MEMORANDUM

TO:	Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM:	John Dunham, Managing Partner
DATE:	June 11, 2012
RE:	Business Impact of Proposed Changes to Well Completion Regulations

As per your request, we have examined the impact of a proposal that would require that companies drilling new wells for the extraction of petroleum products submit a plan outlining the details of well completion operations for approval prior to performing them. The proposed regulation is being promulgated by the US Department of Interior's Bureau of Land Management (BLM) and as currently written would apply only to federal wells on or impacting Federal and Indian lands, or split estate lands. However, this definition is remarkably broad and could potentially be applied to companies drilling on private lands in the western states.[1]

In fact, assuming a best case scenario, where the BLM approves 100 percent of all applications and assuming capital costs of only 7 percent, these regulations – if applied to all projects in the western states – would cost at least $1.226 billion annually based on the carrying costs of the project. Based on the discounted lost value of petroleum output, the proposed regulations would cost about $1.342 billion annually. Averaging these two methods together suggests that a reasonable estimate for the cost of this proposed rule as applied to drilling in the western states is just over $1.284 billion. The average cost per well is estimated at $253,800. This figure does not even include the cost of the regulations for existing wells than will require re-work or re-stimulation. A conservative estimate of this cost is upwards of $233,100 per well or about $273 million per year. **Total aggregate annual costs for new permits and workovers would be at least $1.499 billion and as high as $1.615 billion.**

Proposed Regulation and Background:

The US Department of the Interior, Bureau of Land Management (BLM) recently proposed amendments to current regulations (43 CFR 3160.0-3) that would require significantly more permitting and operational expenses for companies drilling and completing oil and gas wells on federal lands.[2] While BLM claims that the amendments would not constitute a major change in existing regulations, the new rules would add a large number of new requirements for companies exploring for, and producing, oil and natural gas on federal and Indian lands. This rule change would among other things require operators to:

- Provide additional information and meet new requirements for all well stimulation (completion) activity when applying for a permit to drill (APD). A similar application would need to be filed prior to performing additional stimulation on an existing well. The BLM would have to review and verify the additional completions requirements when approving these permits.
- Submit additional cement bond logs for review and approval prior to completing the well.

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1 For the purpose of this analysis the western states include: Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming

2 Bureau of Land Management proposed rule RIN 1004-AE26: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands

- Report the specific source of water used in well completion operations.
- Submit a detailed engineering design and other information related to well stimulation operations to the BLM for approval.
- Submit detailed information related to how they will handle or treat all recovered fluids from well stimulation activities.
- Perform a successful mechanical integrity test prior to commencing any well completion activities.
- Store detail to the agency how recovered fluids are disposed of.

While many of the requirements are simply clarifications or minor additions to the existing permitting process, other components may add significantly to the cost of drilling and completing an oil or gas well. Obviously there will be additional costs to both operators and to the government simply due to the increase in the administrative burden contemplated by these rules. The potential for delay resulting not from any direct operational activity, but rather from waiting for permits and paperwork to be processed, could lead to significant financial costs for both operators and investors.[3] While any additional costs would reduce drilling activity (since marginal wells would no longer be financially practical to develop), were these costs to be high enough they could preclude companies from developing any additional resources on BLM-controlled or impacted land. This is particularly true for wells requiring some sort of workover or retreatment in order to continue to maximize their output. Since the new regulations will also apply to these wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.[4]

Currently, once a company has obtained a lease for mineral extraction on Federal lands, and once it has completed a lengthy environmental analysis under the National Environmental Policy Act (NEPA) process, it must apply for a permit to actually begin drilling. The Energy Policy Act of 2005 specifies that BLM must approve Applications for Permit to Drill (APD) within thirty days, yet according to Bob Abby, the Director of the Bureau of Land Management, the average permit time is 298 days, [5] and depending on the field office, it is not that uncommon for APDs to take years.[6] In addition, data on the number of actual permits outstanding is not generally available in a timely fashion from BLM, making it difficult to estimate the actual amount of time needed to currently process a permit; however, the agency expects to process 5,500 APDs in fiscal year 2012 under the existing regulatory structure.[7]

Estimated Number of Wells Impacted by the Proposed Regulation:

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[3] BLM already takes about 10 months to approve an APD and there is a substantial backlog.

