WORLD RESOURCES INSTITUTE

Appendix

POWER SECTOR OPPORTUNITIES FOR REDUCING CARBON DIOXIDE EMISSIONS

Appendix A: Detailed Overview of Methods

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WRI developed projections of state-level carbon dioxide (CO_2) emissions reductions from the power sector based on existing policies and other reduction opportunities using available infrastructure, including:

- Meeting the current requirements under the state's renewable portfolio standard (RPS) and energy efficiency resource standard (EERS), where they exist
- Increasing combined heat and power (CHP) capacity at commercial and industrial facilities
- Fully utilizing existing natural gas combined cycle (NGCC) capacity
- Increasing the efficiency of the existing coal-fired power plant fleet.

The model used to create these projections builds on a variety of data from EIA's Annual Energy Review, Form EIA-860, and Form EIA-923, as well as data compiled for WRI's report entitled *Can the U.S. Get There from Here?*[1] Depending on availability, we rely on electric generation projections from state environmental and energy agencies or EIA's *Annual Energy Outlook 2012* (*AEO 2012*). We used *AEO 2012* instead of *AEO 2013* because some of the underlying modeling builds on a previous WRI analysis that relied on projections from *AEO 2012*. This analysis is intended to provide a technically feasible range of CO_2 reductions; it is not an economic analysis. See Figure 1 for a summary of our methodology for existing policies and measures that use available infrastructure. The additional steps for expanded policies are shown in Step 4, below.

Figure 1 | **Methodology Summary**

STEP 1.
Reference Case Projections

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STEP 2.
Benefits from Implementing Existing Policies (if not included in Reference Case)

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Step 2a.
CO_2 benefit from reduced generation
Energy Efficiency Resource Standard

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Step 2b.
CO_2 benefit from increasing the proportion of generation from renewable resources
Renewable Portfolio Standard

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Adjusted Reference Case

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STEP 3.
Benefits from Utilizing Existing Infrastructure

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Step 3a.
CO_2 benefit from reduced generation
Increased Utilization of CHP at Industrial and Commercial Facilities

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Step 3b.
CO_2 benefit from increasing the use of natural gas capacity and decreasing use of coal capacity
Increased Utilization of Existing Natural Gas Capacity

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Step 3c.
Decreased emissions from remaining coal-fired generation
Increased Efficiency at Remaining Coal Plants

Step 1. Determine reference case electric generation and carbon dioxide (CO_2) emissions

For all states, we utilized EIA's *Annual Energy Review* for historical electricity generation[2] and CO_2 emissions[3] by fuel (coal, natural gas, other fossil, nuclear, and renewable) during the period from 2005 through 2011. Electric utilities, independent power producers, and commercial and industrial non-CHP units were included in this analysis. A forecast of generated electricity for each state through 2030 was determined by one of two methods as described below, depending on data availability (see Table 1).

Projections available from state environmental and energy agencies. Many state public utility commissions (PUCs) or other agencies provide forecasts of electricity generation for the state. Where available, we utilized these forecasts to help develop our own electricity generation projections. For each year, the percent change in the forecasted energy consumed by fuel, or electricity generated by fuel in the state's power sector, was applied to the state's generation in 2011 to create projections through 2030.Unless the source of the forecasted data made clear that it did *not* include planned retirements, new power plant builds, or fully meeting existing or soon to be adopted policies or programs (including new U.S. EPA rules), we conservatively assumed these were already captured in the reference case projections.

Projections from EIA's AEO 2012. When forecasts were unavailable from state agencies, we obtained regional projections of annual growth rates of electricity generation by fuel from *AEO 2012*.Because projections at the regional level may not accurately represent the trends expected to occur in each state, we used *AEO 2012* only when state-level projections were unavailable. Where *AEO 2012* projections were used, we did not calculate an adjusted reference case since existing renewable portfolio standards and energy efficiency resource standards were captured in these projections.

To project CO_2 emissions, we calculated state-specific emissions rates for each fuel for 2011 and applied these rates to projected generation. Because we examined improved efficiency of existing coal units as a CO_2 reduction measure in this analysis, we did not assume any efficiency increases in our reference case projections.[4]

Step 2: Calculate benefits from implementing existing policies

We calculated the CO_2 benefits from existing state policies—including energy efficiency resource standards and renewable portfolio standards—for states that had such policies in place. We assumed that any goals or required targets set by existing policies would be achieved. If state-level projections did not include existing policies, we incorporated the emissions savings they generated into an "adjusted reference case" projection.

