WILDEARTH GUARDIANS
A FORCE FOR NATURE

January 19, 2016

Via Fax

Mary Jo Rugwell
Acting State Director
U.S. Bureau of Land Management
Wyoming State Office
5353 Yellowstone Road
Cheyenne, WY 82003

Re: Protest of February 2016 Competitive Oil and Gas Lease Sale

Dear Ms. Rugwell:

Pursuant to 43 C.F.R. § 3120.1-3, WildEarth Guardians hereby protests the Bureau of Land Management's ("BLM's") proposal to offer 117 publicly owned oil and gas lease parcels covering 122,432.45 acres of land in the High Plains, Wind River, and Bighorn District Offices of Wyoming for competitive sale on February 2, 2016. These lease parcels include the following, as identified by the BLM's in its Final February 2016 Oil and Gas Sale List:[1]

Lease Number	Acres	Field Office	County
WY-1602-001	194.12	Newcastle	Niobrara
WY-1602-002	560.00	Newcastle	Niobrara
WY-1602-003	160.00	Newcastle	Niobrara
WY-1602-004	1075.22	Newcastle	Niobrara
WY-1602-005	1003.49	Newcastle	Niobrara
WY-1602-006	2241.48	Newcastle	Niobrara
WY-1602-007	1878.24	Newcastle	Niobrara
WY-1602-008	1200.15	Newcastle	Niobrara
WY-1602-009	2283.49	Newcastle	Niobrara
WY-1602-010	2326.31	Newcastle	Niobrara
WY-1602-011	641.03	Newcastle	Niobrara
WY-1602-012	120.00	Newcastle	Niobrara
WY-1602-013	40.00	Newcastle	Niobrara

[1] This list is available on the BLM's website at http://www.blm.gov/style/medialib/blm/wy/programs/energy/og/leasing/2016.Par.21203.File.dat/02list.pdf.

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WY-1602-014	160.00	Newcastle	Goshen
WY-1602-015	600.31	Newcastle	Niobrara
WY-1602-016	2260.73	Newcastle	Niobrara
WY-1602-017	520.00	Newcastle	Niobrara
WY-1602-018	1967.08	Newcastle	Niobrara
WY-1602-019	400.76	Newcastle	Niobrara
WY-1602-020	603.31	Newcastle	Niobrara
WY-1602-021	240.00	Newcastle	Weston
WY-1602-022	236.27	Newcastle	Weston
WY-1602-023	320.69	Newcastle	Weston
WY-1602-024	199.01	Newcastle	Weston
WY-1602-025	40.00	Casper	Converse
WY-1602-026	320.44	Casper	Converse
WY-1602-027	720.35	Casper	Converse
WY-1602-028	40.00	Newcastle	Crook
WY-1602-029	80.00	Newcastle	Crook
WY-1602-030	76.64	Newcastle	Crook
WY-1602-031	360.00	Casper	Converse
WY-1602-032	274.50	Newcastle	Crook
WY-1602-033	283.76	Newcastle	Crook
WY-1602-034	511.97	Casper	Converse
WY-1602-035	80.00	Casper	Converse
WY-1602-036	160.00	Casper	Converse
WY-1602-037	39.47	Casper	Converse
WY-1602-038	240.00	Casper	Converse
WY-1602-039	2377.59	Casper	Natrona
WY-1602-040	2530.03	Casper	Natrona
WY-1602-041	440.00	Casper	Converse
WY-1602-042	1918.73	Casper	Natrona
WY-1602-043	1569.63	Casper	Natrona
WY-1602-044	2240.00	Casper	Natrona
WY-1602-045	2400.00	Casper	Natrona
WY-1602-046	1640.50	Casper	Natrona
WY-1602-047	1840.00	Casper	Natrona
WY-1602-048	720.00	Casper	Natrona
WY-1602-049	2120.00	Casper	Natrona
WY-1602-050	1517.37	Casper	Natrona
WY-1602-051	945.20	Lander	Fremont
WY-1602-052	344.70	Lander	Fremont
WY-1602-053	1268.82	Lander	Fremont
WY-1602-054	1579.68	Lander	Fremont
WY-1602-055	939.92	Lander	Fremont
WY-1602-056	1940.24	Casper/Lander	Fremont
WY-1602-057	384.78	Lander	Fremont

WY-1602-058	40.00	Lander	Fremont
WY-1602-059	2239.12	Lander	Fremont
WY-1602-060	2098.69	Lander	Fremont
WY-1602-061	1480.00	Lander	Fremont
WY-1602-062	1240.00	Lander	Fremont
WY-1602-063	360.00	Lander	Fremont
WY-1602-064	1120.00	Lander	Fremont
WY-1602-065	2400.00	Lander	Fremont
WY-1602-066	1320.00	Lander	Fremont
WY-1602-067	799.32	Lander	Fremont
WY-1602-068	2032.16	Lander	Fremont
WY-1602-069	2490.68	Lander	Fremont
WY-1602-070	1280.00	Lander	Fremont
WY-1602-071	2191.21	Lander	Fremont
WY-1602-072	1600.00	Lander	Fremont
WY-1602-073	160.00	Lander	Fremont
WY-1602-074	280.00	Lander	Fremont
WY-1602-075	640.00	Lander	Fremont
WY-1602-076	465.00	Lander	Fremont
WY-1602-077	480.00	Lander	Fremont
WY-1602-078	240.00	Lander	Fremont
WY-1602-079	200.00	Lander	Fremont
WY-1602-080	280.00	Lander	Fremont
WY-1602-081	2560.00	Lander	Fremont
WY-1602-082	1421.88	Lander	Fremont
WY-1602-083	40.00	Lander	Fremont
WY-1602-084	160.00	Lander	Fremont
WY-1602-085	80.00	Lander	Fremont
WY-1602-086	1460.00	Lander	Fremont
WY-1602-087	2442.68	Lander	Fremont
WY-1602-088	2560.00	Lander	Fremont
WY-1602-089	1688.36	Lander	Fremont
WY-1602-090	720.00	Lander	Fremont
WY-1602-091	1280.00	Lander	Fremont
WY-1602-092	120.00	Lander	Fremont
WY-1602-093	1758.99	Lander	Fremont
WY-1602-094	1240.00	Lander	Fremont
WY-1602-095	1187.82	Lander	Fremont
WY-1602-096	80.00	Lander	Fremont
WY-1602-097	280.00	Lander	Fremont
WY-1602-098	80.90	Lander	Fremont
WY-1602-099	1160.00	Lander	Fremont
WY-1602-100	1200.00	Lander	Fremont
WY-1602-101	1280.00	Lander	Fremont

WY-1602-102	320.00	Lander	Fremont
WY-1602-103	2452.51	Lander	Fremont
WY-1602-104	1905.29	Lander	Fremont
WY-1602-105	2400.00	Lander	Fremont
WY-1602-106	2002.76	Lander	Fremont
WY-1602-107	2160.00	Lander	Fremont
WY-1602-108	80.00	Lander	Fremont
WY-1602-109	763.16	Lander	Fremont
WY-1602-110	1073.33	Lander	Fremont
WY-1602-111	1350.31	Lander	Fremont
WY-1602-112	1280.00	Lander	Fremont
WY-1602-113	2200.00	Lander	Fremont
WY-1602-114	2560.00	Lander	Fremont
WY-1602-115	240.00	Lander	Fremont
WY-1602-116	160.35	Newcastle	Weston
WY-1602-117	72.91	Newcastle	Weston

STATEMENT OF INTEREST

WildEarth Guardians is a nonprofit environmental advocacy organization dedicated to protecting the wildlife, wild places, wild rivers, and health of the American West. On behalf of our members, Guardians has an interest in ensuring the BLM fully protects public lands and resources as it conveys the right for the oil and gas industry to develop publicly owned minerals. More specifically, Guardians has an interest in ensuring the BLM meaningfully and genuinely takes into account the climate implications of its oil and gas leasing decisions and objectively and robustly weighs the costs and benefits of authorizing the release of more greenhouse gas emissions that are known to contribute to global warming.

WildEarth Guardians submitted comments on the BLM's proposed leasing on August 19, 2015. These flagged concerns over the BLM's failure to adequately address the climate impacts of the proposed leasing. As part of these comments, Guardians referenced and attached numerous exhibits. For purposes of this protest, our comments and exhibits are hereby incorporated by reference.

The mailing address for WildEarth Guardians to which correspondence regarding this protest should be directed is as follows:

WildEarth Guardians
1536 Wynkoop, Suite 310
Denver, CO 80202

STATEMENT OF REASONS

WildEarth Guardians protests the BLM's February 2, 2016 oil and gas lease sale over the agency's failure to adequately analyze and assess the climate impacts of the reasonably foreseeable oil and gas development that will result in accordance with the National Environmental Policy Act ("NEPA"), 42 U.S.C. § 4331, *et seq.*, and regulations promulgated thereunder by the White House Council on Environmental Quality ("CEQ"), 40 C.F.R. § 1500, *et seq.*

NEPA is our "basic national charter for protection of the environment." 40 C.F.R. § 1500.1(a). The law requires federal agencies to fully consider the environmental implications of their actions, taking into account "high quality" information, "accurate scientific analysis," "expert agency comments," and "public scrutiny," prior to making decisions. *Id.* at 1500.1(b). This consideration is meant to "foster excellent action," meaning decisions that are well informed and that "protect, restore, and enhance the environment." *Id.* at 1500.1(c).

To fulfill the goals of NEPA, federal agencies are required to analyze the "effects," or impacts, of their actions to the human environment prior to undertaking their actions. 40 C.F.R. § 1502.16(d). To this end, the agency must analyze the "direct," "indirect," and "cumulative" effects of its actions, and assess their significance. 40 C.F.R. §§ 1502.16(a), (b), and (d). Direct effects include all impacts that are "caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a). Indirect effects are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." *Id.* at § 1508.8(b). Cumulative effects include the impacts of all past, present, and reasonably foreseeable actions, regardless of what entity or entities undertake the actions. 40 C.F.R. § 1508.7.

An agency may prepare an environmental assessment ("EA") to analyze the effects of its actions and assess the significance of impacts. *See* 40 C.F.R. § 1508.9; *see also* 43 C.F.R. § 46.300. Where effects are significant, an Environmental Impact Statement ("EIS") must be prepared. *See* 40 C.F.R. § 1502.3. Where significant impacts are not significant, an agency may issue a Finding of No Significant Impact ("FONSI") and implement its action. *See* 40 C.F.R. § 1508.13; *see also* 43 C.F.R. § 46.325(2).

Here, the BLM fell short of complying with NEPA with regards to analyzing and assessing the potentially significant climate impacts of oil and gas leasing. In support of its proposed leasing, the agency prepared two EAs, one for the High Plains District parcels (DOI-BLM-WY-070-EA15-225, hereafter "High Plains EA") and one for parcels in the Wind River and Bighorn Districts (DOI-BLM-WY-R000-2015-0002-EA, hereafter "Wind River-Bighorn EA").[2] In the EAs, however, the BLM failed to analyze the reasonably foreseeable greenhouse

[2] These EAs are available on the BLM's website at http://www.blm.gov/style/medialib/blm/wy/information/NEPA/og/2016/ver1.Par.90542.File.dat/EA_HPD.pdf and http://www.blm.gov/style/medialib/blm/wy/information/NEPA/og/2016/ver1.Par.90459.File.dat/EA_WRBBD.pdf.

gas emissions that would result from selling the oil and gas lease parcels, as well as failed to assess the significance of any emissions, particularly in terms of carbon costs.

In the EAs, the BLM rightfully acknowledges that climate change is a very serious issue and that it is being fueled by the release of human-produced greenhouse gas emissions. *See* EA at 47-52. The BLM acknowledged findings by the Intergovernmental Panel on Climate Change ("IPCC"), stating:

> The IPCC recently concluded that "warming of the climate system is unequivocal" and "most of the observed increase in globally average temperatures sine the mid-20th century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations."

Wind River-Bighorn EA at 3-. Unfortunately, in spite of recognizing these serious climate consequences, the BLM made no effort in the EAs to analyze and assess the reasonably foreseeable greenhouse gas emissions that would result from oil and gas development and the likely climate consequences.

The best the BLM could offer in both EAs was the bizarre assertion that an oil and gas well emits only 0.00059 metric tons of carbon dioxide equivalent ("CO2e") annually. *See* High Plains EA at 51 and Wind River-Bighorn EA at 4-3. Yet reports by the BLM have estimated that, depending on the type of oil and gas well, per well greenhouse gas emissions range from 791 to 3,682 tons of CO2e. *See* Exhibit 1, Kleinfelder, "Air Emissions Inventory Estimates for a Representative Oil and Gas Well in the Western United States," report prepared for Bureau of Land Management (March 25, 2013), available online at https://climatewest.files.wordpress.com/2015/03/blm_oandg_rpt_final_032613_21.pdf. This emission estimates, however, do not account for the reasonably foreseeable emissions that would result from the processing, refining, and ultimate combustion of oil and gas.

Instead of using readily available information and methods, including analyses that other BLM offices have been perfectly capable of preparing, the agency instead asserts that it is simply "impossible" to estimate such emissions. *See* High Plains EA at 51 and Wind River-Bighorn EA at 4-3. The issue, however, is not that it is impossible to estimate emissions, but that BLM believes it cannot estimate emissions as precisely as it prefers to. This is not allowed under NEPA. Although the agency may believe that without definitive development proposals, it cannot project impacts, the whole point of leasing oil and gas is to facilitate development. The BLM cannot claim that the act of leasing carries with it no intention to foster future development. Regardless, because leasing conveys a right to develop, absent any stipulations that provide the agency with authority to constrain or even prevent future development to limit greenhouse gas or climate impacts, the BLM has basis to assert that it is appropriate to wait to conduct its legally required analysis under NEPA, or worse, assert that there would be no reasonably foreseeable emissions associated with its proposed action.

In any case, the BLM has completely failed to provide information and analysis, even brief information and analysis, supporting a FONSI and any decision to sell and issue the

aforementioned lease parcels. Either the BLM must prepare an EIS or it cannot proceed with the lease sale as proposed. Below, we detail how BLM's proposal fails to comply with NEPA.

1. The BLM Failed to Analyze and Assess the Direct, Indirect, and Cumulative Impacts of Greenhouse Gas Emissions that Would Result from Issuing the Proposed Lease Parcels

In the EAs, the BLM completely rejected analyzing and assessing the potential direct and indirect greenhouse gas emissions, including carbon dioxide and methane, that would result from the reasonably foreseeable development of the proposed leases. Although acknowledging that development of the lease parcels would occur and that greenhouse gas emissions would be produced, no analysis of these emissions was actually prepared.

The BLM appears to assert that estimates of emissions are impossible to determine because it is impossible to determinate what reasonably foreseeable development may occur. However, as the agency notes in the EAs, reasonably foreseeable development scenarios have been analyzed for the High Plains, Wind River, and Bighorn Districts. *See* High Plains EA at 48 and Wind River-Bighorn EA at 4-5. In the Casper Field Office, for example, the agency estimated up to 2,642 new oil and gas wells are likely to be developed by 2020. *See* Table below.

Table 15. Total wells projected to be drilled within the Casper Field Office area for the base line and each alternative for the period 2001-2020. The projections of the percent of Federal wells drilled for this period is also presented.

Alternative	Coalbed Gas Wells	Non-coalbed Oil and Gas Wells	Total Wells	Percent Federal
Base Line	700	2,100	2,800	71
Alternative A (No Action)	677	1,965	2,642	69
Alternative B	343	655	998	19
Alternative C	642	1,841	2,483	67
Alternative D	678	1,931	2,609	69
Alternative E	679	1,949	2,628	69

Reasonably Foreseeable Development findings from Casper Reasonably Foreseeable Development Scenario report (hereafter "Casper RFDS"). *See* BLM, "Final Reasonably Foreseeable Development Scenario for Oil and Gas, Casper Field Office" (Feb. 3, 2005) at Table 15, available at www.blm.gov/style/medialib/blm/wy/programs/planning/rmps/casper/docs.Par.27322.File.dat/03_rfd.pdf.

Further, the EAs acknowledge that as a result of past leasing, extensive development has occurred in the High Plains, Wind River, and Bighorn Districts. The BLM explains in the High Plains EA, for example:

> Over the last 10 years including 2010, leasing Federal oil and gas mineral estate has resulted in a total of 13,436 APDs approved in the Buffalo FO, 882 APDs in Casper FO, and 327 APDs in the Newcastle FO. A total of 14,465 APDs have been approved in the HPD over these last ten years for an annual average of 1,465 APDs; 1,344 APDs per year in Buffalo FO, 88 APDs per year in Casper FO and 33 APDs per year in Newcastle FO. As of 2010, there are over 39,000 producing wells in the HPD consisting of: Buffalo FO with over 31,000, Casper FO with over 5,000 and Newcastle FO with over 3,000.

High Plans EA at 48. In this case, although BLM may not know precisely how many wells will be developed, the agency knows that some wells will clearly be developed, and that over the life of the current Resource Management Plans, a certain number of wells are likely to be developed. This cannot support a conclusion that zero wells will be developed, which the BLM appears to advance.

The BLM's position is all the more egregious given that other BLM Field Offices, including, but not limited to, the Four Rivers Field Office in Idaho, the Billings Field Office in Montana, the Miles City Field Office in Montana, the Royal Gorge Field Office in Colorado, and others have not only estimated reasonably foreseeable greenhouse gas emissions associated with the development of oil and gas leases, but clearly do not believe that such information is not "impossible" to analyze under NEPA.

In the Four Rivers Field Office of Idaho, the BLM utilized an emission calculator developed by air quality specialists at the BLM National Operations Center in Denver to estimate likely greenhouse gases that would result from leasing five parcels. *See* Exhibit 2, excerpts from BLM, "Little Willow Creek Protective Oil and Gas Leasing," EA No. DOI-BLM-ID-B010-2014-0036-EA (February 10, 2015) at 41, available online at https://www.blm.gov/epl-front-office/projects/nepa/39064/55133/59825/DOI-BLM-ID-B010-2014-0036-EA_UPDATED_02272015.pdf. Relying on a report prepared in 2013 for the BLM by Kleinfelder, which is attached to this Protest as Exhibit 1, the agency estimated that 2,893.7 tons of carbon dioxide equivalent ("CO_2e") would be released per well. *Id.* at 35. Based on the analyzed alternatives, which projected between 5 and 25 new wells, the BLM estimated that total greenhouse gas emissions would be between 14,468.5 tons and 72,342.5 tons annually. *Id.*

In the Miles City Field Office of Montana, the BLM estimated likely greenhouse gas emissions from development of oil and gas leases. To do so, the agency first calculated annual greenhouse gas emissions from oil and gas activity within the Field Offices. *See* Exhibit 18 to Guardians' August 15, 2015 Comments on the EA at 51. The BLM then calculated total greenhouse gases by assuming that the percentage of acres to be leased within the federal mineral estate of the Field Office would equal the percentage of emissions. *Id.* Although we have concerns over the validity of this approach to estimate emissions (an "acre-based" estimate of emissions is akin to estimating automobile emissions by including junked cars, which has the misleading effect of reducing the overall "per car" emissions), nevertheless it demonstrates that the BLM has the ability to estimate reasonably foreseeable greenhouse gas emissions associated

with oil and gas leasing and that such estimates are valuable for ensuring a well-informed decision.[3]

In the Royal Gorge Field Office of Colorado, the BLM contracted with URS Group Inc. to prepare an analysis of air emissions from the development of seven oil and gas lease parcels. *See* Exhibit 3, URS Group Inc., "Draft Oil and Gas Air Emissions Inventory Report for Seven Lease Parcels in the BLM Royal Gorge Field Office," Prepared for BLM, Colorado State Office and Royal Gorge Field Office (July 2013). This report estimated emissions of carbon dioxide and methane on a per-well basis and estimated the total number of wells that could be developed in these seven parcels. *See* Exhibit 1 at 3 and 5. This report was later supplanted by the Colorado Air Resource Management Modeling Study, or CARMMS, which estimated reasonably foreseeable emissions of greenhouse gases, criteria pollutants, and hazardous air pollutants associated with oil and gas development throughout Colorado, as well as part of New Mexico, and modeled air quality impacts. *See* ENVIRON, "Colorado Air Resource Management Modeling Study (CARMMS) 2021 Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios," Prepared for BLM Colorado State Office (January 2015), available online at http://www.blm.gov/style/medialib/blm/co/information/nepa/air_quality.Par.97516.File.dat/CARMMS_Final_Report_w-appendices_012015.pdf. As part of the CARMMS report, the BLM estimated per well emissions, including greenhouse gas emissions, in tons per year, as follows:

Phase	PM_{10}	$PM_{2.5}$	VOC	CO	NO_X	SO_2	CO_2	CH_4	N_2O	HAP
Conventional Construction	5.21	0.64	0.05	0.23	0.72	0.02	108.1	0.00	0.00	0.01
CBM Construction	3.37	0.44	0.03	0.12	0.36	0.01	56.58	4.06	0.00	0.00
Conventional Production	1.15	0.15	6.67	1.30	0.73	0.00	251.9	17.14	0.00	0.43
CBM Production	2.25	0.25	13.10	1.13	0.62	0.00	181.6	19.05	0.00	1.31

Using these CARMMS estimates, as well as assumptions used in the agency's reasonably foreseeable development scenario analyses, it appears relatively straightforward for the agency to estimate total greenhouse gas emissions, at least on a cumulative basis. For instance, in the Casper Field Office, the agency concluded in 2005 that up to 2,100 new conventional oil and gas wells could be drilled in the area by 2020. *See* Casper RFD at Table 15. 2,100 new wells would amount to 227,010 tons of carbon dioxide for construction (2,100 wells * 108.1 tons of CO_2) and 528,990 tons/year for production (2,100 wells * 251.9 tons/year).

Although the BLM may assert that such information is not possible to analyze, there is no basis for such a claim. Not only has the agency estimated reasonably foreseeable development and disclosed in the EAs that greenhouse gas emissions are a likely reasonably foreseeable

[3] In addition to the Miles City Field Offices, the BLM estimated greenhouse gas emissions associated with oil and gas leasing in the Billings, Butte, and Dillon Field Offices.

consequence of issuing the leases, but using the agency's own logic, this would mean that any analysis of future environmental impacts would be incredibly uncertain. Of course, this would completely undermine NEPA's mandate that significance be based on "uncertain[ty]." 40 C.F.R. § 1508.27(b)(5). Indeed, if the climate impacts of oil and gas leasing are, as the BLM asserts, so uncertain, then an EIS is justified. As CEQ states, whether or not impacts are significant, and therefore trigger the need to prepare an EIS, are based on whether impacts are "highly uncertain or involve unique or unknown risks." *Id.* The BLM cannot summarily dismiss significant issues, such as climate change, on the basis of uncertainty without assessing whether this uncertainty necessitates preparation of an EIS.

Regardless, the agency's arguments in the EAs are belied by the fact that, as just discussed, other BLM Field Offices clearly believe that an analysis of reasonably foreseeable greenhouse gas emissions is not only reasonable, but also possible and useful.

Adding to the shortcomings in the EAs is that the BLM failed to analyze the cumulative impacts of greenhouse gas emissions from past, present, and reasonably foreseeable oil and gas development. As noted above, other BLM Field Offices, including several Montana Field Offices, have analyzed the likely greenhouse gas emissions that would result based on the BLM's own reasonably foreseeable development scenarios. *See e.g.* Exhibit 18 to Guardians' August 15, 2015 EA Comments at 51. In Colorado, the BLM estimated the likely greenhouse gas emissions that would result from the reasonably foreseeable development projected in each field office. *See* Exhibit 4, BLM, "CARMMS GHG Emissions," available online at http://www.blm.gov/style/medialib/blm/co/information/nepa/air_quality.Par.54983.File.dat/CARMMS%20GHG%20Data.xlsx. In this case, the BLM has not made any attempt to estimate greenhouse gas emissions that would result from oil and gas development likely to occur under the agency's reasonably foreseeable development scenarios for any Field Office in the High Plains, Wind River, or Bighorn Districts.

In both EAs, BLM appears to insinuate that greenhouse gas emissions from reasonably foreseeable oil and gas development would simply be insignificant, for example asserting that a single well would only emit 0.00059 metric tons of CO2e annually. This assertion, however, defies the required scope of the BLM's analysis. Under NEPA, an agency must analyze the impacts of "similar" and "cumulative" actions in the same NEPA document in order to adequately disclose impacts in an EIS or provide sufficient justification for a FONSI in an EA. *See* 40 C.F.R. §§ 1508.25(a)(2) and (3). Here, the BLM was required to at least take into account the greenhouse gas emissions resulting from other proposed oil and gas leasing in Wyoming, if not beyond, as well as related oil and gas development, and to analyze the impacts of these actions in terms of their direct, indirect, and cumulative impacts. At a minimum, it would appear the BLM was required to analyze the impacts of leasing in the High Plains, Wind River, and Bighorn Districts in a single NEPA document. The failure to conduct such an analysis underscores that FONSIs are not warranted.[4]

[4] It also indicates the BLM may be inappropriately piecemealing, or segmenting, its analysis under NEPA.

The failure to address cumulative greenhouse gas emissions is made worse by the fact that the underlying Final EISs prepared for the Lander, Newcastle, and Casper Field Offices' Resource Management Plans nowhere analyze or assess greenhouse gas emissions associated with oil and gas development. In light of this, the BLM clearly has no basis to conclude that greenhouse gas emissions resulting from the reasonably foreseeable impacts of oil and gas development associated with the proposed leasing would not be significant. Without any analysis of cumulative greenhouse emissions whatsoever, the agency's proposed FONSIs are unsupported under NEPA.

The BLM finally attempts to argue that an analysis of greenhouse gas emissions is more appropriate at the drilling stage. We have yet to see the BLM actually prepare such a site-specific analysis in conjunction with an oil and gas lease development proposal. As WildEarth Guardians pointed out in its comments, no such analysis is ever conducted by the BLM. *See* Exhibits 7 and 8 to Guardians' August 15, 2015 Comments. What's more, this argument has no merit as the agency has proposed no stipulations that would grant the BLM discretion to limit, or outright prevent, development of the proposed leases on the basis of greenhouse gas emissions and/or climate concerns. The BLM is effectively proposing to make an irreversible commitment of resources, which is the hallmark of significance under NEPA. *See* 42 U.S.C. § 4332(c)(v) and 40 C.F.R. § 1502.16. The failure to prepare an EIS—or any analysis for that matter—for the proposed leases is therefore contrary to NEPA.

2. The BLM Failed to Analyze the Costs of Reasonably Foreseeable Carbon Emissions Using Well-Accepted, Valid, Credible, GAO-Endorsed, Interagency Methods for Assessing Carbon Costs that are Supported by the White House

Compounding the failure of the BLM to make any effort to estimate the greenhouse gas emissions that would result from reasonably foreseeable oil and gas development is that the agency also rejected analyzing and assessing these emissions in the context of their costs to society. It is particularly disconcerting that the agency refused to analyze and assess costs using the social cost of carbon protocol, a valid, well-accepted, credible, and interagency endorsed method of calculating the costs of greenhouse gas emissions and understanding the potential significance of such emissions.

