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Pre-proposal Comments on U.S. EPA Existing Source Guidelines for Greenhouse Gas Limitations

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On June 25th, President Obama announced a broad agenda of future regulatory initiatives to reduce greenhouse gas emissions associated with global climate change. This white paper focuses on one aspect of the President's climate change plan: greenhouse gas guidelines for existing power plants. It examines an aggressive control proposal advanced by a major environmental organization, and provides independent estimates of the potential job and economic impacts of this proposal. It also offers preliminary recommendations for the design of U.S. EPA's guidelines for existing source regulations that the states will be required to implement under section 111(d) of the Clean Air Act. These recommendations are intended to harmonize the President's call for programs utilizing "market-based instruments" and the unit-specific considerations called for by the Clean Air Act.

Background

In 2007, the Supreme Court determined that U.S. EPA had authority under the Clean Air Act to regulate carbon dioxide (CO2) emissions from automobiles (*Massachusetts v. EPA*, S. Ct., 2007). Since that time, EPA has taken steps to regulate CO2 emissions from new vehicles, and has embarked upon an expanded agenda of controls affecting stationary sources such as power plants. President Obama's June 25th Memorandum to the Administrator of EPA required the agency to re-propose New Source Performance Standards (NSPS) for CO2 emissions from new coal- and natural gas-fueled power plants. EPA's initial proposal would have eliminated the construction of new coal plants by requiring carbon capture and storage (CCS), a technology that has not been adequately demonstrated at utility-scale applications. EPA's revised NSPS proposal issued on September 20 provides separate categories for coal and natural gas combined-cycle units, but maintains a CCS requirement for all new coal units.

The President's Memorandum directed EPA to propose guidelines by June 2014 for reducing greenhouse gas emissions from existing power plants, with a final rulemaking by June 2015. This directive followed a judicially-approved consent decree among EPA, several states, and environmental groups. In this agreement, EPA committed to develop standards for existing fossil-fueled power plants. Unlike scrubbers for conventional pollutants such as sulfur dioxide, there are no “off-the-shelf” controls for reducing CO2 emissions from fossil-fueled plants. While improvements in coal plant efficiency may reduce CO2 emissions, large near-term emission reductions could only be achieved by closing or reducing utilization of coal plants in favor of lower-emitting sources such as natural gas or renewables.

The prospect of new CO_2 emission reduction requirements targeted at coal-based power plants comes at a problematic time for electric consumers and for workers in the coal, rail, and utility industries. The Energy Information Administration (EIA) projects that nearly 50 Gigawatts (GW) of coal generating capacity will be retired in the next several years as a result of EPA's 2012 Mercury and Air Toxics Standards Rule (MATS) and other factors (DOE/EIA AEO 2013). These closures, mainly affecting older and smaller units that are not economic to retrofit with new emission controls, will eliminate some 15% of the nation's coal fleet and tens of thousands of existing utility, rail and coal jobs directly tied to the operation of these plants. Electric rates for consumers will soon begin to reflect EPA's estimated $9.6 billion annual cost of MATS compliance (EPA MATS RIA, 2011).

EPA's Authority to Regulate Existing Source CO_2 Emissions

EPA's authority to regulate CO_2 emissions from existing sources is contained in section 111(d) of the Clean Air Act. This provision applies to "regulated" pollutants such as CO_2, which are neither "criteria" nor "hazardous" air pollutants addressed by other provisions of the Act. This distinction is important because the Act prescribes federally-determined deadlines and timetables for meeting the National Ambient Air Quality Standards (NAAQS) for criteria pollutants such as ozone and particulate matter. Other provisions of the Act require the installation of Maximum Achievable Control Technology (MACT) for hazardous air pollutants such as mercury, with stringent compliance timetables. There are no NAAQS for CO_2 or other greenhouse gases, and no legislatively-mandated timetables for achieving any specific level of CO_2 reductions. EPA has broad discretion in the timetables for any reductions called for by its guidelines for existing source greenhouse gas limits.

Section 111(d) is primarily implemented by the states subject to EPA guidelines for compliance. Section 111(d)(1) calls for states to submit plans to EPA that establish "standards of performance" for existing sources, and "provide for … implementation and enforcement." This provision also allows states "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

EPA issued regulations in 1975 outlining the requirements for Section 111(d). These regulations require EPA to issue an "emission guideline document" for the states setting forth the performance standards for affected facilities. These regulations and the Act require the emissions guidelines to reflect "the application of the best system of emission reduction" that has been "adequately demonstrated." Apart from actions such as efficiency improvements that may be obtained by plant modifications, there are no "adequately demonstrated" technologies for achieving large-scale CO_2 emission reductions from fossil-fueled power plants. The Administration's Interagency Task Force on Carbon Capture and Storage concluded in 2010 that CCS technology was not commercially demonstrated.

The Act provides EPA with discretion in creating subcategories for sources within the guidelines: "The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate." This provision for subcategorization would allow states to set emission standards for different boiler types, sizes, or fuel types, avoiding a "one-size-fits-all" approach.

Potential Impacts of Existing Source Standards on Coal-Based Generation

The extent of potential losses of coal-based generation and related jobs in the utility, rail, and coal sectors will be determined by the nature of EPA's guidelines and by state plans developed in response to the guidelines.

