The Effect of CO2 Emissions Reduction on the U.S. Electricity Sector

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May 2011

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Executive Summary

This paper presents the results of an analysis of the effects on the U.S. electricity producing sector, by 2020, of a 17 percent reduction in U.S. CO2 emissions using a computable general equilibrium model. Because the future of nuclear power is uncertain two scenarios are analyzed: In the first, nuclear power is allowed to expand. In the second, nuclear power growth is restricted. The results show both how the structure of the electricity sector changes and how the economy responds to a carbon price that results from a required reduction in CO2 emissions.

Key findings include:

- A 17 percent reduction in CO2 emissions causes a 0.20% decline in real household consumption in the Nuclear Growth scenario and a 0.37% decline in the Nuclear Restricted scenario.
- The price on CO2 emissions is $48.48 per ton in the Nuclear Growth scenario and $60.45 per ton in the Nuclear Restricted scenario.[2]
- The price of electricity is projected to be about 16 percent higher in the Nuclear Growth scenario and nearly 25 percent higher in the Nuclear Restricted scenario.
- GDP and electricity supply shrink in both scenarios, with bigger decreases in the Nuclear Restricted scenario.
- Each scenario predicts a reduction in coal sourced electricity. This reduction is partially offset by increases in renewable, natural gas, and, in the nuclear growth scenario, by nuclear power.

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[2] Domestic and International offsets, and banking of allowances, were not included in this analysis. Inclusion of offsets and allowance banking would lower the price on CO2 emissions considerably. In both the Environmental Protection Agency's and Energy Information Agency's climate change related analyses, prices on CO2 emissions are significantly higher when offsets and allowance banking are not included in their analysis. In addition, the EPA and EIA analyses cover non-CO2 GHG gases while this analysis only covers CO2.

An international offset occurs when a (typically) developed country receives emissions reduction credit by investing in emissions reducing projects in less developed countries. See, for example, the Clean Development Mechanism (CDM) under the *Kyoto Protocol.*

1. Introduction

At the Copenhagen Climate talks held in December of 2009, President Obama pledged to cut greenhouse gas emissions (GHG) in the United States by 17 percent from 2005 levels by 2020. With a goal to reduce emissions 83 percent by 2050, the expected pathway set forth would entail a 30 percent reduction below 2005 levels in 2025 and a 42 percent reduction below 2005 levels in 2030.[3]

U.S. policymakers have been considering a number of options (for example, various emissions allowance allocation strategies) to address the impacts that would result from meeting an emissions reduction target for the United States. Economic analysis can provide information on the impact of various CO2 reduction strategies on economic activity, including the effect of measures that are aimed at reducing the economic impact of the imposition of a price on CO2. Furthermore, the usefulness of the analysis will be greater if it describes the impact on specific industries.

Because a carbon price will have broad impacts across all sectors of the economy, and consequent impacts on terms of trade and other macroeconomic trends, it is appropriate to analyze carbon price impacts in the context of a computable general equilibrium (CGE) model. Unlike partial equilibrium models, CGE models are capable of estimating direct and indirect effects at both the macro-economic and sector-specific levels.

There are two industrial sectors, electricity generation and transportation, that generate the vast majority of CO2 emissions in the United States.[4] This paper estimates the impacts of a reduction of U.S. CO2 emissions on the largest CO2 emitting sector, the U.S. electricity producing sector, under two scenarios using a computable general equilibrium model. In the first scenario, the nuclear power sector is allowed to expand in response to a cap on CO2 emissions (Nuclear Growth), while in the second scenario it is not allowed to expand (Nuclear Restricted).[5]

In each scenario, a 17 percent reduction of CO2 emissions is modeled.[6] In both scenarios, GDP and electricity supply shrink, and the price of electricity rises. However, when nuclear generated electric power growth is restricted, there are larger decreases to GDP and

[3] White House, Office of the Press Secretary, "President to Attend Copenhagen Climate Talks," November 25, 2009.

[4] According to the World Resources Institute, in 2006, Electricity & Heat and Transportation accounted for about 47 and 31 percent of U.S. CO2 emissions, respectively. Electricity & Heat is a World Resources Institute category that is roughly equivalent to electricity production.

[5] A single national electric grid is assumed. Separate electric grids with differing relative shares of energy inputs could affect the price of CO2 necessary to reach the 17 percent reduction in CO2 emissions.

[6] This is an attempt to estimate the price of carbon necessary to obtain a 17 percent reduction in CO2 emissions by 2020. The adjustment is made in the absence of any mitigation policies. The addition of other policies is likely to affect the outcome.

electricity supply, and higher electricity prices than when nuclear generated electric power is allowed to grow. Both scenarios see a reduction in coal sourced electricity, the most CO2 emission intensive electricity fuel source. This coal-fueled electricity reduction is partially offset by increases in renewable, natural gas, and in the Nuclear Growth scenario, by nuclear power.

This paper is the first of a series of studies that will estimate the impact of a reduction in CO2 emissions on various sectors of the U.S. economy. The first study includes a description of technical problems that have been solved in order to evaluate proposed measures aimed at reducing CO2 emissions.

2. USAGE Computable General Equilibrium Model of the United States Economy

This paper uses the USAGE computable general equilibrium (CGE) model of the U.S. economy.[7] The USAGE has a high level of disaggregation, using the Bureau of Economic Analysis (BEA) input-output accounts, the most detailed publicly available industry data. The model imposes utility maximizing behavior on a representative consumer and representative firms in more than 550 U.S. industries. Prices at economic equilibrium are those that lead to demand equaling supply in every market. In a world of perfect competition, producers earn zero profits. The model accounts for international trade, with the rest of the world treated in aggregate, and tracks investment flows driven by differences in rates of returns between industries. With the proper modifications, results from the USAGE model can reveal the impact of various proposed mechanisms in currently proposed climate change legislation, rules, and internationally negotiated agreements. The USAGE model could report the impacts of such provisions, and variations of them, on each sector that is identified as energy intensive and trade exposed by the Environmental Protection Agency (EPA).