The social cost of carbon protocol for assessing climate impacts is a method for "estimat[ing] the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year [and] represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction)." Exhibit 13 to Guardians' August 15, 2015 EA Comments. The protocol was developed by a working group consisting of several federal agencies, including the U.S. Department of Agriculture, EPA, CEQ, and others, with the primary aim of implementing Executive Order 12866, which requires that the costs of proposed regulations be taken into account.

In 2009, an Interagency Working Group was formed to develop the protocol and issued final estimates of carbon costs in 2010. These estimates were revised in 2013 by the Interagency Working Group, which at the time consisted of 13 agencies, including the Department of

Agriculture, and again revised in 2015. *See* Exhibit 16 to Guardians' August 15, 2015 EA Comments.

Depending on the discount rate and the year during which the carbon emissions are produced, the Interagency Working Group estimates the cost of carbon emissions, and therefore the benefits of reducing carbon emissions, to range from $10 to $212 per metric ton of carbon dioxide. *See* Chart Below. In July 2014, the U.S. Government Accountability Office ("GAO") confirmed that the Interagency Working Group's estimates were based on sound procedures and methodology. *See* Exhibit 19 to Guardians' August 15, 2015 EA Comments.

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

Most recent social cost of carbon estimates presented by Interagency Working Group on Social Cost of Carbon. The 95th percentile value is meant to represent "higher-than-expected" impacts from climate change.

Although often utilized in the context of agency rulemakings, the protocol has been recommended for use and has been used in project-level decisions. For instance, the EPA recommended that an EIS prepared by the U.S. Department of State for the proposed Keystone XL oil pipeline include "an estimate of the 'social cost of carbon' associated with potential increases of GHG emissions." Exhibit 17 to Guardians' August 15, 2015 EA Comments.

More importantly, the BLM has also utilized the social cost of carbon protocol in the context of oil and gas leasing. In recent Environmental Assessments for oil and gas leasing in Montana, the agency estimated "the annual SCC [social cost of carbon] associated with potential development on lease sale parcels." Exhibit 18 to Guardians' August 15, 2015 EA Commentsat 76. In conducting its analysis, the BLM used a "3 percent average discount rate and year 2020 values," presuming social costs of carbon to be $46 per metric ton. *Id.* Based on its estimate of greenhouse gas emissions, the agency estimated total carbon costs to be "$38,499 (in 2011 dollars)." *Id.* In Idaho, the BLM also utilized the social cost of carbon protocol to analyze and assess the costs of oil and gas leasing. Using a 3% average discount rate and year 2020 values, the agency estimated the cost of carbon to be $51 per ton of annual CO_2e increase. *See* Exhibit 2 at 81. Based on this estimate, the agency estimated that the total carbon cost of developing 25 wells on five lease parcels to be $3,689,442 annually. *Id.* at 83.

To be certain, the social cost of carbon protocol presents a conservative estimate of economic damages associated with the environmental impacts climate change. As the EPA has

noted, the protocol "does not currently include all important [climate change] damages." Exhibit 13 to Guardians' August 15, 2015 EA Comments. As explained:

> The models used to develop [social cost of carbon] estimates do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research.

Id. In fact, more recent studies have reported significantly higher carbon costs. For instance, a report published this month found that current estimates for the social cost of carbon should be increased six times for a mid-range value of $220 per ton. *See* Exhibit 15 to Guardians' August 15, 2015 EA Comments at 2. In spite of uncertainty and likely underestimation of carbon costs, nevertheless, "the SCC is a useful measure to assess the benefits of CO2 reductions," and thus a useful measure to assess the costs of CO2 increases. Exhibit 13 to Guardians' August 15, 2015 EA Comments.

That the economic impacts of climate change, as reflected by an assessment of social cost of carbon, should be a significant consideration in agency decisionmaking, is emphasized by a recent White House report, which warned that delaying carbon reductions would yield significant economic costs. *See* Exhibit 5, Executive Office of the President of the United States, "The Cost of Delaying Action to Stem Climate Change" (July 2014), available online at https://www.whitehouse.gov/sites/default/files/docs/the_cost_of_delaying_action_to_stem_climate_change.pdf. As the report states:

> [D]elaying action to limit the effects of climate change is costly. Because CO_2 accumulates in the atmosphere, delaying action increases CO_2 concentrations. Thus, if a policy delay leads to higher ultimate CO_2 concentrations, that delay produces persistent economic damages that arise from higher temperatures and higher CO_2 concentrations. Alternatively, if a delayed policy still aims to hit a given climate target, such as limiting CO_2 concentration to given level, then that delay means that the policy, when implemented, must be more stringent and thus more costly in subsequent years. In either case, delay is costly.

Exhibit 5 at 1.

The requirement to analyze the social cost of carbon is supported by the general requirements of NEPA, specifically supported in federal case law, and by Executive Order 13,514. As explained, NEPA requires agencies to analyze the consequences of proposed agency actions and consider include direct, indirect, and cumulative consequences. In terms of oil and gas leasing, an analysis of site-specific impacts must take place at the lease stage and cannot be deferred until after receiving applications to drill. *See New Mexico ex rel. Richardson v. Bureau of Land Management*, 565 F.3d 683, 717-18 (10th Cir. 2009); *Conner v. Burford,* 848 F.2d 1441 (9th Cir.1988); *Bob Marshall Alliance v. Hodel,* 852 F.2d 1223, 1227 (9th Cir.1988).

To this end, courts have ordered agencies to assess the social cost of carbon pollution, even before a federal protocol for such analysis was adopted. In 2008, the U.S. Court of Appeals for the Ninth Circuit ordered the National Highway Traffic Safety Administration to include a monetized benefit for carbon emissions reductions in an Environmental Assessment prepared under NEPA. *Center for Biological Diversity v. National Highway Traffic Safety Administration*, 538 F.3d 1172, 1203 (9th Cir. 2008). The Highway Traffic Safety Administration had proposed a rule setting corporate average fuel economy standards for light trucks. A number of states and public interest groups challenged the rule for, among other things, failing to monetize the benefits that would accrue from a decision that led to lower carbon dioxide emissions. The Administration had monetized the employment and sales impacts of the proposed action. *Id.* at 1199. The agency argued, however, that valuing the costs of carbon emissions was too uncertain. *Id.* at 1200. The court found this argument to be arbitrary and capricious. *Id.* The court noted that while estimates of the value of carbon emissions reductions occupied a wide range of values, the correct value was certainly not zero. *Id.* It further noted that other benefits, while also uncertain, were monetized by the agency. *Id.* at 1202.

More recently, a federal court has done likewise for a federally approved coal lease. That court began its analysis by recognizing that a monetary cost-benefit analysis is not universally required by NEPA. *See* High *Country Conservation Advocates v. U.S. Forest Service*, ---F. Supp.2d---, 2014 WL 2922751 (D. Colo. 2014), citing 40 C.F.R. § 1502.23. However, when an agency prepares a cost-benefit analysis, "it cannot be misleading." *Id.* at 3 (citations omitted). In that case, the NEPA analysis included a quantification of benefits of the project. However, the quantification of the social cost of carbon, although included in earlier analyses, was omitted in the final NEPA analysis. *Id.* at p. 19. The agencies then relied on the stated benefits of the project to justify project approval. This, the court explained, was arbitrary and capricious. *Id.* Such approval was based on a NEPA analysis with misleading economic assumptions, an approach long disallowed by courts throughout the country. *Id.* at pp. 19-20.

A recent op-ed in the New York Times from Michael Greenstone, the former chief economist for the President's Council of Economic Advisers, confirms that it is appropriate and acceptable to calculate the social cost of carbon when reviewing whether to approve fossil fuel extraction. *See* Exhibit 6, Greenstone, M., "There's a Formula for Deciding When to Extract Fossil Fuels," *New York Times* (Dec. 1, 2015), available online at http://www.nytimes.com/2015/12/02/upshot/theres-a-formula-for-deciding-when-to-extract-fossil-fuels.html?_r=0 (last accessed Dec. 15, 2015).

In light of all this, it appears more than reasonable to have expected the BLM to take into account carbon costs as part of its NEPA analyses. The agency did not. Instead, the BLM rejected the notion that a social cost of carbon analysis was appropriate, implicitly concluding that there would be no cost associated with the proposed oil and gas leasing.

In response to Guardians' comments on the EAs, the BLM reiterated its position that it is impossible to analyze the reasonably foreseeable greenhouse gas emissions associated with the proposed leasing. As explained earlier, there is no support for this assertion. Further, absent any stipulations that would retain discretion for the BLM to reject future drilling proposals, the agency lacks any authority or ability to meaningfully limit future emissions to address carbon

costs. At a minimum, any claimed uncertainty associated with greenhouse gas emissions simply means the proposed leasing poses significant impacts to the environment and that the BLM was required to prepare an EIS.

The fact that the BLM has, in the context of other oil and gas lease sale environmental analyses, clearly acknowledged that social cost of carbon analyses are appropriate, useful, and possible, the refusal of the agency to similarly undertake such analyses in the context of the High Plains and Wind River-Bighorn EAs is unsupported under NEPA and cannot stand to support the decision to offer the aforementioned lease parcels for sale and issuance in February 2016.

Sincerely,

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Exhibit 1

KLEINFELDER

AIR EMISSIONS INVENTORY ESTIMATES for a REPRESENTATIVE OIL and GAS WELL in the WESTERN UNITED STATES

March 25, 2013

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March 25, 2013

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1 EXECUTIVE SUMMARY

The Bureau of Land Management National Operations Center (BLM NOC) retained the Kleinfelder Team (which consists of staff from Kleinfelder, Inc. and ENVIRON International Corporation) to prepare an emissions inventory estimate of criteria pollutants, greenhouse gases (GHG), and key hazardous air pollutants (HAPs) for a representative oil and gas well in the western United States (US). The emissions inventory is designed to be used by BLM staff, such as NEPA planners, air resource specialists, and natural resource specialists, to evaluate emissions from small, which for purposes of this inventory is approximately five wells or less, oil and gas projects.

Defining a "representative" oil and gas well for the entire western US is extremely challenging as there are numerous variables, even within a single basin and sub basin that can materially affect the emissions. Such variables include oil and gas composition, difficulty drilling the geologic formation, oil and gas production rate, equipment at the well site, emission controls, produced water that may be associated with oil and gas production, among many others. Accordingly, to develop such an inventory, five different well types (three natural gas wells and two oil wells) representative of five different major oil and gas basins in the western US were evaluated. Figure 1-1, located at the end of this section, shows the major oil and gas producing basins in the western US. In order to develop the emission inventories, information that is not proprietary, not draft, and not pre-decisional was reviewed for the five selected basins plus other oil and gas developments in the western US. The information sources are discussed in Section 2 of this report. The characteristics of the five basins selected are similar to a large portion of the oil and gas produced in the western United States. The five well types and key characteristics are shown Table 1-1 on the next page.

An Excel workbook that provides the detailed and summary of the emission estimates was prepared. The Workbook is interactive, allowing the user to choose one of the five well types based on basin characteristics for the project of interest. Once the well type is selected, the Excel Workbook is automatically populated with the key variables. The electronic version of the Excel Workbook is included as Appendix A. Appendices B through F include printouts of the Excel Workbook for each of the five well types. Table 1-2 presents the summary emission inventory estimate results. Except for sulfur dioxide (SO_2), ethylbenzene, and nitrous oxide

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(N_2O), the values in Table 1-2 are rounded to one decimal place. Global warming potential (GWP) is rounded to a whole number. The number of significant figures shown in Table 1-2 varies as the quantity of individual pollutants is highly variable. For example, SO_2 emissions are reported to only one significant figure because the emissions are on the order of one ten thousandth of a ton per year. But GWP is reported to 5 significant figures because emissions are in the thousands of tons per year.

TABLE 1-1
CHARACTERISTICS OF SELECTED REPRESENTATIVE BASINS

Product	Basin	Key Characteristics
Gas well	Uinta/Piceance	Deep wells which may include shale, dry gas, moderate condensate production
Gas well	Upper Green River	Deep wells, multiple devices per well, high condensate production, wet gas
Gas well	San Juan	Shallow wells, low amounts of condensate production, dry gas
Oil well	Williston	Shale formation, very deep wells, long horizontal drilling, high amounts of associated gas, associated gas flared
Oil well	Denver	Shallow wells, lower amounts of associated gas, associated gas sent to a sales line

TABLE 1-2
SUMMARY OF EMISSION ESTIMATES FOR A SINGLE OIL OR GAS WELL

Well Type:	Gas	Gas	Gas	Oil	Oil
Pollutant	Uinta/ Piceance (tpy)	Upper Green River (tpy)	San Juan (tpy)	Williston (tpy)	Denver (tpy)
NOx	15.6	14.6	5.6	15.6	6.3
CO	3.8	3.9	3.1	8.0	3.4
VOC	3.4	5.2	5.3	17.6	6.7
SO_2	0.0004	0.0004	0.001	0.001	0.001
PM_{10}	6.9	6.7	6.8	6.9	6.6
$PM_{2.5}$	0.8	0.8	0.5	0.8	0.5
CO_2	2,552.1	2,882.1	651.9	3,156.4	1,049.0
CH_4	12.2	14.1	6.1	16.6	1.8
N_2O	0.05	0.05	0.04	0.6	0.04
GWP	2,825	3,194	791	3,682	1,099
Benzene	1.4	1.5	1.4	1.5	1.4
Toluene	1.0	1.2	1.0	1.0	1.0
Ethylbenzene	0.00003	0.01	0.0008	0.0008	0.0006
Xylene	0.6	0.7	0.6	0.6	0.6
n-Hexane	7.5	7.5	7.5	7.9	7.5
Total HAPs	10.4	10.9	10.5	11.0	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported. Greenhouse gas emissions are in terms of short tons CO_2, CH_4, and N_2O. Global Warming Potential (GWP) is in terms of short tons of CO_2 equivalent (CO_2e), using a GWP of 1 for CO_2, 21 for CH_4, and 310 for N_2O.

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Emission estimates can be calculated as annual average emissions, worst-case single year emissions, or some other scenario. The various methods of representing emissions are problematic since a project could involve simultaneous construction and development (drilling and fracturing) and operation (production) in the same location, which is further complicated since well production is not a constant. Therefore, the worst-case emission estimate is to assume that construction, development, and operation occur simultaneously as shown in Table 1-2. If the user is interested in maximum operation-only emissions, then the tables in Section 3.3 of this report can be consulted where emissions from the three activities are reported separately.

As discussed in Sections 3.2.5 and 3.2.6 of this report, the emission calculations do not account for the fact that over time oil and gas well production rates decrease, i.e., the decline curve or decline factor. If one wanted a life-time average emission rate for production operations, a decline factor would have to be applied to the emission estimates in the tables of this report. To estimate lifetime average emissions, one can assume that operational emissions are linearly related to production and thus a linear application of the decline factor to the emissions can be used (i.e., if the decline factor is 50 percent, the lifetime average emissions would be 50 percent of those presented herein for operation). Note that the decline factor is not applied to construction or drilling emissions.

The electronic version of the Excel Workbook in Appendix A allows the user to enter project-specific variables that will over-ride the default values incorporated into the Workbook. Project variables are entered into a single "Constants and References" tab in the Workbook, and the changes automatically populate the remaining tabs and calculations. (The user should not enter the over-ridden value directly into the individual emission calculation sheets, but rather into the "Constants and References" sheet.)

In this document, the emission estimates are reported as a single value for each pollutant and well type rather than a range of values. However, Section 3 presents the range of key parameters evaluated and the basis for the selected single parameter. If the user wants to consider a range of emission estimates for a specific project, the range of key parameters shown in Section 3 or any other range of parameters can be entered into the Excel Workbook and a range of emission estimates easily generated.

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The remaining sections of this report describe the methodology, references, and regulatory analyses used to develop the emission estimates in Section 2. Section 3 presents the parameters selected and results of the emission inventories. Sections 4 and 5 present conclusions and limitations. Section 6 provides a list of references used in the study.

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Oklahoma, and Kansas. In concert with BLM (Mr. Dave Maxwell of the National Operations Center), it was decided that neither California nor Alaska would be included in the project and that the focus would be only on conventional and shale oil and gas (e.g., coal bed methane was excluded). There is relatively little active oil and gas BLM land in California and Alaska has its own program for developing emission inventories and thus were excluded. It was also decided that Texas, Oklahoma, and Kansas would be excluded as well-specific information for wells in these basins tends to be proprietary to the operators. Although some information is available from state permit applications for wells, many of the activities that occur do not need a state permit or do not need a complete emissions inventory. Thus complete information for emissions inventories is not readily available. In addition, there is relatively less BLM controlled oil and gas lands in these Basins. Although the inventory can probably be used with relative confidence in Texas, Oklahoma, Kansas, or California if needed, it should not be used in Alaska because of the unique environment in that area.

For the remaining states, the major producing basins within which there is a relatively large amount of public land are the Williston, Upper Green River, Uinta, Piceance, Denver, San Juan, and Permian basins. These basins are responsible for a large portion of the oil and gas production in the western US that occurs on public lands. The Uinta and Piceance Basins are next to each other and have similar oil and gas geologic formation and production characteristics. Therefore, for purposes of the emission inventories, the Uinta and Piceance Basins were combined. The Permian Basin is also a major producing basin in southeast New Mexico and west Texas. Although this is a major basin, most of the development in Texas is on non-BLM land, and in New Mexico, BLM has already developed an emissions calculator for the Permian Basin. Therefore, the Permian basin was also excluded from this study. A map of the key oil and gas basins is shown in Figure 1-1 and a more detailed map is available from the US Energy Information Administration (EIA, 2013).

Therefore, the basins that were evaluated for this study are the Williston, Upper Green River, Uinta/Piceance, Denver, and San Juan. The Williston and Denver Basins are primarily oil plays, while the Upper Green River, Uinta/Piceance, and San Juan Basins are primarily natural gas plays. This does not mean that there could not be oil wells in the Upper Green River, Uinta/Piceance, or San Juan Basins or gas wells in the Williston and Denver Basins. But for purposes of the emission inventories, the representative wells were selected based on the primary play of that basin.

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The key characteristics of the basins that are relevant for purposes of the emissions inventory are as follows. These characteristics are extremely generalized and actual conditions vary widely even within the same basin.

- Uinta/Piceance. Gas wells in this basin may or may not be drilled into a shale formation, but tend to be deep wells (on the order of 15,000 feet), are difficult to drill, and drill rigs are on a single well pad for a relatively long duration. There is not much water present in the gas, so no dehydrators are normally required at the well site. The gas wells produce a moderate amount of condensate (light oil). Equipment at the well site tends to be simple, with a single separator and a condensate tank. Although there are compressors used in the Basin to move gas to market, the compressors are not at well sites and are not included in the emission inventories.

- Upper Green River. Gas wells in the Upper Green River Basin also tend to be deep (on the order of 15,000 feet) but are drilled into non-shale formations. The gas tends to have more condensate (oil) present than either the San Juan or Uinta/Piceance Basins. There is more water vapor present in the gas from this Basin than others, so there normally is a dehydrator at each well site. The well sites also usually contain a separator and line heater. Wells are drilled at a relatively high density. There are gas compressors in the Basin used to move the gas to market. However, these compressors are not located at a well site.

- San Juan. Some gas wells in the San Juan basin may contain relatively high volumes of liquid water and thus pumpjack engines may be present (to remove the water) even though the wells are gas wells. San Juan gas wells produce relatively little condensate, thus there may not be any condensate tanks present. The wells tend to be shallow (on the order of 5,000 feet) and there is a minimal amount of equipment on site. For purposes of this study, the emission inventory includes a pumpjack engine and a condensate tank, even though they may not be present at all San Juan well types. As is the case for the Upper Green River Basin, gas compressors are used in the Basin, but are not generally located at a well site.

- Williston. Oil wells in the Williston Basin tend to be very deep (on the order of 15,000 to 18,000 feet), and are drilled into a shale formation that is difficult to drill, thus drill rigs are

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on site for a relatively long time. Horizontal drilling in the Williston Basin can be very long, on the order of a mile or more away from the well pad. The Williston formation is relatively very thin, and thus precise drilling is required. There is a relatively large amount of gas associated with the oil wells, and the gas may be flared in a flare pit for a period of time before it can be sent to a sales line.

- Denver. The Denver Basin is the easiest to drill, with relatively shallow wells (on the order of 5,000 feet deep) in non-shale formations. There are relatively low amounts of gas associated with the oil wells and that gas is sent to a sales line. The Denver Basin oil tends to be lighter than the Williston Basin.

Note that the oil and gas wells in these basins tend to be sweet wells (i.e., there is no or very little hydrogen sulfide associated with the wells). However, any of the wells in any of the basins could be sour wells with relatively large amounts of hydrogen sulfide (H_2S). For purposes of the emissions inventory, it was assumed that the wells were all sweet wells with no H_2S. However, if it is known that the project-specific wells are not sweet wells, then a project-specific H_2S concentration can be input in the Excel Workbook and the Workbook will calculate potential H_2S emissions. If the amount of H_2S is significant, the project may be required to install H_2S emission controls (e.g., a sweetening unit). The effectiveness of a sweetening unit and emissions from it are beyond the scope of this study, but would have to be accounted for in an emissions inventory if present. Since H_2S can be an important issue, the Excel Workbook will calculate emissions of it, even though it is not a criteria pollutant or a HAP. The Excel Workbook also accounts for emissions of SO_2 from combustion of gas if the gas contains H_2S.

2.2. LITERATURE AND REFERENCES

Once the basins were selected, several sources of information were consulted in order to determine representative emission calculation parameters. Generally accepted emission estimating techniques published by the USEPA were used for the emission calculations. However, those techniques require a number of parameters in order to yield emissions. The parameters were obtained from NEPA documents, RMPs, air permits to construct, and professional judgment. USEPA publications are peer reviewed and generally accepted for emission estimating techniques. On the other hand, individual parameters needed to calculate the emissions are not generally available in peer reviewed literature, but are detailed in the NEPA documents, RMPs, and permits to construct. Those major documents used for this

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study, although not from scientific peer reviewed journals, were subjected to extensive stakeholder, state, and cooperating agency reviews. Therefore, those publications are suitable as the source of key oil and gas parameters needed for calculating emissions. Section 3 of this report discusses the key parameters and the source of the parameters selected, and Section 6 presents a list of references. The key sources of information for each of the basins are summarized below:

- Uinta/Piceance: Greater Natural Buttes EIS (BLM, 2012a), GASCO EIS (BLM, 2011b), White River RMP (BLM, 2012b), and the Colorado River Valley RMP (BLM, 2011a).
- Upper Green River: Jonah Infill EIS (BLM, 2006), Supplemental FEIS for the Pinedale Anticline (BLM, 2008), Wyoming air permits to construct
- San Juan: Farmington RMP (BLM, 2003)
- Williston. North Dakota air permits to construct and experience with the basin.
- Denver: Colorado air permits to construct and experience with the basin

As indicated, the above references are not the only literature sources used to select representative parameters, and the parameters in these sources were not used without judgment. In other words, the parameters contained in the above publications were evaluated and a representative value chosen based on professional judgment. No attempt was made to perform a statistical analysis of the parameters or choose an average or median from the references. The focus was on selecting representative parameters typical for the well type, not an average, or a conservative "worst case" value. The results of the parameter selection and the basis for the selection are discussed in Section 3 of this report. The equations and emission models used to estimate emissions are shown in the Appendices. The equations and models are those promulgated by the USEPA in such publications as AP-42, *Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* (USEPA, 2013).

The specific references examined and the source of those references is listed below. Each of the key references has been assigned an abbreviation which is shown below in quotes, and which is used throughout the remainder of this report. The specific information obtained and used from each reference is discussed in Section 3 of this report.

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- "NDDEQ": Well site air quality permit to construct applications filed and approved for Helis Oil and Gas Company, LLC (3 sites), Prima Exploration, Inc. (2 sites), Samuel Gary Jr. and Associates, Inc. (2 sites) and G3 Operating, Inc. (3 sites). Available through a public records request to the North Dakota Department of Environmental Quality.
- "CDPHE": Ten well site air quality permits to construct applications filed and approved for Bayswater Exploration and Production, LLC. Available through a public records request to the Colorado Department of Health and Environment Air Pollution Control Division.
- "WYDEQ": Well site air quality permit to construct applications filed and approved for Helis Oil and Gas Company, LLC (4 sites), Enduro Operating, LLC (2 sites), and Samson Oil and Gas Ltd. (6 sites) Available through a public records request to the Wyoming Department of Environmental Quality Air Quality Division.
- "Farmington RMP": Farmington Resource Management Plan and Final Environmental Impact Statement, March 2003 (BLM, 2003).
- "White River": White River Field Office Oil and Gas Resource Management Plan Amendment / Environmental Impact Statement Air Resources Technical Support Document, June 2012 (BLM, 2012b).
- "Jonah": Final Air Quality Technical Support Document for the Jonah Infill Drilling Project Environmental Impact Statement, January, 2006 (BLM, 2006).
- "Pinedale": Supplemental Final Environmental Impact Statement for the Pinedale Anticline Project Area, June, 2008 (BLM, 2008).
- "CRV": Final Colorado River Valley Field Office Resource Management Plan Revision, Air Resources Technical Support Document, Revised August 2011 (BLM, 2011a).
- "GNB". Greater Natural Buttes Final Environmental Impact Statement, FES 12-8, March 2012 (BLM, 2012a).
- "GASCO": Final Environmental Impact Statement (EIS) for the GASCO Uinta Basin Natural Gas Development Project, 2011 (BLM, 2011b).

Note that the above documents are mostly BLM publications. Although other publications were also evaluated, such as EISs published by the Bureau of Indian Affairs (BIA 2012a, BIA 2012b), because most of the public lands with oil and gas resources are in the western US and are controlled by BLM, the BLM EIS and RMP publications tend to be the most detailed and useful for this study.

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The above publications and references provided project-specific detail and calculations for individual well activities, and thus were the most useful. There are other publications and information sources that were also reviewed, such as the Western Regional Air Partnership (WRAP) emissions databases (WRAP, 2013), the West-wide Jumpstart Air Quality Modeling Study (WRAP, 2013), the USEPA National Emissions Inventory (USEPA, 2013), and the USEPA Greenhouse Gas Reporting Program (GHGRP) emissions inventories (USEPA, 2011). However, these databases and information sources provide emissions on a facility-wide, company-wide, or regional basis and do not provide individual well-specific information suitable for use in the emissions inventories which are the subject of this study. On the other hand, the information in those databases were evaluated and compared to the emission estimating techniques and parameters used in this study as an overall confirmation that the individual well inventories are consistent with the facility and company-wide data and that consistent emission estimating techniques were used.