A December 2012 proposal by a national environmental organization gives some indication of the potential impacts of an aggressive plan. In this proposal, coal-based generating units are required to meet the equivalent of statewide declining emission rate standards of 1,800, 1,500, and 1,200 pounds of CO_2 per Megawatt-hour (MWh) over the period from 2015 to 2025. The baseline emission level for today's coal fleet is approximately 2,100 lb. CO_2/MWh (EPA CAMD, 2013).

The proposal gives states and utilities a menu of options for meeting these standards, including intrastate trading and emissions averaging, and credits for actions such as energy efficiency and demand-response programs that encourage electric users to go "off-grid" during peak demand periods. Analyses supporting the proposal indicate that some 154 Gigawatts of overall generating capacity could be displaced by energy efficiency and demand-response measures. The projected level of energy efficiency measures deployed in response to the proposal by 2020 is 89,000 megawatts, equivalent to 2.5X the total electricity generated in California in 2012.

The potential reduction of coal generating capacity indicated by the December 2012 proposal is shown in the table below, for the period up to 2020 when the standard is set at 1,500 lb. CO_2/MWH:

Electric generation resources in the reference case
and with a 1,500 lb. CO_2/MWh standard

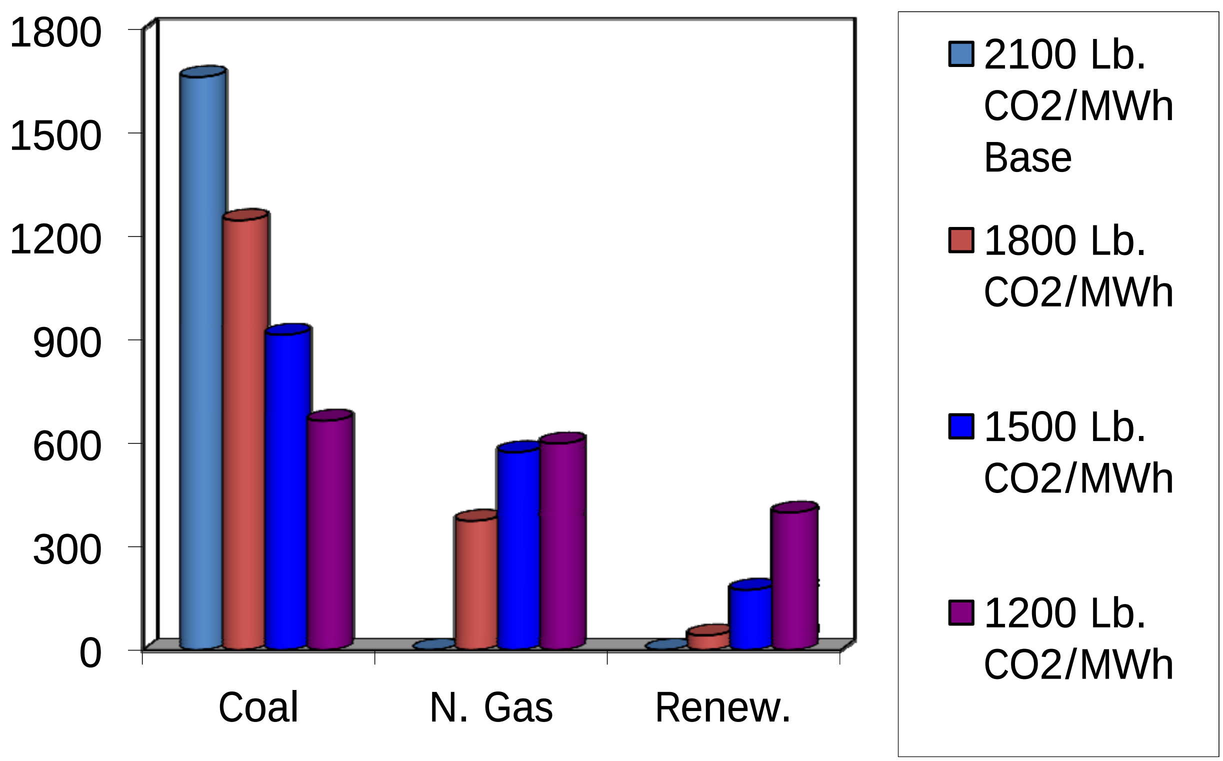
Capacity (GW)	**2012**	**2020 Reference**	**2020 1500 lb. CO_2/MWh**
Coal	320	289	234
Nat'l Gas	258	270	264
Hydro & renewables	158	198	199
En. Eff. & DR	44	51	154

These projections imply a conservative 10% reduction (31 GW) in the coal generating fleet in the 2020 reference case, reflecting the impacts of plant retirements expected due to the EPA MATS rule and other factors. A larger reduction of nearly 20% (55 GW) is projected in 2020 for the 1,500 lb. CO_2/MWh case. A greater impact on coal generation would result if the projected 154 GW of energy efficiency and demand response measures proved unrealistic, or were not subject to "credits" in state programs. Instead, utilities likely would seek alternative means to meet CO_2 targets, such as switching more generation to dispatchable natural gas units. Natural gas combined-cycle units emit approximately 1,000 lb. CO_2/MWh, less than one-half the amount emitted by most coal-based plants.

