one of five sets of actions to comply:

- Install secondary containment and incorporate into an existing, upgraded SPCC plan.
- Install secondary containment and develop a new SPCC plan.
- Where secondary containment is determined to be impractical, implement an I&M program, develop a contingency plan, and incorporate into an existing, upgraded SPCC plan.
- Where secondary containment is determined to be impractical, implement an I&M program, develop a contingency plan, and prepare a new SPCC plan.
- Do nothing, since the facility/equipment is already in compliance, falls below a size/volume threshold, or does not threaten navigable waters.

Even for facilities currently covered by an existing SPCC plan, the 2002 rule sets forth substantial changes that will need to be made to existing plans, *even if no new equipment or facilities are added, or other additional compliance must be pursued.* Requirements for upgrading existing SPCC plans include:

- Reviewing current plans and processes.
- Providing substantially more detailed and comprehensive drawings and information on each facility.
- Adapting existing SPCC plans to make them consistent with the dramatically reorganized structure of the 2002 rule.
- Recertifying plans by a Professional Engineer (PE).

For costing purposes, it was assumed that each facility with an existing SPCC plan would, at a minimum, have to:

- Upgrade their existing SPCC plans, at an assumed cost of $1,000 per plan.
- Receive PE certification for their upgraded plan, at a cost of $500 per plan.

If a piece of equipment or operation that previously was not part of a SPCC plan must now be incorporated into an existing SPCC Plan, then the costs associated with that equipment or operation are assumed to be half of the estimates provided above.

For any piece of equipment requiring a new SPCC plan (i.e., it cannot be incorporated into an existing SPCC Plan), the costs assumed for developing a new SPCC plan and obtaining a PE certification is $3,500 per plan.

These cost estimates are consistent with estimates provided in the industry surveys, and are near the average of the costs from a wide variety of sources, including EPA.

Providing Secondary Containment or Other Appropriate Alternatives

The costs of secondary containment or the costs associated with approved alternatives if secondary containment is determined to be impractical were assumed to vary for different types of equipment or operations, as summarized in the table below:

	Storage Tanks	Vessels	Flow and Gathering Lines	Blowdown/ Emergency Tanks	Compressors	Loading Areas
Secondary Containment	**$3,000**	**$3,000**	**$10,000**	**$3,000**	**$3,000**	**$5,000**
or						
Impracticality Determinations	**$1,000**	**$1,000**	**$5,500**	**$1,000**	**$1,000**	**$2,500**
Implement inspection and testing program	$500	$500	$5,000	$500	$500	$2,000
Develop and implement oil spill contingency plan	$500	$500	$500	$500	$500	$500
Written commitment to control/remove discharge	$0	$0	$0	$0	$0	$0

These cost estimates are consistent with estimates provided in various sources, including industry surveys and EPA regulatory impact studies.

Allocating Incremental SPCC Compliance Costs to Existing Production Wells

Estimates of the total costs of compliance for the oil and gas exploration and production industry were estimated by multiplying the number of pieces of equipment or types of operation corresponding to each compliance option, multiplied by the unit cost of compliance for that option. These were then aggregated to determine the total costs for all oil and natural gas facilities falling under the jurisdiction of the SPCC rule. The total incremental compliance costs associated with oil production facilities were divided by the number of producing oil wells in the U.S. to estimate the incremental compliance costs per oil well. Likewise, the total incremental compliance costs associated with natural gas production facilities were divided by number of producing gas wells in the U.S. to estimate the incremental compliance costs per gas well.

For the reference case set of conditions described above, estimated incremental compliance costs are $9,018 per producing oil well and $9,566 per producing gas well, in 2007 dollars.