Step 2a.Determine reduced demand from existing energy efficiency resource standards

Reducing electricity demand through improved end-use efficiency results in less electricity generated, thereby reducing CO_2 emissions from fossil fuel-fired power plants. A variety of state policies and programs already drive efficiency improvements, including EERS, programs funded by system benefit charges, as well as least-cost procurement.[5] In some cases, CO_2 emissions savings from existing EERS may be captured in the reference case projections and therefore may not generate additional emissions reductions. For instance, *AEO 2012* did not explicitly model state energy efficiency programs, but programs in existence in 2011 and earlier were generally thought to be captured through regional electricity trends. When state forecasts were used, we conservatively assumed that existing EERS were captured in the reference case unless the source explicitly stated that electricity savings from existing programs were excluded.

If reference case projections did not include effects of the EERS, we implemented the annual percent savings required by each state's target from the *Database of State Incentives for Renewables & Efficiency* (DSIRE)[6] (see Table 2). Typically, energy efficiency targets do not apply to all electricity sales within a state. We accounted for this by adjusting electricity savings by the percent of electricity sales covered by the target as estimated by American Council for an Energy-Efficient Economy (ACEEE).[7] This provided an estimated reduction of in-state demand for electricity, which was translated to an estimate of reduced emissions from in-state generation. We assumed that this percent reduction in demand resulted in reduced in-state generation.[8] We assumed power plant operators maximized carbon-free generation, so that reduced demand did not affect nuclear generation, but proportion-

ally reduced generation from the other resources (coal, natural gas, and other fossil fuels; renewable sources were reduced only in those states with an RPS expressed as a percentage of total sales).[9] Resulting emissions savings were calculated using the annual reference case emissions rates for each fuel type.[10]
Some states count CHP toward their energy efficiency standards and some states may allow other policies and programs to count under their energy efficiency goals. In our analysis, we conservatively assumed that the maximum amount of eligible CHP generation counted toward the EERS. This reduced the additional energy and CO_2 emissions savings achieved through increased utilization of CHP, while minimizing the potential for double-counting the savings.

Step 2b: Calculate the benefits from meeting existing renewable energy standards

Renewable portfolio standards (RPS) or alternative energy standards specify a percentage of electricity generation (or sales) that must be met by renewable or other alternative energy sources.[11] In some cases, CO_2 emissions savings from renewable standards were captured in the reference case projections and therefore did not result in additional emissions reductions. For instance, *AEO 2012* included all mandatory renewable portfolio standards that were implemented in 2011 or earlier in its reference case projections. When state forecasts were used, we conservatively assumed that renewable portfolio standards were captured in the reference case unless the source explicitly indicated that such programs were excluded.

When renewable portfolio standards were not included in the reference case projections, we assumed each state met its annual incremental RPS goals, as documented in the DSIRE database published in March 2013 (see Table 3).[12] Since most renewable targets are tied to demand, we estimated renewable generation by multiplying the percent annual goal by the projected electric generation after it was adjusted for the effects of energy efficiency programs. Note, we assumed utilities would not purchase out-of-state renewable energy certificates or make alternative compliance payments for compliance purposes; instead, we assumed each state complied with its RPS requirement with in-state renewable generation only. We assumed that the incremental renewable generation displaced fossil fuel use in proportion to the annual energy mix for electricity generation.[13] Resulting emissions savings were calculated using the reference case emissions rates for each fuel type.

Step 3: Calculate benefits from utilizing available infrastructure

In addition to meeting renewable or efficiency standards that are already on the books, states can take additional measures using existing infrastructure to help meet a potential emissions standard for the power sector.

Step 3a: Determine reduced demand (and increased onsite emissions) from policies that promote CHP systems

State measures that can facilitate CHP deployment include standard interconnection rules, reduced stand-by rates, net metering policies, technical assistance, and financial incentives. We assumed that states implementing these types of programs would add new CHP capacity as a result. If states did not have explicit CHP capacity targets or projected capacity increases as a result of existing programs, we assumed that existing practices (such as those previously described) would allow states to achieve 25 percent of their technical potential for new CHP as estimated by ICF International (see Table 4).[14,15] We assumed that CHP capacity would increase at a constant rate between 2011 and 2030. The CHP benefits presented in this section and on the summary figures of each fact sheet only reflect additional benefits beyond those counted toward state EERS, where applicable.