Illustrative Energy and Job Impact Estimates

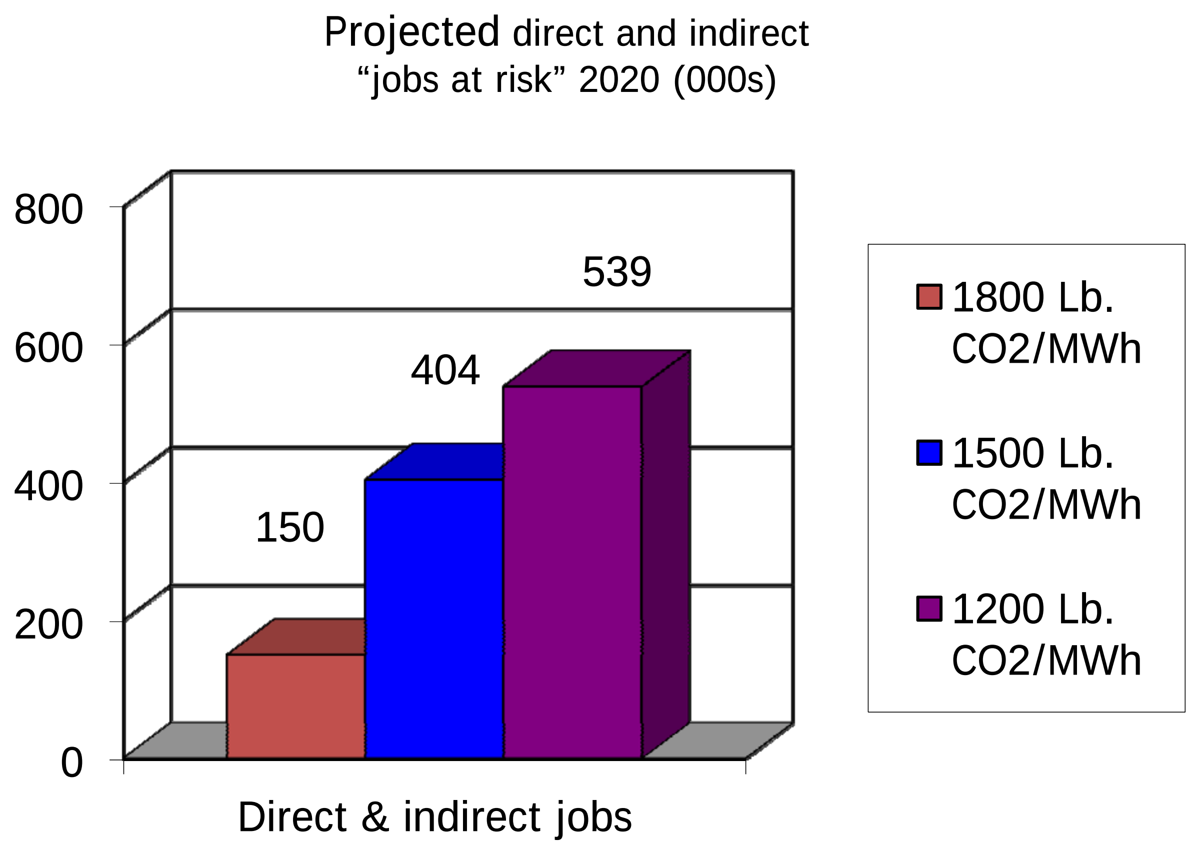
Appendix Table 1 and the chart below illustrate the potential displacement of coal generation by natural gas and renewable energy sources to meet alternative statewide CO_2 emission rate targets. Compliance for all options is estimated for the year 2020, using DOE/EIA reference case projections for coal generation in 2020. This base year takes into account the projected near-term retirement of some 50 GW of coal capacity.

Projected U.S. generation changes in 2020 with alternative CO2 standards (Mil. MWh)



In this scenario, coal-based generation could be reduced by 17% to 60% from projected 2020 reference case levels to meet 1,800 and 1,200 lb./MWh targets, respectively. These coal displacement estimates take into account the greater efficiency of natural gas combined-cycle units compared with the average “heat rate” (BTUs per KWh) of the current coal generation fleet as of 2011.

The chart below summarizes potential direct and indirect jobs "at risk" associated with meeting declining CO2 emission rate targets, based on different assumptions regarding compliance strategies. The estimated impacts are for direct jobs in the utility, rail and coal sectors, and for total jobs based on state-specific multiplier effects using U.S. Department of Commerce "jobs-to-jobs" multipliers for the electric generating sector. These multipliers measure the total number of jobs lost or gained by a change of one job in the power generation sector. Approximately one-third of the total jobs at risk are direct jobs in the utility, rail, and coal sectors.



These job estimates do not take into account any offsetting jobs created in sectors such as natural gas, or job losses resulting from higher electricity prices. It is well established that increased electricity prices due to CO2 controls can lead to net decreases in industrial production, consumption, and GDP, along with net employment losses (see, *e.g.*, DOE/EIA, Energy Market and Economic Impacts of S. 2191, April 2008, at 31-39.) Data from the National Commission on Energy Policy's Task Force on America's Future Energy Jobs (2009) indicate that coal generation is among the most job-intensive forms of power generation, responsible for substantially more permanent jobs per megawatt of capacity than natural gas or renewable sources such as wind.

It is assumed that emission reductions needed to meet an 1,800 lb. CO_2/MWh target could be achieved through a 25% reduction of the utilization of coal plants, with natural gas and renewable sources making up the difference in total generation. In this scenario, direct job losses are confined to the coal and rail transport sectors, reflecting lower generation at coal units. With more stringent targets, coal capacity would be retired and replaced by natural gas generation and by renewable energy (or energy efficiency, if credits for such programs were available.) As the emission target becomes more stringent, a larger proportion of generation must be supplied by renewable energy or energy efficiency with an assumed emission rate of 0 lb. CO_2/MWh. At the lowest target of 1,200 lb. CO_2/MWh, 60% of coal generation would be displaced by a combination of natural gas (36%) and renewables or energy efficiency (24%).