While the details associated with compliance requirements assumed, these aggregate costs are comparable to the high end in the range of costs associated with a "hypothetical" facility reported in EPA Regulatory Impact Analysis (RIA) performed in support of its November 2008 rulemaking.[62] For their hypothetical marginal production facility (described in Exhibit K-2) of that document, the RIA estimates that the cost of compliance with SPCC requirements could range

[62] Abt Associates, Inc., *Regulatory Impact Analysis for the Final Amendments to the Oil Pollution Prevention Regulations (40 CFR PART 112),* prepared for the U.S. Environmental Protection Agency under Contract No. 68-W-03-020, November 12, 2008, Volumes, Appendix K

from $8,370 to $17,100 per facility. Based on their assumption of two wells per facility, this would correspond to $4,185 to $8,550 per facility. For a non-marginal production facility (described in Exhibit K-5), estimated compliance costs in the RIA range from $28,200 to $95,600 per facility. For this case, the typical facility would have five wells, resulting in estimated costs of $5,640 to $19,120 per well.

APPENDIX B
EXISTING WELLS -- ESTIMATING THE IMPACT OF INCREMENTAL COMPLIANCE COSTS ON OIL AND GAS PRODUCTION[63]

The analytical approach used for assessing the impact of increased costs to comply with the SPCC rule, primarily as promulgated in the 2002 rulemaking, consisted of a number of steps, as described in the following.

Step1. Establish data base of U.S. oil and gas production

The Energy Information Administration (EIA) publishes a set of tables showing U.S. oil and gas wells sorted by production rate categories for each state.[64] For each rate category, the table provides the number of wells in the U.S. in that rate category, the production associated with those wells, and the average production rate per well (for both oil and gas). The latest year for which EIA has published this data is 2006. An example of the state table for Texas is shown in Table B-1.

Step 2: Estimate average annual revenues per well for each rate category

Using assumed annual average wellhead oil and gas prices of $50 per barrel and $6.00 per Mcf, respectively, average operating revenues per well were estimated for each rate production rate category.

Step 3: Estimate production costs for each rate category

Using data from EIA's annual survey of oil and gas lease equipment and operating costs,[65] typical or representative annual operation and maintenance (O&M) costs per well were calculated.

Step 4: Estimate average annual operating income per well

Estimates of average operating income per well were developed for each rate category, by subtracting the average annual O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics prior to the imposition of any new SPCC requirements.

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[63] This methodology was used for several reports for DOE including Advanced Resources International,, *Assessment of the Potential Costs and Energy Impacts of Spill Prevention, Control, and Countermeasure Requirements for U.S. Oil and Natural Gas Production,* prepared for U.S. DOE Office of Fossil Energy, August 17, 2006 (Revised) (http://www.fossil.energy.gov/programs/oilgas/publications/environment_otherpubs/SPCC_Impact_Exploration_and_Production_8.pdf; and Advanced Resources International,, "Estimated Economic Impacts of Proposed Storm Water Discharge Requirements on the Oil and Natural Gas Industry (Final), memo to the U.S. Department of Energy/Office of Fossil Energy, dated December 7, 2004 (http://www.fe.doe.gov/programs/oilgas/environment/publications/storm_water_summ120704.pdf)