We estimated the electricity savings and the net increase in onsite fuel combustion associated with new CHP capacity using documented assumptions from ICF International's *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*.[16] We assumed that CHP units that produce cooling, heating, and power used half their thermal output to displace purchased electricity (by replacing electric chillers with thermally driven absorption chillers) and half to displace onsite fuel consumption. We also assumed that all new CHP units used 100 percent natural gas.[17] We assumed that this percent reduction in demand resulted in reduced in-state generation.[18] We assumed power plant operators maximized carbon-free generation so that reduced demand did not affect nuclear generation, but proportionally reduced generation from the other resources (coal, natural gas, and other fossil fuels; renewable sources were reduced only in those states with an RPS expressed as a percentage of total sales). Resulting emissions savings were calculated using the annual reference case emissions rates for each fuel type. We assumed that the CO_2 emissions associated with increased on-site fuel consumption from CHP would be deducted from the credit provided to CHP units under power sector regulations. Thus, we incorporated these additional CO_2 emissions into our projections.

Step 3b: Calculate underutilized natural gas capacity

To calculate underutilized (i.e., slack) natural gas capacity, we first determined the existing NGCC capacity and the current (2011) generation from these units. Because EIA's summary tables from the *Annual Energy Review* did not break down natural gas generation or capacity by technology type (e.g., natural gas combined cycle, or NGCC), we utilized two databases to calculate these values—EIA's *existing units* database from Form EIA-860,[19] and the generation and fuel data database from Form EIA-923.[20,21]

We estimated potential generation by assuming each existing NGCC unit was run at 75 percent capacity for an entire year (see Table 5).[22] We then compared potential generation to projected generation to determine the electricity that could be generated from the state's slack natural gas capacity in 2020. We assumed that slack natural gas capacity would begin to be utilized starting in 2015, increasing to maximum utilization in 2020.[23, 24] We applied this approach to all subsequent years—regardless of changes in electricity demand or coal plant efficiency—so that the maximum amount of electricity would be generated from existing NGCC units from 2020 through 2030. To provide a conservative estimate, we utilized the listed summer capacity for all NGCC units, which is sometimes lower than nameplate capacity due to electricity used for station service or auxiliaries during the period of peak summer demand.[25] If states reported planned or under construction NGCC units in the EIA-860 database, which contains proposed units through 2017, we assumed these units would come online and run the maximum potential capacity calculated previously, increasing the state's potential generation from NGCC units. This assumption is sensitive to relative fuel prices.

The CO_2 emissions benefit was calculated as the difference between reference case (or adjusted reference case, if applicable) emissions levels and the emissions levels resulting from the fleet's new fuel mix. We did not account for the increases in methane associated with the increased production of natural gas due to a higher demand for the fuel. Going forward, industry should work with EPA to reduce methane leakage rates from natural gas systems.[26]

Step 3c: Calculate the benefit from increasing the efficiency of the existing coal-fired power plant fleet

According to the National Energy Technology Laboratory and researchers at Lehigh University, it is likely that the existing coal fleet could achieve a 5 percent increase in efficiency on average.[27] Existing coal plants can increase efficiency through refurbishment and improved operation and maintenance practices, though the actual efficiency potential depends on plant age and other physical limitations.[28, 29] Another option to reduce the emissions intensity of a coal plant is co-firing with natural gas using the igniters that are already built into many existing pulverized coal boilers.[30] For purposes of this analysis, we conservatively assumed that the coal-fired power plant fleet remaining after step 3b decreases its heat rate by 2.5 percent, half of these potential levels.[31] This in turn would reduce CO_2 emissions by 2.5 percent at existing coal plants. The 2.5 percent improvement rate is assumed to be a fleet-wide average, as some units may be able to achieve greater or fewer reductions.

Some studies have examined the phenomenon that improving the efficiency of coal plants would decrease the marginal cost of generation, which would increase their competitiveness and lead to increased operation at those plants (and decreased generation at gas plants).[32] However, for purposes of this analysis we assumed that each state would maximize its fleet of power plants fueled by energy sources other than coal in order to reduce emissions, and so this rebound effect would not materialize.[33]

Step 4: Calculate GHG benefits from expanded policies

In addition to what states can achieve under existing laws and utilizing available resources, we illustrate the CO_2 benefits that states could achieve if they expanded current EERS and RPS targets and measures to promote CHP (see Table 6).