The largest potential job impacts would occur in states most dependent on coal generation, with negligible impacts in states with relatively little or no coal generation, regardless of their total CO_2 emissions. The table below summarizes job impacts for the ten most-impacted states based on the 1,200 lb./MWh CO_2 standard:

Direct and indirect jobs "at risk" with 1,200 lb. CO_2/MWh standard for fossil-based electric generating plants, ten most-impacted states

Most-impacted states, 1,200 lb. CO_2/MWh	**Direct and indirect jobs at risk**	**Pct. of total U.S. jobs at risk**
Texas	61,310	11.4%
Pennsylvania	38,329	7.1%
Ohio	35,294	6.5%
Illinois	32,880	6.1%
Indiana	31,643	5.9%
Kentucky	27,486	5.1%
Missouri	23,431	4.3%
West Virginia	22,324	4.1%
Michigan	19,550	3.6%
North Carolina	17,420	3.2%
Subtotal	309,067	57.3%
U.S. total	539,293	100.0%

Potential Fuel Cost Impacts

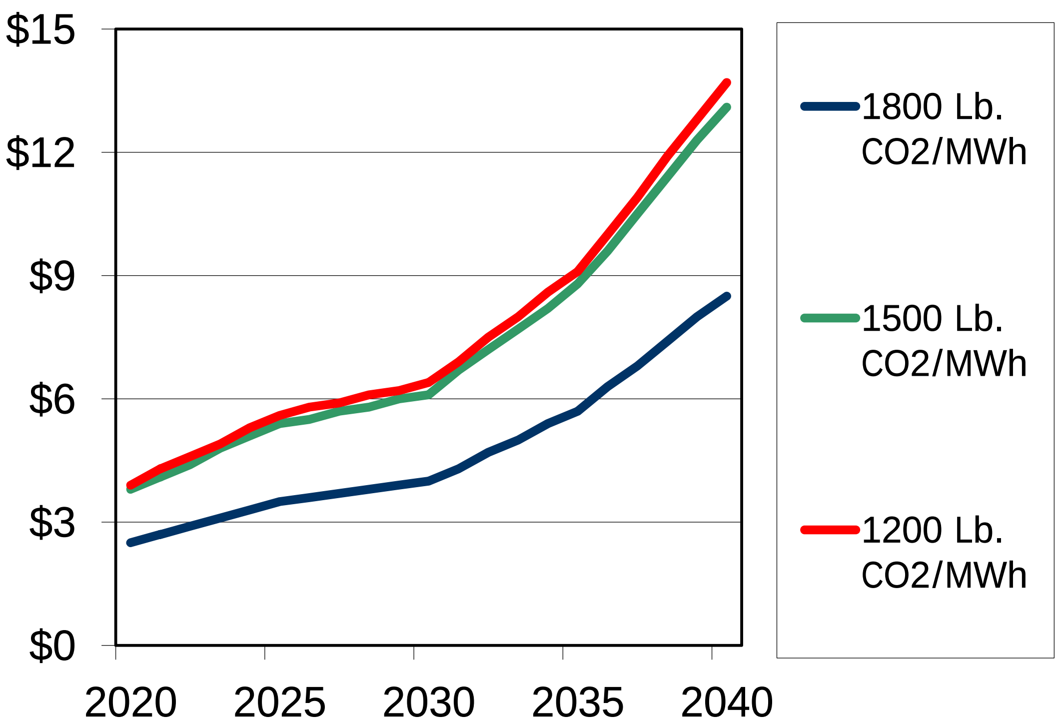
Large-scale switching from coal to natural gas would increase the cost of generating electricity in affected states, due to the projected rates of real price increase for these two fuels. The additional net annual fuel costs for switching from coal to natural gas generation could exceed \$3.5 to \$5.5 billion by 2025, increasing steadily thereafter.

Appendix Table 2 contains illustrative calculations of the potential increased fuel costs associated with the displacement of coal in the 1,800, 1,500, and 1,200 lb. CO_2/MWh cases. These estimates are based on DOE/EIA reference case delivered fuel cost projections for 2020-2040 (2013 Annual Energy Outlook.) These estimates do not consider the capital investment costs associated with replacement natural gas or renewable-based generation, or the "stranded asset" costs of retiring coal-based generation that has incurred substantial capital investments to comply with MATS and other EPA rules.

The net increased cost of natural gas is estimated annually for the period 2020-2040 using EIA's delivered fuel costs (in 2010 constant dollars) adjusted by the relative heat rates of coal and natural gas combined-cycle units. The estimates do not include costs for renewable energy or other options that may be needed to meet state- or system-wide emission rate targets. DOE/EIA's 2013 Annual Energy Outlook and FERC Form 1 data for existing coal-based generating plants from indicate that the cost of generation from <u>new</u> renewable sources such as wind or solar is substantially greater than the costs of generation from <u>existing</u> coal-based plants.

