The Natural Gas Gamble

A Risky Bet on America's Clean Energy Future
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Technical Appendix: Scenario Descriptions and Modeling Approach

Union of Concerned Scientists

In *The Natural Gas Gamble*, the Union of Concerned Scientists (UCS) investigates possible energy pathways under different carbon and clean energy policy scenarios. This appendix includes descriptions of the scenarios and the key assumptions upon which the energy pathways are based; we note differences between UCS assumptions and those the U.S. Department of Energy (DOE) uses in their energy modeling.

Our analysis uses the National Energy Modeling System (NEMS), developed by the Energy Information Administration (EIA) of the DOE. NEMS is a computer model of the energy-economy system of the United States. EIA uses NEMS to develop baseline projections that it publishes annually in the *Annual Energy Outlook* (AEO) (EIA 2013a). The AEO reference case projections are based on current federal, state, and local laws and regulations.

For *The Natural Gas Gamble*, UCS uses a version of NEMS modified to include changes to some assumptions, such as future capital costs, capacity factors, and energy efficiency outcomes, that better reflect our research on current and projected conditions. Our analysis compares results from a total of nine scenarios: three main scenarios and six examining sensitivity of the three main scenarios to alternative natural gas price projections.

Scenario Summary

To analyze the impacts of climate and clean energy policies, we focus on three main scenarios: a business as usual scenario, a carbon standard scenario, and a carbon standard complemented by additional renewable energy and energy efficiency policies scenario. We also examine six sensitivity scenarios using higher and lower natural gas price projections.

Our main scenarios are similar to the scenarios modeled in the May 2014 UCS analysis, *Game Changer*, which examines opportunities for reducing carbon emissions originating in the U.S. electricity sector (Cleetus et al. 2014). Our current analysis does not assess the Environmental Protection Agency's (EPA) proposed Clean Power Plan for existing power plants, but rather examines the potential for achieving deeper emissions reductions in the electricity sector.

BUSINESS AS USUAL SCENARIO

Our Business as Usual scenario establishes a baseline for our analysis. We base our scenario on a modified NEMS version of the AEO 2013 reference case. The Business as Usual scenario includes state and federal policies in place at the end of 2012 and assumes no additional policies have been or will be implemented. We use project-specific technology cost and performance assumptions benchmarked to recent studies. We do not make any changes to AEO 2013's assumptions for electricity demand growth, natural gas and coal prices, fixed and variable operations and maintenance (O&M) costs, and heat rates, with a few exceptions noted below. We do make several changes to AEO 2013's capital cost assumptions and capacity factors for wind and solar technologies based on project-specific data for recently installed and proposed projects. When project-specific data were limited or unavailable, we supplement the data with estimates from recent studies.

CARBON STANDARD SCENARIO

The Carbon Standard scenario shows the impacts of a possible carbon standard on the U.S. electricity sector. Because NEMS does not include the option to set annual carbon constraints for the electricity sector, we use a federal carbon price as a proxy for a carbon cap. We set the price to achieve at least a 35 percent emissions reduction from 2005 levels in 2025 at least a 45 percent emissions reduction from 2005 levels in 2030 and at least a 65 percent emissions reduction from 2005 levels in 2040. The price starts at $10 per metric ton in 2020 and increases by 10 percent each year through 2040.

This scenario uses the same assumptions as our Business as Usual scenario for renewables and energy efficiency policies; it includes the state and federal policies that were in place at the end of 2012 but no additional policies.

CARBON STANDARD PLUS RENEWABLES AND EFFICIENCY SCENARIO

Our third scenario assumes implementation of the same federal carbon prices assumed in our Carbon Standard scenario, supplemented by strengthened state and federal renewable energy and energy efficiency policies. We find that these policies would drive a higher penetration of renewable energy and efficiency resources, especially in the 2015–2025 timeframe, than would a carbon standard alone. The analysis of this scenario helps estimate the benefits and costs of a more diversified energy portfolio.

The renewable energy and efficiency policies we build into this scenario include:

- a federal renewable electricity standard (RES) of 25 percent by 2025 and energy efficiency resource standard (EERS) of 15 percent by 2025 patterned on the American Renewable Energy and Efficiency Act of 2014 (S. 1627)
- a full extension of the federal production tax credit through 2016, with a gradual ramp-down through 2018
- an extension and ramp-down of the current federal solar investment tax credit from 30 percent in 2016 to 10 percent in 2020 and thereafter
- adoption of lower-cost financing mechanisms such as master limited partnerships and real estate investment trusts
- updated residential and commercial building codes and equipment efficiency standards and an extension of the federal investment tax credit for combined heat and power systems based on the EIA's "extended policies" case from the AEO 2013 (EIA 2013a).