Computable general equilibrium models are typically deterministic, and the USAGE model follows that practice. This means that the model does not incorporate uncertainty. The principle implication of this property, for the purposes of this study, is that a carbon tax and a cap and trade program that generate the same carbon price will produce identical results.[8]

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[7] USAGE was developed by Peter Dixon and Maureen Rimmer of the Centre of Policy Studies, Monash University, Australia. The underlying theory of the model can be found in Dixon and Rimmer, *Dynamic General Equilibrium Modeling for Forecasting and Policy; A Practical Guide and Documentation of MONASH*, 2002. MONASH is a model of the Australian economy. For detailed documentation of the USAGE model see Koopman and Winston (2009), "A Dynamic Baseline in the USITC USAGE Model – Insights and Issues."

[8] There are a number of analytic tools in use by the U.S. government that can estimate the impact of carbon prices on the U.S. economy. For example, the Department of Energy uses the NEMS model, which describes the energy producing and energy intensive industrial sectors in some detail. The Environmental Protection Agency's ADAGE model also models the energy producing sectors, and includes a sector representing energy intensive, trade exposed industries. EPA's supplementary analysis of H.R. 2454, available at http://www.epa.gov/climatechange/economics/economicanalyses.html, includes modeling results from a version of the Global Trade Analysis Project (GTAP) that has more detail on the energy sector. The GTAP model has more industry specific detail than either the ADAGE or the NEMS model, particularly in non-energy intensive industries.

Scenario analysis is performed by using a projection of the U.S. economy in 2020, generated with estimated trends in technology and consumer preferences, and forecasts of macroeconomic variables and future energy prices from the Energy Information Administration's (EIA) Annual Energy Outlook for 2010. For the effect of carbon emissions reduction, a policy neutral projection (the "base case") is compared to one with carbon emission reduction in place (the "policy" case). Findings are reported as percentage differences in economic variables between the base case and the policy case.

3. Quantifying the Impact of a Carbon Price on the Electricity Industry

Potential climate change mitigation measures are not costless. A market based mechanism for reducing CO2 emissions would impose a price on CO2 emissions. The White House Council of Economic Advisors has evaluated a number of scenarios from climate change models used in the academic community to generate a "Social Cost of Carbon" (SCC) that is meant to approximate the cost to the global economy of one additional ton of carbon emissions.[9] Thus, a price on carbon aimed at addressing the market failure associated with carbon emissions would be set equal to the SCC.

Setting a carbon price equal to the SCC only on U.S industries would likely not be sufficient to mitigate the global effects of climate change. According to estimates by the United Nations Intergovernmental Panel on Climate Change (IPCC) limiting the increase in global temperature over the long run to 2.8 degrees Celsius would require a reduction in global emissions of up to 60 percent by 2050.[10] Currently the United States emits about 21 percent of the world's carbon, thus the remaining CO2 reduction must come from other countries.

In 2006, the United States was second only to China in CO2 emissions. China's emissions that year were almost 23.4 percent of global CO2 emissions, followed by the United States at just over 20.9 percent. The European Union was a distant third at nearly 12.8 percent of world CO2 emissions (Figure 1).[11]

Prior to 2006, the United States was the world's largest CO2 emitting country.[12] In addition, the United States emits a higher proportion of CO2 to total green house gas (GHG)

This study uses the USAGE model developed by the U.S. International Trade Commission. The USAGE model is most similar to the GTAP model, with some important theoretical differences, and has much more industry detail than any of the other models.

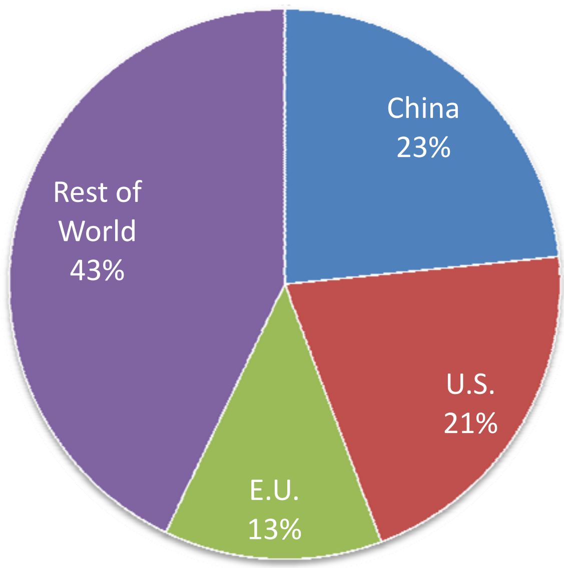
[9] http://www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/sem_finalrule_appendix15a.pdf

[10] Cited in EPA's Advanced Notice of Proposed Rulemaking for regulating greenhouse gases under the Clean Air Act in July 2008. Federal Register / Vol. 73, No. 147 / Wednesday, July 30, 2008 / Proposed Rules. p 44401.

[11] World Resources Institute, 2009; excludes land use.

[12] World Resources Institute, 2009; excludes land use.

Figure 1: Share of 2006 Global CO2 Emissions



emissions (over 84 percent) than the world (about 76 percent) or the European Union (about 81 percent), primarily because the share of coal in electricity generation is relatively greater.

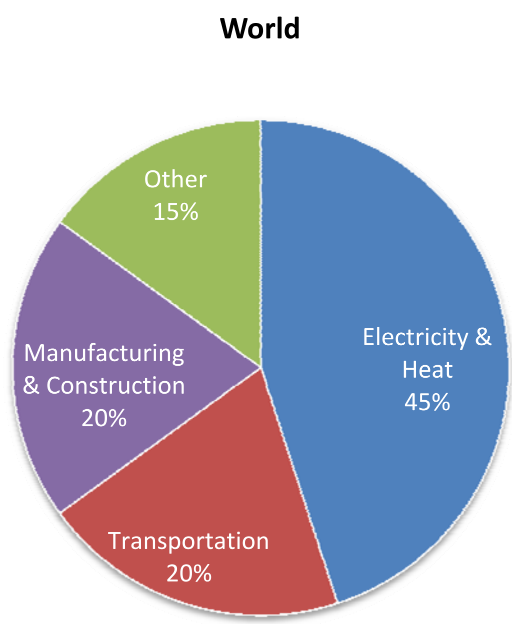
While all industries produce GHG, the electricity generating industry is the largest GHG emitting sector in the world. The Electricity & Heat sector accounted for 45.1 and 44.7 percent of world CO2 emissions in 2006 and 2005, respectively, far higher than the next two largest sectors, Manufacturing & Construction and Transportation, each at between 19 and 20 percent in both years (Figure 2).[13,14,15]

[13] World Resources Institute, 2009; excludes Land use.