The results of these calculations are summarized in the chart below. In the 1,800 lb. CO_2/MWh case, incremental annual fuel costs for natural gas (i.e., minus the cost of coal displaced) increase from \$2.5 billion in 2020 to \$8.5 billion in 2040, measured in constant 2010 dollars. In the most stringent case, incremental natural gas costs rise from \$4.0 billion in 2020 to \$13.7 billion in 2040. The annual fuel cost increase for the 1,500 lb. and 1,200 lb. CO_2/MWh cases are similar because the 1,200 lb. case requires a much larger share of renewable or similar "zero-carbon" resources to meet an assumed state- or system-wide target.

Projected incremental cost of natural gas
for coal displaced (Bil. 2010 $)



These estimates do not consider any potential price impacts associated with increased natural gas demand, or with decreased coal demand. However, these price impacts could be material given the potential magnitudes of utility demand shifts: the additional natural gas demand estimated in the three cases ranges from 2.5 to 4.0 Quadrillion BTUs (Quads) annually, while the decreased annual coal demand ranges from 3.9 to 6.2 Quads. For comparison, DOE/EIA's 2013 Annual Energy Outlook projects electric utility natural gas consumption of 8.6 Quads in 2025, with 17.7 Quads of coal consumption. An increased natural gas demand of 2.5 to 4.0 Quads would represent a 29% to 47% increase over EIA's projected electric utility natural gas consumption for 2025.

Preliminary Recommendations

As EPA develops guidelines for existing source CO_2 standards, it should give careful consideration to the statutory requirements for states to consider factors such as the remaining useful life of sources and the availability of control technology that has been “adequately demonstrated.” Measures such as subcategorization among boiler and coal types could help to mitigate electric rate impacts and worker displacement. Arbitrary statewide or industry-wide emission rate targets that cannot be met by available technologies at existing sources would invite massive fuel-switching and the retirement of coal generating plants that had just invested in retrofit controls to meet EPA's Mercury and Air Toxics Standards Rule.

The statutory requirements of section 111(d) appear to call for an "inside the fence" plant- or unit-specific assessment linked to the availability of control measures such as energy efficiency and heat rate improvements. Once overall unit or plant targets or goals are established, sources then could have flexibility to look "outside the fence" for the means to achieve them, including the use of emissions trading, averaging, or the use of other market-based mechanisms. This combination of site-specific, engineering-based determinations of emission reductions, and flexibility in the means to achieve them, appears to balance the objectives of the President's June 25th memorandum with the statutory requirements of section 111(d).

Appendix Table 1

Illustrative Impacts of Existing Source CO2 Reductions on Coal Generation and Existing Coal-Related Jobs (Utility, Rail, Coal)