In addition to the above publications and permit applications, state regulations for the western US that could affect the emission inventories were also reviewed. This review is discussed in Section 2.5 of this report.

2.3. EMISSION CALCULATIONS

The parameters selected from the above references and professional judgment were then input into an Excel Workbook in order to calculate the emissions for each of the five representative basins. The Excel Workbook is contained in Appendix A, hard copies for each basin are shown in Appendices B through F, and a discussion of the key parameters and reason for selection is presented in Section 3 of this report. The Appendices also present the equations, emission models, and emission factors used to calculate the emissions and details for each of the individual emitting activities.

2.4. QUALITY CONTROL/QUALITY ASSURANCE OF THE EMISSION CALCULATIONS

As the Appendices show, the emission calculations involve a large number of activities, a large number of emission estimating techniques and parameters, and the parameters vary by well type. Quality Control/Quality Assurance (QC/QA) of the spreadsheets was conducted through

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independent (i.e., Kleinfelder Team staff who were not involved in the initial calculations) review of the estimating techniques, the parameters chosen, application of the parameters, and the emission calculations. The equations in the Excel Workbook were subjected to hand-calculation to confirm the value calculated electronically. Visual inspection was used to confirm population of the variables from the "Constants and References" tab of the Workbook throughout the appropriate equations. Selection of emission parameters for each well type was reviewed by engineers familiar with oil and gas operations but who were not involved in the initial selection. Finally, the emission totals were compared to other emission totals from other publications and projects to confirm representativeness.

2.5. STATE AND FEDERAL REGULATIONS

The final step was to evaluate state and federal regulations that could affect the emission calculations for isolated wells which are the subject of this study. For example, the new New Source Performance Standard (NSPS) for oil and gas production (40 CFR Part 60 Subpart OOOO) requires emission controls on condensate/oil tanks if the uncontrolled emissions are greater than 6 tons per year. In parallel with the NSPS, there are also National Emission Standards for Hazardous Air Pollutants (NESHAPs) that could apply to oil and gas wells, e.g., 40 CFR 63 Subpart HH.

The regulations evaluated and how they affect the emission calculations are summarized below. Only those portions of the regulations that could change the emissions inventory for the situation where there are a few isolated wells are noted. There are numerous federal and state regulatory requirements that could apply to large stationary and mobile sources or groups of sources, but it is beyond the scope of this study to present all of those regulatory requirements.

2.5.1. Federal NSPS

The primary federal regulation that affects individual wells is the NSPS for the Oil and Gas Sector (40 CFR 60 Subpart OOOO). Subpart OOOO (and 40 CFR 60 Subpart VVa which is referenced by Subpart OOOO as a requirement) could affect well emissions through the following requirements:

- The NSPS requires control of flowback emissions (associated natural gas) that could occur during the hydraulic fracturing process. Therefore, in this study it was assumed

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that hydraulic fracturing flowback emissions during well development would be controlled to the 95 percent level. However Subpart OOOO does not require control of flowback emissions during workovers, and thus no control during workovers was assumed.

- All storage tanks for oil or condensate are required to be controlled with a minimum of 95 percent efficiency if the uncontrolled VOC emissions are more than 6 tons per year. For the wells evaluated in this study, the storage tank VOC emissions from wells in all of the Basins except the San Juan were assumed to have uncontrolled emissions greater than 6 tons per year, and were controlled. (As discussed in Section 2.4.3, storage tanks in the Denver Basin are required to be controlled with a minimum of 70 percent efficiency even if uncontrolled emissions are less than 6 tons per year. However, in this study, uncontrolled VOC emissions for the Denver Basin oil well are greater than 6 tons per year, and the Subpart OOOO requirement of 95 percent control was applied to the Denver Basin well type).
- The NSPS requires, beginning October 15, 2013, that all pneumatic controllers on new wells emit less than 6 standard cubic feet per hour (scf/hr) of natural gas (generally termed "low bleed" pneumatics) unless high bleed pneumatic controllers are required for safety or other justifiable operational requirements. Accordingly, for purposes of the emission inventory, it was assumed that all pneumatic controllers were low-bleed. Other pneumatic devices (e.g. dump valves and pumps) do not have the low bleed requirement.

The second NSPS affecting emissions from single well sites is the NSPS for stationary spark ignition reciprocating engines, 40 CFR 60 Subpart JJJJ. This NSPS only applies to the pumpjack engines in the emissions inventory as the other engines are either not stationary or are diesel-fueled compression ignition engines. (Subpart JJJJ also applies to reciprocating compressor engines, but as discussed, the emissions inventories do not include compressors since compressors are not located at individual well sites). The NSPS requires engines manufactured after July 1, 2008 to meet emission limits of 2.8 grams per horsepower hour (g/bhp-hr) NO_x and 4.8 g/bhp-hr CO for engines less than 100 horsepower (the pumpjack engines are smaller than 100 horsepower). For purposes of this study, it was assumed that the pumpjack engines would be model year 2008 or later and thus will meet the Subpart JJJJ emission limits.

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In addition to the NSPS, there are federal regulations (40 CFR 89 and 40 CFR 1039) that require manufacturers of diesel-fueled engines used on the drill rig and drill platform to meet certain emission limits. The emission limits differ according to the size and year of manufacturer of the engine, with the most stringent limits being for engines manufactured after 2015 (i.e., large Tier 4 engines). However, older model year engines can continue to be used after 2015. For purposes of the emission inventories, it was assumed that drill rig engines would meet Tier 2 emission limits, i.e., limits for engines manufactured after 2001 for the smaller engines and after 2006 for the large drill rig engines over 750 horsepower. It was assumed that the remainder of the engines would not meet any specific emission limits (i.e., so-called Tier 0 engines). The emission limits on engines are complex and a complete description of the limits and alternatives is beyond the scope of this study. The engine emission limits also affect construction equipment and other tailpipe emissions; however, those emission limits are built into the USEPA NONROAD emission model used to select emission factors for that type of equipment.

2.5.2. Federal NESHAP

Federal NESHAPs can apply to major and non-major sources of hazardous air pollutants (HAPs). The individual wells in this study are not major sources of HAPs, and thus only the non-major provisions of the NESHAP apply (non-major sources of HAPs are termed "area sources"). There are two NESHAP provisions that apply to single well site area sources: Subpart HH and Subpart ZZZZ. For area sources, Subpart HH only applies to dehydrators that process more than 3 million cubic feet per day of natural gas or have benzene emissions greater than 1 ton per year. It was assumed that all of the gas wells in this study produce 4 million cubic feet per day of natural gas, and thus it was assumed that dehydrators, if present, would be controlled to a minimum of 95 percent efficiency.

40 CFR 63 Subpart ZZZZ applies to both stationary spark ignition and stationary compression ignition engines, called reciprocating internal combustion engines (RICE). For this study, the only stationary RICE is the pumpjack engine, (because compressors are not included in the inventory), and in that case, for the small pumpjack engines, compliance with Subpart ZZZZ is met by complying with Subpart JJJJ as discussed previously.

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2.5.3. State Regulations

The key state regulations that could affect the emission inventory are summarized below. As in the case with the federal regulations, the following is not a complete list of all of the compliance obligations that individual well sites may have to meet, but rather only a brief summary of those regulations that could meaningfully affect the emission calculations. State requirements must be at least as stringent as Federal requirements, and in some cases are more stringent. For completeness, even when the state requirements are not more stringent than the federal requirements, the requirements are summarized below. Section 6 of this report identifies where the regulations discussed for each state can be obtained.

Montana

Montana requires sites where uncontrolled emissions from oil or condensate tanks or loading operations have the potential to emit VOCs greater than 15 tons per year to be controlled. The Federal 40 CFR 60 Subpart OOOO requires controls at 6 tons per year. For purposes of this emissions inventory, all of the oil or condensate tanks in all of the basins except for the San Juan Basin were assumed to have uncontrolled emissions greater than 6 tons per year, and thus emission controls were included in the emissions inventory for the Williston Basin well type. Montana regulations require submerged filling during loading operations, but this type of emission control has been included in all of the emission inventories because it is standard practice.

Montana requires stationary internal combustion engines over 85 horsepower to install oxidation catalytic reduction (or similar controls) to reduce emissions of NOx and CO (Montana Regulation ARM Title 17, Chapter 8, Subchapter 16, Section 1603(e) and (f)). However, the stationary engines at the well sites, i.e., the pump jack engines, are smaller than 85 horsepower, so no additional controls were included in the emission inventory.

North Dakota

North Dakota requires all sites with the potential to emit 20 tons per year or greater of VOCs from the storage tanks, including produced water tanks, to control vapors from the tanks by at least 98 percent control efficiency. For those sites where the vapors from storage tanks have the potential to emit less than 20 tons per year of VOCs, the tanks at those sites need to be

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controlled by at least 90 percent control efficiency. However, the Federal 40 CFR 60 Subpart OOOO requires 95 percent control at 6 tons per year, and thus 95 percent emission controls for wells in the Williston Basin were included in the emissions inventory.

North Dakota also requires vapors from dehydrator still vents that exceed the following emission levels to be routed to a control device: greater than or equal to 5.0 tons per year of any combination of HAPs or greater than or equal to 15.0 tons per year of VOCs. The dehydrators in this study do not have that level of emissions, thus no controls were included in the emission inventories.

As is the case in Montana, splash loading is not permitted in North Dakota, and submerged filling was assumed in the emission inventories.

South Dakota

No specific regulations are currently established that affect the emission inventories for well sites in South Dakota.

Wyoming

Due to the extensive oil and gas development in Wyoming over a number of years, there are a number of Wyoming state regulations that could affect the emission inventories. The requirements vary by location within the oil and gas basins.

For the Jonah-Pinedale Anticline Development (JPAD) Area, the following are required:

- Tank flashing: 98 percent control on all new and modified tanks if uncontrolled emissions are greater than 8 tons per year. Because this level of control is only for the JPAD, which is a subset of the Upper Green River Basin, it was assumed that only 95 percent control would apply to the Upper Green River Basin well type as that yields an upper bound emission estimate.
- Dehydration units: 98 percent control on all new and modified dehydrators. This level of control was included in the emissions inventory for the Upper Green River well type.
- Pneumatic pumps: 98 percent control requirement or closed loop system on all new natural gas operated pumps (heat trace or other pumps) or existing pumps at modified facilities. Pneumatic pumps (as opposed to pneumatic controllers) are not always

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required for wells in the Upper Green River Basin, and more modern wells are using solar-powered pumps. However, for purposes of the emissions inventory, because control on pneumatic pumps is for the JPAD, which is a subset of the Upper Green River Basin, it was assumed that pneumatic pumps would be controlled. The San Juan and Uinta/Piceance gas well types also have pneumatic pumps, but no controls are required nor included in the emissions inventory.

- Pneumatic controllers: All new (post 2010) natural gas operated pneumatic controllers must be low or no bleed. Low bleed pneumatic controllers were assumed for the emissions inventory for the Upper Green River well type as well as the other two gas-well basins. Note that there are other pneumatic devices (e.g., dump valves) which are not required to be low bleed.
- Completions: Green completion permits required for all completions with goal of achieving 98 percent control of venting emissions or use of Best Management Practices (BMPs) where feasible. It was assumed for the emission inventory that there would be no BMP feasible for single well sites in a small project (i.e., less than 5 wells, which is the focus of this study), and, therefore, no controls were included.
- Well blowdowns: Well blowdowns are associated with non-routine maintenance activities (e.g., depressurization of a well to affect repair) and are not included in the emissions inventory. However, Wyoming regulations require the use of BMPs (e.g., limiting the duration of venting) to minimize emissions to the extent practical.
- Produced water tanks: 98 percent control requirement on all new and modified tanks in the JPAD area (a Wyoming specific requirement only for the JPAD area) if the VOC emissions are over 8 tons per year. However, when the potential emissions from the produced water tanks are calculated, none of the single well sites have this level of emissions and no control is included in the emissions inventory.

For the Concentrated Development Area (Carbon, Fremont, Lincoln, Natrona, Sublette (non-JPAD), Sweetwater, and Uinta Counties) the requirements are essentially the same as the JPAD area except that the controls must be in place for one year and then can be removed if emissions are less than 8 tons per year. However, the Subpart OOOO NSPS requires control at 6 tons per year. Therefore, for purposes of the emission inventory, none of the controls were removed.

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The Wyoming statewide requirements, i.e., counties not in the JPAD or Concentrated Development Area, are similar to the JPAD requirements, although the thresholds are less stringent and there are no requirements on well completions or produced water tanks. The JPAD requirements on completions and produced water tanks did not affect the emissions inventories; therefore, there is no difference between statewide requirements and JPAD requirements with regard to the emission inventories in this study.

Colorado

The Colorado Department of Public Health, Air Pollution Control Division, also has extensive regulatory requirements for oil and gas wells, depending on the area within which the well is located.

In the Front Range, Denver-Julesburg Basin (i.e., the North Front Range 8-hour ozone non-attainment area), the following are required:

- Tanks at the well site must achieve a minimum of 70 percent control during the non-ozone season and 90 percent control during the ozone season. However, for purposes of the emission inventory, uncontrolled VOC emissions were assumed greater than 6 tons per year. Thus 40 CFR 60 Subpart OOOO requires 95 percent control, and that level of control was applied.
- Pneumatic controllers installed after Feb. 1 2009 are required to meet the definition of a low-bleed controller. Subpart OOOO also requires low bleed controllers. However, for purposes of this study, it was assumed that there were no pneumatic controllers (low bleed or otherwise) present at the Denver Basin wells, as such devices are not normally present for oil wells. (No pneumatic devices were included for the Williston oil well type either).

The following are statewide requirements in Colorado:

- New and existing condensate tanks emitting 20 tons VOC per year or more are required to control emissions by 95 percent. Although none of the well sites in this study exceed that threshold, the federal threshold is 6 tons per year and 95 percent control was assumed.

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- New and existing glycol dehydrators emitting more than 15 tons VOC per year or more are required to control, but none of the well sites in this study exceed that threshold.

In addition to the Air Pollution Control Division, the Colorado Oil and Gas Conservation Commission (COGCC) also has regulations that require emission controls on tanks and dehydrators with uncontrolled emissions over 5 tons per year, no or low-bleed pneumatics where feasible, and BMPs or green completions. As noted, tank controls and low-bleed pneumatic controllers are included in the emission inventories, but no BMPs that affect emissions were included, and it was assumed that associated gas entered the sales line.

Utah

There are no specific requirements for single well-site sources that would affect the emission inventories.

New Mexico

There are no specific requirements for single well-site sources that would affect the emission inventories.

Arizona

There are no specific requirements for single well-site sources that would affect the emission inventories, other than dust control requirements. Dust control has been included in the emissions inventories of this study.

Nevada

There are no specific requirements for single well-site sources that would affect the emission inventories.

Idaho

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Washington

There are no specific requirements for single well-site sources that would affect the emission inventories.

Oregon

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3 EMISSION INVENTORY ESTIMATE RESULTS

The emission inventories for the five representative basins are presented in Appendices A through F. The following sub-sections of this report discuss the activities included and excluded from the emission inventories and the results of the inventories by activity and pollutant.

3.1. EMISSION ACTIVITIES

The emission inventories include the following general activities. The specific detailed activities and equations for calculating emissions are shown in the Appendices. The general activities are as follows:

Construction (access road, pipeline, well pad)

- Fugitive dust from access road and well pad construction, interim and final reclamation, and construction heavy equipment
- Fugitive dust from pipeline construction
- Tailpipe and fugitive dust emissions from light duty vehicles (e.g., pickup trucks for construction workers), construction heavy equipment, and heavy duty trucks such as tanker trucks
- Wind erosion from disturbed surfaces

Development (drilling/completion/workovers)

- Tailpipe emission from engines used on the drill rig platform to install the conductor pipe
- Tailpipe emissions from engines associated with drilling the well, including drill rig, air compressors, electrical generators, and dozer and other heavy equipment engines
- Tailpipe emissions from hydraulic fracturing pump and associated engines (i.e., well completions)
- Well cementing emissions
- Well workover emissions
- Hydraulic fracturing flowback emissions
- Tailpipe and fugitive dust emissions from worker and delivery/transport vehicles

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Operation (production of natural gas and oil)

- Well production emissions from heaters, pneumatic controllers, pumpjack engines, plus fugitive emissions (i.e., leaks from valves, flanges, open ended lines, etc.) at the well site
- Storage tank and loading emissions, including tailpipe and fugitive dust emissions from tanker trucks and other vehicles servicing the well
- Well-site dehydrators
- Tailpipe and fugitive dust emissions from worker and delivery/transport vehicles

Reclamation (included as part of Construction)

- Interim reclamation fugitive dust and tailpipe emissions, which are included as part of the well pad construction by adding vehicles and the duration of activities
- Final reclamation fugitive dust and tailpipe emissions, which are included as part of the well pad construction by adding vehicles and the duration of activities

No emission estimates were included for pipeline natural gas compressors and dehydrators not located at the well site, although pipeline compression and possibly pipeline dehydration will be required somewhere along a pipeline leading to a central gathering station and for moving the gas to market. But these emissions are not at a single well site.

Combustion emissions from flares that may be used to control potential emissions from storage tanks or dehydrators were included in the emissions inventory (as well as un-combusted VOCs and GHGs were included). If there is H_2S present in the flared gas, flare combustion can create SO_2. For purposes of this study it was assumed that the wells did not contain meaningful amounts of H_2S, so no SO_2 emissions from flares were included. However, if the user of the inventory has information that there is meaningful amounts of H_2S present at a project, the user can enter the H_2S content of the gas and the Excel Workbook will calculate both the H_2S and SO_2 emissions resulting from combustion of gas containing H_2S. On the other hand, oil wells in the Williston Basin produce a large amount of associated gas, and that gas is flared in flare pits or other flare devices. The amount of associated gas can be considerable in the Williston Basin, thus the emissions inventory for the Williston Basin well type includes combustion emissions from flared associated gas.

Road maintenance emissions were not included in the emissions inventory, because this study focuses on projects that contain a small number of wells, typically wildcat or delineation wells.

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In that that case, there may or may not be road maintenance activities and such activities are not at individual wells.

Some of the well sites in the San Juan Basin will have compressors located at the well head, but these compressors typically serve a group of gas wells even when located at a well site. However, for the wells which are the focus of this study (i.e., approximately five or fewer isolated wells), it is not likely that there would be well site compressor engines utilized. Therefore, no such engines were included in the emissions inventory, although field compression for a large group of wells somewhere in a large well field will be required in order to move the gas to market.

Two potential sources of VOC emissions are associated with liquids unloading (blowdowns) and working/breathing losses from storage tanks or mobile tanks. Working/breathing losses are much smaller than flashing emissions. The emissions inventory of this study was developed as a stand-alone document (and Excel Workbook) that could be used without additional emission estimating techniques. In order to calculate working and breathing losses, the USEPA TANKS emissions model would need to be used on a case by case basis. Working and breathing emissions are much smaller than flashing emissions and working and breathing losses could not be included without the user having to separately run the TANKS model (USEPA, 2012) on a case by case basis; therefore they have not been included in the inventory. Liquid unloading blowdowns are associated with a central facility. For the isolated few well scenario of this study, liquid unloading blowdowns would not likely be present and have thus not been included. Although unloading and working/breathing emissions can be meaningful when emissions from a large well field with thousands of wells are considered, in the case of the isolated wells which are the subject of this study, they are de minimis.

There may also be VOC emissions from drilling mud pits caused by hydrocarbons that may come up from the well during drilling. No emission factors were found in the references evaluated for this study, including no USEPA emission factors for this source. Accordingly, potential emissions from mud pits have not been included in the emission inventory.

The main activities producing meaningful amounts of HAPs typically associated with oil and gas drilling and production have been included in the emissions inventory. These HAPs are benzene, toluene, ethylbenzene, xylene (BTEX) and n-hexane. Tailpipe emissions of hazardous air pollutants from drill rig, hydraulic pump and similar engines and tailpipe emissions

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of HAPs from on-road and off-road equipment have not been included as those emissions tend to be much smaller than HAPs associated with the oil and gas products. Some of the HAPs associated with tailpipe emissions are acetaldehyde, acrolein, benzene, 1,3-butadiene, and formaldehyde. These tailpipe emissions combined would constitute less than 0.3% of CO emissions, or on the order of 0.0008 tons per year in this emissions inventory. The percentage of tailpipe HAPs was derived from the I-15 Corridor Utah County to Salt Lake County FEIS, Table 3.8-8 (USDOT FHWA, 2008). Note that ethylbenzene emissions from oil and gas activities included in the emissions inventory are also relatively small, but ethylbenzene is one of the BTEX compounds associated with oil and gas production and it has been included in the emission inventory. Furthermore, some gas can contain larger amounts of benzene than the gas profiles used for the inventories in this study. If it is known that larger amounts of benzene are present, the project-specific gas composition can be entered into the Excel Workbook of Appendix A and the emissions will be automatically calculated.

In the Appendices, where a value of 0.00 appears, that indicates that there were no or de minimis emissions of that specific pollutant for that well type. If there are non-zero emissions, then at least one significant figure was reported. The number of significant figures shown in the Appendices varies as the quantity of individual pollutants is highly variable. For example, SO_2 emissions are reported to only one significant figure because the emissions are on the order of one ten thousandth of a ton per year. In the spreadsheets, the emission summaries are reported to two decimal places because in order to show a 0.00 value, two decimal places must appear in the Excel Workbook.

3.2. SELECTION OF PARAMETERS FOR EMISSION CALCULATIONS

The equations used to calculate the emissions for each of the above activities are shown on the spreadsheets in the Appendices. The equations use a combination of physical constants (e.g., conversion from meters to feet), variables required by the emission equations (e.g., moisture content of soil being moved), and well-specific parameters. The well-specific parameters are those parameters that were chosen to represent the five different well types that are the focus of this study. The basis for the physical constants, variables, and well-specific parameters are contained in the spreadsheets. The basis for most of the parameters are typical values based on professional judgment (e.g., 4 days to construct a well pad) and are generally used in all of the references discussed in Section 2.2 of this report. However, some of the well-specific parameters are more critical to the emissions estimates and required additional investigation

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and judgment for selection. The critical well-specific parameters and the basis for selection are as follows. The terminology used for the references (e.g., "NDDEQ") is that presented in Section 2.2.

3.2.1. Vehicle Tailpipe and Fugitive Dust Emissions

Emissions associated with vehicle travel are a function of the emission factors (e.g., pounds per vehicle mile traveled, lb/VMT) and the number of miles traveled. The VMT is a function of the location and spacing of the wells, number and type of equipment and supply deliveries, number of workers, duration and magnitude of hydraulic fracturing, size of trucks bringing supplies (especially water) to the well, oil and condensate production rate of the well, size of the tanker trucks pumping the stock tanks, and numerous other variables. For purposes of the emission inventory, typical vehicle traffic counts and distances were used for wells drilled where there is relatively little hydraulic fracturing fluid needed. If project specific information is available for calculating project specific VMT (e.g., it is know that very large amounts of water will be needed for hydraulic fracturing), that information can be entered into the Workbook.

3.2.2. Drill Rig Engine Size

Drill rig and hydraulic fracturing pump engine horsepower vary widely among various inventories and studies, depending on the specific engines used by the drilling and production company and how quickly the drilling company intends to complete a well. GNB uses a drill rig engine of 1,476 horsepower (hp) and a completion rig of 475 hp. Jonah used 2,100 hp total for three engines when vertical drilling and 2,600 hp when horizontal drilling. Pinedale drill rig engines range from 3,640 to 4,040 hp. CRV used 2,952 hp for drill rig engines. For purposes of this emission inventory, the following drill rig engine sizes were assumed:

- Uinta/Piceance Drill Rig Engine 2,950 hp (i.e., the CRV value)
- Upper Green River Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- San Juan Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- Williston Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- Denver Drill Rig Engine 2,950 hp (i.e., the CRV value)

The horsepower for other engines involved in drilling, hydraulic fracturing, and workovers (e.g., electrical generators, pump engines) are detailed in the Appendices. As shown in the

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Appendices, hydraulic fracturing pump engines can also be relatively large, on the order of 1,500 horsepower.

The various reference documents either assume no load factor or variable load factors. For example, GNB used 65 percent load and 65 percent utilization for an overall load factor of 42 percent. For purposes of the emission inventory, two different load factors were used, depending on the operation and the engine. The 42 percent overall load factor was used for all engines except horizontal drilling and hydraulic fracturing pump engines. For those engines, a load factor of 59 percent was used, (90 percent load and 65 percent utilization), based on professional judgment, to reflect the fact that horizontal drilling and hydraulic fracturing are more power-intensive activities.

3.2.3. Drill Rig Engine Emission Limits

As discussed in Section 2.4.1, there are federal requirements for engine manufacturers to meet certain emission limits based on the "Tier" of the engine and date of manufacture. Various agency and EIS Records of Decision require more modern engines than federally required. For example, GNB required a minimum of Tier 2 engines, one of the alternatives evaluated in White River required Tier 4 engines, and Jonah required Tier 4 engines to be phased in between 2008 and 2015. Engines greater than 750 horsepower manufactured between 2011 and 2014 are required to meet interim Tier 4 emission limits while engines manufactured from 2015 and later are required to meet final Tier 4 emission limits. Turnover of the drill rig engine fleet to Tier 4 engines is dependent on individual rig operators; however, for purposes of the emissions inventory, Tier 2 engines were assumed. This provides a reasonable upper bound for the emissions from drill rig engines.

3.2.4. Hydraulic Fracturing Flowback Emissions

During hydraulic fracturing of the formation, the fracturing fluid is returned to the surface. This is termed "frac flowback." The flowback can contain a meaningful amount of associated natural gas from the formation. In some cases, all of the associated gas is captured and either flared or sent to a sales line. When the flowback gas is completely captured and sent to a sales line, it is called a "green completion". In other cases the associated gas is either flared or simply released to the atmosphere.

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GNB assumed that all wells would be green completions with no flowback emissions. Jonah assumed that the flowback gas would be vented uncontrolled for 4 hours and flared for 80 hours with a total gas flowback amount of 35 thousand standard cubic feet (scf). CRV assumed that one-half the flowback gas would be vented uncontrolled and one-half flared, with a total flow of 1 million scf per well. Based on these references, for purposes of the emission inventory the CRV value of 1 million scf was used. The amount of flowback gas is highly variable and a function of the individual well, although for this study a constant value of 1 million scf was used. But as is the case with all variables, a different value can be input into the Excel Workbook if project-specific information is known. Consistent with 40 CFR Subpart OOOO and other regulations, it was assumed that all of the flowback gas was flared with 95 percent control.

3.2.5. Gas Production Rate, Decline Factor, and Dehydrator Emissions for Gas Wells

The gas production rate (standard cubic per day or scfd) of natural gas from an individual gas well is used to calculate potential dehydrator emissions. The anticipated production rate may be known, but the actual rate often varies greatly from the expected rate. For purposes of the emissions inventory, only the Upper Green River Basin well type has a dehydrator present.