[64] http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html

[65] http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

Table B-1
Distribution of Wells by Well Production Rate Bracket in Texas – 2006

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (Bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0 - 1	41,213	30.1	5,177.00	1.6	0.4	1,868.50	0.1	10,145	9.7	8,936.60	0.2	2.6	132.3	0
1 - 2	16,349	12	7,935.10	2.4	1.3	4,424.10	0.7	8,403	8	24,063.90	0.4	8.1	386.3	0.1
2 - 4	19,352	14.2	18,237.60	5.5	2.6	12,118.10	1.7	14,080	13.4	79,609.20	1.3	15.9	1,401.10	0.3
4 - 6	12,046	8.8	18,892.30	5.7	4.4	14,573.90	3.4	9,328	8.9	89,864.10	1.5	27	1,432.50	0.4
6 - 8	8,744	6.4	19,268.50	5.8	6.1	16,697.60	5.3	7,105	6.8	95,842.90	1.6	38	1,511.50	0.6
8 - 10	7,020	5.1	18,847.10	5.7	7.4	21,744.30	8.6	5,320	5.1	94,281.30	1.6	50	1,172.00	0.6
10 - 12	7,158	5.2	22,319.10	6.7	8.7	33,397.70	12.9	4,433	4.2	95,305.20	1.6	60.60	1,347.80	0.9
12 - 15	6,982	5.1	29,479.00	8.9	11.7	24,687.70	9.8	5,404	5.1	143,783.40	2.4	75.50	1,624.30	0.9
15 - 20	5,454	4	29,537.20	8.9	15.00	26,452.40	13.50	7,239	6.9	243,561.50	4.1	95.30	4,118.10	1.6
20 - 25	3,250	2.4	22,942.50	6.9	19.8	20,036.50	17.3	5,058	4.8	224,284.10	3.8	126.40	2,342.20	1.3
25 - 30	1,829	1.3	15,494.90	4.7	23.8	13,910.40	21.4	3,915	3.7	210,660.90	3.5	154.5	2,118.40	1.6
30 - 40	2,311	1.7	23,640.80	7.1	28.8	27,623.60	33.6	5,299	5	361,402.10	6.1	197.70	3,041.70	1.7
40 - 50	1,897	1.4	23,971.20	7.2	35.5	33,027.20	49	3,710	3.5	322,587.80	5.4	253.1	3,251.20	2.6
50 - 100	2,365	1.7	45,448.20	13.7	54.9	96,619.80	116.8	8,109	7.7	1,065,290.50	17.9	399.9	8,832.20	3.3
100 - 200	644	0.5	20,680.00	6.2	92.7	33,471.40	150.1	4,610	4.4	1,065,105.20	17.9	786.4	8,921.50	6.6
200 - 400	88	0.1	5,388.90	1.6	223.2	7,352.30	304.5	1,982	1.9	822,508.30	13.9	1,560.00	6,082.20	11.5
400 - 800	25	0	3,094.30	0.9	436.1	5,697.40	803	614	0.6	486,388.90	8.2	3,068.00	4,967.60	31.3
800 - 1600	11	0	1,811.30	0.5	652.7	9,322.50	3,359.50	174	0.2	275,140.10	4.6	6,071.90	4,428.00	97.7
1600 - 3200	0	0	0.00	0	0	0.00	0	45	0	145,274.30	2.4	11,463.30	2,035.00	160.6
3200 - 6400	0	0	0.00	0	0	0.00	0	9	0	70,106.50	1.2	25,850.50	278	102.5
6400 - 12800	0	0	0.00	0	0	0.00	0	1	0	13,012.00	0.2	35,649.30	583.2	1,597.90
> 12800	0	0	0.00	0	0	0.00	0	0	0	0.00	0	0	0	0
Total	**136,738**	**100**	**332,165**	**100**	**6.66**	**403,025**	**8.08**	**104,983**	**100**	**5,937,009**	**100**	**154.94**	**60,007**	**1.57**

Notes:
1) The source of data is the IHS Energy Group and various State agencies.
2) The Reserves and Production Division, Office of Oil and Gas, EIA has reviewed and edited inaccurate production data.
3) To be consistent between states a GOR of 6,000 (cf/bbl) for each years production was used to classify wells.
If the GOR was less than 6,000 (cf/bbl) the well was classed an oil well, greater than or equal 6,000 (cf/bbl) were gas wells.
4) To determine production rate brackets for the first and last year of a wells life the annual production was divided
by the number of days in the productive months. For other years the annual production was divided by 365 or 366 days.
5) Gas volumes have been converted from the various state pressure bases to the Federal base (14.73 psia).

Step 5. Estimate average annual operation income per well, accounting for incremental compliance requirements

Revised estimates of average operating income per well were developed for each rate category by adding the incremental compliance costs to the average annual operating costs per well, and then subtracting the revised average annual O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics after the imposition of the new compliance requirements.

Step 6. Determine shut in production as a result of the increased compliance costs

The process of adding the incremental costs for compliance results in costs exceeding revenues for certain categories of low productivity or “marginal” wells. The amount of production for these rate categories was assumed to be shut-in, since wells in the category, on average, would no longer be profitable to produce.