	EIA 2020 Ref. Case Coal Gen.* (000 MWh)	Est. CO2 Tons (000) 2020	Coal Gen. at Alternative C02 Targets (000 MWh)			Est. Direct Coal related Jobs 2020**	Pct. of Total Coal-related Jobs	Estimated Existing Direct Job Losses***				Estimated Total Direct and Indirect Job Losses		
			1800 lb/MWh	1500 lb/MWh	1200 lb/MWh			1800 lb/MWh	1500 lb/MWh	1200 lb/MWh	RIMS II Multiplier****	1800 lb/MWh	1500 lb/MWh	1200 lb/MWh
New England	5,288	5,552	3,966	2,908	2,115	899	0.3%	150	405	539		424	1,146	1,527
Connecticut	318	334	238	175	127	54	0.0%	9	24	32	2.6737	24	65	87
Maine	51	54	38	28	20	9	0.0%	1	4	5	2.6726	4	10	14
Mass.	3,144	3,301	2,358	1,729	1,258	535	0.2%	89	241	321	2.8775	256	692	923
N.Hampshire	1,775	1,864	1,331	976	710	302	0.1%	50	136	181	2.7838	140	378	504
Rhode Island														
Vermont														
Middle Atl.	106,555	111,883	79,916	58,605	42,622	18,114	6.4%	3,021	8,151	10,869		11,444	30,884	41,179
New Jersey	3,091	3,245	2,318	1,700	1,236	525	0.2%	88	236	315	3.0118	264	712	949
New York	7,136	7,493	5,352	3,925	2,854	1,213	0.4%	202	546	728	2.6109	528	1,425	1,900
Pennsylvania	96,329	101,145	72,246	52,981	38,531	16,376	5.8%	2,731	7,369	9,826	3.901	10,652	28,747	38,329
E.N. Central	379,903	398,898	284,927	208,946	151,961	64,583	22.9%	10,769	29,063	38,750		36,283	97,915	130,553
Illinois	87,249	91,612	65,437	47,987	34,900	14,832	5.3%	2,473	6,675	8,899	3.6946	9,138	24,660	32,880
Indiana	100,464	105,487	75,348	55,255	40,186	17,079	6.1%	2,848	7,686	10,247	3.0879	8,794	23,732	31,643
Michigan	57,345	60,212	43,009	31,540	22,938	9,749	3.5%	1,626	4,387	5,849	3.3423	5,433	14,662	19,550
Ohio	97,721	102,607	73,291	53,747	39,089	16,613	5.9%	2,770	7,476	9,968	3.5409	9,809	26,471	35,294
Wisconsin	37,123	38,979	27,842	20,417	14,849	6,311	2.2%	1,052	2,840	3,787	2.9543	3,109	8,390	11,186
W.N. Central	228,734	240,170	171,550	125,803	91,493	38,885	13.8%	6,484	17,498	23,331		17,193	46,399	61,866
Iowa	37,684	39,569	28,263	20,726	15,074	6,406	2.3%	1,068	2,883	3,844	2.214	2,365	6,383	8,510
Kansas	30,456	31,979	22,842	16,751	12,182	5,177	1.8%	863	2,330	3,106	2.4615	2,125	5,735	7,647
Minnesota	26,206	27,516	19,654	14,413	10,482	4,455	1.6%	743	2,005	2,673	2.8648	2,128	5,743	7,658
Missouri	77,206	81,066	57,905	42,463	30,882	13,125	4.7%	2,189	5,906	7,875	2.9754	6,512	17,574	23,431
Nebraska	26,083	27,387	19,562	14,346	10,433	4,434	1.6%	739	1,995	2,660	2.5171	1,861	5,022	6,697
North Dakota	28,262	29,675	21,196	15,544	11,305	4,805	1.7%	801	2,162	2,883	2.5375	2,033	5,486	7,315
South Dakota	2,837	2,979	2,128	1,561	1,135	482	0.2%	80	217	289	2.1022	169	456	608
South Atlantic	301,924	317,021	226,443	166,058	120,770	51,327	18.2%	8,559	23,097	30,796		25,243	68,122	90,829
Delaware	1,490	1,564	1,117	819	596	253	0.1%	42	114	152	2.6627	112	303	405
Florida	49,207	51,667	36,905	27,064	19,683	8,365	3.0%	1,395	3,764	5,019	2.9109	4,060	10,958	14,610
Georgia	51,508	54,084	38,631	28,330	20,603	8,756	3.1%	1,460	3,940	5,254	2.8393	4,146	11,188	14,917
Maryland	18,993	19,942	14,245	10,446	7,597	3,229	1.1%	538	1,453	1,937	2.9302	1,578	4,257	5,677
North Carolina	56,565	59,394	42,424	31,111	22,626	9,616	3.4%	1,603	4,327	5,770	3.0193	4,841	13,065	17,420
South Carolina	31,998	33,597	23,998	17,599	12,799	5,440	1.9%	907	2,448	3,264	2.8929	2,624	7,081	9,442
Virginia	17,472	18,345	13,104	9,609	6,989	2,970	1.1%	495	1,337	1,782	3.3859	1,677	4,526	6,034
West Virginia	74,693	78,428	56,020	41,081	29,877	12,698	4.5%	2,117	5,714	7,619	2.9302	6,204	16,743	22,324
E.S. Central	188,960	198,408	141,720	103,928	75,584	32,123	11.4%	5,357	14,455	19,274		16,003	43,186	57,581
Alabama	52,342	54,959	39,257	28,788	20,937	8,898	3.2%	1,484	4,004	5,339	3.094	4,591	12,389	16,519
Kentucky	88,970	93,418	66,727	48,933	35,588	15,125	5.4%	2,522	6,806	9,075	3.0288	7,639	20,615	27,486
Mississippi	8,649	9,081	6,487	4,757	3,459	1,470	0.5%	245	662	882	2.7431	673	1,815	2,420
Tennessee	38,998	40,948	29,249	21,449	15,599	6,630	2.3%	1,106	2,983	3,978	2.8046	3,100	8,367	11,156
W.S. Central	236,775	248,614	177,581	130,226	94,710	40,252	14.3%	6,712	18,113	24,151		23,954	64,644	86,192

Arkansas	29,542	31,019	22,156	16,248	11,817	5,022	1.8%	837	2,260	3,013	2.5667	2,149	5,801	7,734
Louisiana	23,519	24,695	17,640	12,936	9,408	3,998	1.4%	667	1,799	2,399	2.9982	1,999	5,394	7,193
Oklahoma	32,561	34,189	24,421	17,909	13,025	5,535	2.0%	923	2,491	3,321	2.9974	2,767	7,466	9,955
Texas	151,153	158,711	113,365	83,134	60,461	25,696	9.1%	4,285	11,563	15,418	3.9766	17,039	45,982	61,310
Mountain	200,227	210,239	150,171	110,125	80,091	34,039	12.1%	5,676	15,317	20,423		18,393	49,638	66,183
Arizona	42,850	44,992	32,137	23,567	17,140	7,284	2.6%	1,215	3,278	4,371	3.2046	3,893	10,505	14,006
Colorado	35,031	36,782	26,273	19,267	14,012	5,955	2.1%	993	2,680	3,573	3.6788	3,653	9,859	13,145
Idaho	81	85	61	45	32	14	0.0%	2	6	8	2.5528	6	16	21
Montana	14,944	15,691	11,208	8,219	5,977	2,540	0.9%	424	1,143	1,524	3.0074	1,274	3,438	4,584
Nevada	4,844	5,086	3,633	2,664	1,938	824	0.3%	137	371	494	2.6912	370	997	1,330
New Mexico	26,626	27,957	19,969	14,644	10,650	4,526	1.6%	755	2,037	2,716	2.8724	2,168	5,851	7,801
Utah	32,647	34,279	24,485	17,956	13,059	5,550	2.0%	925	2,497	3,330	4.1894	3,877	10,463	13,951
Wyoming	43,204	45,364	32,403	23,762	17,282	7,345	2.6%	1,225	3,305	4,407	2.5746	3,153	8,509	11,346
Pacific	9,464	9,937	7,098	5,205	3,786	1,609	0.6%	268	724	965		786	2,122	2,829
California	1,825	1,916	1,369	1,004	730	310	0.1%	52	140	186	3.3199	172	464	618
Oregon	3,048	3,200	2,286	1,676	1,219	518	0.2%	86	233	311	3.1442	272	733	977
Washington	4,592	4,822	3,444	2,526	1,837	781	0.3%	130	351	468	2.6333	343	925	1,233
Pacific Other	2,168	2,277	1,626	1,193	867	369	0.1%	61	166	221		154	415	554
Alaska	660	693	495	363	264	112	0.0%	19	50	67	2.4835	46	125	167
Hawaii	1,509	1,584	1,131	830	603	256	0.1%	43	115	154	2.5117	107	290	386
U.S. Total	1,660,000	1,743,000	1,245,000	913,000	664,000	282,200	100.0%	47,057	126,990	169,320		149,878	404,469	539,293
Pct reduction of direct jobs:								-17%	-45%	-60%				