Farmington RMP used an initial gas production rate of 55,584 Mscfd (55.6 MMscfd) per well but then applies a decline factor of 50 percent for the average life of the well (i.e., average production of 27.8 MMscfd). Pinedale used a gas production rate of 4,000 Mscfd (4.0 MMscfd) per well.

Both gas and oil wells initially produce much more on a daily basis than later in the life of the well. This is the decline factor or decline curve. Many of the reference documents do not specify a decline curve, either assuming that the initial production rate would remain constant or specifying an average production rate for the "life of the well", basically an average production rate over a period of 10 to 20 years. For purposes of the emission inventory in this study, no decline factor was built in to the emission estimates because the project-specific production rate is not known, and thus a decline factor is meaningless. Thus, the emission inventories provide an upper bound estimate of emissions based on the production rate specified.

Accordingly, a 4.0 MMscfd gas production rate was used for the Upper Green River Basin well type dehydrator emission calculation.

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Depending upon the size of the dehydrator and the potential uncontrolled emission rate, emission controls on the dehydrator potential VOC emissions may be required. Pinedale assumed that all well site dehydrators were controlled at 95 percent. White River assumed dehydrator control for one of the alternatives. For purposes of this study, only wells in the Upper Green River Basin will have well-site dehydrators. Pinedale assumed 95 percent control; therefore the emission inventory also assumes 95 percent control on well-site dehydrators.

3.2.6. Oil and Condensate Production Rate and Decline Factor at Gas and Oil Wells

One of the key variables in determining emissions from storage tanks is the oil production rate for oil wells, the condensate production rate for gas wells, and the decline factor. Natural gas wells often have hydrocarbon liquids associated with the produced gas, and these liquids are termed condensate. Likewise, oil wells can have associated natural gas produced with the oil. For this study, the term "produced gas" is used for the natural gas produced from gas wells, the term "associated gas" is used for the natural gas associated (or produced) with oil wells, and the term "flash gas" is used for the vapor that is released from oil or condensate in storage tanks.

NDDEQ assumes an oil production rate of 250 barrels per day (bbl/d) for the first 30 days of production at oil wells. GNB assumed 10 bbl/d of condensate production for the first year, 3 bbl/d condensate production for the second and following years for gas wells. Jonah used a constant 25.3 bbl/d condensate production rate for gas wells. Pinedale used 30 bbl/d condensate for gas wells. San Juan Basin gas wells have relatively little to no condensate. Therefore, for purposes of this emissions inventory, the following oil and condensate production rates were assumed:

- Uinta/Piceance Gas Well ... 10 bbl condensate per day
- Upper Green River Gas Well ... 30 bbl condensate per day
- San Juan Gas Well ... 5 bbl condensate per day
- Williston Oil ... 150 bbl oil per day
- Denver Oil ... 125 bbl oil per day

NDDEQ uses an assumed decline factor of 0.6 (i.e., the average annual production rate in terms of bbl/d after the first 30 days will be 60 percent of the daily production during the first 30 days). GNB used a decline factor of 0.7 after the first year, Farmington RMP uses a 0.5 decline factor, Jonah used a factor of 0.7, and Pinedale used a factor of 0.335. For purposes of the

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emission inventory, no decline factor was built in to the emission estimates because the project-specific production rate is not known, and thus a decline factor is meaningless. Thus, the emission inventories provide an upper bound estimate of emissions based on the production rate specified. If a project-specific production rate and/or decline factor is known, that data can be entered in to the spreadsheets to change the emission estimates.

3.2.7. Flash Gas to Oil Ratio for Gas and Oil Wells

The amount of vapor released in oil or condensate storage tanks is a function of the flash gas to oil ratio (Flash GOR). Flash GOR is also highly variable, even among different wells in the same basin. For purposes of the emissions inventory, the following Flash GORs were used for the gas and oil wells based on professional judgment:

- Uinta/Piceance Gas Well Flash GOR ...100 standard cubic foot of gas per barrel of condensate (scf/bbl)
- Upper Green River Gas Well Flash GOR ...98 scf/bbl of condensate
- San Juan Gas Well Flash GOR ... 75 scf/bbl of condensate
- Williston Oil Well Flash GOR ... 98 scf/bbl of oil
- Denver Oil Well Flash GOR ... 45 scf/bbl of oil

3.2.8. Well Gas-to-Oil Ratio for Oil Wells

Even though oil wells are developed to produce oil, they also have natural gas associated with them that comes from the geologic formation. This gas is termed "casing gas," "associated gas," or "produced gas." The amount of associated gas is determined by the Well Gas-to-Oil Ratio (Well GOR).

In the Denver Basin, there is sufficient pipeline infrastructure that associated gas produced with Denver oil wells is normally either used on-site or piped to a sales line essentially as soon as the well is completed. Therefore, in the Denver Basin, it was assumed that there are no emissions from the associated gas.

On the other hand, in the Williston Basin, there is insufficient natural gas infrastructure available, and the associated gas can be vented, flared, used at the well site, sent to a sales line, or a combination. For purposes of this study, it was assumed that all of the associated gas from

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Williston Basin oil wells was flared for a period of 3 months, after which it was assumed that the associated gas would be sent to a sales line. Accordingly, there are emissions from associated gas for a period of 3 months. The emissions result from combustion of the associated gas plus un-combusted associated gas (95 percent of the gas was assumed to be combusted with 5 percent passing through the flare un-combusted). The amount of associated gas flared was calculated from the assumed oil production rate of 150 bbl/day and a Well GOR of 1,100 scf/bbl of oil produced, or 165 Mscf of associated gas per day. The Well GOR value assumed for this study is based on professional judgment, and the Excel Workbook allows the user to enter a different value if known.

3.2.9. Produced Gas, Associated Gas, and Flash Gas Composition

As discussed previously, it was assumed that all five well types have oil/condensate storage tanks on site. The largest source of emissions from the storage tanks is the flash gas. The flash gas composition determines potential VOC, GHG and HAPs emissions. For this study, the flash gas composition was varied for each basin. The source of the flash gas compositions used in the study is as follows:

- Uinta/Piceance gas well ... liquids analysis of the condensate used in filed and approved Utah permit applications and the E&P Tanks emissions model
- Upper Green River gas well ... liquids analysis of the condensate used in the Wyoming Pinedale Tri-Annual Emissions Reporting default values and the E&P Tanks emissions model.
- San Juan gas well ... liquids analysis of the condensate used in filed and approved permit applications for Colorado and the E&P Tanks emissions model (same as the Denver Basin oil well)
- Williston oil well ... liquids analysis of oil used in filed and approved emission reporting efforts in North Dakota
- Denver oil well ... liquids analysis of the condensate used in filed and approved permit applications for Colorado and the E&P Tanks emissions model

For produced and associated gas composition, the CRV provided a detailed gas composition table, and that composition was used for all five basins. If project specific gas composition data are available, they can be entered into the Excel Workbook and the composition will flow through the calculations. The associated/produced gas composition data are used in the

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emission calculations for fugitive emissions, pneumatic device emissions, venting, workover, and frac flowback emissions, plus emissions from flaring of associated gas in the Williston Basin.

3.2.10. Emissions from Produced Water

Some oil and gas wells have a meaningful amount of water associated with them. The produced water, which is stored in tanks, can contain VOCs that are emitted to the atmosphere. In order to calculate emissions from produced water, a produced water production rate needs to be known and then a known emission factor, or the USEPA TANKS emissions model could be used. For purposes of the emission inventories the TANKS model was not run because of the goal to have a stand-alone spreadsheet as discussed earlier with respect to working/breathing losses. Rather than running the TANKS model on a case by case basis, CDPHE published an emission factor (lb VOC per bbl of produced water) for produced water, which is 0.262 lb VOC per bbl for the Denver Basin and 0.178 lb VOC per bbl for some of the Colorado counties in the Piceance Basin. Due to the lack of other emission rates for produced water tanks, and to provide a reasonable upper bound estimate of emissions, each of the produced water tank emissions from each basin were calculated using the single CDPHE emission factor of 0.262 lb VOC per bbl.

To determine the amount of produced water, the PI/Dwights oil and gas production database was accessed through IHS Enerdeq (IHS, 2013) and an average produced water rate per well per year (rounded to the nearest thousand barrels) was calculated for all wells in the basin. The resulting produced water rates are as follows:

- Uinta/Piceance ...4,000 bbl water per well per year (bbl/well/yr)
- Upper Green River ...3,000 bbl/well/yr
- San Juan ... 800 bbl/well/yr
- Williston ... 36,000 bbl/well/yr
- Denver ... 11,000 bbl/well/yr

The amount of produced water is highly variable within a basin and depends on the specific well. For example, the range of produced water values for gas wells in the San Juan Basin is from zero to over 160,000 bbl/well/yr according to the PI/Dwights database.

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3.2.11. Pneumatic Controllers

Pneumatic controllers are used at the well sites to open and close valves, operate pumps, and other purposes. Pneumatic controllers can emit natural gas containing VOCs as part of the operation. Pneumatic controllers are classified as high bleed, intermittent bleed, low bleed, and no bleed. High and low bleed controllers emit a small stream of gas continuously. Intermittent bleed controllers emit on an occasional basis, however the frequency of bleeding is generally not known. Accordingly, emission inventories usually assume either high, low, or no bleed controllers.

The number and type of pneumatic controllers varies depending on the needs of the well field and the operating company's standard practices. For purposes of the emission inventories it was assumed that all gas wells have pneumatic controllers (in addition to pneumatic pumps and other pneumatic devices) and the pneumatic controllers are all low bleed. This is consistent with the 40 CFR Subpart OOOO regulatory requirements discussed previously. No pneumatic controllers, pumps, or other pneumatic devices were assumed present for the oil wells in the Williston or Denver Basins.

3.2.12. Pumpjack Engines

Pumpjack engines are generally natural gas fueled and are relatively small, on the order of 65 to 95 horsepower. The Farmington RMP assumed a 95 hp engine; other EISs assume smaller engines and/or a 95 hp engine but use a load factor that results in an effective continuous horsepower that is much lower than the engine rating. For purposes of the emission inventory, it was assumed that all of the pumpjack engines would be 65 hp, with a load factor of 0.54, or an effective continuous hp of 35. These values were chosen based on professional judgment.

3.2.13. Fugitive Emissions (Equipment Leaks)

Well site equipment processes and transfers gases and light oils with meaningful amounts of VOCs. Therefore, fugitive emissions from equipment leaks must be accounted for and were included in the emission inventories. USEPA emission factors for leaks from valves, connectors (flanges), open ended lines, and pressure relief valves as published in 40 CFR 98 Subpart W were used. Although 40 CFR 98 Subpart W is for greenhouse gas (GHG) emissions, it includes emission factors for the amount of fugitive gas emissions at oil and gas well sites; and these

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emission factors can be used to estimate not only GHG emissions but also HAPs and VOC emissions based on the gas composition. Thus the Subpart W emission factors were used. Typical counts for each type of leaking device at the well sites were input based on professional judgment. If other project specific information is available, equipment counts can be over-ridden in the spreadsheets. The emission factors assume no leak detection and repair (LDAR) program is implemented. If some sort of LDAR or inspection program is implemented, the emission factors should be adjusted accordingly. (LDAR may be required by 40 CFR 60 Subpart OOOO at some well sites on some of the equipment).

3.3. EMISSION INVENTORY RESULTS

Tables 3-1 through 3-5 show the emissions totals for each well type by activity. Except for sulfur dioxide, ethylbenzene, and nitrous oxide, the values in the Tables are rounded to one decimal place. Global warming potential (GWP) is rounded to a whole number.

Note that the tables report "total HAPs"; however, the total is based on only the five HAPs listed. There are trace amounts of other HAPs associated with oil and gas well development and production, but the amounts of those other HAPs are much, much smaller than the five key HAPs listed (the trace HAPs add less than a tenth of a percent to the total HAPs). There are three other HAPs emitted in meaningful quantities that are often associated with oil and gas production: formaldehyde, acetaldehyde, and acrolein. However, the main source of these HAPs are large natural gas compression engines at central gathering stations or field compression stations, which are not included in this study.

The Global Warming Potential (GWP) shown in the tables is calculated using a GWP of 1.0 for carbon dioxide, 21 for methane, and 310 for nitrous oxide. The individual greenhouse gas emissions are in terms of short tons for the individual greenhouse gas. The GWP is in terms of short tons of carbon dioxide equivalent (CO_2e).

As noted in Section 3.1, Construction emissions include emissions from interim and final reclamation of the well pad. Tables 3-1 through 3-5 are on the following pages.

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Table 3-1
Emission Estimates by Activity for a Natural Gas Well in the Uinta/Piceance Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO_x	0.5	14.8	0.4	15.6
CO	0.3	3.2	0.4	3.8
VOC	0.04	0.7	2.6	3.4
SO_2	0.0001	0.0002	0.0001	0.0004
PM_{10}	2.0	4.9	0.04	6.9
$PM_{2.5}$	0.06	0.5	0.2	0.8
CO_2	33.8	2,127.7	390.6	2,552.1
CH_4	0.001	1.1	11.1	12.2
N_2O	0.0003	0.05	0.0008	0.05
GWP	34	2,165	624	2,825
Benzene	0.00	1.4	0.04	1.4
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.00003	0.00003
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.19	7.5
Total HAPs	0.00	10.2	0.25	10.4

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-2
Emission Estimates by Activity for a Natural Gas Well in the Upper Green River Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO_x	0.5	13.2	0.9	14.6
CO	0.3	2.9	0.8	3.9
VOC	0.04	0.7	4.4	5.2
SO_2	0.0001	0.0002	0.0001	0.004
PM_{10}	1.9	4.7	0.08	6.7
$PM_{2.5}$	0.06	0.4	0.3	0.8
CO_2	33.8	1,900.3	948.0	2,882.1
CH_4	0.001	1.1	13.0	14.1
N_2O	0.0003	0.05	0.002	0.05
GWP	34	1,937	1,222	3,194
Benzene	0.00	1.4	0.1	1.5
Toluene	0.00	1.0	0.2	1.2
Ethylbenzene	0.00	0.00	0.01	0.01
Xylene	0.00	0.6	0.2	0.7
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.7	10.9

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

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Table 3-3
Emission Estimates by Activity for a Natural Gas Well in the San Juan Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO_x	0.5	4.0	1.1	5.6
CO	0.3	1.1	1.8	3.1
VOC	0.04	0.3	5.0	5.3
SO_2	0.0001	0.0002	0.0008	0.001
PM_{10}	2.1	4.7	0.08	6.8
$PM_{2.5}$	0.06	0.1	0.3	0.5
CO_2	33.8	561.6	56.4	651.9
CH_4	0.001	1.1	5.0	6.1
N_2O	0.0003	0.04	0.0004	0.04
GWP	34	595	161	791
Benzene	0.00	1.4	0.03	1.4
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.0008	0.0008
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.3	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-4
Emission Estimates by Activity for an Oil Well in the Williston Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO_x	0.5	13.2	1.8	15.6
CO	0.3	2.9	4.9	8.0
VOC	0.04	0.7	16.8	17.6
SO_2	0.0001	0.0002	0.0008	0.001
PM_{10}	2.0	4.8	0.1	6.9
$PM_{2.5}$	0.06	0.4	0.3	0.8
CO_2	33.8	1,900.3	1,222.3	3,156.4
CH_4	0.001	1.1	15.4	16.6
N_2O	0.0003	0.05	0.5	0.6
GWP	34	1,922	1,700	3,682
Benzene	0.00	1.4	0.2	1.5
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.0008	0.0008
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.6	7.9
Total HAPs	0.00	10.2	0.9	11.0

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

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Table 3-5
Emission Estimates by Activity for an Oil Well in the Denver Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO_x	0.5	4.5	1.3	6.3
CO	0.3	1.2	2.0	3.4
VOC	0.04	0.3	6.4	6.7
SO_2	0.0001	0.0002	0.008	0.001
PM_{10}	2.0	4.5	0.1	6.6
$PM_{2.5}$	0.06	0.2	0.3	0.5
CO_2	33.8	623.7	391.5	1,050.0
CH_4	0.001	1.1	0.7	1.8
N_2O	0.0003	0.04	0.001	0.04
GWP	34	657	406	1,099
Benzene	0.00	1.4	0.06	1.4
Toluene	0.00	1.0	0.01	1.0
Ethylbenzene	0.00	0.00	0.0006	0.0006
Xylene	0.00	0.6	0.004	0.6
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.4	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

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4 CONCLUSION

Five different emission estimate inventories were developed to represent typical oil and gas well emissions in the western US. California, Texas, Oklahoma, Kansas, and Alaska were not included in the study due to relatively little BLM land with oil and gas development in those states, those states have their own program for estimating emissions, and/or the unique environment of Alaska. The five well types chosen for analysis were natural gas wells from the Uinta/Piceance, Upper Green River, and San Juan Basins and oil wells from the Williston and Denver Basins. These Basins are responsible for a large portion of the oil and gas produced in the western United States. Characteristics of these basins as they affect emission estimates were described so that a user of the emission inventory can select a representative well type for development in other basins or sub-basins in the western US. The emission inventories focus on projects where there are a small number of wells, generally termed wildcat or delineation wells.

The emission estimates are suitable for use to estimate emissions from a small number of wells, and should not normally be extrapolated to large well fields with multiple wells. The inventories are based on generally accepted emission estimating techniques published by the USEPA. However, these techniques require a large number of case-specific parameters in order to estimate emissions. Typical parameters for each of the Basins studied were used to calculate the emissions, but there is a wide range of possible values, and project-specific information should be used whenever available.

Electronic and hard copy emission inventories were created. The electronic version of the emission spreadsheets can be modified by the user by overriding key parameters with project-specific data if available. Emissions were calculated for the criteria pollutants associated with oil and gas development, greenhouse gases (including calculation of global warming potential), and the five hazardous air pollutants that are emitted in meaningful amounts and traditionally associated with emissions from a single oil or gas well: hexane, benzene, toluene, ethylbenzene, and xylene.

The emission inventories can be easily modified to account for project-specific information that may be available. If no project-specific information is available, the emission inventories provide typical values for the selected basins and the inventories can be extrapolated to other basins in

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the western US as needed. If project-specific variables are entered into the Excel Workbook, the variables should be entered in the "Constants and References" tab and the entered variables will be automatically populated into the emission estimating equations in the Workbook. If a range of emission estimates are needed instead of a single value, a range of emission estimates can be created by entering a range of parameters in the Excel Workbook.

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5 LIMITATIONS

This work was performed in a manner consistent with that level of care and skill ordinarily exercised by other members of Kleinfelder's profession practicing in the same locality, under similar conditions and at the date the services are provided. Our conclusions, opinions, and recommendations are based on a limited number of observations and data. It is possible that conditions could vary between or beyond the data evaluated. Kleinfelder makes no other representation, guarantee, or warranty, express or implied, regarding the services, communication (oral or written), report, opinion, or instrument of service provided. This report may be used only by the client and only for the purposes stated for this specific engagement within a reasonable time from its issuance.

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Exhibit 2

BLM

U.S. Department of the Interior
Bureau of Land Management

Environmental Assessment
DOI-BLM-ID-B010-2014-0036-EA

Little Willow Creek
Protective Oil and Gas Leasing

February 10, 2015

U.S. Department of the Interior
Bureau of Land Management
Four Rivers Field Office
3948 Development Avenue
Boise, ID 83705

NATIONAL SYSTEM OF PUBLIC LANDS

3.4 Air Resources

Air resources include air quality, air quality related values (AQRVs), and climate change. As part of the planning and decision making process, the BLM considers and analyzes the potential effects of BLM and BLM-authorized activities on pollutant emissions and on air resources.

The Environmental Protection Agency (EPA) has the primary responsibility for regulating air quality, including seven criteria air pollutants subject to National Ambient Air Quality Standards (NAAQS). Pollutants regulated under NAAQS include carbon monoxide (CO), lead, nitrogen dioxide (NO2), ozone, particulate matter with a diameter less than or equal to 10 microns (PM10), particulate matter with a diameter less than or equal to 2.5 microns (PM2.5), and sulfur dioxide (SO2). Two additional pollutants, nitrogen oxides (NOx) and volatile organic compounds (VOCs) are regulated because they form ozone in the atmosphere. Air quality regulation is also delegated to the IDEQ. Air quality is determined by pollutant emissions and emission characteristics, atmospheric chemistry, dispersion meteorology, and terrain. The AQRVs include effects on soil and water such as sulfur and nitrogen deposition and lake acidification, and aesthetic effects such as visibility.

Climate is the composite of generally prevailing weather conditions of a particular region throughout the year, averaged over a series of years. Climate change includes both historic and predicted climate shifts that are beyond normal weather variations.

3.4.1 Affected Environment – Air Resources

Air Quality

Based on data from monitors located in Baker County Oregon (west and generally upwind of the lease area) and Ada and Canyon counties (southeast and generally downwind of the lease area), air quality in Payette County is believed to be much better than required by the NAAQS. The EPA air quality index (AQI) is an index used for reporting daily air quality (http://www.epa.gov/airdata/) to the public. The index tells how clean or polluted an area's air is and whether associated health effects might be a concern. The EPA calculates the AQI for five criteria air pollutants regulated by the Clean Air Act (CAA): ground-level ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide. For each of these pollutants, EPA has established NAAQS to protect public health. An AQI value of 100 generally corresponds to the primary NAAQS for the pollutant. The following terms help interpret the AQI information:

- **Good** – The AQI value is between 0 and 50. Air quality is considered satisfactory and air pollution poses little or no risk.
- **Moderate** – The AQI is between 51 and 100. Air quality is acceptable; however, for some pollutants there may be a moderate health concern for a very small number of people. For example, people who are unusually sensitive to ozone may experience respiratory symptoms.
- **Unhealthy for Sensitive Groups** – When AQI values are between 101 and 150, members of "sensitive groups" may experience health effects. These groups are likely to be affected at lower levels than the general public. For example, people with lung disease are at greater risk from exposure to ozone, while people with either lung disease or heart disease

are at greater risk from exposure to particle pollution. The general public is not likely to be affected when the AQI is in this range.

- **Unhealthy** – The AQI is between 151 and 200. Everyone may begin to experience some adverse health effects, and members of the sensitive groups may experience more serious effects.
- **Very Unhealthy** – The AQI is between 201 and 300. This index level would trigger a health alert signifying that everyone may experience more serious health effects.

AQI data show that there is little risk to the general public from air quality in the analysis area (Table 5). Based on available aggregate data for Baker, Ada, and Canyon counties (the nearest counties with monitoring data) for years 2011–2013, more than 84% of the days were rated "good" and the three-year median daily AQI was 19 to 32. Moderate or lower air quality days were typically associated with winter inversions or summer wildfire activity.

Table 5. Air Quality Index Report – Analysis Area Summary (2011-2013), Baker County Oregon and Ada Canyon Counties Idaho.

County[1]	# Days in Period	Median AQI	# Days rated Good	Percent of Days Rated Good	# Days Rated Moderate	# Days Rated Unhealthy for Sensitive Groups	# Days Rated Unhealthy	# Days Rated Very Unhealthy
Baker	1,084	28	915	84	167	2	0	0
Ada	1,088	32	917	84	157	11	2	1
Canyon	1,019	19	925	91	87	4	3	0

Source: EPA 2013a.

Emissions in Payette County are low, due to a small populations and little industrial activity. Based on 2011 emission inventory data available from the EPA National Emission Inventory, oxides of nitrogen, carbon monoxide, ≤10 micron particulate matter (PM_{10}), volatile organic compounds, and carbon dioxide were the most common non-biogenic emissions in Payette County (EPA 2014a). As described above, these emissions occur in an area with good air quality.

Table 6. Annual emissions (tons/year) of typical pollutants, typical annual emissions for a well (Upper Green River, Wyoming), and emissions for the reasonably foreseeable development scenario wells (Payette County) and cumulative impacts analysis area (Baker, Ada, Canyon, and Payette counties), Idaho and Oregon.

Pollutant	Payette County	Cumulative Impacts Analysis Area	Per Well[1]	Alternative (%increase over Payette County values)			Hamilton and Willow Fields[2]
				A	B	C	
NOx (Oxides of Nitrogen)	1,445.4	24,851.4	14.6	29.2 (2%)	321.2 (22.2%)	365 (25.3%)	774 (3.1%)
CO (Carbon Monoxide)	6,308.3	149,894.3	3.9	7.8 (0.1%)	85.8 (1.4%)	97.5 (1.6%)	207 (0.1%)
SO_2 (Sulfur Dioxide)	39.1	2,800.2	0.0004	0.0008 (<0.01%)	0.0088 (0.02%)	0.01 (0.03%)	0.02 (0.001%)
PM_{10} (Particulates	6,195.6	61,101.9	6.7	13.4	147.4	167.5	355.1

Pollutant	Payette County	Cumulative Impacts Analysis Area	Per Well[1]	Alternative (%increase over Payette County values)			Hamilton and Willow Fields[2]
				A	B	C	
with diameters ≤10 microns or ≤10 x 10^{-6} meters)				(0.2%)	(2.4%)	(2.7%)	(0.7%)
$PM_{2.5}$ (Particulates with diameters ≤ 2.5 microns or ≤2.5 x 10^{-6} meters)	828.4	12,815.4	0.8	1.6 (0.2%)	17.6 (2.1%)	20.0 (2.4%)	42.4 (0.3%)
VOCs (Volatile Organic Compounds)	1,123.1	28,539.1	5.2	10.4 (0.9%)	114.4 (10.2%)	130.0 (11.6%)	275.6 (1.0%)
HAPs (Hazardous Air Pollutants)							
Benzene	18.2	583.2	0.12	0.2 (1.3%)	2.6 (14.5%)	3.0 (16.5%)	6.4 (1.2%)
Toulene	67.4	1,509.5	0.22	0.4 (0.7%)	4.8 (7.2%)	5.5 (8.2%)	11.7 (0.8%)
Ethylbenezene	9.7	190.3	0.00003	0.00006 (<0.01%)	0.0007 (0.01%)	0.0008 (0.01%)	0.002 (0.001%)
Xylene	39	801.5	0.17	0.3 (0.9%)	3.7 (9.5%)	4.3 (10.9%)	9.0 (1.1%)
n-Hexane	23	615.1	0.20	0.4 (1.7%)	4.4 (19.1%)	5.0 (21.7%)	10.6 (1.7%)
Total HAPs	157.3	3,654.6	0.72	1.4 (0.9%)	15.8 (10.2%)	18.0 (11.4%)	38.2 (1.0%)
GHGs (Greenhouse Gases)							
CO_2 (Carbon Dioxide)	240,158	4,029,296	2,582.1	5,164.2 (2.2%)	56,806.2 (23.7%)	64,552.5 (26.9%)	136,851.3 (3.4%)
CH_4 (Methane)	28.6	1,478.8	14.1	28.2 (98.6%)	310.2 (1,085%)	352.5 (1,233%)	747.3 (50.5%)
N_xO (Nitrous Oxides)	8.4	169.0	0.05	0.1 (1.2%)	1.1 (13.1%)	1.3 (14.9%)	2.7 (1.6%)
CO_2 eq (Global Warming Potential)[3]	243,362	4,112,744	2,893.7	5,787.4 (2.4%)	63,661.4 (26.2%)	72,342.5 (29.7%)	153,366.1 (3.7%)

[1] Source: Kleinfelder (2014)
[2] %increase over CIAA
[3] GWP (Global Warming Potential/Carbon Dioxide Equivalent [CO_2eq]) for CO_2 =1, CH_4 = 21, and N_2O = 310.