To estimate the CO_2 benefits that states could achieve if they build off existing energy efficiency programs and expand their current EERS targets, we assumed that states achieve their targets more quickly than their existing ramp-up schedules. If annual state savings targets were less than 2 percent, we assumed that the standards would be increased to 2 percent per year, consistent with the assumption made by Synapse Energy Economics and the Natural Resources Defense Council in their analyses.[34] We assumed that states would continue to achieve the maximum annual rate of electricity savings from their existing target date through 2030.We assumed that expanded measures to promote CHP systems would allow states to increase capacity to 50 percent of their technical potential in 2030. Where applicable, we conservatively assumed that the maximum amount of eligible CHP would be applied toward expanded state efficiency standards.

To estimate the CO_2 benefits that states could achieve with an expanded RPS, we assumed that states would continue to increase their renewable generation after their target was reached. The rate of increase was determined by the average annual rate of increase over the period covered by the RPS. If annual targets require renewable growth of less than 1 percent per year, we assumed that the standards would be increased to 1 percent per year, the most common average growth rate required by mature state programs. We used the same methods to calculate the CO_2 benefits from each measure as described in the existing policies section. To ensure that slack natural gas capacity remains utilized, we assumed that demand reductions from expanded measures only displaced coal and other fossil generation. To calculate resulting CO_2 emissions, we applied the emissions rate for each fuel type based on the new fossil fuel mix after accounting for existing policies and utilization of slack natural gas capacity.

Figure 2 | **Estimating the CO_2 Benefit of Expanded Policies and Infrastructure**

Reference Case Projections

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Existing Policies and Infrastructure (see Figure 1)

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CO_2 benefit from reduced generation

Expanded Efficiency Resource Standard and Increased Utilization of CHP Technical Potential

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CO_2 benefit from increasing the proportion of generation from renewable sources

Expanded Renewable Portfolio Standard

KEY UNCERTAINTIES AND LIMITATIONS

- This is not an economic analysis. Due to modeling limitations, we were not able to estimate the costs and benefits from taking the measures we included in our analysis.
- This analysis focuses solely on CO_2 emissions. We do not account for methane emissions associated with natural gas production, processing, and transmission.
- The EPA has not yet proposed a national emissions standard for existing power plants. We use the NRDC proposal—the only detailed plan of potential rules with requirements for each individual state that existed at the time we conducted this analysis—for illustration purposes only and not as an endorsement of any particular rules. State measures may be counted differently under the actual rules developed by EPA, thus actual compliance levels could potentially be greater or less than what was modeled in our analysis.
- Where possible, we relied on state-specific electricity projections. Where these were not available, we utilized regional projections from the EIA Annual Energy Outlook, which might not accurately capture expected state-specific trends. Additionally, because we relied on these other data sources for projected electric generation, any limitations inherent in those projections also hold true for our analysis.

- We assume the entire NGCC fleet in each state can achieve a capacity factor of 75 percent. Unit-specific factors may decrease the maximum capacity factor an individual NGCC unit can achieve.
- If states are implementing policies that promote increased CHP utilization, but do not have a specific target for new CHP capacity, we assume CHP capacity increases to 25 percent of the state's technical potential for new CHP (as estimated by ICF International). Existing policies may actually achieve fewer or greater new CHP installations.
- We assumed utilities would not purchase out-of-state renewable energy certificates or make alternative compliance payments for compliance with RPS requirements; instead, we assumed each state complied with in-state renewable generation only.

Table 1 | **Reference Case Assumptions**

STATE	SOURCE	NOTES
Ohio	Public Utilities Commission of Ohio. 2012. Ohio Long-Term Forecast of Energy Requirements 2011–2030. Accessible at: <http://www.puco.ohio.gov/emplibrary/files/util/UtilitiesDeptReports/OhioLTFEnergyReq2011-2030.pdf>.	Provided fuel-specific energy requirements for electricity generation in Ohio. For modeling purposes, we calculated the annual percent change in energy consumption by fuel. These values were applied to Ohio's 2011 electric generation to forecast generation by fuel type from 2012 through 2030. Existing RPS and EERS requirements are not included in reference case forecasts.

Table 2 | **State Energy Efficiency Resource Standards**

STATE	EERS
Ohio	22 percent cumulative electricity savings between 2009–25; annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–18 and 2 percent per year from 2019–25.