Step 7. Estimate other associated economic impacts

Estimated associated economic impacts were estimated based as a results of the increased costs all wells would incur to comply with the new requirements, as well as those resulting from the production that would be shut in since the oil and/or gas production from these wells would not generate enough revenue to cover the incremental costs of compliance. The methods for estimating these economic impacts are described in the following:

- Estimated Compliance Expenditures. Estimated incremental compliance expenditures associated with onshore producing oil and gas wells were estimated by multiplying the estimated weighted average compliance costs by the number of wells complying. Wells that were assumed to be shut in were not assumed to incur the incremental compliance costs.

- Estimated Lost Royalties. Estimated lost royalties were determined by assuming royalties at 1/8 of wellhead revenues, equivalent to current rates in most onshore areas of the country. This includes both royalties paid to private royalty interest owners and royalties paid to the federal government, with no distinction made between the two.
- Estimated Lost State and Local Severance/Ad Valorum Taxes. Estimated state and local severance taxes were estimated based on individual severance and ad valorem tax rates for the states assessed.[66] These rates were applied to estimated wellhead revenues. These were estimated based on revenues to operating and working interest owners, as well as revenues from royalties.
- Estimated Lost State Income Taxes. Lost state income taxes were estimated both on the lost production due to some wells being shut in because of the incremental compliance requirements, as well as a result of the decrease in income from wells remaining on production but incurring increased costs. Estimated state and local severance taxes were estimated based on individual state corporate tax rates.[67]
- Estimated Lost Federal Income Taxes. Lost federal income taxes were also estimated both on the lost production due to some wells being shut in because of the incremental compliance requirements, as well as a result of the decrease in income from wells remaining on production but incurring increased costs. A corporate federal tax rate of 35% was assumed for these estimates.

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[66] Estimates of state severance and ad valorem tax rates were based on that reported in Interstate Oil and Gas Compact Commission, *Summary of Severance, Ad Valorem and Total Oil and Gas Tax Rates of IOGCC Member States*, October 2002.
[67] http://www.taxadmin.org/fta/rate/corp_inc.html

APPENDIX C
CO_2 ENHANCED OIL RECOVERY[68]

OVERVIEW. A six part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling the Major Oil Reservoirs Data Base; (2) calculating the minimum miscibility pressure; (3) screening reservoirs for CO_2-EOR; (4) calculating oil recovery; (5) assembling the cost and economic model; and, (6) performing economic and sensitivity analyses. These steps are summarized in following paragraphs.

ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. Table C-1 illustrates the oil reservoir data recording format used in this study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Major Oil Reservoirs Data Base contains 2,012 reservoirs, accounting for 74% of the oil expected to be ultimately produced in the U.S. by primary and secondary oil recovery processes.

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model the essential input data for calculating CO_2 injection requirements and oil recovery.

CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure C-1. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most Gulf Coast oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

$$MMP = 15.988*T^{(0.744206+0.0011038*MW\ C5+)}$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

[68] This methodology has been used in a number of studies for DOE, including Advanced Resources International, *Storing CO2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology,* Report DOE/NETL-2009/1350 prepared for the U.S. Department of Energy, National Energy Technology Laboratory, January 9, 2009 (http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20Next%20Generation%20CO2-EOR.pdf); Advanced Resources International, "*Storing CO2 with Enhanced Oil Recovery*" report prepared for U.S. DOE/NETL, Office of Systems, Analyses and Planning, DOE/NETL-402/1312/02-07-08, February 7, 2008. http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf; and a series of ten "basin studies" were the first to comprehensively address CO_2 storage capacity from combining CO_2 storage and CO_2-EOR. These reports are available on the U.S. Department of Energy's web site at: http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html

Table C-1. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Print Sheets

Reservoir Parameters:

	ARI
Area (A)	
Net Pay (ft)	
Depth (ft)	
Porosity	
Reservoir Temp (deg F)	
Initial Pressure (psi)	
Pressure (psi)	
B_{oi}	
B_o @ S_o, swept	
S_{oi}	
S_{or}	
Swept Zone S_o	
S_{wi}	
S_w	
API Gravity	
Viscosity (cp)	
Dykstra-Parsons	

Oil Production

	ARI
Producing Wells (active)	
Producing Wells (shut-in)	
2002 Production (Mbbl)	
Daily Prod - Field (Bbl/d)	
Cum Oil Production (MMbbl)	
EOY 2002 Oil Reserves (MMbbl)	
Water Cut	