Air resources also include visibility, which can be degraded by regional haze caused in part by sulfur, nitrogen, and particulate emissions. Based on trends identified during 2000-2009, visibility has improved slightly near the analysis area on the haziest and clearest days. Blue-shaded circles in Figure 3 indicate negative deciview (dv) changes, which mean that people can see more clearly at greater distances.

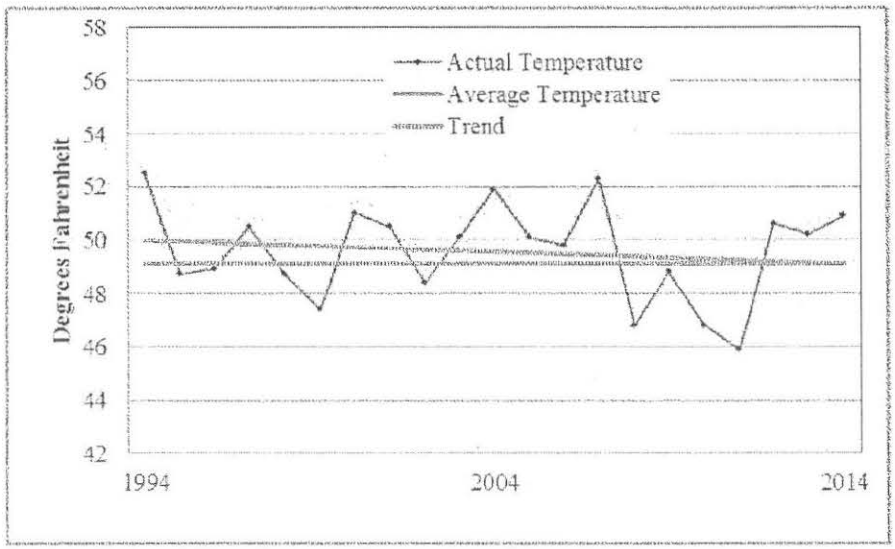

Figure 5. Regional climate summary of spring temperatures (March-May) for Idaho Southwestern Valleys, from 1994-2014. (Source: NOAA website http://www.ncdc.noaa.gov/oa/climate/research/cag3/wn.html)

3.4.2 Environmental Consequences – Air Resources

Impacts to air resources are based on the RFDS created for this document (Table 2, Appendix 1).

3.4.2.1 General Discussion of Impacts

Air Quality

Potential impacts of development could include increased airborne soil particles blown from new well pads or roads; exhaust emissions from drilling equipment, compressors, vehicles, and dehydration and separation facilities; as well as potential releases of GHGs and VOCs during drilling or production activities. The amount of increased emissions cannot be precisely quantified at this time since it is not known for certain how many wells might be drilled, the types of equipment needed if a well were to be completed successfully (e.g., compressor, separator, dehydrator), or what technologies may be employed by a given company for drilling any new wells. The degree of impact would also vary according to the characteristics of the geologic formations from which production occurs, as well as the scope of specific activities proposed in an APD. Oxides of nitrogen, carbon monoxide, volatile organic compounds, carbon dioxide, and methane are the most common emissions from a typical well (Green River, Wyoming; Table 6). The Kleinfelder report provides estimated pollutants for wells in three locations (San Juan, Uinta/Piceance, and Upper Green River basins). This analysis uses the Upper Green River values which represent the upper end of pollution production in the examples. The majority of pollution occurs during the production phase, where fugitive emissions (e.g., leaking pipes and valves) and dump valves (used to control the amount of fluid in the product) are the primary sources.

Climate Change/Greenhouse Gases

Sources of GHGs associated with development of lease parcels include construction activities, operations, and facility maintenance in the course of oil and gas exploration, development, and production. Estimated GHG emissions are discussed for these specific aspects of oil and gas activity because the BLM has direct involvement in these steps. Anticipated GHG emissions are based on emissions calculators developed by air quality specialists at the BLM National Operations Center in Denver, Colorado, based on a typical well in Green River Wyoming (Table 6).

3.4.2.2 Alternative A

Air Quality

Two new State lease wells and associated infrastructure would have minor adverse impacts on air quality over the long term. Small increases in nitrogen oxides (2%), carbon monoxide (0.1%), sulfur dioxide (<0.01%), and particulate matter (0.4%) would occur annually (Table 6). Good AQI values would likely predominate; however, well emissions could slightly increase the number of moderate AQI days especially during inversions. There would be negligible decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases

Emissions from two new wells on State leases would increase Payette County's annual carbon dioxide equivalent production by 2.4% (Table 6).

3.4.2.3 Alternative B

Air Quality

Twenty-two new BLM lease wells and associated infrastructure would have moderate adverse impacts on air quality over the long term. Increases in nitrogen oxides (22%), carbon monoxide (1.4%), sulfur dioxide (0.02%), and particulate matter (4.5%) would occur annually (Table 6). The percent of days rated good AQI could decrease, especially during inversions. There would be minor decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases

Twenty-two new wells on BLM leases would increase Payette County's annual carbon dioxide equivalent production by 26.2% (Table 6).

3.4.2.4 Alternative C

Air Quality

Twenty-five new BLM lease wells and associated infrastructure would have moderate adverse impacts on air quality over the long term. Controlled surface use stipulations could reduce some pollutants when or where they are in effect (e.g., the winter use restriction CSU-4 would reduce or eliminate some pollutants [e.g., PM_{10}] between December 1 and March 31; minimizing disturbance of fragile soils could reduce dust over the long term). Increases in nitrogen oxides (25%), carbon monoxide (1.6%), sulfur dioxide (0.03%), and particulate matter (5.1%) would occur annually (Table 6). The percent of days rated good AQI could decrease, especially during inversions. There would be minor decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases
Twenty-five new wells on BLM leases would increase Payette County's annual carbon dioxide equivalent production by 29.7% (Table 6).

3.4.3 Mitigation

The BLM encourages industry to incorporate and implement BMPs to reduce impacts to air quality and climate change by reducing emissions, surface disturbances, and dust from field production and operations. Measures may also be required as COAs on permits by either the BLM or IDEQ. The BLM also manages venting and flaring of gas from federal wells as described in the provisions of Notice to Lessees (NTL) 4A, Royalty or Compensation for Oil and Gas Lost.

Some of the following measures could be imposed at the development stage:

- flare or incinerate hydrocarbon gases at high temperatures to reduce emissions of incomplete combustion;
- install emission control equipment of a minimum 95% efficiency on all condensate storage batteries;
- install emission control equipment of a minimum 95% efficiency on dehydration units, pneumatic pumps, produced water tanks;
- operate vapor recovery systems where petroleum liquids are stored;
- use Tier II or greater, natural gas or electric drill rig engines;
- operate secondary controls on drill rig engines;
- use no-bleed pneumatic controllers (most effective and cost effective technologies available for reducing volatile organic compounds (VOCs));
- operate gas or electric turbines rather than internal combustions engines for compressors;
- use nitrogen oxides (NO_x) emission controls for all new and replaced internal combustion oil and gas field engines;
- water dirt and gravel roads during periods of high use and control speed limits to reduce fugitive dust emissions;
- perform interim reclamation to re-vegetate areas of the pad not required for production facilities and to reduce the amount of dust from the pads.
- co-locate wells and production facilities to reduce new surface disturbance;
- use directional drilling and horizontal completion technologies whereby one well provides access to petroleum resources that would normally require the drilling of several vertical wellbores;
- operate gas-fired or electrified pump jack engines;
- install velocity tubing strings;
- use cleaner technologies on completion activities (i.e. green completions), and other ancillary sources;
- use centralized tank batteries and multi-phase gathering systems to reduce truck traffic;
- forward looking infrared (FLIR) technology to detect fugitive emissions; and
- perform air monitoring for NO_x and ozone (O_3).

Specifically with regard to reducing GHG emissions, Section 6.0 of the Climate Change SIR identifies and describes in detail commonly used technologies to reduce methane emissions from natural gas production operations. Technologies discussed in the Climate Change SIR and as summarized in Table 7 (reproduced from Table 6-2 in Climate Change SIR), display common methane emission technologies reported under the EPA Natural Gas STAR Program and associated emission reduction, cost, maintenance, and payback data.

Table 7. Selected methane emission reductions reported under the EPA Natural Gas STAR Program.

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($1,000)	Annual Operating and Maintenance Cost ($1,000)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Wells					
Reduced emission (green) completion	7,000 [2]	$1 – $10	>$1	1 – 3 yr	$3
Plunger lift systems	630	$2.6 – $10	NR	2 – 14 mo	$7
Gas well smart automation system	1,000	$1.2	$0.1 – $1	1 – 3 yr	$3
Gas well foaming	2,520	>$10	$0.1 – $1	3 – 10 yr	NR
Tanks					
Vapor recovery units on crude oil tanks	4,900 – 96,000	$35 – $104	$7 – $17	3 – 19 mo	$7
Consolidate crude oil production and water storage tanks	4,200	>$10	<$0.1	1 – 3 yr	NR
Glycol Dehydrators					
Flash tank separators	237 – 10,643	$5 – $9.8	Negligible	4 – 51 mo	$7
Reducing glycol circulation rate	394 – 39,420	Negligible	Negligible	Immediate	$7
Zero-emission dehydrators	31,400	>$10	>$1	0 – 1 yr	NR
Pneumatic Devices and Controls					
Replace high-bleed devices with low-bleed devices					
End-of-life replacement	50 – 200	$0.2 – $0.3	Negligible	3 – 8 mo	$7
Early replacement	260	$1.9	Negligible	13 mo	$7
Retrofit	230	$0.7	Negligible	6 mo	$7
Maintenance	45 – 260	Negl. to $0.5	Negligible	0 – 4 mo	$7
Convert to instrument air	20,000 (per facility)	$60	Negligible	6 mo	$7
Convert to mechanical control systems	500	<$1	<$0.1	0 – 1 yr	NR
Valves					
Test and repair pressure safety valves	170	NR	$0.1 – $1	3 – 10 yr	NR
Inspect and repair compressor station blowdown valves	2,000	<$1	$0.1 – $1	0 – 1 yr	NR

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($1,000)	Annual Operating and Maintenance Cost ($1,000)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Compressors					
Install electric compressors	40 – 16,000	>$10	>$1	>10 yr	NR
Replace centrifugal compressor wet seals with dry seals	45,120	$324	Negligible	10 mo	$7
Flare Installation	2,000	>$10	>$1	None	NR

Source: Multiple EPA Natural Gas STAR Program documents. Individual documents are referenced in Climate Change SIR (2010).

[1] Unless otherwise noted, emission reductions are given on a per-device basis (e.g., per well, per dehydrator, per valve, etc).

[2] Emission reduction (Mcf = thousand cubic feet of methane) is per completion, rather than per year.

NR = not reported

3.4.4 Cumulative Impacts – Air Resources

Cumulative impacts to air resources are based on the RFDS created for this document (Appendix 1), RFDS for Hamilton and Willow fields, and the actions discussed below.

3.4.4.1 Scope of Analysis

The CIAA includes the airshed associated with Ada, Baker, Canyon, and Payette counties. Because of prevailing wind patterns, changes in Baker County air quality would affect Payette County and impacts from Payette County air quality would dissipate at the eastern side of Ada County. The analysis period covers the 10-year lease period; however, pollutants are reported by their annual production levels.

3.4.4.2 Current Conditions and Effects of Past and Present Actions

Because of a large population base (615,335 people in 2013), Ada and Canyon counties contribute substantial amounts of nitrogen oxides (79%), PM_{10} (83%), volatile organic compounds (75%), hazardous air pollutants (87%), and GHG (80%) to the four-county total pollution (Table 6). Baker County, with a relatively small population (16,018 people in 2013) and large area (3,068 mi^2 compared with 2,047 mi^2 for the other three counties combined), accounts for 71% of methane production, while other pollutant contributions vary from 7-24% of totals. The majority of growth during the 10-year period is expected to occur in Ada and Canyon counties; therefore, pollutant contributions from growth-related activities (e.g., construction, vehicle emissions, dust, and manufacturing) in these counties would be expected remain similar or increase proportionately more than Baker and Payette counties.

3.4.4.3 Reasonably Foreseeable Future Actions

An estimated 53 wells could come into production in the Hamilton (33,400 acres) and Willow (7,000 acres outside the proposed lease area) fields (Map 1). These wells would contribute from<0.01-3.4% of most pollutants; however, they would cause a 51% increase in methane production annually. AM Idaho (Alta Mesa's Idaho subsidiary) is constructing a hydrocarbon liquid treatment (dehydrator) facility (4 miles south of New Plymouth, Idaho), an ancillary

minimal. The amount of inconvenience would depend on the activity affected, traffic patterns within the area, noise levels, length of time, and season these activities occurred, etc. Creation of new access roads into an area could allow increased public access and exposure of private property to vandalism. For split estate leases, surface owner agreements, standard lease stipulations, and BMPs could address many of the concerns of private surface owners. Production and development activities could disproportionately affect disadvantaged groups where the activities are specifically targeted to their communities or properties to the benefit or avoidance of non-disadvantaged groups. They could also provide job opportunities for those groups.

Economics

Local and/or out-of-state workers could be hired or contracted to meet the direct and indirect needs of development and production. Individual income for workers typically associated with development and production activities would vary from $8,300 to $94,500 annually (Table 12). Mining-related jobs would likely pay above the median income ($32,400/year). Total new jobs created could be relatively low because some work would be short-term in nature. For each million dollars in gas production, 2.4 jobs could be created in the county of production (Weber 2012). Employees may shift to higher paying energy-related jobs creating a labor shortage for local employers. Sudden influxes of workers could reduce affordable housing availability. An influx of workers and equipment without commensurate financial support could adversely affect public and private sector infrastructure (schools, hospitals, law enforcement, fire protection, and other community needs), especially in rural communities. Tax, royalty, spending, and income revenues associated with leasing, development, and production would benefit local, county, State, and national economies. Stipulations that affect access to mineral resources could reduce economic return for lessors and lessees. Activities that increase access to mineral resources could benefit other mineral rights holders. Activities that adversely affect health, safety, or the environment could cause short- or long-term decreases in personal income and property values. Wildlife depredation on agricultural fields could adversely affect productivity of some crops (e.g., winter wheat, alfalfa).

Disclosure of the direct, indirect, and cumulative effects of GHG emissions provides information on the potential economic effects of climate change including effects that could be termed the "social cost of carbon" (SCC). The EPA and other federal agencies developed a method for estimating the SCC and a range of estimated values (EPA 2014). The SCC estimates damages associated with climate change impacts to net agricultural productivity, human health, property damage, and ecosystems. Using a 3% average discount rate and year 2020 values, the incremental SCC is estimated to be $51 per ton of annual CO_2eq increase.

3.14.2.2 Alternative A

Social and Environmental Justice

Not leasing the federal mineral estate in the project area would limit the development potential of the project area to only two wells, both located on private lands. Developing two wells and associated infrastructure would have minor short-term impacts from increased traffic and noise and long-term visual, public access, and vandalism impacts. Limited increases in access and

worker influx would occur. There are disadvantaged groups in Payette County, but they do not appear to be disproportionately associated with the two wells or the proposed lease area.

Economics

By not leasing, federal, state, or local revenues would not be generated from leasing, rents, or royalties from federal mineral estate. If BLM does not lease the federal minerals, it is likely that the IOGCC would allow the federal mineral estate to be omitted from the drilling unit. Moderate (if 493 acres associated with existing wells are omitted) to major (if up to 6,349 acres throughout the lease area are omitted) resource and revenue losses would occur if the IOGCC omitted the federal mineral estate and productive wells are drilled on private lands in the same unit. Development and production of two wells would cause minor employment and income increases. Negligible to minor impacts to labor and housing availability and infrastructure would occur over the short term. Adjacent mineral rights holders would experience minor beneficial (omission allowed) or moderate adverse (omission not granted) financial impacts. Adverse water quality and availability (Section 3.5.2.2), safety, and environmental impacts would primarily affect individual landowners in the immediate vicinity of the wells. Negligible wildlife depredation losses could occur.

Based on the GHG emission estimate (Table 6), the annual SCC associated with two wells would be $295,137 (in 2011 dollars). Estimated SCC is not directly comparable to economic contributions reported above, which recognize certain economic contributions to the local area and governmental agencies, but do not include all contributions to private entities at the regional and national scale. Direct comparison of SCC to the economic contributions reported above is also not appropriate because costs associated with climate change are borne by many different entities.

3.14.2.3 Alternative B

Social and Environmental Justice

Developing 22 wells and associated infrastructure would have moderate to major short-term increased traffic and noise impacts and long-term visual impacts. Minor (access controlled by private landowners) to major (access not controlled by private landowners) access and vandalism impacts could occur over the long term. A moderate worker influx could adversely affect traditional lifestyles. Disadvantaged groups in Payette County would not be directly affected by the wells, but access to affordable housing and social services in nearby communities could be reduced during the short term.

Economics

Federal, state, or local revenues would be generated from leasing and rents ($9,528 to $12,704 annually) during the 10-year lease period. The NSO and NSSO stipulations could reduce the lease value and bonus bid amounts. Developing and maintaining 22 wells would have minor to moderate short-term and negligible long-term job increases. Royalty income would depend on how productive the wells are and cannot be estimated at this time. Minor to moderate impacts to labor and housing availability and infrastructure would occur over the short term. Adjacent mineral rights holders would experience moderate financial benefits where access to their minerals improved. Adverse water quality and availability (Section 3.5.2.3), safety, and

environmental impacts could have negligible (wells remain intact and don't affect ground water) to major (surface and ground water adversely affected by multiple wells) to the adjacent landowners and downstream communities. Minor to moderate wildlife depredation losses could occur. Based on the GHG emission estimate (Table 6), the annual SCC associated with 22 wells would be $3,246,711 (in 2011 dollars).

3.14.2.4 Alternative C

Social and Environmental Justice

The impacts of developing 25 wells and associated infrastructure would be as described in Alternative B (Section 3.14.2.3).

Economics

Leasing 6,349 acres and associated development and production would have similar revenue, job, labor and housing availability, infrastructure, and adjacent mineral rights holder impacts as described in Alternative B (Section 3.14.2.3). The impact of CSU stipulations on lease value would be less than Alternative B and royalty income could be greater. Adverse water quality and availability (Section 3.5.2.4), safety, and environmental impacts would be similar to Alternative B; however, the freshwater aquatic habitat CSU stipulation could provide minor to moderate surface water protection. Minor wildlife depredation losses could occur. Based on the GHG emission estimate (Table 6), the annual SCC associated with 25 wells would be $3,689,442 (in 2011 dollars).

3.14.3 Mitigation

Measures that limit or control dust, noise, odors and protect visual impacts and water quality resources would help reduce social and economic impacts (Dahl et. al. 2010).

3.14.4 Cumulative Impacts – Social and Economic

Cumulative impacts to the social and economic environment are based on the RFDS created for this document (Table 2, Appendix 1), RFDS for the Willow and Hamilton fields, and the activities identified below.

3.14.4.1 Scope of Analysis

Payette County will serve as the CIAA. Although social and economic costs and benefits could occur at regional, state, national, and international levels, the majority would occur at the county level. The lease period of 10 years will be used for the temporal analysis limit because the federal mineral estate would be available for production during that time period, but not necessarily beyond.

3.14.4.2 Current Conditions and Effects of Past and Present Actions

Current Payette County social and economic conditions are described in Section 3.14.1. All State-owned minerals (Section 3.13.1) and an unknown acreage of privately-owned minerals have been leased in recent years. The State leases will expire between 2016 (14,181 acres) and 2024. The existing 17 oil and gas wells have been developed over several years, although the

Exhibit 3

Attachment F

DRAFT OIL AND GAS AIR EMISSIONS INVENTORY REPORT FOR SEVEN LEASE PARCELS IN THE BLM ROYAL GORGE FIELD OFFICE

Prepared for:

BLM
Colorado State Office and Royal Gorge Field Office
Colorado

Prepared by:

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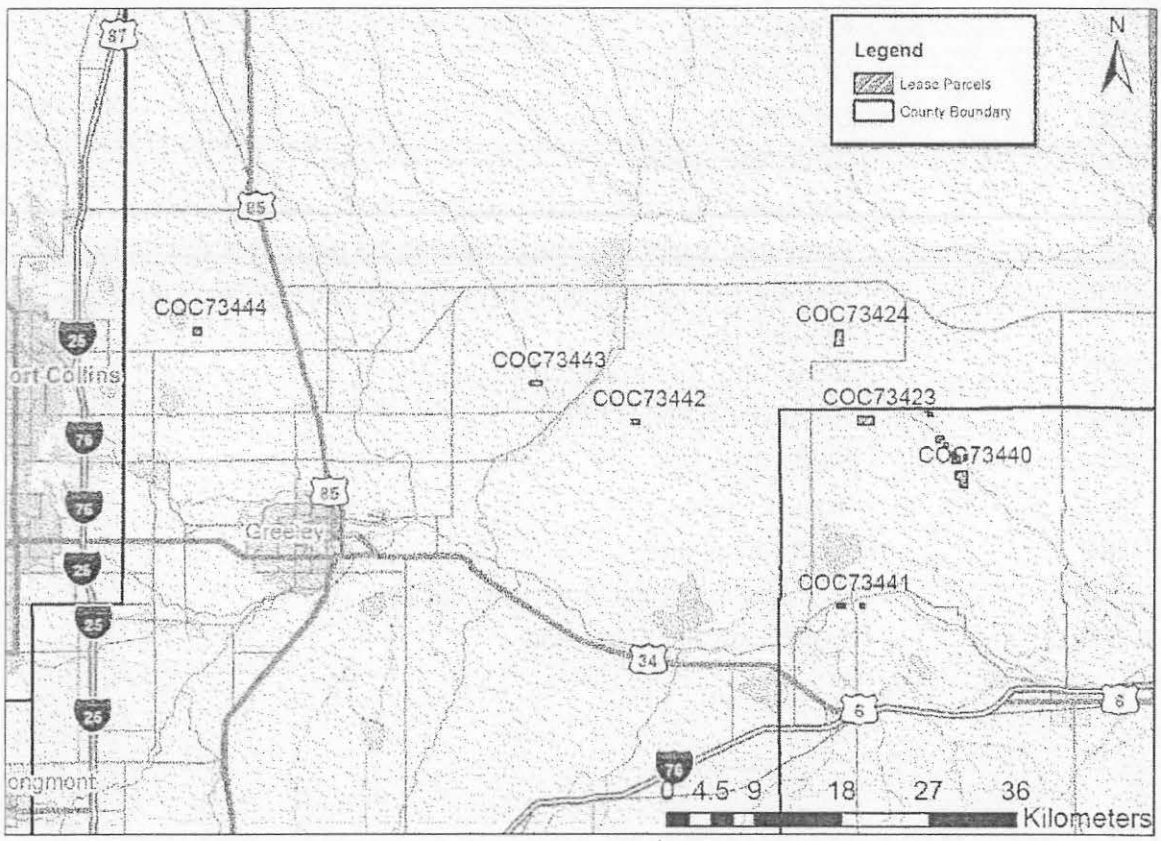
LIST OF ACRONYMS AND ABBREVIATIONS

AP-42	*Compilation of Air Pollutant Emission Factors*
APD	Application for Permit to Drill
API	American Petroleum Institute
bbls	Barrels
BLM	Bureau of Land Management
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COGCC	Colorado Oil and Gas Conservation Commission
CSO	Colorado State Office
Mscf	Thousands of standard cubic feet
NAA	Non-Attainment Area
NH_3	Ammonia
N_2O	Nitrous oxides
NO_x	Oxides of nitrogen
O&G	Oil and Gas
PM	Particulate matter
PM_{10}	Particulate matter less than or equal to 10 microns in size
$PM_{2.5}$	Particulate matter less than or equal to 2.5 microns in size
PSICC	Pike and San Isabel National Forests and Cimarron and Comanche National Grasslands
RFD	Reasonably foreseeable development
RGFO	Royal Gorge Field Office
SO_2	Sulfur dioxide
tpy	Tons per year
URS	URS Group, Inc.
USEPA	U.S. Environmental Protection Agency
VOC	Volatile organic compound

PROJECT INTRODUCTION AND STUDY AREA

This oil and gas (O&G) emissions inventory report identifies the data and methodologies used in developing air emissions inventories for potential oil and gas development and production activities on seven (7) specific lease parcels in the Bureau of Land Management (BLM) Royal Gorge Field Office (RGFO). These seven parcels are part of the twelve (12) lease parcels in eastern Colorado referred to in the Stipulation and Order entered into by WildEarth Guardians and the BLM (WildEarth 2012) and for this report will further be known as "Study" or "Project". The emissions inventories include quantified potential emissions based on the 2012 BLM RGFO Reasonable Foreseeable Development (RFD) document (BLM 2012).

For emissions inventory domain purposes, the Study Area focuses on the seven lease parcels in the BLM RGFO in Colorado. The RGFO administers over 680,000 surface acres of public land along the Colorado Front Range and 6.8 million sub-surface acres. This Field Office covers approximately the eastern half of Colorado and includes a variety of terrain. The Project emissions inventory development will focus on potential oil and gas activities on the seven lease parcels in the RGFO. A map showing the locations of the seven BLM lease parcels is presented below (Map 1-1).



Map 0-1. Locations of Seven BLM Lease Parcels

The number of active wells for each Township that contains one of the seven lease parcels is shown below in Table 1-1 (data taken from Figure 5b of the RFD [BLM 2012]). Also shown in this table are the number of active wells in the county in 2011, as well as the 2011 oil, gas, and water production for each of the two counties containing the seven lease parcels (COGCC 2013). In order to provide a background of the emissions levels in the area of the lease parcels, Table 1-2 provides county level emissions inventories in tons per year (tpy) for Weld and Morgan counties taken from the 2008 National Emissions Inventory (USEPA 2013).