[4] See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

[5] Cappiello, Dina, *New process to expedite drilling on public lands*, Associated Press, April 3, 2012. On-line at: www.newsvine.mobi/_news/2012/04/03/11002223-new-process-to-expedite-drilling-on-public-lands

[6] Sgamma, Kathleen, Vice President of Government & Public Affairs, Western Energy Alliance, *Testimony Before the House Natural Resources Committee Subcommittee on Energy and Mineral Resources Legislative Hearing on H.R. 4381, H.R. 4382 and H.R. 4383*, April 26, 2012.

[7] *Secretary Salazar Visits North Dakota's Oil Boom; Unveils Initiatives to Accelerate Drilling Permits and Leases on Federal Lands*, US Department of Interior, Bureau of Land Management, Press Release, April 3, 2012, available at: www.blm.gov/wo/st/en/info/newsroom/2012/april/nr_04_03_2012.html

The Bureau of Land Management does not release detailed statistics on pending permits, however, a good estimate of the number of wells impacted by this proposed rule can be developed based on state permitting information. This analysis examines the impact of the proposed rule in 13 Western states.[8] Based on data from state regulatory authorities, there are approximately 12,300 oil wells, and 14,100 gas wells currently in the process of receiving a permit, or permitted but not yet drilled. Only some of these wells are on Federal or Indian lands, so not all would be required to go through the extra permitting process. In addition, at the present price for oil and natural gas, not all of the wells are economically viable. In fact, in many areas natural gas wells in particular are being capped because the actual cost of production exceeds the price of gas.

This analysis examines these wells as individual units at the state level. It estimates the number on federal permit lands based on a linear estimate of the number of permits issued over the past 24 years. In addition, the analysis assumes that no wells will be drilled in states where the average profits from either oil or gas plays are less than zero. Based on these limiting assumptions, the proposed regulation would impact about 1,800 currently proposed oil wells, and about 3,250 gas wells. Table 1 below outlines the number of wells currently waiting for permits or for drilling to commence by state, along with an estimate of impacted wells.

Table 1
Estimated Oil and Gas Wells Waiting to Be Permitted or Drilled

	Estimated Total			Estimated Impacted		
State	Oil Wells	Gas Wells	Total Wells	Oil Wells	Gas Wells	Total Wells
Arizona	3	1	4	-	-	-
Colorado	3,187	5,718	8,905	212	380	592
Idaho	-	5	5	-	-	-
Montana	398	240	638	63	-	63
Nebraska	106	11	117	-	-	-
Nevada	14	14	27	-	-	-
New Mexico	4,519	2,564	7,083	700	-	700
North Dakota	1,993	6	1,999	99	-	99
Oregon	-	6	6	-	-	-
South Dakota	22	2	24	1	-	1
Utah	1,392	2,098	3,490	252	380	632
Washington	-	3	3	-	-	-
Wyoming	685	3,461	4,146	491	2,480	2,971
Total	12,318	14,129	26,447	1,818	3,240	5,058

This of course represents only one moment in time. Were natural gas prices to rise above their current low levels, the resulting number of wells that could be impacted would increase substantially. In addition, were the Federal government to open more areas for oil and gas

[8] Arizona, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

exploration and leasing the number could also increase well beyond what is currently considered in this analysis. In fact, according to a report by the Congressional Research Service oil production on federal on-shore leaseholds was down slightly between 2007 and 2011.[9]

According to the BLM in its cursory examination of the benefits and costs of these proposed regulations, approximately 3,100 wells would be impacted each year. This analysis examines only the current impact of the proposed rules – in that they will impact 5,058 existing permits. No assumptions are made as to future permits on either existing or future leases or costs incurred on existing wells that may need future stimulation or acidization. Recent research conducted for the American Petroleum Institute suggests that about 93 percent of gas wells are completed with hydraulic fracture, and of these about 1.6 percent require some sort of work-over in a given year.[10] Based on these figures, and the number of wells on Federal leases, it is estimated that as many as 1,346 wells per year will need some sort of rework that falls under these regulations

Model Data and Assumptions:

This model was developed for the Western Energy Alliance by John Dunham and Associates (JDA), a New York City based economic consulting firm. It is based on a wide range of data sources and assumptions, each of which impacts the final results. JDA has strived to ensure that the assumptions are as cautious as possible leading to what is likely a low estimate of the overall cost of the proposed rule. Each of these assumptions, along with the data used in the development of the models in detailed below:

<u>Average Drilling Costs</u> are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis, by the Minnesota IMPLAN Group in 2010. These data come from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas well drilling including wages, capital costs, leasing costs, and costs of various materials and services used in the drilling and completion of oil and gas wells. The data are from 2010. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas as the wellhead in each state as of 2011 which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[11] Costs are divided between exploration/leasing/permitting, drilling and completion based on the type of input and labor costs are divided based on input commodity and service costs with about 52.4 percent of the drilling/completion cost assumed to be for drilling and the rest for completion.[12]

<u>Production Costs</u> are estimated based on data derived from the US Department of Commerce, Bureau of Economic Analysis by the Minnesota IMPLAN Group in 2010. These data come

9 Humphries, Marc, *U.S. Crude Oil Production in Federal and Non-Federal Areas*, Congressional Research Service, March 20, 2012, at: http://cnsnews.com/sites/default/files/documents/CRSreport%20Oil%20Production.pdf

10 Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

11 See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

12 The model is based on average costs and revenues. These can vary greatly by play, product and individual well.

from the Input/Output accounts of the United States. These data present detailed figures on the input costs for oil and gas production including wages, capital costs, leasing costs, and costs of various materials and services used in the exploration/leasing/permitting, production, infrastructure development and reclamation of oil and gas plays. The data are from 2010. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas as the wellhead in each state as of 2011 which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.[13] Costs are divided between different activities based on the type of input and labor costs are divided based on input commodity and service costs.

Anticipated Revenues are based on data from the US Department of Energy. It is simply equal to the annualized price of either oil or natural gas at the wellhead (by state) multiplied by annual production.[14] Revenues per well cannot be derived simply by dividing this by the number of producing wells since oil and gas wells tend to have either a hyperbolic or an exponentially declining production trend. Based on discussions with industry principles, a well will generally not be drilled and put into production unless it can recoup at least the direct drilling costs in the first year after completion. Using this assumption and a simple declining exponential function, the model suggests that about 97 percent of the production occurs in the first 4 years after drilling. The four year production total (multiplied by the current price of either oil or gas) was used to estimate total revenue per well. Operating costs were then multiplied by 4 to reflect the economic life of each well.

The Number of Wells To Be Drilled is estimated based on data from individual state permitting authorities. Each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage in the production process. While complete standardization between the states is not possible, in general it is possible to label a well as oil or gas, and as in some stage of pre-production. These are aggregated for each state and the summary results are shown on Table 2 on the following page.

The Number of Producing Wells is also estimated based on data from individual state permitting authorities. Again, each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage of production. While complete standardization between the states is not possible, in general it is possible to label a well as oil or gas, and that it is in some stage of production. Water wells, disposal wells, capped wells, injection wells, and other operations not directly used to extract petroleum are not included. A summary of these wells is also included in Table 2 on the following page.

The Number of Wells on Federal Land is estimated based on a linear trend of permits issues by state. These data come directly from the Bureau of Land Management.[15] Based on a linear trend, the BLM will approve 5,841 drilling permits on all Federal land in 2012, of which 87 percent (5,058) will be in the 13 subject states.

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[13] See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

[14] Ibid.

[15] *Number of Drilling Permits Approved by Fiscal Year on Federal Lands*, US Department of the Interior, Bureau of Land Management, November 9, 2011. Available on-line at: www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html

The Number of Wells requiring Rework: is estimated by multiplying the 90,452 existing wells on Federal leases by 87 percent (the estimated percentage in the 13 subject states) and then by 93 percent (the percentage completed using hydraulic fracture) and then by 1.6 percent or the annual rework rate in a given year.[16] Under these assumptions 1,171 wells in the subject states will require re-work in a given year.

Table 2
Summary of Wells Included in The Cost Analysis

	Estimated Number of Wells in			
	Production	Permitting Process	Federal Permit Process	Impacted
Oil	108,753	12,318	1,818	1,818
Gas	92,915	14,129	3,675	3,240
Total	201,668	26,447	5,493	5,058

The Number of Impacted Wells is calculated by taking the number of estimate permits on Federal lands (see above) and dividing them into oil or gas wells based on the overall number of oil versus gas wells in each state that are currently in the permitting process. These figures are then adjusted downward to remove all wells in states where the average oil or gas well would be unprofitable. While this does not mean that individual wells would not be profitable, and therefore subject to this new rule, it does ensure that the estimated costs calculated as part of this analysis are conservatively estimated.