Table 3 | **State Renewable Portfolio Standards**

STATE	RENEWABLE TARGET (% OF SALES)	MODELING NOTES
Ohio	12.5 percent by 2024	RPS not included in BAU projections

Table 4 | **Combined Heat and Power Assumptions**

STATE	CHP PROGRAMS AND POLICIES	SOURCE FOR CHP TECHNICAL POTENTIAL	EXISTING CHP CAPACITY	CHP CAPACITY IN 2030
Ohio	Ohio has partnered with U.S. DOE to provide guidance, technical assistance, and sharing of best practices among industrial facilities to promote CHP. The state also began offering CHP as an eligible resource to count toward its energy efficiency resource standard in 2012.	ICF International; estimate prepared in 2012 for Ohio Coalition for Combined Heat and Power	521MW	3.0 GW; 70 percent of electricity savings go toward meeting the state's EERS

Table 5 | **Slack Natural Gas Capacity Assumptions**

STATE	2011 NGCC CURRENT CAPACITY FACTOR	2011 SLACK NGCC GENERATION	SLACK NGCC GENERATION, INCLUDING PROPOSED UNITS THROUGH 2017	"MAXIMUM" NGCC GENERATION BY 2020 (EXISTING + SLACK INCLUDING PROPOSED UNITS)
Ohio	47%	6.6 TWh	15 TWh	26 TWh

Table 6 | **Expanded Policies Assumptions**

STATE	EXISTING EERS	EXPANDED EERS
Ohio	Twenty-two percent cumulative electricity savings between 2009–25; annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–18 and 2 percent per year from 2019–25.	Annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–14 and 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	3.0 GW; 70 percent of the electricity savings go toward meeting the state's existing EERS	5.4 GW; 55 percent of the electricity savings go toward the expanded EERS
	EXISTING RPS	**EXPANDED RPS**
	12.5 percent by 2024	18.5 percent by 2030

ENDNOTES

1. Report available at: <http://www.wri.org/publication/can-us-get-there-from-here>.
2. U.S. Energy Information Administration (EIA). *Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>.
3. U.S. Energy Information Administration (EIA). *U.S. Electric Power Industry Estimated Emissions by State (EIA-767, EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>.
4. See Step 3c for a discussion on the historical CO_2 emissions improvement rate for the existing coal-fired power plant fleet in the United States.
5. American Council for an Energy-Efficient Economy (ACEEE). 2012. *The 2012 State Energy Efficiency Scorecard.* Report Number E12C.
6. The database can be found at www.dsireusa.org. If a state has a cumulative savings target and does not specify an annual savings schedule, we assume the target is reached by achieving a constant rate of annual savings between the implementation date and the target year.
7. American Council for an Energy-Efficient Economy (ACEEE). 2012. *The 2012 State Energy Efficiency Scorecard*. Report Number E12C.
8. Because most states operate on a regional grid and demand reductions will impact regional generation, it is unlikely that demand reductions will result in the same amount of reduced in-state generation. Because all states would be operating under the new EPA standards, other states in the region would likely be making similar shifts in demand and generation, so assuming no shifts in the balance of imports and exports provides a good estimate of the effect of demand reduction on in-state emissions. In addition, EPA standards will likely credit in-state demand reductions for the benefits that accrue, even if the benefits occur outside state borders.
9. In reality, reduced demand will displace generation from units that are at the margin of the dispatch curve, which may have an emission rate that is higher or lower than the fleet average. It is also likely that the emissions impacts of reduced demand will vary on a temporal basis.
10. The fleet-wide CO_2 emissions rate represents the quantity of CO_2 emitted for every unit of electricity generated.
11. In states where "alternative" energy sources include fossil fuels, we conservatively assume that the maximum amount of fossil fuel generation will be applied toward the standard and the remainder, if any, will be met by renewable sources.
12. The database can be found at: <www.dsireusa.org>.
13. Renewable generation displaces fossil fuel generation only; nuclear generation is not affected.
14. ICF International (2010) provides state-level technical potential estimates in *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*. We used more recent ICF estimates if they were available.
15. This level of technical potential aligns with a moderate policy scenario assessed by ICF International (2010) in *California: Combined Heat and Power: Policy Analysis and 2011–2030 Market Assessment.*
16. ICF International. 2010. *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power.*
17. According to the ICF International CHP database (http://www.eea-inc.com/chpdata/), the majority of CHP capacity added in the past ten years has been natural-gas fired.
18. Because most states operate on a regional grid and demand reductions will impact regional generation, it is unlikely that demand reductions will result in the same amount of reduced in-state generation. Because all states would be operating under the new EPA standards, other states in the region would likely be making similar shifts in demand and generation, so assuming no shifts in the balance of imports and exports provides a good estimate of the effect of demand reduction on in-state emissions. In addition, EPA standards will likely credit in-state demand reductions for the benefits that accrue, even if the benefits occur outside state borders.
19. U.S. Energy Information Administration (EIA). *Form EIA-860 detailed data.* Accessible at: <http://www.eia.gov/electricity/data/eia860/>.
20. U.S. Energy Informtion Administration (EIA). *Form EIA-923 detailed data.* Accessible at: <http://www.eia.gov/electricity/data/eia923/>.
21. The EIA-860 database includes generator-level information about existing and planned generators at electric power plants with 1 megawatt or greater of combined nameplate capacity, including the fuel type and capacity for each plant but not generation. EIA-923 contains plant-level data for all plants operating in 2011, including generation by prime mover and fuel type.
22. NGCC plants are designed to be operated at a capacity of 85 percent. However, actual potential capacity factors vary among units. We assume a maximum capacity factor of 75 percent to remain conservative. See: Massachusetts Institute of Technology (MIT). 2011. "Electric Power Generation." *The Future of Natural Gas.* Accessible at: <http://mitei.mit.edu/system/files/NaturalGas_Chapter4_Electricity.pdf>; National Energy Technology Laboratory.Natural Gas Combined-Cycle Plant. Accessible at: <http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf>.
23. We assumed that all slack natural gas would be used to displace coal generation. If slack natural gas capacity was greater than coal generation, we assumed that natural gas generation only increased to the amount necessary to displace all coal generation.
24. There may be current infrastructure limitations that prevent utilization of slack capacity (e.g., transmission constraints, pipeline capacity limitations). We assumed a lead time to account for infrastructure improvements that might be needed to enable maximum utilization of slack capacity.
25. U.S. Energy Information Administration (EIA). *Net summer capacity.* Accessible at: <http://www.eia.gov/tools/glossary/index.cfm?id=net%20summer%20capacity>.
26. For additional information, see: <http://www.wri.org/publication/clearing-the-air>.