Table 0-1. Active Wells and Production Values

Parcel Serial #	Township	Number of Active Wells in Township in 2011	County	Number of Active Wells in County in 2011	2011 Average Monthly Oil Production (bbls)	2011 Average Monthly Gas Production (Mscf)	2011 Average Monthly Water Production (bbls)
COC73423	Township 6 North Range 60 West	6	Morgan	252	9,159	10,946	265,862
COC73440	Township 6 North Range 59 West	4					
COC73441	Township 4 North Range 60 West	0					
COC73424	Township 7 North Range 60 West	8	Weld	22,323	2,220,768	19,964,793	954,887
COC73442	Township 6 North Range 62 West	54					
COC73443	Township 7 North Range 63 West	50					
COC73444	Township 7 North Range 67 West	21					

bbls = barrels
Mscf = thousands of standard cubic feet
Source: COGCC 2011 County Production Report

Table 0-2. 2008 County Level Emissions Inventories (tpy)

County	PM_{10}	$PM_{2.5}$	CO	NO_x	SO_2	VOC	CO_2	CH_4	N_2O	NH_3	HAPs
Morgan	6,880	1,529	10,471	9,561	13,466	10,234	306,257	22	10	5,765	2,232
Weld	28,851	5,962	60,876	20,088	352	52,991	1,683,038	137	66	17,042	7,389

PM = Particulate matter
PM_{10} = Particulate matter less than or equal to 10 microns in size
$PM_{2.5}$ = Particulate matter less than or equal to 2.5 microns in size
CO = Carbon monoxide
NO_x = Oxides of nitrogen
SO_2 = Sulfur dioxide
VOC = Volatile organic compounds
CO_2 = Carbon dioxide
CH_4 = Methane
N_2O = Nitrous oxide
NH_3 = Ammonia
HAPs = Hazardous air pollutants
Source: USEPA 2008 NEI

EMISSIONS INVENTORY METHODOLOGY

This section describes the data sources and methods that were used to develop the seven lease parcel-specific emission inventories.

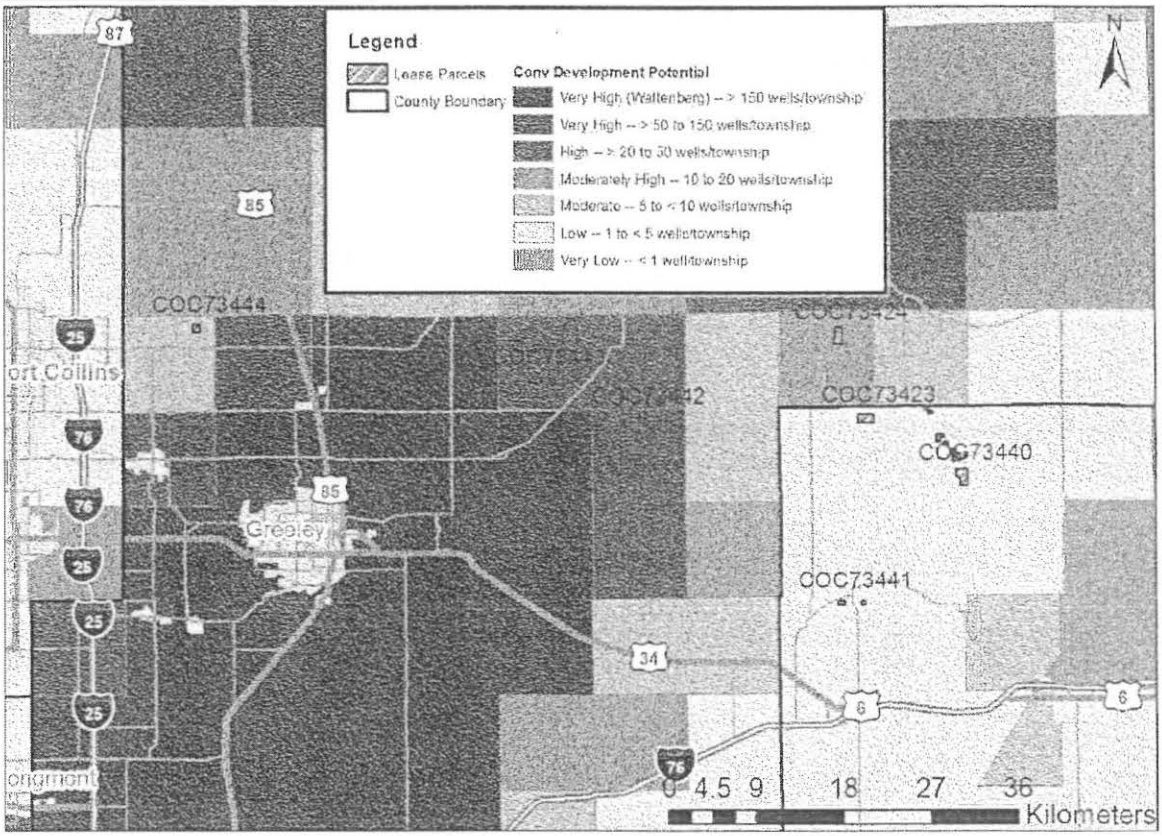
POTENTIAL WELL DEVELOPMENT

Potential well development was estimated using data from the 2012 BLM RGFO RFD and is shown in Table 2-1. Map 2-1 shows oil and gas development potential and projected drilling densities for the years 2011 through 2030 for each Township in the RGFO (Figure 17, 2012 BLM). The minimum and maximum number of potential wells per Township was determined for each lease parcel based on this figure. The average acres disturbed per well was calculated using Table 14a of the RFD document along with the expected percentages of multi-well and single-well pads found on page 31. Parcels must have at least one well in order to retain a lease; therefore, the potential minimum wells developed for each of the lease parcels is one. To determine the potential maximum wells developed for each lease parcel, the area of each parcel in acres was divided by the average acres disturbed for each well. If the result was greater than the maximum wells per Township, the potential maximum was set to the maximum wells per Township; otherwise, the result was used.

Table 0-3. Potential Conventional Well Development for the Seven Lease Parcels

Parcel Serial #	In Non-attainment Area? [1]	Development Category	Minimum Wells per Township	Maximum Wells per Township	Area of Parcel (acres)	Average Acres Disturbed per Well [2]	Potential Minimum Wells Developed in Parcel [3]	Potential Maximum Wells Developed in Parcel [4]
COC73444	Y	Moderate	5	9	160	7.6	1	9
COC73443	Y	High	21	50	123	7.6	1	16
COC73442	Y	Very High	51	150	80	7.6	1	10
COC73424	Y	Moderately High	10	20	320	7.6	1	20
COC73423	N	Low	1	4	320	2.1	1	4
COC73441	N	Low	1	4	120	2.1	1	4
COC73440	N	Low	1	4	879	2.1	1	4

(1) Parcels are either within the Greater Wattenberg Non-Attainment Area (NAA) or to the east of the NAA.
(2) Average acres disturbed is determined from values in the RFD.
(3) Parcels must have at least one well to retain lease.
(4) Potential maximum wells developed is either the number of wells that will fit in the parcel, or the maximum per Township, if the former is greater.



Map 0-2. Conventional O&G Development Potential

POTENTIAL OIL AND GAS ACTIVITIES

Potential oil and gas activities on the lease parcels range from land disturbance from construction and drilling, to well completion activities from venting and flaring, and production activities. Particulate emissions could be generated from the construction of new well pads, roads and pipelines. Construction emissions will also include criteria pollutants from exhaust emissions from construction traffic and drilling engines. At times, during completion, well workovers, or blowdowns, gas may be vented or flared.

Potential oil and gas activity levels for the seven lease parcels were estimated from a variety of sources. Potential oil, gas, condensate, and water produced from wells that could be developed on the lease parcels were estimated by the BLM Colorado State Office (BLM-CSO) from Applications for Permit to Drill (APD) submissions from other sites in the area of the seven lease parcels.

Data requests were sent out to oil and gas operators that work in the area of the seven lease parcels. Only one operator sent back a response. This data was used to supplement the data from the APDs.

Another source of data was the Pike and San Isabel National Forests and Cimarron and Comanche National Grasslands (PSICC) Air Quality Study. The data from this study was used to fill in any data gaps left after the APD and operator data had been entered.

PER-WELL EMISSIONS INVENTORY

The per-well emissions were calculated using the activity data listed in the above section along with emission factors taken from AP-42 (USEPA 1998, 2000, 2006), the American Petroleum Institute's Compendium (API 2009), the USEPA's *Protocol for Equipment Leak Emissions Estimates*, as well as, emissions factors developed for the Piceance Basin in western Colorado.

Emissions calculations took into account all current EPA and Colorado regulations on the oil and gas industry. The latest EPA regulations that affect this project include the following (USEPA 2012):

- High-bleed pneumatic controllers must have a gas bleed limit of 6 cubic feet of gas per hour, and
- Storage tanks with VOC emissions of 6 tons per year or more are required to reduce emissions by at least 95%.

The estimated per-well emissions for the seven lease parcels are listed in Table 2-2 below.

Table 0-4. Per-Well Emissions Estimates

Resource/Phase	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	HAPs	CO_2	CH_4	N_2O
	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
Oil										
Construction	28.51	3.61	11.16	0.03	2.63	0.75	0.08	1,518.74	0.03	0.01
Operation	15.62	1.64	10.58	0.01	6.26	20.96	2.01	1,149.23	20.86	0.02
Maintenance	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.00
Reclamation	0.06	0.01	0.02	0.00	0.01	0.00	0.00	1.73	0.00	0.00
Total	44.27	5.27	21.75	0.03	8.90	21.72	2.09	2,670.32	20.89	0.03
Natural Gas										
Construction	28.62	3.63	11.18	0.03	2.77	0.76	0.08	1,563.51	0.03	0.01
Operation	14.68	1.65	4.53	0.01	8.06	33.30	3.65	1,211.83	31.69	0.01
Maintenance	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.00
Reclamation	0.06	0.01	0.02	0.00	0.01	0.00	0.00	1.73	0.00	0.00
Total	43.45	5.30	15.73	0.03	10.84	34.06	3.73	2,777.69	31.72	0.03

SUMMARY

Per-well emissions estimates have been calculated for seven parcels in Weld and Morgan Counties in Colorado. These estimates were calculated using the most current data available and included the most current rules and regulations. Colorado has published recommended modeling thresholds for new sources of emissions (CDPHE 2011). These thresholds are exceeded by the per-well emissions estimates for short-term and long-term PM_{10} and $PM_{2.5}$, and short-term NO_x. Approximately half of the estimated emissions of PM_{10}, $PM_{2.5}$, NO_x and CO_2 come from construction related activities. These activities are expected to last a few weeks per well. The BLM may also require additional controls as conditions of approvals at the permitting stage, which could further reduce emissions. These additional controls may include, but are not limited to, Tier 4 engines and fugitive dust control for construction and traffic.

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Exhibit 4

CARMMS + RGFO GHG Emissions

Summary of Total Wellsite and Midstream Cumulative (Federal and Non-Federal) Direct and Mid-Stream Emissions (tons/year) by Field Office and Designation

		CARMMS Scenario	CARMMS - High			CARMMS - Medium			CARMMS - Low			Current Track (April 2015)
Field Office	Designation	Year	CO2	CH4	N2O	CO2	CH4	N2O	CO2	CH4	N2O	
LSFO	Federal	2021	829,039	19,533	15	822,604	17,441	15	261,378	8,527	5	Low
LSFO	non-Federal	2021	573,758	12,918	10	573,724	12,728	10	138,610	4,574	2	
WRFO	Federal	2021	4,128,642	87,610	66	4,121,429	73,579	66	1,128,378	27,244	19	Low
WRFO	non-Federal	2021	647,205	14,139	10	647,205	14,139	10	316,268	7,526	5	
CRVFO (Roan)	Federal	2021	542,495	13,980	8	541,634	12,158	8	422,336	11,391	7	Low
CRVFO (Roan)	non-Federal	2021	682,922	18,839	11	682,922	18,839	11	682,922	18,839	11	
CRVFO (outside Roan)	Federal	2021	773,232	23,898	13	771,396	19,946	13	604,270	18,767	10	Low
CRVFO (outside Roan)	non-Federal	2021	2,314,913	71,955	38	2,314,913	71,955	38	1,842,049	57,597	31	
GJFO	Federal	2021	1,613,851	47,855	22	1,581,415	40,880	22	218,742	5,377	3	Low
GJFO	non-Federal	2021	2,755,830	72,688	41	2,755,830	72,688	41	1,528,480	42,134	23	
UFO	Federal	2021	185,482	6,666	3	181,929	5,663	3	21,369	893	0	Low
UFO	non-Federal	2021	326,891	12,323	5	326,891	12,323	5	15,438	687	0	
TRFO	Federal	2021	497,444	23,853	6	484,764	19,943	6	195,592	7,792	3	Low
TRFO	non-Federal	2021	1,323,613	76,610	21	1,323,613	76,610	21	1,340,077	77,844	21	
KFO	Federal	2021	84,614	2,630	1	83,793	2,409	1	38,815	1,280	1	Low
KFO	non-Federal	2021	63,903	2,003	1	63,903	2,003	1	32,570	1,027	1	
RGFO Area 1	Federal	2021	146,617	6,263	2	145,193	5,573	2	27,296	1,166	1	High
RGFO Area 1	non-Federal	2021	4,184,047	178,738	66	4,184,047	178,738	66	1,678,298	71,695	22	
RGFO Area 2	Federal	2021	28,076	1,199	1	27,803	1,067	1	3,120	133	0	Low
RGFO Area 2	non-Federal	2021	115,422	4,931	2	115,422	4,931	2	90,466	3,865	2	
RGFO Area 3	Federal	2021	12,597	1,059	0	12,474	942	0	8,398	706	0	Low
RGFO Area 3	non-Federal	2021	151,161	12,710	2	151,161	12,710	2	83,978	7,061	1	
RGFO Area 4	Federal	2021	28,076	1,199	1	27,803	1,067	1	3,120	133	0	Low
RGFO Area 4	non-Federal	2021	90,466	3,865	1	90,466	3,865	1	21,837	933	1	
Colorado Projections Federal:			8,870,164	235,746	138	8,801,738	200,669	138	2,932,812	83,411	48	
Colorado Projections Non-Federal:			13,230,131	481,719	208	13,230,098	481,528	208	7,770,994	293,732	120	

* Medium CARMMS scenario summary data not provided to BLM as part of CARMMS contract

* RGFO Emissions NOT estimated by CARMMS

Exhibit 5

THE COST OF DELAYING ACTION TO STEM CLIMATE CHANGE

July 2014

Executive Summary

The signs of climate change are all around us. The average temperature in the United States during the past decade was 0.8° Celsius (1.5° Fahrenheit) warmer than the 1901-1960 average, and the last decade was the warmest on record both in the United States and globally. Global sea levels are currently rising at approximately 1.25 inches per decade, and the rate of increase appears to be accelerating. Climate change is having different impacts across regions within the United States. In the West, heat waves have become more frequent and more intense, while heavy downpours are increasing throughout the lower 48 States and Alaska, especially in the Midwest and Northeast.[1] The scientific consensus is that these changes, and many others, are largely consequences of anthropogenic emissions of greenhouse gases.[2]

The emission of greenhouse gases such as carbon dioxide (CO_2) harms others in a way that is not reflected in the price of carbon-based energy, that is, CO_2 emissions create a negative externality. Because the price of carbon-based energy does not reflect the full costs, or economic damages, of CO_2 emissions, market forces result in a level of CO_2 emissions that is too high. Because of this market failure, public policies are needed to reduce CO_2 emissions and thereby to limit the damage to economies and the natural world from further climate change.

There is a vigorous public debate over whether to act now to stem climate change or instead to delay implementing mitigation policies until a future date. This report examines the economic consequences of delaying implementing such policies and reaches two main conclusions, both of which point to the benefits of implementing mitigation policies now and to the net costs of delaying taking such actions.

First, although delaying action can reduce costs in the short run, on net, delaying action to limit the effects of climate change is costly. Because CO_2 accumulates in the atmosphere, delaying action increases CO_2 concentrations. Thus, if a policy delay leads to higher ultimate CO_2 concentrations, that delay produces persistent economic damages that arise from higher temperatures and higher CO_2 concentrations. Alternatively, if a delayed policy still aims to hit a given climate target, such as limiting CO_2 concentration to given level, then that delay means that the policy, when implemented, must be more stringent and thus more costly in subsequent years. In either case, delay is costly.

These costs will take the form of either greater damages from climate change or higher costs associated with implementing more rapid reductions in greenhouse gas emissions. In practice, delay could result in both types of costs. These costs can be large:

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[1] For a fuller treatment of the current and projected consequences of climate change for U.S. regions and sectors, see the Third National Climate Assessment (United States Global Change Research Program (USGCRP) 2014).

[2] See for example the Summary for Policymakers in Working Group I contribution to the Intergovernmental Panel on Climate Change Fifth Assessment Report (IPCC WG I AR5 2013).

- Based on a leading aggregate damage estimate in the climate economics literature, a delay that results in warming of 3° Celsius above preindustrial levels, instead of 2°, could increase economic damages by approximately 0.9 percent of global output. To put this percentage in perspective, 0.9 percent of estimated 2014 U.S. Gross Domestic Product (GDP) is approximately $150 billion. The incremental cost of an additional degree of warming beyond 3° Celsius would be even greater. Moreover, these costs are not one-time, but are rather incurred year after year because of the permanent damage caused by increased climate change resulting from the delay.

- An analysis of research on the cost of delay for hitting a specified climate target (typically, a given concentration of greenhouse gases) suggests that net mitigation costs increase, on average, by approximately 40 percent for each decade of delay. These costs are higher for more aggressive climate goals: each year of delay means more CO_2 emissions, so it becomes increasingly difficult, or even infeasible, to hit a climate target that is likely to yield only moderate temperature increases.

Second, climate policy can be thought of as "climate insurance" taken out against the most severe and irreversible potential consequences of climate change. Events such as the rapid melting of ice sheets and the consequent increase of global sea levels, or temperature increases on the higher end of the range of scientific uncertainty, could pose such severe economic consequences as reasonably to be thought of as climate catastrophes. Confronting the possibility of climate catastrophes means taking prudent steps now to reduce the future chances of the most severe consequences of climate change. The longer that action is postponed, the greater will be the concentration of CO_2 in the atmosphere and the greater is the risk. Just as businesses and individuals guard against severe financial risks by purchasing various forms of insurance, policymakers can take actions now that reduce the chances of triggering the most severe climate events. And, unlike conventional insurance policies, climate policy that serves as climate insurance is an investment that also leads to cleaner air, energy security, and benefits that are difficult to monetize like biological diversity.

I. Introduction

The changing climate and increasing atmospheric greenhouse gas (GHG) concentrations are projected to accelerate multiple threats, including more severe storms, droughts, and heat waves, further sea level rise, more frequent and severe storm surge damage, and acidification of the oceans (USGCRP 2014). Beyond the sorts of gradual changes we have already experienced, global warming raises additional threats of large-scale changes, either changes to the global climate system, such as the disappearance of late-summer Arctic sea ice and the melting of large glacial ice sheets, or ecosystem impacts of climate change, such as critical endangerment or extinction of a large number of species.

Emissions of GHGs such as carbon dioxide (CO_2) generate a cost that is borne by present and future generations, that is, by people other than those generating the emissions. These costs, or economic damages, include costs to health, costs from sea level rise, and damage from increasingly severe storms, droughts, and wildfires. These costs are not reflected in the price of those emissions. In economists' jargon, emitting CO_2 generates a negative externality and thus a market failure. Because the price of CO_2 emissions does not reflect its true costs, market forces alone are not able to solve the problem of climate change. As a result, without policy action, there will be more emissions and less investment in emissions-reducing technology than there would be if the price of emissions reflected their true costs.

This report examines the cost of delaying policy actions to stem climate change, and reaches two main conclusions. First, delaying action is costly. If a policy delay leads to higher ultimate CO_2 concentrations, then that delay produces persistent additional economic damages caused by higher temperatures, more acidic oceans, and other consequences of higher CO_2 concentrations. Moreover, if delay means that the policy, when implemented, must be more stringent to meet a given target, then it will be more costly.

Second, uncertainty about the most severe, irreversible consequences of climate change adds urgency to implementing climate policies *now* that reduce GHG emissions. In fact, climate policy can be seen as climate insurance taken out against the most damaging potential consequences of climate change—consequences so severe that these events are sometimes referred to as climate catastrophes. The possibility of climate catastrophes leads to taking prudent steps now to sharply reduce the chances that they occur.

The costs of inaction underscore the importance of taking meaningful steps today towards reducing carbon emissions. An example of such a step is the Environmental Protection Agency's (EPA) proposed rule (2014) to regulate carbon pollution from existing power plants. By adopting economically efficient mechanisms to reduce emissions over the coming years, this proposed rule would generate large positive net benefits, which EPA estimates to be in the range of $27 - 50 billion annually in 2020 and $49 - 84 billion in 2030. These benefits include benefits to health from reducing particulate emissions as well as benefits from reducing CO_2 emissions.

Delaying Climate Policies Increases Costs

Delaying climate policies avoids or reduces expenditures on new pollution control technologies in the near term. But this short-term advantage must be set against the disadvantages, which are the costs of delay. The costs of delay are driven by fundamental elements of climate science and economics. Because the lifetime of CO_2 in the atmosphere is very long, if a mitigation policy is delayed, it must take as its starting point a higher atmospheric concentration of CO_2. As a result, delayed mitigation can result in two types of cost, which we would experience in different proportions depending on subsequent policy choices.

First, if delay means an increase in the ultimate end-point concentration of CO_2, then delay will result in additional warming and additional economic damages resulting from climate change. As is discussed in Section II, economists who have studied the costs of climate change find that temperature increases of 2° Celsius above preindustrial levels or less are likely to result in aggregate economic damages that are a small fraction of GDP. This small net effect masks important differences in which some regions could benefit somewhat from this warming while other regions could experience net costs. But global temperatures have *already* risen nearly 1° above preindustrial levels, and it will require concerted effort to hold temperature increases to within the narrow range consistent with small costs.[3] For temperature increases of 3° Celsius or more above preindustrial levels, the aggregate economic damages from climate change are expected to increase sharply.

Delay that causes a climate target to be missed creates large estimated economic damages. For example, a calculation in Section II of this report, based on a leading climate model (the DICE model as reported in Nordhaus 2013), shows that if a delay causes the mean global temperature increase to stabilize at 3° Celsius above preindustrial levels, instead of 2°, that delay will induce annual additional damages of approximately 0.9 percent of global output, as shown in Figure 1.[4] To put this percentage in perspective, 0.9 percent of estimated 2014 U.S. GDP is approximately $150 billion.[5] The next degree increase, from 3° to 4°, would incur greater *additional* annual costs of approximately 1.2 percent of global output. These costs are not one-time: they are incurred year after year because of the permanent damage caused by additional climate change resulting from the delay.

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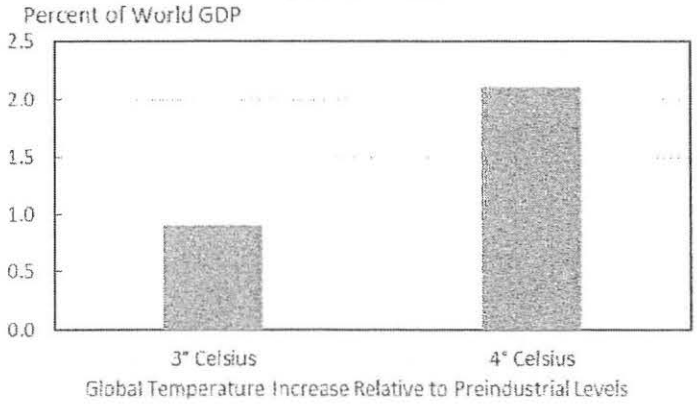
[3] The Working Group III contribution to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (IPCC WG III AR5 2014) does not analyze scenarios producing temperatures in 2100 less than 1.5 Celsius above preindustrial, because this is considered so difficult to achieve.

[4] Nordhaus (2013) stresses that these estimates "are subject to large uncertainties...because of the difficulty of estimating impacts in areas such as the value of lost species and damage to ecosystems." (pp. 139-140).

[5] These percentages apply to gross world output and the application of them to U.S. GDP is illustrative.

Figure 1: Economic Damage from Temperature Increase Beyond 2° Celsius



Source: Nordhaus (2013) and CEA calculations

The second type of cost of delay is the increased cost of reducing emissions more sharply if, instead, the delayed policy is to achieve the same climate target as the non-delayed policy. Taking meaningful steps now sends a signal to the market that reduces long-run costs of meeting the target. Part of this signal is that new carbon-intensive polluting facilities will be seen as bad investments; this reduces the amount of locked-in high-carbon infrastructure that is expensive to replace. Second, taking steps now to reduce CO_2 emissions signals the value of developing new low- and zero-emissions technologies, so additional steps towards a zero-carbon future can be taken as policy action incentivizes the development of new technologies. For both reasons, the least-cost mitigation path to achieve a given concentration target typically starts with a relatively low price of carbon to send these signals to the market, and subsequently increases as new low-carbon technology becomes available.[6]

The research discussed in Section II of this report shows that any short run gains from delay tend to be outweighed by the additional costs arising from the need to adopt a more abrupt and stringent policy later.[7] An analysis of the collective results from that research, described in more detail in Section II, suggests that the cost of hitting a specific climate target increases, on average, by approximately 40 percent for each decade of delay. These costs are higher for more aggressive climate goals: the longer the delay, the more difficult it becomes to hit a climate target. Furthermore, the research also finds that delay substantially decreases the chances that even concerted efforts in the future will hit the most aggressive climate targets.

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[6] The 2010 National Research Council, *Limiting the Magnitude of Future Climate Change*, also stressed the importance of acting now to implement mitigation policies as a way to reduce costs. The NRC emphasized the importance of technology development in holding down costs, including by providing clear signals to the private sector through predictable policies that support development of and investment in low-carbon technologies.

[7] The IPCC WG III AR5 (2014) includes an extensive discussion of mitigation, including sectoral detail, potential for technological progress, and the timing of mitigation policies.

Although global action is essential to meet climate targets, unilateral steps both encourage broader action and benefit the United States. Climate change is a global problem, and it will require strong international leadership to secure cooperation among both developed and developing countries to solve it. America must help forge a truly global solution to this global challenge by galvanizing international action to significantly reduce emissions. By taking credible steps toward mitigation, the United States will also reap the benefits of early action, such as investing in low-carbon infrastructure now that will reduce the costs of reaching climate targets in the future.