[14] According to World Resources Institute, 2009; includes Land use. If other GHGs are included the percentages fall, but the Electricity and Heat at 28.6 percent is still more than double that of the next largest emitting sector, transportation at 12.4 percent.

[15] In another report, energy emissions from the Power sector, accounts for about 24 percent of all world greenhouse-gas emissions, larger than any other sector. See Stern Review: The Economics of Climate Change, October 2006.

Figure 2: Share of 2006 C02 Emissions by Sector

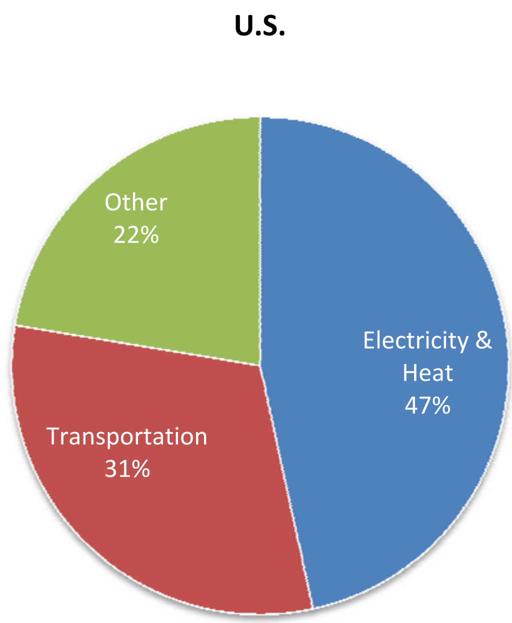


In the United States, Electricity & Heat accounted for 46.6 percent of CO2 emissions in both 2006 and 2005, followed by the Transportation sector at about 31 percent for both years (Figure 3).[16,17]

[16] World Resources Institute, 2009; excludes Land use.

[17] Including other GHGs has less influence on the United States Electricity and Heat sector as this sectors' share only falls from 46.6 percent to 40.1 percent of GHG emissions, much less so than in the World as a whole. World Resources Institute, 2009; includes Land use.

Figure 3: U.S. Distribution of 2006 C02 Emissions by Sector



The type of fuel used by an electric power generating plant largely determines the level of CO2 emissions of that plant. According to the International Energy Agency, "Fossil fuels provide over 70 percent of the world's electricity and heat generation", and coal accounted for "41 percent of the generation in 2007."[18] Fossil fuels are the primary CO2 emitting fuel in electric generation,[19] and coal is the "most carbon-intensive of fossil fuels, amplifying the sector's share in global emissions" and is thus a major source of GHG.[20]

In the United States, about half of electricity production in 2005 was produced by coal-fired generation. Other sources of electricity generation include natural gas at 18.7 percent, oil at

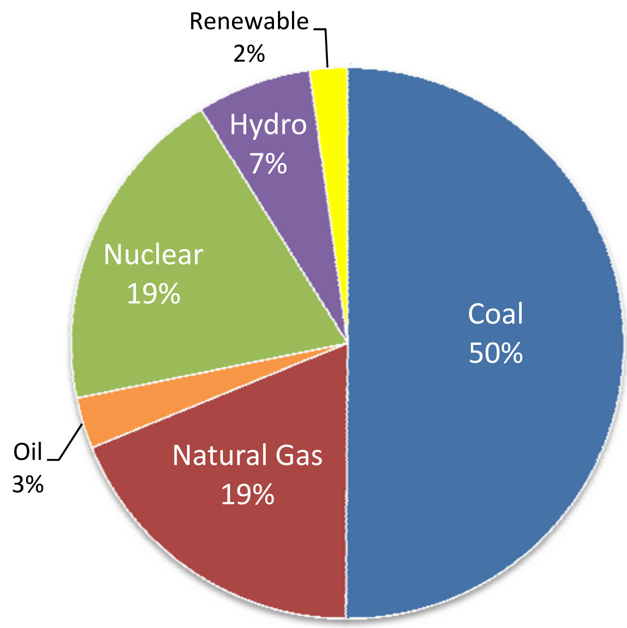
[18] International Energy Agency, CO_2 Emissions from Fuel Combustion, 2009 edition, p 13.

[19] The Intergovernmental Panel on Climate Change default carbon emission factors from the 1996 IPCC Guidelines: 15.3 t C/TJ for gas, 16.8 to 27.5 t C/TJ for oil products, and 25.8 to 29.1 t C/TJ for primary coal products. Other energy sources, including nuclear, hydro, geothermal, solar, and wind produce little or no CO2 emissions.

[20] International Energy Agency, CO_2 Emissions from Fuel Combustion, 2009 edition, p 13.

3.0 percent, nuclear power at 19.3 percent, hydro at 6.7 percent, and other renewables at 2.2 percent (Figure 4).[21]

Figure 4: Share of 2005 U.S. Electricity Generation by Source



In order to adequately estimate the effect a price on carbon has on electricity generation in the United States, it is necessary to properly address the variety of processes, and therefore fuels, that are used to produce electricity. A breakout of the electricity sector by fuel type allows the distribution of energy use by fuel type to vary in response to a price on CO2 emissions (resulting from either a cap and trade system or a carbon tax).[22] Attempts at estimating the effect of a cap and trade system or a carbon tax will be more accurate if it takes into account how either will affect changes in demand for electricity produced from different fuel types: coal, natural gas, nuclear, hydro and other renewables.

[21] World Resources Institute, 2009

[22] The key difference between a carbon tax and a cap and trade program is that the tax fixes the carbon price and allows emissions to fluctuate, while the cap and trade program fixes emissions and allows the carbon price to fluctuate. In both instances, a price is imposed on CO2 emissions.

3.1 *The breakout of the electricity industry in the USAGE model*

Although the USAGE model uses the BEA benchmark input-output accounts, the electricity generating industry is not separated by fuel type or method of production. We have expanded the USAGE model to include a breakout of the electricity generating sector by fuel type – coal, natural gas, nuclear, hydro, and other renewables.