*2020 COAL GENERATION FROM EIA AEO 2013 ALLOCATED BY STATE BASED ON AVERAGE 2011-2012 GENERATION BY STATE.

**DIRECT UTILITY/COAL/RAIL JOBS ESTIMATED AT 0.17 EXISTING JOBS PER GIGAWATT-HOUR, BASED ON 2007 DATA FROM DOE/EIA AND ENERGY VENTURES ANALYSIS. DIRECT JOB LOSSES DUE TO COAL CAPACITY REDUCED UTILIZATION IN 1800 LB/MWh CASE ESTIMATED AT 0.113 JOBS PER GIGAWATT-HOUR (MINING AND RAILROAD SECTORS).

***CALCULATION OF COAL GENERATION CHANGES AT ALTERNATIVE COAL CO2 TARGETS WITH NATURAL GAS (1000 LB/MWh) AND RENEWABLE (0 LB/MWh) REPLACEMENT GENERATION AS SHOWN BELOW.

MWh AND CO2 TONS IN 000s	2020 Coal Gen. Ref. Case		1800 LB TARGET			1500 LB TARGET			1200 LB TARGET		
	MWh	TONS CO2	SHARE	MWh	TONS CO2	SHARE	MWh	TONS CO2	SHARE	MWh	TONS CO2
COAL	1,660,000	1,743,000	75.0%	1,245,000	1,307,250	55.0%	913,000	958,650	40.0%	664,000	697,200
NATL GAS	0	0	22.5%	373,500	186,750	34.5%	572,700	286,350	36.0%	597,600	298,800
RENEWABLES/EE	0	0	2.5%	41,500	0	10.5%	174,300	0	24.0%	398,400	0
SUM	1,660,000	1,743,000	100.0%	1,660,000	1,494,000	100.0%	1,660,000	1,245,000	100.0%	1,660,000	996,000
CO2 LB/MWH		2100			1800			1500			1200

***DIRECT EFFECT TYPE II EMPLOYMENT MULTIPLIERS FOR ELECTRIC POWER GENERATION, FROM U.S. DEPT OF COMMERCE, BUREAU OF ECONOMIIC ANALYSIS, BASED ON 2002 BENCHMARK INPUT-OUTPUT TABLES FOR THE NATION AND 2010 REGIONAL DATA (2013).

Appendix Table 2

INCREMENTAL COST OF NATURAL GAS GENERATION IN THE 1,800, 1,500 AND 1,200 LB. CO2/MWH CASES

EIA DELIVERED NATURAL GAS AND COAL PRICES
IN 2010 $ PER MILLION BTU

				INCREMENTAL N. GAS MWH (000)			INCREMENTAL N. GAS MMBTU@6,719 BTU/KWH			INCREMENTAL N. GAS COST (MIL. 2010$)		
	N. GAS	COAL	DIFF.	1,800 LB	1,500 LB	1,200 LB	1,800 LB	1,500 LB	1,200 LB	1,800 LB	1,500 LB	1,200 LB
2020	$4.90	$2.52	$2.38	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$12,297	$18,855	$19,675
	$5.04	$2.55	$2.48	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$12,638	$19,378	$20,221
	$5.17	$2.59	$2.58	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$12,979	$19,902	$20,767
	$5.31	$2.62	$2.69	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$13,321	$20,425	$21,313
	$5.44	$2.66	$2.79	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$13,662	$20,948	$21,859
2025	$5.58	$2.69	$2.89	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$14,003	$21,472	$22,405
	$5.67	$2.73	$2.95	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$14,239	$21,833	$22,783
	$5.77	$2.76	$3.01	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$14,475	$22,195	$23,160
	$5.86	$2.80	$3.06	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$14,711	$22,557	$23,538
	$5.96	$2.83	$3.12	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$14,947	$22,919	$23,915
2030	$6.05	$2.87	$3.18	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$15,183	$23,280	$24,292
	$6.24	$2.90	$3.33	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$15,650	$23,996	$25,039
	$6.42	$2.93	$3.49	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$16,116	$24,712	$25,786
	$6.61	$2.97	$3.64	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$16,583	$25,427	$26,533
	$6.79	$3.00	$3.80	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$17,050	$26,143	$27,280
2035	$6.98	$3.03	$3.95	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$17,517	$26,859	$28,027
	$7.26	$3.06	$4.20	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$18,219	$27,936	$29,151
	$7.54	$3.10	$4.44	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$18,922	$29,014	$30,275
	$7.82	$3.13	$4.69	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$19,625	$30,091	$31,399
	$8.10	$3.17	$4.93	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$20,327	$31,169	$32,524
2040	$8.38	$3.20	$5.18	373,500	572,700	597,600	2,509,546,500	3,847,971,300	4,015,274,400	$21,030	$32,246	$33,648
TOTAL										$333,494	$511,357	$533,590
NPV @ 7% DISCOUNT										$161,770	$248,048	$258,833