Climate Policy as Climate Insurance

Individuals and businesses routinely purchase insurance to guard against various forms of risk such as fire, theft, or other loss. This logic of self-protection also applies to climate change. Much is known about the basic science of climate change: there is a scientific consensus that, because of anthropogenic emissions of CO_2 and other GHGs, global temperatures are increasing, sea levels are rising, and the world's oceans are becoming more acidic. These and other climate changes are expected to be harmful, on balance, to the world's natural and economic systems. Nevertheless, uncertainty remains about the magnitude and timing of these and other aspects of climate change, even if we assume that future climate policies are known in advance. For example, the Working Group I contribution to the IPCC's Fifth Assessment Report (IPCC WG I AR5 2013) provides a likely range of 1.5° to 4.5° Celsius for the equilibrium climate sensitivity, which is the long-run increase in global mean surface temperature that is caused by a sustained doubling of atmospheric CO_2 concentrations. The upper end of that range would imply severe climate impacts under current emissions trajectories, and current scientific knowledge indicates that values in excess of this range are also possible.[8]

An additional, related source of climate uncertainty is the possibility of irreversible, large-scale changes that have wide-ranging and severe consequences. These are sometimes called abrupt changes because they could occur extremely rapidly as measured in geologic time, and are also sometimes called climate catastrophes. We are already witnessing one of these events—the rapid trend towards disappearance of late-summer Arctic sea ice. A recent study from the National Research Council (NRC 2013) found that this strong trend toward decreasing sea-ice cover could have large effects on a variety of components of the Arctic ecosystem and could potentially alter large-scale atmospheric circulation and its variability. The NRC also found that another large-scale change has been occurring, which is the critical endangerment or loss of a significant percentage of marine and terrestrial species. Other events judged by the NRC to be likely in the more distant future (after 2100) include, for example, the possible rapid melting of the Western Antarctic ice and Greenland ice sheets and the potential thawing of Arctic permafrost and the consequent release of the potent GHG methane, which would accelerate global warming. These and other potential large-scale changes are irreversible on relevant time

[8] It is important to note that, as a global average, the equilibrium climate sensitivity masks the expectation that temperature change will be higher over land than the oceans, and that there will be substantial regional variations in temperature increases. The equilibrium climate sensitivity describes a long-term effect and is only one component of determining near term warming due to the buildup of GHGs in the atmosphere.

scales—if an ice sheet melts, it cannot be reconstituted—and they could potentially have massive global consequences and costs. For many of these events, there is thought to be a "tipping point," for example a temperature threshold, beyond which the transition to the new state becomes inevitable, but the values or locations of these tipping points are typically unknown.

Section III of this report examines the implications of these possible climate-related catastrophes for climate policy. Research on the economic and policy implications of such threats is relatively recent. As detailed in Section III, a conclusion that clearly emerges from this young but active literature is that the threat of a climate catastrophe, potentially triggered by crossing an unknown tipping point, implies erring on the side of prudence today. Accordingly, in a phrase used by Weitzman (2009, 2012), Pindyck (2011), and others, climate policy can be thought of as "climate insurance." The logic here is that of risk management, in which one acts now to reduce the chances of worst-case outcomes in the future. Here, too, there is a cost to delay: the longer emission reductions are postponed, the greater are atmospheric concentrations of GHGs, and the greater is the risk arising from delay.

Other Costs of Delay and Benefits of Acting Now

An additional benefit of adopting meaningful mitigation policies now is that doing so sends a strong signal to the market to spur the investments that will reduce mitigation costs in the future. An argument sometimes made is that mitigation policies should be postponed until new low-carbon technologies become available. Indeed, ongoing technological progress has dramatically improved productivity and welfare in the United States because of vast inventions and process improvements in the private sector (see for example CEA 2014, Chapter 6). The private sector invests in research and development, and especially in process improvements, because those technological advances reap private rewards. But low-carbon technologies, and environmental technologies more generally, face a unique barrier: their benefits – the reduction in global impacts of climate change – accrue to everyone and not just to the developer or adopter of such technologies.[9] Thus private sector investment in low-carbon technologies requires confidence that those investments, if successful, will pay off, that is, the private sector needs to have confidence that there will be a market for low-carbon technologies now and in the future. Public policies that set out a clear and ongoing mitigation path provide that confidence. Simply waiting for a technological solution, but not providing any reason for the private sector to create that solution, is not an effective policy. Although public financing of basic research is warranted because many of the benefits of basic research cannot be privately appropriated, many of the productivity improvements and cost reductions seen in new technologies come from incremental advances and process improvements that only arise through private-sector experience producing the product and learning-by-doing. These advances are protected through the patent system and as trade secrets, but those advances will only transpire if it is clear that they will have current and

[9] Popp, Newell, and Jaffe (2010) provide a thorough review of the literature regarding technological change and the environment.

future value. In other words, policy action induces technological change.[10] Although a full treatment of the literature on technological change is beyond the scope of this report, providing the private sector with the certainty needed to invest in low-carbon technologies and produce such technological change is a benefit of adopting meaningful mitigation policies now.

Finally, because this report examines the economic costs of delay, it focuses on actions or consequences that have a market price. But the total costs of climate change include much that does not trade in the market and to which it is difficult to assign a monetary value, such as the loss of habitat preservation, decreased value of ecosystem goods and services, and mass extinctions. Although some studies have attempted to quantify these costs, including all relevant climate impacts is infeasible. Accordingly, the monetized economic costs of delay analyzed in this report understate the true total cost of delaying action to mitigate climate change.

[10] For example, Popp (2003) provides empirical evidence that Title IV of the 1990 Clean Air Act Amendments (CAAA) led to innovations that reduced the cost of the environmental technologies that reduced SO_2 emissions from coal-fired power plants. Other literature shows evidence linking environmental regulation more broadly to innovation (e.g., Popp 2006, Jaffe and Palmer 1997, Lanjouw and Mody 1996).

II. Costs from Delaying Policy Action

Delaying action on climate change can increase economic costs in two ways. First, if the delayed policy is no more stringent, it will miss the climate target of the original, non-delayed policy, resulting in atmospheric GHG concentrations that are permanently higher, thereby increasing the economic damages from climate change. Second, suppose a delayed policy alternatively strove to achieve the original climate target; if so, it would require a more stringent path to achieve that target. But this delayed, more stringent policy typically will result in additional mitigation costs by requiring more rapid adjustment later. In reality, delay might result in a mix of these two types of costs. The estimates of the costs of delay in this section draw on large bodies of research on these two types of costs. We first examine the economic damages from higher temperatures, then turn to the increased mitigation costs arising from delay.

Our focus here is on targets that limit GHG concentrations, both because this is what most of the "delay" literature considers and because concentration limits have been the focus of other assessments. These concentration targets are typically expressed as concentrations of CO_2-equivalent (CO_2e) GHGs, so they incorporate not just CO_2 concentrations but also methane and other GHGs. The CO_2e targets translate roughly into ranges of temperature changes as estimated by climate models and into the cumulative GHG emissions budgets discussed in some other climate literature. More stringent concentration targets decrease the odds that global average temperature exceeds 2°C above preindustrial levels by 2100. According to the IPCC WG III AR5 (2014), meeting a concentration target of 450 parts per million (ppm) CO_2e makes it "likely" (probability between 66 and 100 percent) that the temperature increase will be at most 2°C, relative to preindustrial levels, whereas stabilizing at a concentration level of 550 ppm CO_2e makes it "more unlikely than likely" (less than a 50 percent probability) that the temperature increase by 2100 will be limited to 2°C (IPCC WG III AR5 2014).[11]

Increasing Damages if Delay Means Missing Climate Targets

If delay means that a climate target slips, then the ultimate GHG concentrations, temperatures, and other changes in global climate would be greater than without the delay.[12]

A growing body of work examines the costs that climate change imposes on specific aspects of economic activity. The IPCC WG II AR5 (2014) surveys this growing literature and summarizes the impacts of projected climate change by sector. Impacts include decreased agricultural production; coastal flooding, erosion, and submergence; increases in heat-related illness and other stresses due to extreme weather events; reduction in water availability and quality;

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[11] IPCC WG III AR5 (2014, ch. 6) provides a further refinement of these probabilities, associating a concentration target of 450 ppm of CO_2e with an approximate 70-85 percent probability of maintaining temperature change below 2°C, and a concentration level of 550 CO_2e with an approximate 30-45 percent probability of maintaining temperature change below 2°C.

[12] For information on the impacts of climate change at various levels of warming see *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (NRC 2011).

displacement of people and increased risk of violent conflict; and species extinction and biodiversity loss. Although these impacts vary by region, and some impacts are not well-understood, evidence of these impacts has grown in recent years.[13]

A new class of empirical studies draw similar conclusions. Dell, Jones, and Olken (2013) review academic research that draws on historical variation in weather patterns to infer the effects of climate change on productivity, health, crime, political instability, and other social and economic outcomes. This approach complements physical science research by estimating the economic impacts of historical weather events that can be used to extrapolate to those expected in the future climate. The research finds evidence of economically meaningful impacts of climate change on a variety of outcomes. For example, when the temperature is greater than 100° Fahrenheit in the United States, labor supply in outdoor industries declines up to one hour per day relative to temperatures in the 76°-80° Fahrenheit range (Graff Zivin and Neidell 2014). Also in the United States, each additional day of extreme heat (exceeding 90° Fahrenheit) relative to a moderate day (50° to 59° Fahrenheit) increases the annual age-adjusted mortality rate by roughly 0.11 percent (Deschênes and Greenstone 2011).

These studies provide insights into the response of specific sectors or aspects of the economy to climate change. But because they focus on specific aspects of climate change, use different data sources, and use a variety of outcome measures, they do not provide direct estimates of the aggregate, or total, cost of climate change. Because estimating the total cost of climate change requires specifying future baseline economic and population trajectories, efforts to estimate the total cost of climate change typically rely on integrated assessment models (IAMs). IAMs are a class of economic and climate models that incorporate both climate and economic dynamics so that the climate responds to anthropogenic emissions and economic activity responds to the climate. In addition to projecting future climate variables and other economic variables, the IAMs estimate the total economic damages (and, in some cases, benefits) of climate change which includes impacts on agriculture, health, ecosystems services, productivity, heating and cooling demand, sea level rise, and adaptation.

Overall costs of climate change are substantial, according to IAMs. Nordhaus (2013) estimates global costs that increase with the rise in global average temperature, and Tol (2009, 2014) surveys various estimates. Two themes are common among these damage estimates. First, damage estimates remain uncertain, especially for large temperature increases. Second, the costs of climate change increase nonlinearly with the temperature change. Based on Nordhaus's (2013, Figure 22) net damage estimates, a 3° Celsius temperature increase above preindustrial levels, instead of 2°, results in additional damages of 0.9 percent of global output.[14] To put this

[13] The EPA's Climate Change Impacts and Risk Analysis project collects new research that estimates the potential damages of inaction and the benefits of GHG mitigation at national and regional scales for many important sectors, including human health, infrastructure, water resources, electricity demand and supply, ecosystems, agriculture, and forestry (Waldhoff et al. 2014).

[14] Some studies estimate that small temperature increases have a net economic *benefit*, for instance due to increased agricultural production in regions with colder climates. However, projected temperature increases even

percentage in perspective, 0.9 percent of estimated 2014 U.S. GDP is approximately $150 billion. The next degree increase, from 3° to 4°, would incur additional costs of 1.2 percent of global output. Moreover, these costs are not one-time, rather they recur year after year because of the permanent damage caused by increased climate change resulting from the delay. It should be stressed that these illustrative estimates are based on a single (albeit leading) model, and there is uncertainty associated with the aggregate monetized damage estimates from climate change; see for example the discussion in IPCC WG II AR5 (2014).

Increased Mitigation Costs from Delay

The second type of cost of delay arises if policy is delayed but still hits the climate target, for example stabilizing CO_2e concentrations at 550 ppm. Because a delay results in additional near-term accumulation of GHGs in the atmosphere, delay means that the policy, when implemented, must be more stringent to achieve the given long-term climate target. This additional stringency increases mitigation costs, relative to those that would be incurred under the least-cost path starting today.

This section reviews the recent literature on the additional mitigation costs of delay, under the assumption that both the original and delayed policy achieve a given climate target. We review 16 studies that compare 106 pairs of policy simulations based on integrated climate mitigation models (the studies are listed and briefly described in the Appendix). The simulations comprising each pair implement similar policies that lead to the same climate target (typically a concentration target but in some cases a temperature target) but differ in the timing of the policy implementation, nuanced in some cases by variation in when different countries adopt the policy. Because the climate target is the same for each scenario in the pair, the environmental and economic damages from climate change are approximately the same for each scenario. The additional cost of delaying implementation thus equals the difference in the mitigation costs in the two scenarios in each paired comparison. The studies reflect a broad array of climate targets, delayed timing scenarios, and modeling assumptions as discussed below. We focus on studies published in 2007 or later, including recent unpublished manuscripts.

In each case, a model computes the path of cost-effective mitigation policies, mitigation costs, and climate outcomes over time, constraining the emissions path so that the climate target is hit. Each path weighs technological progress in mitigation technology and other factors that encourage starting out slowly against the costs that arise if mitigation, delayed too long, must be undertaken rapidly. Because the models typically compute the policy in terms of a carbon price, the carbon price path computed by the model starts out relatively low and increases over the course of the policy. Thus a policy started today typically has a steadily increasing carbon price, whereas a delayed policy typically has a carbon price of zero until the start date, at which point it jumps to a higher initial level then increases more rapidly than the optimal immediate policy.

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under immediate action fall in a range with a strong consensus that the costs of climate change exceed such benefits. The cost estimates presented here are net of any benefits expected to accrue.

The higher carbon prices after a delay typically lead to higher total costs than a policy that would impose the carbon price today.[15]

The IPCC WG III AR5 (2014) includes an overview of the literature on the cost of delayed action on climate change. They cite simulation studies showing that delay is costly, both when all countries delay action and when there is partial delay, with some countries delaying acting alone until there is a more coordinated international effort. The present report expands on that overview by further analyzing the findings of the studies considered by the IPCC report as well as additional studies. Like the IPCC report, we find broad agreement across the scenario pairs examined that delayed policy action is more costly compared to immediate action conditional on a particular climate target. This finding is consistent across a range of climate targets, policy participants, and modeling assumptions. The vast majority of studies estimate that delayed action incurs greater mitigation costs compared to immediate action. Furthermore, some models used in the research predict that the most stringent climate targets are feasible only if immediate action is taken under full participation. One implication is that considering only comparisons with numerical cost estimates may understate the true costs of delay, as failing to reach a climate target means incurring the costs from the associated climate change.

The costs of delay in these studies depend on a number of factors, including the length of delay, the climate target, modeling assumptions, future baseline emissions, future mitigation technology, delay scenarios, the participants implementing the policy, and geographic location. More aggressive targets are more costly to achieve, and meeting them is predicted to be particularly costly, if not infeasible, if action is delayed. Similarly, international coordination in policy action reduces mitigation costs, and the cost of delay depends on which countries participate in the policy, as well as the length of delay.

[15] Some models explicitly identify the carbon price path that minimizes total social costs. These optimization models always find equal or greater costs for scenarios with a delay constraint. Other models forecast carbon prices that result in the climate target but do not demand that the path results in minimal cost. These latter models can predict that delay reduces costs, and a small number of comparisons we review report negative delay costs.

The Role of Technological Progress in Cost Estimates

Assumptions about energy technology play an important role in estimating mitigation costs. For example, many models assume that carbon capture and storage (CCS) will enable point sources of emission to capture the bulk of carbon emissions and store them with minimal leakage into the atmosphere over a long period. Some comparisons also assume that CCS will combine with large-scale bio-energy ("bio-CCS"), effectively generating "negative emissions" since biological fuels extract atmospheric carbon during growth. Such technology could facilitate reaching a long-term atmospheric concentration target despite relatively modest near-term mitigation efforts. However, the IPCC warns that "There is only limited evidence on the potential for large-scale deployment of [bio-CCS], large-scale afforestation, and other [CO_2 removal] technologies and methods" (IPCC WG III AR5 2014). In addition, models must also specify the cost and timing of availability of such technology, potentially creating further variation in mitigation cost estimates.

The potential importance of technology, especially bio-CCS, is manifested in differences across models. Clarke et al. (2009) present delay cost estimates for 10 models simulating a 550 ppm CO_2 equivalent target by 2100 allowing for overshoot. The three models that assume bio-CCS availability estimate global present values of the cost of delay ranging from $1.4 trillion to $4.7 trillion. Among the seven models without bio-CCS, four predict higher delay costs, one predicts that the concentration target was infeasible under a delay, and two predict lower delay costs. The importance of bio-CCS is even clearer with a more stringent target. For example, two of the three models with bio-CCS find that a 450 ppm CO_2 equivalent target is feasible under a delay scenario, while none of the seven models without bio-CCS find the stringent target to be feasible.

The Department of Energy sponsors ongoing research on CCS for coal-fired power plants. As part of its nearly $6 billion commitment to clean coal technology, the Administration, partnered with industry, has already invested in four commercial-scale and 24 industrial-scale CCS projects that together will store more than 15 million metric tons of CO_2 per year.

An important determinant of costs is the role of technological progress and the availability of mitigation technologies (see the box). The models typically assume technological progress in mitigation technology, which means that the cost of reducing emissions declines over time as energy technologies improve. As a result, it is cost-effective to start with a relatively less stringent policy, then increase stringency over time, and the models typically build in this cost-effective tradeoff. However, most models still find that immediate initiation of a less stringent policy followed by increasing stringency incurs lower costs than delaying policy entirely and then increasing stringency more rapidly.

We begin by characterizing the primary findings in the literature broadly, discussing the estimates of delay costs and how the costs vary based on key parameters of the policy scenarios; additional details can be found in the Appendix. We then turn to a statistical analysis of all the available

delay cost estimates that we could gather in a standardized form, that is, we conduct a meta-analysis of the literature on delay cost estimates.

Effect on Costs of Climate Targets, Length of Delay, and International Coordination

Climate Targets

Researchers estimate a range of climate and economic impacts from a given concentration of GHGs and find that delaying action is much costlier for more stringent targets. Two recent major modeling simulation projects conducted by the Energy Modeling Forum (Clarke et al. 2009) and by AMPERE (Riahi et al. 2014) consider the economic costs of delaying policies to reach a range of CO_2e concentration targets from 450 to 650 ppm in 2100. In the Energy Modeling Forum simulations in Clarke et al. (2009), the median additional cost (global present value) for a 20-year delay is estimated to be $0.7 trillion for 650 ppm CO_2e but a substantially greater $4.7 trillion for 550 ppm CO_2e. Many of the models in these studies suggest that delay causes a target of 450 ppm CO_2e to be much more costly to achieve, or possibly even infeasible.

Length of Delay

The longer the delay, the greater the cumulative emissions before action begins and the shorter the available time to meet a given target. Several recent studies examine the cost implications of delayed climate action and find that even a short delay can add substantial costs to meeting a stringent concentration target, or even make the target impossible to meet. For example, Luderer et al. (2012) find that delay from 2010 to 2020 to stabilize CO_2 concentration levels at 450 ppm by 2100 raises mitigation cost by 50 to 700 percent.[16] Furthermore, Luderer et al. find that delay until 2030 renders the 450 ppm target infeasible. Edmonds et al. (2008) find that additional mitigation costs of delay by newly developed and developing countries are substantial. In fact, they find that stabilizing CO_2 concentrations at 450 ppm even for a relatively short delay from 2012 to 2020 increases costs by 28 percent over the idealized case, and a delay to 2035 increased costs by more than 250 percent.

International Coordination

Meeting stringent climate targets with action from only one country or a small group of countries is difficult or impossible, making international coordination of policies essential. Recent research shows, however, that even if a delay in international mitigation efforts occurs, unilateral or fragmented action reduces the costs of delay: although immediate coordinated international action is the least costly approach, unilateral action is less costly than doing nothing.[17] More specifically, Jakob et al. (2012) consider a 10-year delay of mitigation efforts to reach a 450 ppm CO_2 target by 2100 and find that global mitigation costs increase by 43 to 700 percent if all countries begin mitigation efforts in 2020 rather than 2010. However, early action in 2010 by more developed countries reduces this increase to 29 to 300 percent. In a similar scenario,

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[16] We present a range of cost estimates which comes from the three IAMs – ReMIND-R, WITCH and IMACLIM-R – used by Luderer et al. (2012). These scenarios also allow temporary overshoot of the target.

[17] Waldhoff and Fawcett (2011) find that early mitigation action by industrialized economies significantly reduces the likelihood of large temperature changes in 2100 while also increasing the likelihood of lower temperature changes, relative to a no policy scenario.

Luderer et al. (2012) find that costs increase by 50 to 700 percent with global delay from 2010 to 2020, however if the industrialized countries begin mitigation efforts unilaterally in 2010 (and are joined by all countries in 2020), the estimated cost increases range from zero to about 200 percent. Luderer et al. (2013) and Riahi et al. (2014) find that costs of delay are smaller when fewer countries delay mitigation efforts, or when short-term actions during the delay are more aggressive.

Jakob et al. (2012) find it is in the best interest of the European Union to begin climate action in 2010 rather than delaying action with all other countries until 2020. They also estimate that the cost increase to the United States from delaying climate action with all other countries until 2020 is from 28 to 225 percent, relative to acting early along with other industrialized economies.[18] McKibbin, Morris, and Wilcoxen (2014) consider the impact that a delay in imposing a unilateral price of carbon would have on economic outcomes in the United States including GDP, investment, consumption and employment. They find that although unilateral mitigation efforts do incur costs, delay is costlier.

Summary: Quantifying Patterns across the Studies

We now turn to a quantitative summary and assessment, or meta-analysis, of the studies discussed above.[19] The data set for this analysis consists of the results on all available numerical estimates of the average or total cost of delayed action from our literature search. Each estimate is a paired comparison of a delay scenario and its companion scenario without delay. To make results comparable across studies, we convert the delay cost estimates (presented in the original studies variously as present values of dollars, percent of consumption, or percent of GDP) to percent change in costs as a result of delay.[20] We capture variation across study and experimental designs using variables that encode the length of the delay in years; the target CO_2e concentration; whether only the relatively more-developed countries act immediately (partial delay); the discount rate used to calculate costs; and the model used for the simulation.[21] All comparisons consider policies and outcomes measured approximately through the end of the century. To reduce the effect of outliers, the primary regression analysis only uses results with less than a 400 percent increase in costs (alternative methods of handling the outliers are

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[18] Note that the IMACLIM model finds that U.S. mitigation declines to the point in which they are slightly negative (i.e. net gains compared to business-as-usual).

[19] A study of the results of other studies is referred to as a meta-analysis, and there is a rich body of statistical tools for meta-analysis, see for example Borenstein et al. (2009).

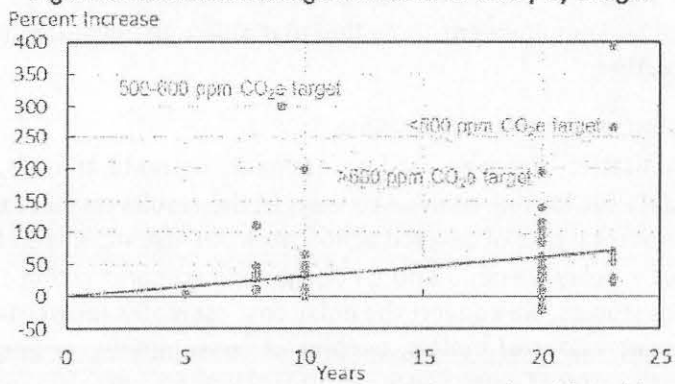
[20] For example, if in some paired comparison delay increased mitigation costs from 0.20 percent of GDP to 0.30 percent of GDP, the cost increase would be 50 percent. Comparisons for which the studies provided insufficient information to calculate the percentage increase in costs (including all comparisons from Riahi et al. 2014) are excluded. Also excluded are comparisons that report only the market price of carbon emissions at the end of the simulation, which is not necessarily proportional to total mitigation costs.

[21] When measuring delay length for policies with multiple stages of implementation, we count the delay as ending at the start of any new participation in mitigation by any party after the start of the simulation. We also exclude scenarios with delays exceeding 30 years. When other climate targets were provided (e.g., CO_2 concentration or global average temperature increase), the corresponding CO_2e concentration levels are estimated using conversions from IPCC WG III AR5 (2014).

discussed below as sensitivity checks), and only includes paired comparisons for which both the primary and delayed policies are feasible (i.e. the model was able to solve for both cases).[22] The dataset contains a total of 106 observations (paired comparisons), with 58 included in the primary analysis. All observations in the data set are weighted equally.

Analysis of these data suggests two main conclusions, both consistent with findings from specific papers in the underlying literature. The first is that, looking across studies, costs increase with the length of the delay. Figure 2 shows the delay costs as a function of the delay time. Although there is considerable variability in costs for a given delay length because of variations across models and experiments, there is an overall pattern of costs increasing with delay.

Figure 2: Additional Mitigation Costs of Delay by Length



Notes: Data points are percentage increase in mitigation costs from delay and the associated length of delay for a given paired simulation. The scatterplot presents a total of 58 paired delay simulations. The solid line is the regression fit to these data, restricted to pass through the origin.
Source: CEA calculations.

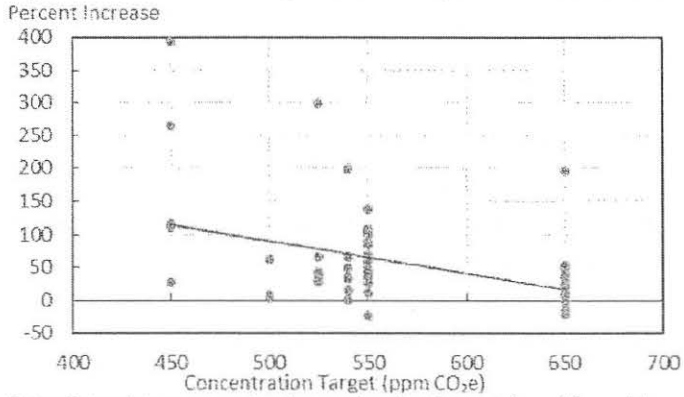
For example, of the 14 paired simulations with 10 years of delay (these are represented by the points in Figure 2 with 10 years of delay), the average delay cost is 39 percent. The regression line shown in Figure 2 estimates an average cost of delay per year using all 58 paired experiments under the assumption of a constant increasing delay cost per year (and, by definition, no cost if there is no delay), and this estimate is 37 percent per decade. This analysis ignores possible confounding factors, such as longer delays being associated with less stringent targets, and the multiple regression analysis presented below controls for such confounding factors.

The second conclusion is that the more ambitious the climate target, the greater are the costs of delay. This can be seen in Figure 3, in which the lowest (most stringent) concentration targets tend to have the highest cost estimates. In fact, close inspection of Figure 2 reveals a related pattern: the relationship between delay length and additional costs is steeper for the points representing CO_2e targets of 500 ppm or less than for those in the other two ranges. That is, costs

[22] In the event that a model estimates a cost for a first-best scenario but determines the corresponding delay scenario to be infeasible, the comparison is coded as having costs exceeding 400 percent. In addition, one comparison from Clarke et al. (2009) is excluded because a negative baseline cost precludes the calculation of a percent increase.

of delay are particularly high for scenarios with the most stringent target and the longest delay lengths.

Figure 3: Additional Mitigation Costs by CO_2 Concentration



Notes: Data points are percentage increase in mitigation costs from delay and the associated CO_2 concetration target for a given paired simulation. The scatterplot presents a total of 58 paired delay simulations. The solid line is the regression line fit to these data.