We are interested in imposing a carbon emission reduction and simulating the substitution between fuel types. Fuels should be relatively more sensitive to changes in prices of other fuel types than in price changes of other intermediate inputs. The simplest way to implement this in the USAGE model is to disaggregate the different fuel types into separate industries. Each fuel type will produce a fuel-specific electricity commodity, which is then combined with a high degree of substitutability by a "virtual" electricity services industry.[23]

We look at two different scenarios with respect to electricity generation from nuclear energy. Because nuclear power emits little CO2, nuclear power generation would be expected to expand significantly in response to a emissions reduction 17 percent below 2005 levels. One simulation is based on this assumption. However, there may be resistance to expanding nuclear power beyond the expected growth predicted by EIA. Accordingly, a second simulation assumes the supply of nuclear power is highly inelastic, thus restricting nuclear expansion to that predicted by EIA. In each case, we impose a shock that brings a 17 percent reduction in CO2 emissions by 2020.

3.2 *Calibrating the supply response of electricity generating industries*

The USAGE model is a "tops-down" model, where changes in variables are driven by assumptions about the behavior of economic agents representing the government, the U.S. consumer, and each of the 550 industries. Demand for intermediate inputs by the representative producer in each industry is thus driven by assumptions about the producer's reaction to price changes. The degree of response is determined by parameters derived from theoretically modeled economic behavior. Assumptions about the magnitudes of the relevant parameters in the USAGE model are key to determining the overall response to a given carbon price, so it is necessary to choose the parameter values carefully.

An industry's relative demand for input *i* in the USAGE model can be written as follows:

$$x_i = -\sigma(p_i - P) + a_i - \sigma(a_i - A)$$

[23] Virtual industries have no value added and are used to allow different industries to produce the same commodity. Details of how the Electric Service data are broken out can be found in Appendix A.

Where:

x_i is the change in the relative demand for each input;
σ is a substitution parameter;
p_i is the change in price for each input i;
P is the change in an index of all input prices;
a is the change in technology for each input i; and
A is an index of technological change.

The electricity generating industry in USAGE is a zero value added "virtual industry" that uses the outputs of the various electricity producing sectors (coal, natural gas, nuclear, hydro, renewable) to produce the electricity that is ultimately consumed. Thus, the σ parameter determines the degree to which the various producing sectors will respond to exogenous changes in price and technology. Because σ is currently assumed equal for all inputs, the various electricity sources are equally substitutable for each other.

The Department of Energy and the EPA both model H.R. 2454, which proposes a CO2 mitigation framework. The Department of Energy's EIA analysis of H.R. 2454 estimates that the cost of emissions allowances in 2020 will be $32 per ton, while the combined output of electricity from coal and natural gas declines by nearly 18 percent.[24] The EPA analysis of H.R. 2454 finds that emissions allowances will cost about $20.00 per ton in 2020, while electricity output fueled by fossil fuels falls by 19 percent.[25] Clearly, the EPA analysis assumes a much higher elasticity of supply for electricity from fossil fuels than does EIA's analysis. Supply responses tend to be higher in the long run, so the higher supply response in the EPA analysis is consistent with EPA's analytical approach. The objective function governing electricity supply in EPA's ADAGE model assumes that a "central planner" with perfect foresight and information minimizes the present discounted value of the total costs of electricity capacity needed to meet electricity demand over the entire time horizon of the model. This assumption will provide long-run solutions in every year. The EIA's NEMS model determines electricity capacity decisions each year and is more consistent with short run behavior.[26]

Thus, calibration of the σ parameter for the virtual electricity industry is potentially a two step process. First, a value for σ is chosen to roughly reproduce the supply responses in the EIA

[24] Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[25] Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.

[26] EPA's ADAGE model assumes a joint constraint on nuclear and carbon capture and storage, (CCS), that due to subsidies for CCS in H.R. 2454, causes firms to choose to build CCS instead of nuclear power up to 2020. In later years, after the CCS bonus allowances expire, firms choose to build more nuclear. This is another area where the EPA analysis departs from EIA's, where nuclear power expands by 7 percent in 2020.

and EPA simulations of H.R. 2454. Then, if necessary, the individual σ for each subsector can be chosen to fine tune the results.[27]

Given that it is impossible to replicate both agencies' results, we will instead calculate the differences between the USAGE model results and the EPA and EIA results for final electricity output of each sub-industry. We demonstrate how "close" the USAGE model results are to those of EIA and EPA by summing the square of these differences.[28]

3.3 *Comparison of USAGE Results to EPA Simulation of H.R. 2454*

Table 1 shows the results of EPA's ADAGE analysis of "Scenario 2 - H.R. 2454," which yields a $20 per ton carbon price in 2020, and reports the results from USAGE of imposing a $20 per ton carbon price using values of σ of 3, 5, and 7.[29] In the USAGE simulation, the weighted decline in coal and natural gas output, combined, ranges from 10.0 to 13.4 percent. Reported are the percentage changes of key variables when carbon prices are imposed in 2020 compared to the 2020 baseline.

Table 1: EPA's "H.R. 2454" Scenario and USAGE results from $20/ton carbon price in 2020 simulation (percent changes from baseline)

Electricity Source:	EPA simulation	USAGE $\sigma = 3$	USAGE $\sigma = 5$	USAGE $\sigma = 7$
Fossil fuels: (Coal And Natural Gas/Petroleum)	-19.0	-16.0	-20.1	-23.0
		3.7	6.6	8.5
Nuclear	0.0	12.1	18.1	22.3
Hydro	0.0	0.0	0.0	0.0
Other renewables	120.4	15.7	24.5	31.1
Total Electricity Output:	-7.2	-4.9	-4.9	-4.8

Source: Supplemental HR.2454 EPA Data Annex - ADAGE & IGEM v1.0.xls, available at http://www.epa.gov/climatechange/economics/downloads/HR2454_SupplementalAnalysis_DataAnnex.zip

Note: According to the EPA, not including international offsets would increase the allowance price by up to 148 percent and would affect the results accordingly.

[27] This may be done in a future version of this paper.

[28] The analytical findings in this paper are based on the latest Annual Energy Outlook, AEO 2010. However, the EIA and EPA analyses of H.R. 2454 were based on the 2009 AEO, so we use the AEO 2009 for the calibration exercise.

[29] According to the EPA, not including international offsets would increase the allowance price by up to 148 percent. See: http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf.

3.4 *Comparison of USAGE Results to EIA Simulation of H.R. 2454*

Table 2 shows the results of EIA's estimate of the response of the electricity sector to a \$32 per ton carbon price in 2020 and reports the results from USAGE of imposing a \$32 per ton carbon price using values of $\boldsymbol{\sigma}$ of 3, 5, and 7.[30] The weighted decline in coal and natural gas output, combined, ranges from 15.9 to 22.4 percent.