Water Production

2002 Water Production (Mbbl)	
Daily Water (Mbbl/d)	

Injection

Injection Wells (active)	
Injection Wells (shut-in)	
2002 Water Injection (MMbbl)	
Daily Injection - Field (Mbbl/d)	
Cum Injection (MMbbl)	
Daily Inj per Well (Bbl/d)	

EOR

Type	
2002 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2002 Reserves (MMbbl)	
Ultimate Recovered (MMbbl)	

Volumes

	ARI P/S
OOIP (MMbl)	
P/S Cum Oil (MMbl)	
EOY P/S 2002 Reserves (MMbl)	
P/S Ultimate Recovery (MMbl)	
Remaining (MMbl)	
Ultimate Recovered (%)	

OOIP Volume Check

Reservoir Volume (AF)	
Bbl/AF	
OOIP Check (MMbl)	

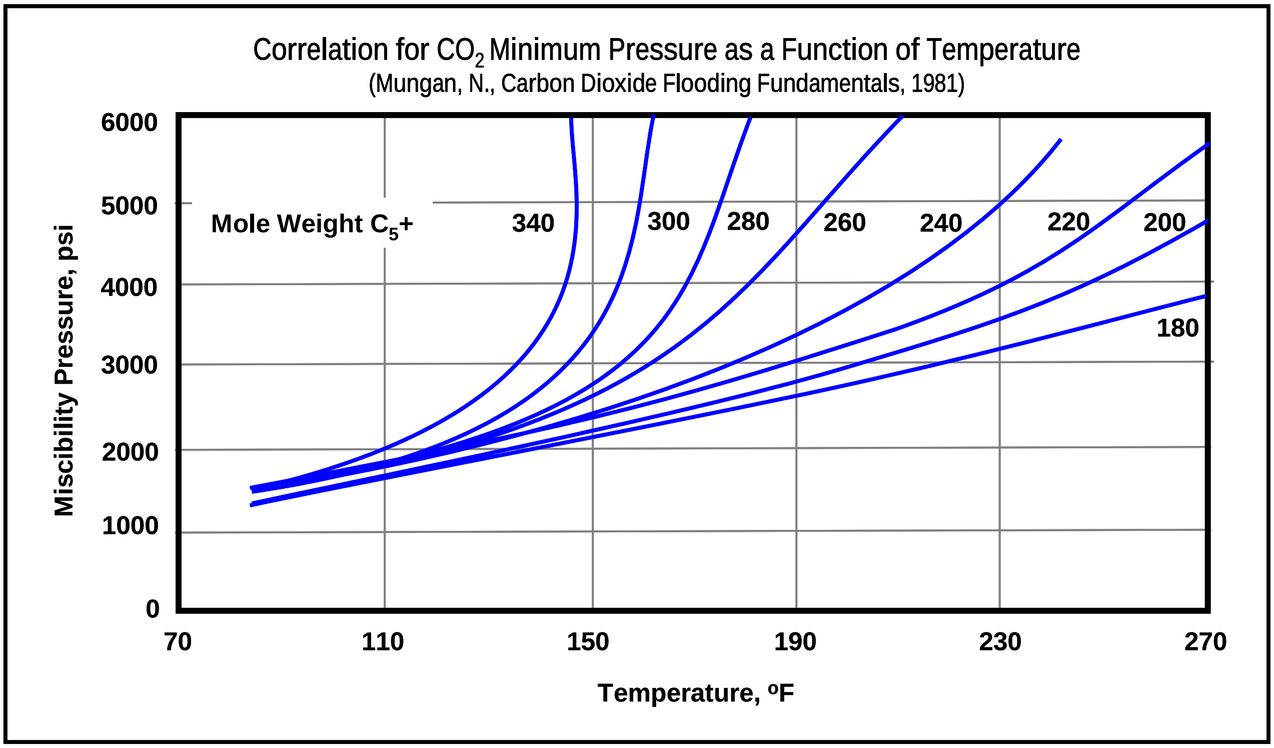
SROIP Volume Check

Reservoir Volume (AF)	
Swept Zone Bbl/AF	
SROIP Check (MMbbl)	