Table 1 presents the results of multiple regression analysis that summarizes how various factors affect predictions from the included studies, holding constant the other variables included in the regression. The dependent variable is the cost of delay, measured as the percentage increase relative to the comparable no-delay scenario, and the length of delay is measured in decades. Specifications (1) and (2) correspond to Figures 2 and 3, respectively. Each subsequent specification includes the length of the delay in years, an indicator variable for a partial delay scenario, and the target CO_2e concentration. In addition to the coefficients shown, specification (4) includes model fixed effects, which control for systematic differences across models, and each specification other than column (1) includes an intercept.

The results in Table 1 quantify the two main findings mentioned above. The coefficients in column (3) indicate that, looking across these studies, a one decade increase in delay length is on average associated with a 41 percent increase in mitigation cost relative to the no-delay scenario. This regression does not control for possible differences in baseline costs across the different models, however, so column (4) reports a variant that includes an additional set of binary variables indicating the model used ("model fixed effects"). Including model fixed effects increases the delay cost to 56 percent per decade. When the cost of a delay is estimated separately for different concentration target bins (column (5)), delay is more costly the more ambitious is the concentration target. But even for the least ambitious target – a CO_2e concentration exceeding 600 ppm – delay is estimated to increase costs by approximately 24 percent per decade. Because of the relatively small number of cases (58 paired comparisons), which are further reduced when delay is estimated within target bins, the standard errors are large, especially for the least ambitious scenarios, so for an overall estimate of the delay cost we do not differentiate between the different targets. While the regression in column (4) desirably controls for differences across models, other (unreported) specifications that handle

the outliers in different ways and include other control variables give per-decade delay estimates both larger and smaller than the regression in column (3).[23] We therefore adopt the estimate in regression (3) of 41 percent per decade as the overall annual estimate of delay costs.

One caveat concerning this analysis is that it only considers cases in which model solutions exist. The omitted, infeasible cases tend to be ones with ambitious targets that cannot be met when there is long delay, given the model's technology assumptions. For this reason, omitting these cases arguably understates the costs of delay reported in Table 1.[24] Additionally, we note that estimates of the effect of a partial delay (when some developed nations act now and other nations delay action) are imprecisely estimated, perhaps reflecting the heterogeneity of partial delay scenarios examined in the studies.

[23] The results in Table 1 are generally robust to using a variety of other specifications and regression methods, including: using the percent decrease from the delay case, instead of the percent increase from the no-delay case, as the dependent variable as an alternative way to handle outliers; using median regression, also as an alternative way to handle outliers; and including the discount factor as additional explanation of variation in the cost of delay, but this coefficient is never statistically significant. These regressions use linear compounding, not exponential, because the focus is on the per-decade delay cost not the annual delay cost. An alternative approach is to specify the dependent variable in logarithms (although this eliminates the negative estimates), and doing so yields generally similar results after compounding to those in Table 1.

[24] An alternative approach to omitting the infeasible-solution observations is to treat their values as censored at some level. Accordingly, the regressions in Table 1 were re-estimated using tobit regression, for which values exceeding 400 percent (including the non-solution cases) are treated as censored. As expected, the estimated costs of delay per year estimated by tobit regression exceed the ordinary least squares estimates. A linear probability model (not shown) indicates that scenarios with longer delay and more stringent targets are more likely to have delay cost increases exceeding 400 percent (including non-solution cases). The assumption of bio-CCS technology has no statistically significant correlation with delay cost increase in a censored regression but is associated with a significantly lower probability of delay cost increases exceeding 400 percent.

Table 1: Increased Mitigation Costs Resulting from a Delay, Given a Specified Climate Target: Regression Results

	(1)	(2)	(3)	(4)	(5)
Delay (decades)	37.3***		41.1**	56.3***	
	(5.9)		(17.0)	(18.2)	
Delay (decades) x ppm $CO_2e \leq 500$					66.7**
					(27.1)
Delay (decades) x $500 < ppm\ CO_2e \leq 600$					24.9
					(18.5)
Delay (decades) x ppm $CO_2e > 600$					24.1
					(33.9)
Partial delay			8.3	-20.0	14.8
			(26.0)	(27.8)	(25.7)
Target CO_2e concentration		-0.49***	-0.61***	-0.61***	-0.30
		(0.16)	(0.16)	(0.15)	(0.49)
Model fixed effects?	No	No	No	Yes	No
Observations	58	58	58	58	58
R-squared	0.41	0.15	0.24	0.53	0.30

Notes: The table presents ordinary least squares regression coefficients, with each column representing a different regression. For each, the dependent variable is the percent increase in cost from a scenario involving no delay to a scenario involving a delay. Each observation is a comparison of a pair of scenarios with the same climate target, for a total of 58 observations. The regressors represent some of the variables that characterize each paired comparison: the simulated delay, the delay interacted with the concentration target (binned), whether only some countries delayed (partial delay), and the target concentration. The appendix lists all studies from which the data were drawn. The specification in column (1) does not include a constant.

Significant at the: *10% **5% ***1% significance level.

Source: CEA calculations on results from studies listed in appendix.

III. Climate Policy as Climate Insurance

As discussed in the 2013 NRC report, *Abrupt Impacts of Climate Change: Anticipating Surprises*, the Earth's climate history suggests the existence of "tipping points," that is, thresholds beyond which major changes occur that may be self-reinforcing and are likely to be irreversible over relevant time scales. Some of these changes, such as the rapid decline in late-summer Arctic sea ice, are already under way. Others represent potential events for which a tipping point likely exists, but cannot at the present be located. For example, there is new evidence that we might already have crossed a previously unrecognized tipping point concerning the destabilization of the West Antarctic Ice Sheet (Joughin, Smith, and Medley 2014 and Rignot et. al. 2014). A tipping point that is unknown, but thought unlikely to be reached in this century, is the release of methane from thawing Arctic permafrost, which could reinforce the greenhouse effect and spur additional warming and exacerbate climate change. Tipping points can also be crossed by slower climate changes that exceed a threshold at which there is a large-scale change in a biological system, such as the rapid extinction of species. Such impacts could pose such severe consequences for societies and economies that they are sometimes called potential climate catastrophes.

This section examines the implications of these potentially severe outcomes for climate policy, a topic that has been the focus of considerable recent research in the economics literature. The main conclusion emerging from this growing body of work is that the potential of these events to have large-scale impacts has important implications for climate policy. Because the probability of a climate catastrophe increases as GHG emissions rise, missing climate targets because of postponed policies increases risks. Uncertainty about the likelihood and consequences of potential climate catastrophes adds further urgency to implementing policies now to reduce GHG emissions.

Tail Risk Uncertainty and Possible Large-Scale Changes

Were some of these large-scale events to occur, they would have severe consequences and would effectively be irreversible. Because these events are thought to be relatively unlikely, at least in the near term – that is, they occur in the "tail" of the distribution – but would have severe consequences, they are sometimes referred to as "tail risk" events. Because these tail risk events are outside the range of modern human experience, uncertainty surrounds both the science of their dynamics and the economics of their consequences.

Because many of these events are triggered by warming, their likelihood depends in part on the equilibrium climate sensitivity. The IPCC WG I AR5 (2013) provides a likely range of 1.5° to 4.5° Celsius for the equilibrium climate sensitivity. However, considerably larger values cannot be ruled out and are more likely than lower values (i.e. the probability distribution is skewed towards higher values). Combinations of high climate sensitivity and high GHG emissions can result in extremely large end-of-century temperature changes. For example, the IPCC WG III AR5 (2014) cites a high-end projected warming of 7.8° Celsius by 2100, relative to 1900-1950.

A second way to express this risk is to focus on specific large-scale changes in Earth or biological systems that could be triggered and locked in by GHG concentrations rising beyond a certain point. At higher climate sensitivities, the larger temperature response to atmospheric GHG concentrations would make it even more likely that we would cross temperature-related tipping points in the climate system. The potential for additional releases of methane, a potent GHG, from thawing permafrost, thus creating a positive feedback to further increase temperatures, is an example of such a tail risk event. Higher carbon dioxide concentrations in the atmosphere, by increasing the acidity of the oceans, could also trigger and lock in permanent changes to ocean ecosystems, such as diminished coral reef-building, which decreases biodiversity supported on reefs and decreases the breakwater effects that protect shorelines. The probability of significant negative effects from ocean acidification can be increased by other stressors such as higher temperatures and overfishing.

The box summarizes some of these potential large-scale events, which are sometimes also referred to as "abrupt" because they occur in a very brief period of geological time. These events are sufficiently large-scale they have the potential for severely disrupting ecosystems and human societies, and thus are sometimes referred to as catastrophic outcomes.

Abrupt Impacts of Climate Change: Anticipating Surprises

The National Research Council's 2013 report, *Abrupt Impacts of Climate Change: Anticipating Surprises*, discusses a number of abrupt climate changes with potentially severe consequences. These events include:

- **Late-summer Arctic sea ice disappearance:** Strong trends of accelerating late-summer sea ice loss have been observed in the Arctic. The melting of Arctic sea ice comprises a positive feedback loop, as less ice means more sunlight will be absorbed into the dark ocean, causing further warming.
- **Sea level rise (SLR) from destabilization of West Antarctic ice sheets (WAIS):** The WAIS represents a potential SLR of 3-4 meters as well as coastal inundation and stronger storm surges. Much remains unknown of the physical processes at the ice-ocean frontier. However, two recent studies (Joughin, Smith, and Medley 2014, Rignot et. al. 2014) report evidence that irreversible WAIS destabilization has already started.
- **Sea level rise from other ice sheets melting:** Losing all other ice sheets, including Greenland, may cause SLR of up to 60 meters as well as coastal inundation and stronger storm surges. Melting of the Greenland ice sheet alone may induce SLR of 7m, but it is not expected to destabilize rapidly within this century.
- **Disruption to Atlantic Meridional Overturning Circulation (AMOC):** Potential disruptions to the AMOC may disrupt local marine ecosystems and shift tropical rain belts southward. Although current models do not indicate that an abrupt shift in the AMOC is likely within the century, the deep ocean remains understudied with respect to measures necessary for AMOC calculations.
- **Decrease in ocean oxygen:** As the solubility of gases decrease with rising temperature, a warming of the ocean will decrease the oxygen content in the surface ocean and expand existing Oxygen Minimum Zones. This will pose a threat to aerobic marine life as well as release nitrous oxide—a potent GHG—as a byproduct of microbial processes. The NRC study assesses a moderate likelihood of an abrupt increase in oxygen minimum zones in this century.
- **Increasing release of carbon stores in soils and permafrost:** Northern permafrost contains enough carbon to trigger a positive feedback response to warming temperatures. With an estimated stock of 1700-1800 Gt, the permafrost carbon stock could amplify considerably human-induced climate change. Small trends in soil carbon releases have been already observed.
- **Increasing release of methane from ocean methane hydrates:** This is a particularly potent long-term risk due to hydrate deposits through changes in ocean water temperature; the likely timescale for the physical processes involved spans centuries, however, and there is low risk this century.

- **Rapid state changes in ecosystems, species range shifts, and species boundary changes:** Research shows that climate change is an important component of abrupt ecosystem state-changes, with a prominent example being the Sahel region of Africa. Such state-changes from forests to savanna, from savanna to grassland, et cetera, will cause extensive habitat loss to animal species and threaten food and water supplies. The NRC study assesses moderate risk during this century and high risk afterwards.
- **Increases in extinctions of marine and terrestrial species:** Abrupt climate impacts include extensive extinctions of marine and terrestrial species; examples such as the destruction of coral reef ecosystems are already underway. Numerous land mammal, bird, and amphibian species are expected to become extinct with a high probability within the next one or two centuries.

Implications of Tail Risk

An implication of the theory of decision-making under uncertainty is that the risks posed by irreversible catastrophic events can be substantial enough to influence or even dominate decisions.

Weitzman's Dismal Theorem

Over the past few years, economists have examined the implications of decision-making under uncertainty for climate change policy. In a particularly influential treatment, Weitzman (2009) proposes his so-called "Dismal Theorem," which provides a set of assumptions under which the current generation would be willing to bear very large (in fact, arbitrarily large) costs to avoid a future event with widespread, large-scale costs. The intuition behind Weitzman's mathematical result rests with the basic insight that because individuals are risk-averse, they prefer to buy health, home, and auto insurance than to take their chances of a major financial loss. Similarly, if major climate events have the potential to reduce aggregate consumption by a large amount, society will be better off if it can take out "climate insurance" by paying mitigation costs now that will reduce the odds of a large-scale—in Weitzman's (2009) word, catastrophic—drop in consumption later.[25]

[25] This logic has its basis in expected utility theory. Because individuals are risk averse, each additional dollar of consumption provides less value, or utility, to individuals than the previous dollar. To avoid this major loss, an individual will buy home insurance. That insurance is provided by the market because an insurance company can offer home insurance to many homeowners in different regions of the country, and through diversification the company will on average have many homeowners paying premiums and a few collecting insurance, so diversification allows the company to run a relatively low-risk business. But risks from severe climate change are not diversifiable because their enormous costs would impact the global economy. Consequently, as long as there is a non-negligible probability of a large drop in consumption, and therefore a very large drop in utility, arising from a large-scale loss in consumption, society today should be willing to pay a substantial amount if doing so would avoid that loss.

Weitzman's (2009) dismal theorem has spurred a substantial amount of research on the economics of what this literature often refers to as climate catastrophes. A number of authors (e.g. Newbold and Daigneault 2009, Ackerman et al. 2010, Pindyck 2011, 2013, Nordhaus 2011, 2012, Litterman 2013, Millner 2013), including Weitzman (2011, 2014), stress that although the strong version of Weitzman's (2009) result—that society would be willing to pay an arbitrarily large amount to avoid future large-scale economic losses—depends on specific mathematical assumptions, the general principle of taking action to prevent such events does not. The basic insight is that, just as the sufficiently high threat of a fire justifies purchasing homeowners insurance, the threat of large-scale losses from climate change justifies purchasing "climate insurance" in the form of mitigation policies now (Pindyck 2011), and that taking actions today could help to avoid worst-case outcomes (Hwang, Tol, and Hofkes 2013). According to this line of thinking, the difficulty of assessing the probabilities of such large-scale losses or the location of tipping points does not change the basic conclusion that, because their potential costs are so overwhelming, the threat of very large losses due to climate change warrants implementing mitigation policies now.

Several recent studies have started down the road of quantifying the implications of the precautionary motive for climate policy. One approach is to build the effects of large-scale changes into IAMs, either by modeling the different risks explicitly or by simulation using heavy-tailed distributions for key parameters such as the equilibrium climate sensitivity or parameters of the economic damage function. Research along these lines includes Ackerman, Stanton, and Bueno (2013), Pycroft et al. (2011), Dietz (2011), Ceronsky et al. (2011), and Link and Tol (2011). Another approach is to focus on valuation of the extreme risks themselves outside an IAM, for example as examined by Pindyck (2012) and van der Ploeg and de Zeeuw (2013). Kopits, Marten, and Wolverton (2013) review some of the tail risk literature and literature on large-scale Earth system changes, and suggest steps forward for incorporating such events in IAMs, identifying ways in which the modeling could be improved even within current IAM frameworks and where additional work is needed. One of the challenges in assessing these large-scale events is that some of the most extreme events could occur in the distant future, and valuing consumption losses beyond this century raises additional uncertainty about intervening economic growth rates and questions about how to discount the distant future.[26] The literature is robust in showing that the potential for such events could have important climate policy implications, however, the scientific community has yet to derive robust quantitative policy recommendations based on a detailed analyses of the link between possible large-scale Earth system changes and their economic consequences.

Implications of Uncertainty about Tipping Points

Although research that embeds tipping points into climate models is young, one qualitative conclusion is that the prospect of a potential tipping point with unknown location enhances the precautionary motive for climate policy (Baranzini, Chesney, and Morisset 2003, Brozovic and Schlenker 2011, Cai, Judd, and Lontzek 2013, Lemoine and Traeger 2012, Barro 2013, van der

[26] For various perspectives on the challenges of evaluating long-term climate risks, see Dasgupta (2008), Barro (2013), Ackerman, Stanton, and Bueno (2013), Roe and Bauman (2013), and Weitzman (2013).

Ploeg 2014). To develop the intuition, first suppose that the tipping point is a known temperature increase, say 3° Celsius above preindustrial levels, and that the economic consequences of crossing the tipping point are severe, and temporarily put aside other reasons for reducing carbon emissions. Under these assumptions climate policy would allow temperature to rise, stopping just short of the 3° increase. In contrast, now suppose that the tipping point is unknown and that its estimated mean is 3°, but that it could be less or more with equal probability. In this case, the policy that stops just short of 3° warming runs a large risk of crossing the true tipping point. Because that mistake would be very costly, the uncertainty about the tipping point generally leads to a policy that is more stringent today than it would be absent uncertainty. To the extent that delayed implementation means higher long-run CO_2 concentrations, then the risks of hitting a tipping point increase with delay.

As a simplification, the above description assumes away other costs of climate change that increase smoothly with temperature, as well as the reality that important tipping points in biological systems could be crossed by small gradual changes in temperatures, so as to focus on the consequences of uncertainty about large-scale temperature changes. When the two sets of costs are combined, the presence of potential large-scale changes increases the benefits of mitigation policies, and the presence of uncertainty about tipping points that would produce abrupt changes increases those benefits further.[27] Cai, Judd, and Lontzek (2013) use a dynamic stochastic general equilibrium version of DICE model that is modified to include multiple tipping points with unknown (random) locations. To avoid the Weitzman "infinities" problem, they focus on tipping events with economic consequences that are large (5 or 10 percent of global GDP) but fall short of global economic collapses. They conclude that the possibility of future tipping points increases the optimal carbon price today: in their benchmark case, the optimal pre-tipping carbon price more than doubles, relative to having no tipping point dynamics. Similarly, Lemoine and Traeger (2012) embed unknown tipping points in the DICE model and estimate that the optimal carbon price increases by 45 percent as a result. In complementary work, Barro (2013) considers a simplified model in which the only benefits of reducing carbon emissions come from reducing the probability of potential climate catastrophes, and finds that this channel alone can justify investment in reducing GHG pollution of one percent of GDP or more, beyond what would normally occur in the market absent climate policy.

[27] Cai, Judd, and Lontzek (2013) provide a stark example of this dynamic. Their analysis, which is undertaken using a modified version of Nordhaus's (2008) DICE-2007 model, includes both the usual reasons for emissions mitigation (damages that increase smoothly with temperature) and the possibility of a tipping point at an uncertain future temperature which results in a jump in damages.

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Appendix: Literature on Delay Costs

This appendix lists the studies reviewed Section II and used in the meta-analysis, and briefly describes the scenarios they analyzed.

The EMF22 project engaged ten leading integrated assessment models to analyze the climate and economic consequences of delay scenarios. The EMF22 studies consist of Loulou, Labriet, and Kanudia (2009), Tol (2009), Gurney, Ahammad, and Ford (2009), van Vliet, den Elzen, and van Vuuren (2009), Blanford, Richels, and Rutherford (2009), Krey and Riahi (2009), Calvin et al. (2009a, 2009b), Russ and van Ierland (2009), and Bosetti, Carraro, and Tavoni (2009), with Clarke et al. (2009) providing an overview of the project.[28] Among other objectives, each study estimates the mitigation costs associated with five climate targets under both an immediate action scenario and a harmonized delay scenario. The targets are 450, 550, and 650 ppm CO_2e in 2100, and the models consider the first two targets alternatively allowing or prohibiting an overshoot before 2100.[29] In the delay scenario, only more developed countries (minus Russia) begin mitigation immediately in 2012 in a coordinated fashion (i.e., with the same carbon pricing), with some countries delaying action until 2030, and remaining countries delay action until 2050. These scenarios enable calculating the additional mitigation costs associated with delay for each concentration target.

The AMPERE project engaged nine modeling teams to analyze the climate and economic consequences of global emissions following the proposed policy stringency of the national pledges from the Copenhagen Accord and Cancún Agreements to 2030. (The AMPERE scenarios were not included in the meta-analysis in Section II because Riahi et al. (2014) did not provide sufficient information to calculate the percent increase in mitigation costs for each delay scenario.) One of the questions addressed by this project is the economic costs of delaying policies to reach CO2e concentration targets of 450 and 550 ppm in 2100 (Riahi et al. 2014). Eight models simulate pairs of policy scenarios reaching each target. One simulation in each pair assumes that all countries act immediately in a coordinated fashion (i.e., with the same carbon pricing), while the other simulation assumes that all countries follow the less stringent emissions commitments made during the Copenhagen Accord and Cancun Agreements until 2030, when coordinated international action begins.

The meta-analysis includes the following studies not associated with either AMPERE or EMF22: Jakob et al. (2012); Luderer et al. (2012, 2013); Edmonds et al. (2008); Richels et al. (2007), and Bosetti et al. (2009). Jakob et al. (2012) consider a 10-year delay of mitigation efforts to reach a 450 ppm CO_2 target by 2100, including variations where more developed countries implement mitigation immediately. Luderer et al. (2012) consider a similar 10-year delay and the same 450 ppm CO_2 target by 2100, with a scenario where Europe and all other industrialized countries

[28] Russ and van Ierland (2009) did not present estimates of total delay costs, so this paper is not included in the meta-analysis in Section II.

[29] We included three additional scenarios in van Vliet, den Elzen, and van Vuuren (2009) with alternate targets and models that were not reported in Clarke et al. (2009).

begin mitigation efforts in 2010. Luderer et al. (2013) analyze a scenario where countries implement fragmented policies before coordinating efforts in 2015, 2020, or 2030 to meet a target of 2°C above preindustrial levels by 2100, allowing for overshooting. Edmonds et al. (2008) consider targets of 450, 550, and 660 ppm CO_2, with newly developed and developing countries delaying climate action from a start date of 2012 to 2020, 2035 and 2050. Richels et al. (2007) estimate the additional cost of delay by newly developing countries until 2050 for a 450 and 550 ppm CO_2 target. Finally, Bosetti et al. (2009) estimate the additional cost when all countries delay climate action for 20 years with a goal of reaching a 550 ppm and 650 ppm CO_2e target by 2100.

Exhibit 6

The New York Times | http://nyti.ms/21rt5UC

Edited by David Leonhardt

CLIMATE CHANGE

There's a Formula for Deciding When to Extract Fossil Fuels

"Drill, Baby, Drill" became a popular campaign mantra back in the 2008 election cycle. But now we're hearing the opposite call: "Leave It in the Ground."

These calls come from environmentalists who see the end of drilling and mining as the way to avoid disruptive climate change. They direct these calls toward the federal government because it is estimated that about half of the carbon in technologically recoverable fossil fuels in the United States is on public lands.

Is there a middle ground that can supply the energy we need without causing significant climate damages? Yes. And it doesn't involve exploiting all available resources, nor banning their use.

What if we continued to lease the rights to access fossil fuels on federal land but required the leases and royalty payments to reflect the full climate damages from these fuels? Doing so would put the market to work by unlocking fossil fuels that have the highest value in relation to their impact on the climate. The bonus: It provides money to pay for some of the damage of climate change.

We've seen the benefits of using our domestic resources over the last decade as the amount of our energy coming from domestic oil and gas resources increased 54 percent. Chiefly, we have lower fuel prices. We now pay 74 percent less for natural gas and 25 percent less for petroleum, compared with 2005. Further, net imports will account for just 23 percent of American liquid fuel supplies this year — down from 60 percent in 2005 — with important energy security benefits. Our carbon emissions are also below 2005 levels, with cheap natural gas having taken significant market share from coal, which is more carbon intensive.

At the same time, the combustion of fossil fuels causes climate change that is projected to impose myriad costs around the world. But in this regard, not all fossil fuels are created equal. The value per unit of energy, measured by the market price, is greater for some (like petroleum) than others (like coal). Further, some contain more carbon or result in the release of more emissions because of other factors like the extraction and transportation process, and inflict greater climate damages. Knowing the monetary value of climate damages associated with a ton of carbon emissions is therefore the key to this whole problem.

Luckily, there is a way to determine this. It is called the Social Cost of Carbon (S.C.C.), and the federal government sets it at $40 per metric ton of CO_2 emissions. The S.C.C. is used to inform a wide variety of regulations that limit the use of fossil fuels, including emissions standards for vehicles, appliances and power plants. But the S.C.C. has not been used to guide extraction policies. (I was co-leader of an interagency group that set the S.C.C. when I worked in the Obama administration from 2009 to 2010.)

If the S.C.C. were applied as a part of leasing and royalty rates on federal lands, we would unlock resources with the greatest net benefits. To illustrate the consequences of such a shift, I did some calculations based on the spot prices for coal, petroleum and natural gas and their respective energy and carbon contents. The addition of a charge based on the S.C.C. is unlikely to

have a substantial effect on domestic production of petroleum: The spot price per million British thermal units (B.T.U.s) this year has been $8.81, and the associated climate damages are $2.98. If the federal government collected a charge of $2.98 for each million B.T.U.s of petroleum extracted on federal lands, the revenue could be refunded directly to taxpayers or used to help the nation adapt to climate damages. The story is similar for natural gas; its value today exceeds the expected climate damages.

The case of coal is different, especially coal from the federal land in the Powder River Basin in Wyoming and Montana. The climate damages from coal mined from this region are five to six times greater than its market value ($0.66 at market value versus $3.89 of climate damages). Thus, a climate charge linked to the S.C.C. would probably make at least some of the coal mining in this region unprofitable. There is currently an opportunity for policy overhaul: The Department of the Interior is considering how to restructure lease terms for fossil fuels on federal lands. Further, a federal judge ruled last year that the government should take into account climate impacts when making decisions about mining on federal lands.

The application of an S.C.C.-related fee would meet many goals. Environmentalists would naturally like it, and so should fiscal conservatives who recognize that the federal government will be increasingly on the hook for climate damages (recall the more than $50 billion of federal tax dollars appropriated in response to Hurricane Sandy). At the same time, this fee would not stop the development of economically attractive fossil fuels.

Such a change in policy would have challenges. There would inevitably be some shifting of fossil fuel production to private lands in the United States, as well as to other countries; but it would also reduce the long-run global supply of fossil fuels. Further, there would be a strong case for harmonizing S.C.C. charges with existing domestic climate regulations to ensure that the carbon policies operate as efficiently as possible. There is also a strong case for providing support to communities that experience meaningful declines in

economic activity because of an extraction fee linked to the S.C.C.

An efficient climate policy would price carbon throughout the global economy so that users of all fossil fuels recognized their climate costs. It does not appear likely that the current Paris climate negotiations will produce such a system. In the absence of such a policy, the solution doesn't need to be to use all fossil fuels, or to ban their usage. Common sense suggests that we use the ones that provide more value than harm and that we leave the others in the ground.

For a detailed analysis of the calculations, the technical document is available here.

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