Table 2: Results from EIA's "H.R. 2454" Scenario and USAGE results from \$32/ton carbon price in 2020 simulation (percent changes from baseline)

Electricity Source	EIA simulation	USAGE $\sigma = 3$	USAGE $\sigma = 5$	USAGE $\sigma = 7$
Coal	-14.7	-23.1	-29.3	-33.6
Petroleum and Natural Gas	-3.1	3.4	6.3	8.0
Nuclear	7.3	17.2	25.6	31.2
Hydro For EIA: Implied	0.0	0.0	0.0	0.0
Other Renewables: For EIA: Implied increase in non-hydro renewable production (includes "other")	39.1	23.3	36.8	47.1
Total Electricity Production	-2.4	-6.6	-6.5	-6.4

Source: http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Note: According to EIA, not including international offsets would increase the allowance price to \$52.08 and would affect the results accordingly.

[30] According to EIA, not including international offsets would increase the allowance price to \$52.08. See: http://www.eia.doe.gov/oiaf/servicerpt/hr2454/excel/hr2454noint.xls.

3.5 *Calibration of the USAGE Model*

Table 3 compares the USAGE results with the EPA simulation. The last row shows the sum of squared differences in outcomes in kilowatt-hours for each of the electricity subsectors – the USAGE simulation with the lowest sum of squared differences would be considered "closest" to the other simulation. The overall sum of squared differences between the USAGE and EPA simulations is lowest when $\sigma = 7$, indicating that the overall price response in the EPA model is fairly elastic.

Table 3: Comparison of USAGE results with EPA Simulation, billions of kilowatt hours (unless otherwise indicated)

EPA comparison:	EPA simulation:	USAGE $\sigma = 3$	USAGE $\sigma = 5$	USAGE $\sigma = 7$
Total Electricity Output	4,103	4,206	4,208	4,210
Fossil fuels (Coal and Natural Gas/Petroleum)	2,458	2,730	2,669	2,626
Nuclear	862	967	1,019	1,054
Hydro	316	316	316	316
Other renewables	467	245	264	278
Sum of squared differences:		134,139	110,308	100,795

Note: USAGE simulations use EPA's 2020 $20 per ton carbon price

Table 4 compares the USAGE results to the EIA simulation. The overall sum of squared differences between the USAGE and EIA simulations is lowest when $\sigma = 3$, showing the price response in the EIA simulation is less elastic.

Table 4: Comparison of USAGE results with EIA Simulation, billions of kilowatt hours (unless otherwise indicated)

EIA comparison:	EIA simulation:	USAGE $\sigma = 3$	USAGE $\sigma = 5$	USAGE $\sigma = 7$
Total Electricity Output	4462	4351	4243	4133
Coal	1875	1691	1402	1090
Natural Gas/Petroleum	740	790	866	965
Nuclear	940	1027	1203	1471
Hydro	316	316	316	316
Other renewables	591	482	436	424
Sum of squared differences:		55,974	333,205	975,808

Note: USAGE simulations use EIA's 2020 $32 per ton carbon price

Since the value of σ with the lowest sum of squared differences is 3 for the EIA simulation and 7 for the EPA exercise, it is clear that the differences in modeling assumptions make it very difficult to determine a value for σ that will reconcile the USAGE model with both

EIA and EPA's estimates. It may be possible to fine tune the model by changing the σ parameters for each sub-industry. However, for this exercise, we set $\sigma = 5$.

3.6 *Tracking CO2 emissions in the USAGE model*

The input-output matrices in the USAGE model provide the dollar value of various fossil fuels used throughout the U.S. economy. We introduced an indexing formula to allow the USAGE model to track quantity, rather than value, of fuel used. This prevents the (physically impossible) creation of additional electricity while substituting cheap fuel for expensive fuel.

An emissions matrix based on the quantity of fossil fuel use tracks emissions in each industry and a 17 percent CO2 emissions reduction below 2005 levels is imposed in the policy simulation.[31] Additional pieces of programming language allow for "emissions allowance allocations" for the electricity generating sector, for example, as proposed in H.R. 2454.

4. USAGE Results of CO2 Emissions Reductions[32]

4.1 *Simulation Details*

There are two basic ways to implement a carbon price in USAGE. Carbon taxes can be imposed on emissions, or a cap can be implemented as an exogenous limit on permitted emissions levels. In this instance, we modeled an exogenous limit on emissions equal to a 17 percent CO2 reduction below 2005 levels. The model then endogenously computes the permit price as the shadow carbon price necessary to bring about the necessary reductions in emissions. Results are compared to what is projected in the base case scenario that does not incorporate the 17 percent CO2 reduction.

We modeled the 17 percent emissions reduction in two scenarios. In the "Nuclear Growth" scenario, nuclear power is allowed to expand in response to the carbon price caused by the emissions cap. In the "Nuclear Restricted" scenario, nuclear power growth is exogenously held to the 2020 level projected in the base case.

4.2 *Macroeconomic Effects*

A 17 percent emissions reduction imposes a cost on the U.S. economy in the form of a price on CO2 emissions.[33] For this reason, we would expect to see a reduction in GDP relative

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[31] Currently the matrix contains information on CO2 emissions only, but the matrix can be expanded to include other GHGs. Much of this work was done by Ashley Winston of the Centre of Policy Studies, Monash University, Australia.

[32] The simulation assumes the rates of technological change implied by EIA's forecast for 2020. The cost of producing a unit of electricity from renewable sources in particular is assumed to drop significantly by 2020. This reduces the economic impacts of the emissions reduction. Other assumptions about technology, such as technological innovations that reduce carbon emissions per unit of fuel consumed, would further reduce these economic impacts.

to the base case scenario in both the Nuclear Growth and Nuclear Restricted scenarios. We would also expect electricity prices to be higher and electricity output lower in both scenarios.

Of the five fuel types used to generate electricity, coal emits the most CO2. Natural gas emits 40-47 percent less CO2 than coal.[34] Emissions from nuclear, hydro and renewable energy are negligible. For this reason we would expect to see a shift away from coal, towards the "cleaner" fuel types in both scenarios.[35] In the Nuclear Restricted scenario, where nuclear capacity cannot grow beyond projected 2020 levels, there are fewer alternatives available to lower emissions cheaply. In comparison to the Nuclear Growth scenario, we would expect an increase in the price of electricity, and a decline in both electricity consumption and GDP. We would also expect the CO2 permit price to be higher.