The Discount Rate used in this analysis is 7 percent based on the rate used in the BLMs cursory analysis of the benefits and costs of these regulations.[17] The Federal government recommends that significantly lower discount rates be used in internal analyses; however, the cost of capital for government projects is significantly lower than that for risky ventures like oil and gas exploration, drilling and production. Industry sources have suggested to JDA that a discount rate of 12 to 15 percent is generally standard in the financial decision-making process;[18] however, this could not be independently substantiated. Therefore, this analysis assumes a cost of capital equal to the coupon of non-investment grade corporate bonds as of April 23, 2012.[19]

The Number of Delay Days is invariably difficult to predict since the permit in question currently does not exist. The proposed rule does not propose a limit on the number of days that the BLM can take to either approve or reject the permit. Currently the agency is taking about 10 months to approve a drilling permit, and there is already a substantial backlog. No additional funds to enforce the proposed rule could be found in the FY 2012 Federal Budget, so the agency

[16] Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

[17] See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

[18] John Dunham and Associates interviews with various industry principles and staff of drillers, operators, service companies and leaseholders.

[19] From Bloomberg.com at: www.bloomberg.com/markets/rates-bonds/corporate-bonds/

will be required to process at least 5,000 expanded permit applications with its current staffing levels. As such it is probably not unreasonable to assume that the approval time for these permits with the additional requirements to add about a third of that of approving the existing drilling permits, and will likely be much longer. In this analysis, it is assumed that the additional permitting time will be about 49 days. This is based on a Monte Carlo analysis using a log-normal function and assuming an average increase in permitting time of 47 days, with on outside change of either zero additional days or 99 additional days (which is one-third of the current permitting time). In addition to this, it is assumed that about 13.5 additional days will be needed in between the drilling of a well and the stimulation process. Again, a Monte Carlo analysis is used which assumes a median of 7 additional days and an outside chance of either zero or 30 days.

<u>Additional Casing Costs</u> will be required under the provision that requires casing to protect the "usable groundwater" where this is defined as water containing 10,000 parts per million of total dissolved solids. This change in definition of usable ground water will require operators to run deeper surface casing, two stage cementing on the production casing or the addition of an intermediate string of casing. Currently this casing is brought down to an average depth of about 2,000 feet, but may now have to be brought down to a depth of 4,000 or even 7,500 feet or deeper depending on conditions. It costs about $37 per foot for casing of this type. Again, using a Monte Carlo simulation it is estimated that each well will require approximately 2,350 feet of additional casing.

<u>Additional Cement Bond Log</u>: The new regulations will require operators to maintain an additional Cement Bond Log for all pipes and other surface operations. This is an analysis which provides a representation of the integrity of the cement job on pipes and is generally only required or used on drill casings. According to the BLM this will be required on about $9,000 per well and will be required on 97.5 percent of covered wells.[20] <u>However, on top of the cost of the CBL, operators will need to</u> ensure that all drilling and field equipment is maintained at the site while the cement cures. Cost estimates provided by companies operating in the Williston, Piceance and San Juan basins suggest that on average the hourly cost for maintaining this equipment on-site (and idle) is as much as $1,950. Costs can be even higher in areas where deep, horizontal wells are being drilled. Assuming that 72 hours of additional delay time is required for the cement to cure this would mean that each well would require an additional $140,400 expense simply to cover the down time for the rig while the operator is completing the CBL, meaning that the total cost for this requirement will be $145,665 per well.