27. Phil DiPetro and Katrina Krulla. 2010. "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions." National Energy Technology Laboratory, Office of Systems, Analyses and Planning. DOE/NETL-2010/1411. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/ImpCFPPGHGRdctns_0410.pdf>; Chris Nichols, Gregson Vaux, Connie Zaremsky, James Murphy, and MassoodcRamezan. 2008. "Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet." National Energy Technology Laboratory, Office of Systems, Analyses and Planning, and Research and Development Solutions, LLC, DOE/NETL-2008/1329. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/CFPP%20Efficiency-FINAL.pdf>; Bilirgen et al. 2010. "Analyses Show Benefits of Improving Unit Heat Rate as Part of a Carbon Mitigation Strategy." *Lehigh Energy Update* 28 (1). Accessible at: <http://www.lehigh.edu/~inenr/leu/leu_65.pdf>.
28. Phil DiPetro and Katrina Krulla. 2010. *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions.* National Energy Technology Laboratory, Office of Systems, Analyses and Planning. DOE/NETL-2010/1411. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/ImpCFPPGHGRdctns_0410.pdf>.
29. "Regulating Greenhouse Gas Emissions Under the Clean Air Act." 73 *Register* §147(2008). Accessible at: <http://www.gpo.gov/fdsys/pkg/FR-2008-07-30/pdf/E8-16432.pdf>.
30. Personal communication with Tomas Carbonell, Environmental Defense Fund, July 12 2013.
31. For comparative purposes, the emissions rate for the U.S. coal fleet has improved by about 0.7 percent since 2000. Calculated using: U.S. Energy Information Administration (EIA). *Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>; and U.S. Energy Administration Administration (EIA). U.S. Electric Power Industry Estimated Emissions by State (EIA-767, EIA-906, EIA-920, and EIA-923). Accessible at: <http://www.eia.gov/electricity/data/state/>.
32. It was found that coal generation would increase by 0.83 percent as a result of the efficiency gains. For more information, refer to: Joshua Linn, Dallas Burtraw, and Erin Mastrangelo. 2012. "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act." RFF Discussion Paper 11-43; and Dallas Burtraw and Matt Woerman. 2012. "The Consequences of Subcategorization in a GHG Tradable Performance Standard Policy." Presentation at the annual meeting of the Association of Environmental and Resource Economists, Asheville TN, June 4, 2012.
33. As this is meant to be an illustrative analysis of what is technically feasible, not what is economically likely under a specific set of policy choices, we have not applied the rebound effect in this context; it would run counter to the assumption that states will maximize gas generation to help meet a potential emissions standard for the power sector.
34. Daniel A. Lashof, Starla Yeh, David Doniger, Sheryl Carter, and Laurie Johnson. 2012. *Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters*. Natural Resources Defense Council. Accessible at: <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf>.