Table 5 reports the effects of the 17 percent emissions reduction in both scenarios. As expected, most measures of economic activity decline in both scenarios, with bigger impacts in the Nuclear Restricted scenario. Real household consumption, in particular, declines nearly twice as much in the Nuclear Restricted scenario. Electricity consumption declines and electricity prices increase in both scenarios. The reduction in electricity consumption is almost 3 percentage points greater in the Nuclear Restricted scenario. Electricity prices increase significantly more in the Nuclear Restricted scenario, almost 25 percent higher than the 2020 base case. The permit price of $48.48 in the Nuclear Growth scenario increases significantly to over $60 per ton in the Nuclear Restricted scenario.

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[33] This analysis only estimates the cost of reducing CO2 emissions; no estimates of potential benefits of CO2 emission reductions are made.

[34] Calculated from the Intergovernmental Panel on Climate Change (IPCC) default carbon emission factors from the 1996 IPCC Guidelines: 15.3 t C/TJ for gas, 16.8 to 27.5 t C/TJ for oil products, and 25.8 to 29.1 t C/TJ for primary coal products. Other energy sources, including nuclear, hydro, geothermal, solar, and wind produce little or no CO2 emissions.

[35] Due to the lack of new sources of hydro power, its supply is assumed to be infinitely elastic. Thus, the expansion of hydro power is not feasible in these simulations.

Table 5: Macroeconomic Effects

	Nuclear Growth Scenario	Nuclear Restricted Scenario
Emissions	-17%	-17%
Real GDP	-0.30%	-0.47%
Real Household Consumption	-0.20%	-0.37%
Real Investment	-0.61%	-0.70%
Real Aggregate Government Demand	-0.20%	-0.37%
Real Exports	-0.72%	-0.94%
Real Imports	-0.50%	-0.61%
Electricity Consumption	-8.78%	-11.56%
Electricity Price	15.94%	24.85%
Permit Price (per ton of C02)	$48.56	$60.59

Note: All changes are relative to the 2020 base case. International offsets were not included in this analysis. Inclusion of international offsets would lower the price on CO2 emissions considerably.

4.3 *Effects in the Electricity Generating Sector*

One of the biggest effects of imposing a price on CO2 emissions is a shift away from coal-fired electricity generation. Figure 5 shows the share of electricity generation by fuel type in the base case in 2020 and the effects on this distribution in the Nuclear Growth and Nuclear Restricted scenarios.

In 2020, without any imposed 17 percent reduction, EIA projects that electricity produced from coal, the cheapest but most CO2 emission intensive form of electricity, will make up about 47 percent of all electricity generation. In both the Nuclear Growth and Nuclear Restricted scenarios, this share shrinks to a little over 30 percent.

In the base case scenario, hydro electricity is projected to make up about 8 percent of 2020 generation. Hydro electricity growth is restricted in both scenarios so its share remains about the same, growing slightly due to the decline in overall electricity generation in both scenarios.

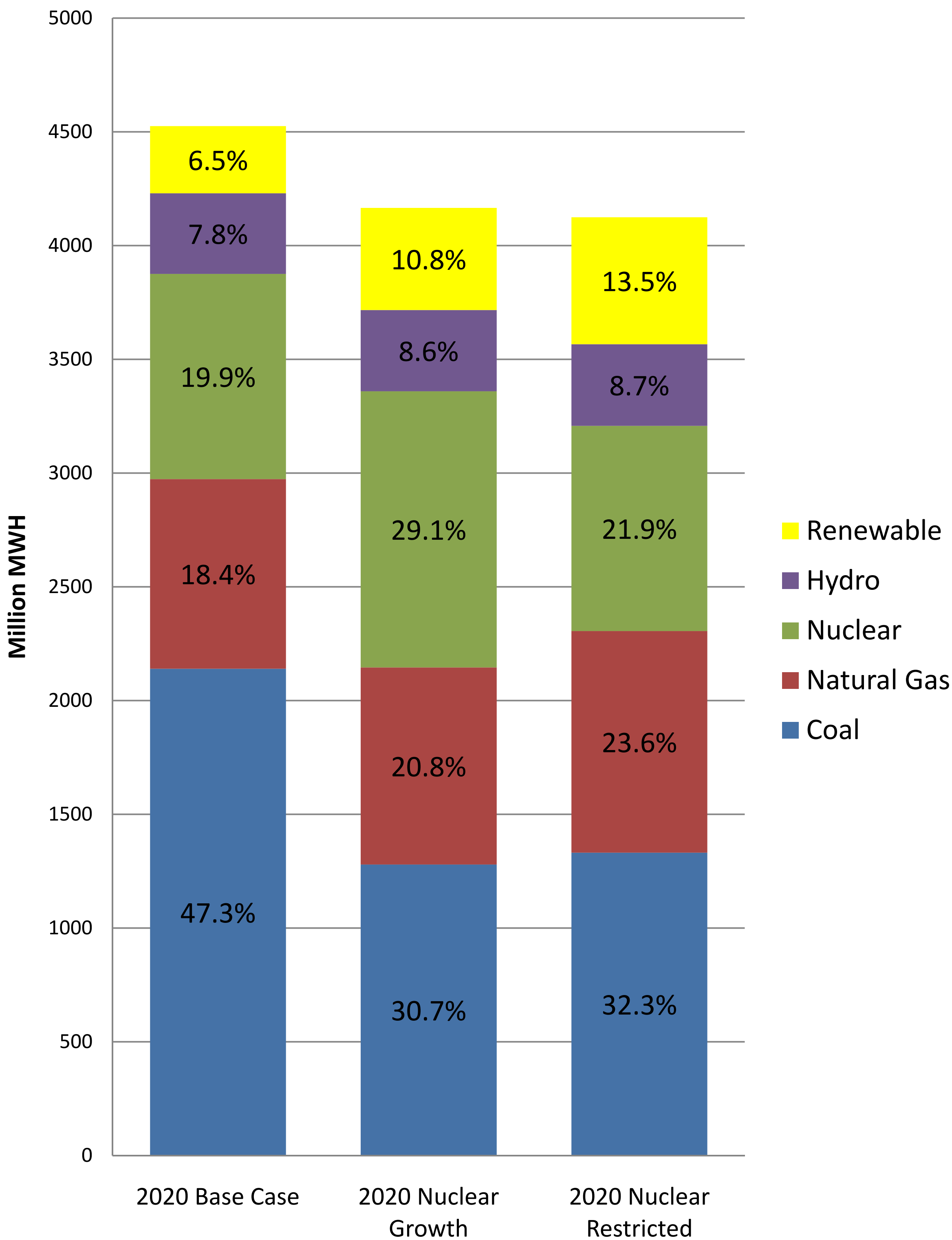
Nuclear electricity is projected, in the base case, to make up about 20 percent of generation in 2020. In the Nuclear Growth scenario, this share grows to almost 30 percent of total generation. In the Nuclear Restricted scenario nuclear electricity growth is held at zero, so its share grows slightly due to the overall decline in electricity generation.