ROIP Volume Check

ROIP Check (MMbl)	

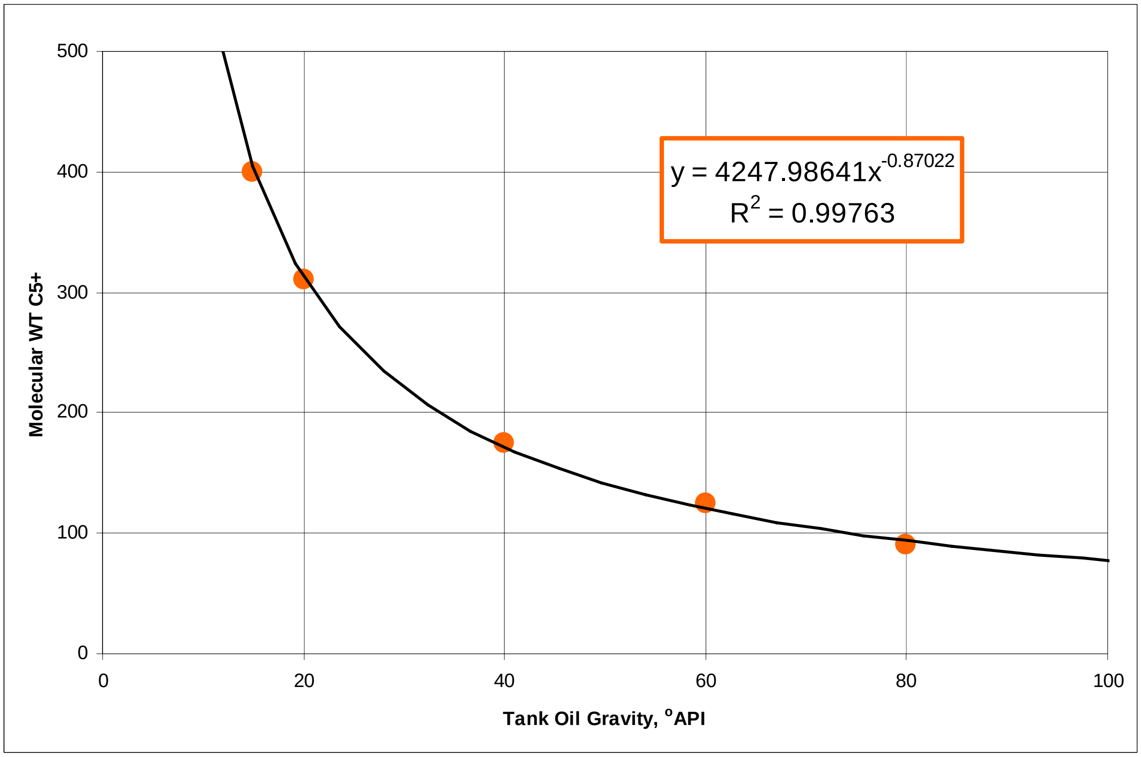
Figure C-1. Estimating CO_2 Minimum Miscibility Pressure



The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure C-2.

The next step was calculating the minimum miscibility pressure (MMP) for a given reservoir and comparing it to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 psi/foot. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for consideration by immiscible CO_2-EOR.

Figure C-2. Correlation of MW C5+ to Tank Oil Gravity



SCREENING RESERVOIRS FOR CO_2-EOR. The data base was screened for reservoirs that would be applicable for CO_2-EOR. Five prominent screening criteria were used to identify favorable reservoirs. These were: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 ^{o}API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection.

CALCULATING OIL RECOVERY. The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR.

- *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and
- The model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

Even with these improvements, it is important to note the CO_2-PROPHET is still primarily a "screening-type" model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.

ASSEMBLING THE COST MODEL. A detailed, up-to-date CO_2-EOR Cost Model was developed by the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and, (5) various miscellaneous costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user.

CONSTRUCTING AN ECONOMICS MODEL. The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. A variety of oil prices are available to the model user.

APPENDIX D
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