<u>Mechanical Integrity Tests</u> are assumed to be required on 20 percent of wells prior to commencing stimulation operations, and that these tests are assumed to cost approximately $10,000 as per the BLM.[21]

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<u>The Permit Approval Rate</u> is assumed to be 100 percent. This ensures that the estimated cost generated by the model will be the lowest possible. A lower approval rate would result in a

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20 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

21 Ibid.

higher cost of the proposed rule. The administrative cost to operators is assumed to be only $495 per well as per the BLM.[22]

Detailed Results – Cost of the Proposed Regulations:

Based on the data and assumptions presented in the prior section it is possible to calculate the anticipated cost of the proposed rule on the oil and natural gas industry. There are two potential ways to calculate this cost. The first assumes that development stops for a period of time while the permitting/verification process takes place. The capital already tied up in the development of the well during this time can be discounted at a reasonable rate of interest which would represent the direct cost to the driller/producer. This method assumes that the well development would continue unabated following the completion of the regulatory process and that production from the well would occur at the same rate and with the same revenues as would have occurred 62.5 days earlier. In such, this model simply represents the additional cost of capital to the producer.

Table 3
Summary of Estimated Costs by State

	State	Method 1	Method 2	Average
AZ	Arizona	$ -	$ -	$ -
CO	Colorado	$ 140,597,918	$ 144,944,919	$ 142,771,418
ID	Idaho	$ -	$ -	$ -
MT	Montana	$ 15,676,353	$ 17,450,231	$ 16,563,292
NE	Nebraska	$ -	$ -	$ -
NV	Nevada	$ -	$ -	$ -
NM	New Mexico	$ 167,170,616	$ 169,003,720	$ 168,087,168
ND	North Dakota	$ 25,147,180	$ 33,310,119	$ 29,228,649
OR	Oregon	$ -	$ -	$ -
SD	South Dakota	$ 253,752	$ 286,759	$ 270,256
UT	Utah	$ 150,566,431	$ 159,886,215	$ 155,226,323
WA	Washington	$ -	$ -	$ -
WY	Wyoming	$ 726,475,894	$ 817,064,564	$ 771,770,229
Total	Total 13 States	$ 1,225,888,144	$ 1,341,946,527	$ 1,283,917,335

A second method can be used to calculate the cost to the industry. Under this method, it is assumed that the overall cost of completing a well would remain the same; however, there would be a delay to the producer in realizing a return. Under this model, the value of production over the delay period is discounted back representing a lost return on capital.

While either method can produce a reasonable assumption for the overall cost of the regulations, the magnitude of the difference between them would be impacted by the current market price of petroleum products and capital. In a market where prices are high, the lost return on capital would produce a higher figure, where in a market where interest rates are relatively high, the cost of capital method would produce a more substantial loss estimate. As such, the average value between these two approaches should serve as a good estimate of the cost of the proposed rule.

22 Ibid.

Based on the first approach and the assumptions outlined above, the total cost of the proposed rule would be just over $1.225 billion, with nearly 60 percent of that coming from operations located on Federal lands in Wyoming.   The second approach, which examines the lost value of production, leads to a forecast loss of about $1.342 billion, with Wyoming again accounting for the bulk of this cost. Table 3 on the prior page shows the estimated losses by state based on the two approaches.

The arithmetic average of these estimates is $1,284 billion which is John Dunham and Associates' estimate of the overall cost to the oil and gas industry of the proposed rule based on the existing wells in the regulatory pipeline. As the rule will impact future operations, it may also have significant costs as long as the industry continues to operate on Federal leases. This analysis does not examine future costs nor does it examine costs incurred for additional well stimulation efforts on existing – and either currently producing or capped wells.

Table 4
Cost Component Comparison

		BLM	Percent		JDA	Percent		Difference
Initial Delay Costs	$	-	0.00%	$	56,404,007	4.39%	$	56,404,007
Pre Completion Delay Costs	$	-	0.00%	$	38,326,948	2.99%	$	38,326,948
Administrative Costs	$	3,798,558	6.52%	$	2,503,710	0.20%	$	(1,294,848)
Enhanced Casing Costs	$	-	0.00%	$	439,793,100	34.25%	$	439,793,100
Cement Bond Log Costs	$	44,383,950	76.13%	$	736,773,570	57.38%	$	692,389,620
Mechanical Integrity Test Costs	$	10,116,000	17.35%	$	10,116,000	0.79%	$	-
Total Costs	$	58,298,508	100.00%	$	1,283,917,335	100.00%	$	1,225,618,827

Table 4 above presents these costs in comparison with those documented by the BLM in its cursory analysis of the benefits and costs of the proposed rules. As the table shows, the bulk of the additional costs (about 36 percent) come from the additional well casing that the new rules would require and 56.5 percent from the additional cement bond log. However, the costs related to delays are so substantial that even eliminating the additional casing expense and accepting the government's estimates for Mechanical Integrity Tests and administrative costs as given, the total cost to drillers and operators will still exceed $107 million even if the casing and cement bond log costs were not included.