In the base case scenario, renewable electricity is projected to make up about 6.5 percent of generation in 2020. This share grows to almost 11 percent in the Nuclear Growth scenario, and 13.5 percent in the Nuclear Restricted scenario.

Natural gas electricity is projected, in the base case, to make up a little over 18 percent of generation in 2020. Since the natural gas fired electricity generating process emits CO2, the price of natural gas electricity rises with the carbon price. However, natural gas electricity emits much less CO2 than coal electricity, so there is substitution towards natural gas in both scenarios. In the Nuclear Growth scenario natural gas electricity grows to about 21 percent of total generation. In the Nuclear Restricted scenario natural gas grows to over 23 percent of total generation.

The price of electricity relative to the base case scenario is projected to be about 16 percent higher in the Nuclear Growth scenario and nearly 25 percent higher in the Nuclear Restricted scenario.

Figure 5: Share of Electricity Generation in the United States



4.4 *Summary of Results*

With a 17 percent reduction in CO_2 emissions, real household consumption declines 0.20 percent in the Nuclear Growth scenario and 0.37 percent in the Nuclear Restricted scenario. Demand for electricity declines as the price of electricity rises in both scenarios relative to the base case scenario. In the Nuclear Growth scenario there is a price of $48.48 on CO2 emissions while in the Nuclear Restricted scenario the price on CO2 emissions is $60.45 per ton.

Both scenarios see a reduction in coal sourced electricity, the most CO2 emission intensive electricity fuel source. This reduction is partially offset by increases in renewable, natural gas, and in the Nuclear Growth scenario, by nuclear power.

5. Future Steps

While this simulation models the economic effects of a CO2 emissions reduction, there are several steps that we can take to improve the descriptive power of the model. We plan to these steps in future iterations of the simulation. They include:

1. **Domestic and International Offsets:** Offsets are expected to have a significant impact on the cost of any CO2 mitigation strategy. These simulations do not model the effect of offsets, so the resulting permit prices are much higher than those in analyses that do model offsets.

2. **Regional Electricity sourcing.** Regulation of electricity prices in the United States creates differences in prices between electricity consumed in for example, Texas, vs. west of the Rockies, or in the Midwest and East coast. As a result, some industries have strategically located themselves in regions with lower electricity prices. Analysis of the impact of a carbon price would be more accurate if the regional differences were taken explicitly into account by splitting the United States into sub-regions and allowing electricity prices to differ between them according to historical trends.

APPENDIX

Disaggregating the Electric Service Industry in USAGE

The USAGE model aggregates together all electricity generated by coal, gas, petroleum, nuclear power, wind, hydro power, etc. Our task was to split the aggregated electric generating industry into sectors by fuel source. Using data from BEA, EIA and other public sources we split the electricity generating industry's inputs and output into five sub-sectors: Coal, Natural Gas, Nuclear, Hydro and Renewable.

Table A-1 illustrates how we disaggregated data for the electric power generating sector. Here are the expenditures on capital, labor, and the top ten intermediate inputs for the electric power generating sector for 2004:

Table A-1

Intermediate Input	Expenditure on Input (million $)
Other repair and maintenance construction	27,784
Coal	16,909
Natural gas distribution	15,056
Crude petroleum and natural gas	14,723
Computer and data processing services	8,061
Petroleum refining	5,560
Legal services	4,700
Banking	4,159
Colleges, universities, and professional schools	3,011
Personnel supply services	2,780
Labor	32,637
Capital	92,869

Source: Bureau of Economic Analysis, Department of Commerce

In 2004 the electric power generating industry had returns to capital of about $92.9 billion, spent $32.6 billion on labor, $27.8 billion on repair and maintenance construction, $16.9 billion on coal, etc. In order to analyze the effects of CO2 emission regulation policies we needed to disaggregate these values among the various fuel sources in the industry. We needed to determine, for example, how much of the $32.6 billion spent on labor was spent by coal-fired plants, how much was spent by gas-fired plants, how much was spent by nuclear plants, etc.

With labor, capital, and intermediate inputs disaggregated in this way we could then predict the effects of policies that change the relative prices of inputs. For example, a CO2 emission permit price would make burning coal more expensive. In this scenario the USAGE model can predict the substitution effect towards cleaner sources of power generation as well as other economy-wide effects.

We used several methods to disaggregate capital, labor, and intermediate inputs among fuel sources. These methods are explained in detail below:[36]

1. Capital

Expenditures on capital in the USAGE model are the returns to capital used to generate electricity in a year. These figures are estimates based on aggregate capital expenditures provided by BEA. A method to distribute capital was developed from the estimated capital for electricity services among the different fuel sources, using EIA's Net Summer Capacity[37] figures, adjusted by overnight costs per kilowatt for new capacity.[38, 39]

To determine the capital stock of each energy source we started with Total Overnight Cost per kilowatt.[40] The Total Overnight Cost provided by EIA is the cost of constructing a kilowatt of new technology. Total Overnight Cost was assigned to each fuel source based on the technology it is associated with. For example, the Total Overnight Cost of a new scrubbed coal plant was used for the coal fuel source, conventional gas/oil combined cycle was used for the gas and petroleum fuel sources, advanced nuclear was used for the nuclear fuel source, etc.

Multiplying Total Overnight Cost per kilowatt by Net Summer Capacity gave Total Replacement Cost of Existing Capacity, the cost of replacing all the existing capacity with newly

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[36] Calculations are available upon request.