DECREASED COST OF COAL DISPLACED BY GAS FOR GENERATION IN THE 1,800, 1,500 AND 1,200 LB. CO2/MWH CASES

				DECREASED COAL MWH (000)			DECREASED COAL MMBTU@10,444 BTU/KWH			DECREASED COAL COST (MIL. 2010$)		
	N. GAS	COAL	DIFF.	1,800 LB	1,500 LB	1,200 LB	1,800 LB	1,500 LB	1,200 LB	1,800 LB	1,500 LB	1,200 LB
2020	$4.90	$2.52	$2.38	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$9,830	-$15,054	-$15,728
	$5.04	$2.55	$2.48	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$9,963	-$15,258	-$15,940
	$5.17	$2.59	$2.58	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,095	-$15,461	-$16,153
	$5.31	$2.62	$2.69	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,228	-$15,664	-$16,365
	$5.44	$2.66	$2.79	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,361	-$15,867	-$16,577
2025	$5.58	$2.69	$2.89	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,493	-$16,070	-$16,789
	$5.67	$2.73	$2.95	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,634	-$16,285	-$17,014
	$5.77	$2.76	$3.01	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,774	-$16,500	-$17,239
	$5.86	$2.80	$3.06	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$10,915	-$16,715	-$17,463
	$5.96	$2.83	$3.12	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,055	-$16,930	-$17,688
2030	$6.05	$2.87	$3.18	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,195	-$17,145	-$17,913
	$6.24	$2.90	$3.33	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,320	-$17,336	-$18,112

	$6.42	$2.93	$3.49	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,445	-$17,528	-$18,312
	$6.61	$2.97	$3.64	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,570	-$17,719	-$18,512
	$6.79	$3.00	$3.80	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,695	-$17,910	-$18,712
2035	$6.98	$3.03	$3.95	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,820	-$18,101	-$18,911
	$7.26	$3.06	$4.20	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$11,952	-$18,304	-$19,123
	$7.54	$3.10	$4.44	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$12,085	-$18,507	-$19,336
	$7.82	$3.13	$4.69	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$12,217	-$18,710	-$19,548
	$8.10	$3.17	$4.93	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$12,350	-$18,914	-$19,760
2040	$8.38	$3.20	$5.18	-373,500	-572,000	-597,600	-3,900,834,000	-5,973,968,000	-6,241,334,400	-$12,483	-$19,117	-$19,972
TOTAL										-$234,479	-$359,095	-$375,167
NPV @ 7% DISCOUNT										-$117,528	-$179,990	-$188,045

NET COST OF ADDITIONAL NATURAL GAS GENERATION

				NET NAT. GAS COSTS (MIL. 2010 $)		
	N. GAS	COAL	DIFF.	1,800 LB	1,500 LB	1,200 LB
2020	$4.90	$2.52	$2.38	$2,467	$3,801	$3,947
	$5.04	$2.55	$2.48	$2,675	$4,121	$4,281
	$5.17	$2.59	$2.58	$2,884	$4,441	$4,614
	$5.31	$2.62	$2.69	$3,093	$4,761	$4,948
	$5.44	$2.66	$2.79	$3,301	$5,081	$5,282
2025	$5.58	$2.69	$2.89	$3,510	$5,402	$5,616
	$5.67	$2.73	$2.95	$3,605	$5,548	$5,769
	$5.77	$2.76	$3.01	$3,701	$5,695	$5,922
	$5.86	$2.80	$3.06	$3,796	$5,842	$6,074
	$5.96	$2.83	$3.12	$3,892	$5,988	$6,227
2030	$6.05	$2.87	$3.18	$3,987	$6,135	$6,380
	$6.24	$2.90	$3.33	$4,329	$6,659	$6,927
	$6.42	$2.93	$3.49	$4,671	$7,184	$7,474
	$6.61	$2.97	$3.64	$5,013	$7,709	$8,021
	$6.79	$3.00	$3.80	$5,355	$8,233	$8,568
2035	$6.98	$3.03	$3.95	$5,697	$8,758	$9,115
	$7.26	$3.06	$4.20	$6,267	$9,632	$10,027
	$7.54	$3.10	$4.44	$6,837	$10,506	$10,940
	$7.82	$3.13	$4.69	$7,407	$11,381	$11,852
	$8.10	$3.17	$4.93	$7,977	$12,255	$12,764
2040	$8.38	$3.20	$5.18	$8,547	$13,129	$13,676
TOTAL				$99,015	$152,262	$158,423
NPV @ 7% DISCOUNT				$44,242	$68,058	$70,787

NOTES: Natural gas combined-cycle heat rate of 6,179 BTU/kwh is for a new Class F NGCC unit, as estimated by DOE/NETL at http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf.

Heat rate of 10.444 BTU/KWh for coal units is assumed based on EIA analysis of average coal heat rates in 2011. http://www.eia.gov/electricity/annual/html/epa_08_01.html.

EIA annual delivered coal and natural gas prices for intermediate years (e.g., 2021-24) calculated at average annual price change for each 5-year interval reported in EIA/AEO 2013, Table A3.