On a per well basis the regulations will cost about $253,800. Obviously this is an average as the costs for a deep horizontal oil well on the Bakken will be significantly higher than that of a shallower vertical gas well drilled on the San Juan Basin. However, the actual per well costs could rise if the regulations were to eliminate the economic incentive for drilling marginal wells. Were that to happen, only deep, horizontal plays with high expected returns may be drilled on federal lands, and more marginal natural gas leases may simply lie fallow. Table 5 below outlines the costs of the proposed rule based on an average oil/gas well.

Table 5
Cost Component Comparison per Well

	BLM Estimate	JDA Estimate
Initial Delay Costs	$ -	$ 11,151
Pre Completion Delay Costs	$ -	$ 7,577
Administrative Costs	$ 751	$ 495
Enhanced Casing Costs	$ -	$ 86,950
Cement Bond Log Costs	$ 8,775	$ 145,665
Mechanical Integrity Test Costs	$ 2,000	$ 2,000
Total Costs	$ 11,526	$ 253,839

Costs from Reworking Existing Oil and Gas Wells:

Since the new regulations will also apply to maintenance stimulation of existing wells, operators maintaining many of the current 90,452 producible and service drill holes on Federal leases will also experience greatly increased costs over time.[23] Assuming that wells require stimulation in line with figures recently calculated for the American Petroleum Institute, as many as 1,171 wells in the subject states will require re-work in a given year.[24]

Assuming that re-work can re scheduled to minimize the costs and delays that will come about due to the proposed rules, and that operators already perform integrity tests prior to re-stimulation, these projects will incur additional costs related only to:

- Administration and permitting ($495 per well);
- Additional costs to ensure that casings meet the new requirements ($86,950 per well);
- Additional Cement Bond Log costs to ensure that all pipes and surface infrastructure conforms to the new requirements ($145,665 per well);

Based on the assumptions above, operators will incur additional costs equal to over $233,100 per well for the first re-stimulation event for all existing wells. Since it is difficult to determine the actual number of wells on federal lands that will be cost effective to maintain once these regulations are in effect, this analysis examines the costs for only one year. Assuming, therefore, that 1,171 wells on federal leaseholds will require re-work, the cost of the regulations for just workovers will be almost $273.0 million. This figure will only increase as wells require re-work or new stimulation activities over time.

In sum, the above analysis suggests that these proposed regulations will have a significant impact on the oil and gas production industry even without considering future discounted costs.

23 See: US Bureau of Land Management, *Well Stimulation Proposed Rule: Economic Analysis and Initial Regulatory Flexibility Analysis*, at: www.regulations.gov/#!documentDetail;D=BLM-2012-0001-0003.

24 Shires, Terri and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production*, prepared by URA Corporation and the LEVON Group for the American Petroleum Institute and American's Natural Gas Alliance, June 1, 2012.

About John Dunham and Associates:

John Dunham and Associates is a leading New York City based economic consulting firm specializing in the economics of fast moving issues. JDA is an expert at translating complex economic concepts into clear, easily understandable messages that can be transmitted to any audience. Our company's clients include a wide variety of businesses and organizations, including some of the largest Fortune 500 companies in America, such as:

- Altria
- Diageo
- Feld Entertainment
- Forbes Media
- MillerCoors
- Verizon
- Wegmans Stores

John Dunham is a professional economist with over 25 years of experience. He holds a Master of Arts degree in economics from the New School for Social Research as well as a Masters of Business Administration from Columbia University. He also has a professional certificate in Logistics from New York University. Mr. Dunham has worked as a manager and an analyst in both the public and private sectors. He has experience in conducting cost-benefit modeling, industry analysis, transportation analysis, economic research, and tax and fiscal analysis. As the chief domestic economist for Philip Morris, he developed tax analysis programs, increased cost-center productivity, and created economic research operations. He has presented testimony on economic and technical issues in federal court and before federal and state agencies.

Prior to Phillip Morris John was an economist with the Port Authority of New York and New Jersey, the Philadelphia Regional Port Authority and the City of New York.