[37] Source: http://www.eia.doe.gov/emeu/aer/elect.html)

[38] We were unable to find overnight costs for older capital vintages on EIA's website. Instead we weight net summer capacity by current overnight costs to determine cost shares of each fuel type. Effectively we assume that the relative costs of different fuel types have not changed over time. Net Summer Capacity reflects reductions in capacity due to station service and other factors. Stations under service, however, are still part of the capital stock. For this reason, Generator Nameplate Capacity may be a better determinant of capital stock. Data on Generator Nameplate Capacity for renewable energy plant types, however, was not available on EIA's website.

[39] Definitions of capacity:

- **Net summer capacity:** The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to a system load, as demonstrated by a multi-hour test, adjusted to ambient weather conditions for summer peak demand (from June 1 through September 30). This output reflects a reduction in capacity attributed to station service or auxiliary equipment requirements.
  Source: http://www.eia.doe.gov/glossary/glossary_n.htm
- **Generator nameplate capacity:** The maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator.
  Source: http://www.eia.doe.gov/glossary/glossary_g.htm

[40] Source: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

constructed technology. Each energy source's percentage share of Total Replacement Cost of Existing Capacity was applied to the USAGE model's value for total capital stock in the electric power industry. In this way capital was allocated to each fuel source. It is possible that the calculated proportions are not correct for energy sources where a large amount of current capacity is of a very old vintage.

2. Labor

Expenditures on labor in the USAGE model are the value of the labor used to generate electricity in a year. These figures are estimates based on aggregate labor expenditures provided by BEA. Fixed Operations and Maintenance (O&M)[41] was used as a proxy for labor costs associated with each fuel source. Again, the data available from EIA are for new technologies. While specific definitions of Variable and Fixed O&M were not available from EIA, the California Energy Commission offers the following:

> The operation and maintenance (O&M) costs of DER [Distributed Energy Resource] technologies have both fixed and variable components. *Fixed O&M consists primarily of plant operating labor*. It is highly dependent on the operating cycle and staffing philosophy of the plant. Variable O&M represents variable maintenance and is estimated from an algorithm incorporating a DER unit's expected capacity factor. *The variable O&M includes periodic inspection, replacement, and repair of system components (i.e., filters, desulfurizer, etc.), as well as consumables (i.e., water, limestone, etc.)* computed directly from the DER plant material balance.[42]

This definition suggests that Fixed O&M consists mostly of labor costs. Variable O&M seems to closely correspond to the repair and maintenance intermediate inputs, which are dealt with below. Therefore, Fixed O&M was used for labor cost estimates. As with capital, Fixed O&M was assigned to each fuel source based on the technology it is associated with. Multiplying Fixed O&M by Net Summer Capacity gave us a measure of how much was spent on labor by each fuel source in a year (again, because the figures provided by EIA are for new technologies, our estimates may be inaccurate). Each fuel source's percentage share of this number was applied to the USAGE model's value for total labor expenditure in the electric power industry. In this way labor was allocated to each fuel source.

[41] Source: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

[42] Source: http://www.energy.ca.gov/distgen/economics/operation.html. Variable O&M may include some labor component.

3. Intermediate Inputs

Each fuel source's share of its 2004 net electricity generation[43] served as a "basic distribution" for determining its share of inputs. When it was reasonable to assume a fuel source used an input in relation to the amount of electricity it produced, this distribution was used. One modification was made to the net electricity generation data in order to calculate the basic distribution: Hydroelectric Pumped Storage was treated as a producer even though it was actually a net consumer of electricity. This is because regardless of whether Hydroelectric Pumped Storage plants were consuming or producing electricity they still consumed a certain share of inputs during operation. To account for the share of consumed inputs, net electricity generation was added, not subtracted, from the total.

For some inputs, the basic distribution was not an accurate measure of each energy source's share of that input. In these cases an input-specific distribution was created. Some are based on calculations and some are assumed distributions. These inputs are discussed in detail below.

Input 1: 45 OthMRconst - Other repair and maintenance construction

To calculate each fuel source's share of this input we started with Variable Operations and Maintenance[44], which includes maintenance, replacement and repair of system components[45]. By multiplying Variable O&M by Net Summer Capacity of each fuel source, we arrived at a measure of the amount of repair and maintenance conducted by plant types associated with each fuel source. These values were then expressed as a percentage of the total, which was used as a distribution for this input.

Input 2: 24 Coal – Coal

Since almost all coal in electric power generation is used by coal fired plants, 100 percent of this input was distributed to the Coal fuel source.

Input 3: 412 NatgasDistrb - Natural gas distribution[46]

Since almost all natural gas in electric power generation is used by gas fired plants, 100 percent of this input was distributed to the Natural Gas fuel source.

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[43] Source: http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html

[44] Source: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

[45] Source: http://www.energy.ca.gov/distgen/economics/operation.html

[46] Definition of Natural gas distribution:
This industry comprises: (1) establishments primarily engaged in operating gas distribution systems (e.g., mains, meters); (2) establishments known as gas marketers that buy gas from the well and sell it to a distribution system; (3) establishments known as gas brokers or agents that arrange the sale of gas over gas distribution systems operated by others; and (4) establishments primarily engaged in transmitting and distributing gas to final consumers.
Source: http://www.census.gov/epcd/naics02/def/ND221210.HTM

Input 4: 25 CrdpetNatgas - Crude petroleum and natural gas[47]

The expenditures on crude petroleum and natural gas provided by BEA are aggregated together. It was assumed that crude petroleum was used exclusively by petroleum plants and natural gas was used exclusively by natural gas plants. To disaggregate the BEA data the ratio of petroleum to natural gas purchased in the electric power generating industry in 2004was used[48] and applied this ratio to the total spent on Crude Petroleum and Natural Gas.

Input 6: 193 PetrolRefin – Petroleum Refining[49]

It was assumed that all petroleum refining was conducted by petroleum fired plants and distributed 100 percent of this input to the Petroleum fuel source.

The basic distribution was used to divide all other inputs among energy sources.

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[47] Since crude petroleum makes up a relatively small share of electricity generation, it was ultimately aggregated together with natural gas electricity.

[48] Source: http://www.eia.doe.gov/cneaf/electricity/epa/epat4p5.html

[49] Since crude petroleum makes up a relatively small share of electricity generation, it was ultimately aggregated together with natural gas electricity.