While we model these strengthened renewable energy and efficiency policies at the federal level, similar results could be achieved in many cases by states adopting their own enhanced policies. For modeling simplicity, we assume that the policy impacts would be achieved across the country whether policies were adopted at the state, regional, or federal level.

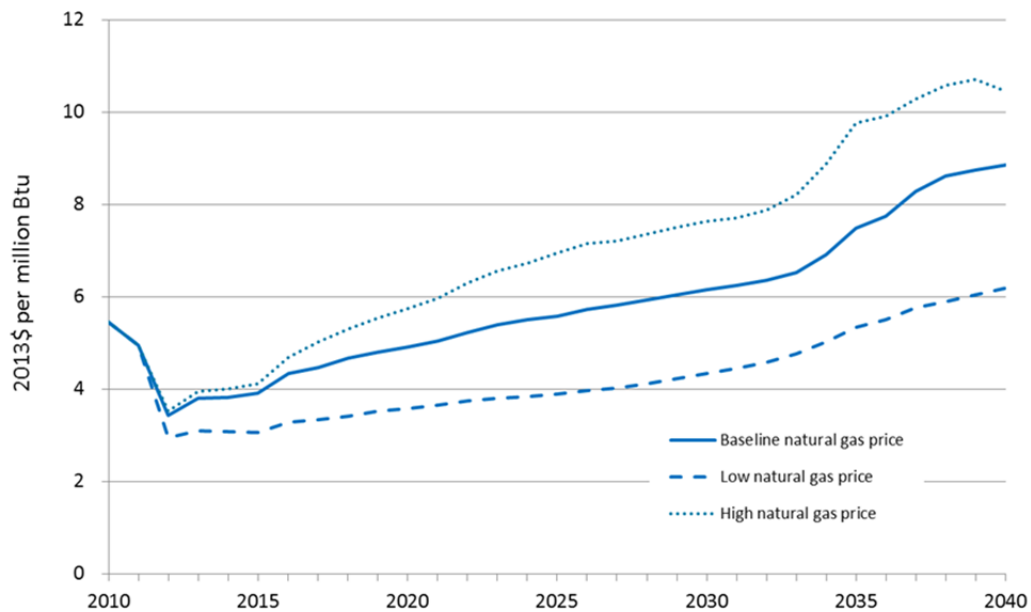
SENSITIVITY SCENARIOS

In our sensitivity scenarios, we evaluate the effects of natural gas price variation on our three main scenarios. To vary natural gas prices, we change the rate of natural gas extraction—also referred to as "recovery rate"—from wells. This is the same approach the EIA used for their alternative cases included in the AEO 2013. The recovery rate from natural gas wells has a direct impact on the cost per unit of production and, in turn, on prices.

For our Low Natural Gas Prices, we use the EIA's parameters for the High Oil and Gas Resource case from the AEO 2013, which assumed estimated ultimate recovery rates of shale gas, tight gas (found in reservoirs with low permeability), and tight oil wells 100 percent higher than for our Baseline Natural Gas Prices.. This higher recovery rate results in lower natural gas prices each year of the forecast (Figure 1). The average decrease between the Low Natural Gas Prices and the Baseline Natural Gas Prices is 29 percent for the years 2020 through 2040.

For our High Natural Gas Prices, we use the EIA's parameters for the Low Oil and Gas Resource case from the AEO 2013, which assumed the estimated ultimate recovery rates of wells are 50 percent lower than for our Baseline Natural Gas Prices. This lower recovery rate results in higher natural gas prices. On average for the years 2020 through 2040, prices are 23 percent higher in the High Natural Gas Prices than for the Baseline Natural Gas Prices (Figure 1). We consider six sensitivity scenarios by layering each of these resource recovery rates onto our three main scenarios.

FIGURE 1. **Comparison of Natural Gas Price Forecasts (Average Delivered Price to Power Sector)**



UCS Assumptions for AEO 2013 version of NEMS

UCS uses the AEO 2013 version of NEMS as the basis of our analysis. However, we make some changes to the EIA's AEO 2013 model assumptions. We outline the specific changes, based on project-specific data and mid-range estimates from recent studies, in detail below.

Tables 2 through 5 show the cost and performance assumptions for electricity generating technologies and efficiency measures we use in the AEO 2013 version of NEMS. Tables 2, 3, 4, and 5 show the EIA's AEO 2013 assumptions (EIA 2013b). Tables 2, 4, and 5 also show our cost assumptions for energy technology that are not included in the AEO 2013 version of NEMS.

We do not make any changes to the EIA's assumptions for electricity demand growth, natural gas and coal prices, fixed and variable O&M costs, and heat rates, with a few exceptions noted below (EIA 2013b). However, we change several of the EIA's capital cost assumptions and wind and solar capacity factors based on project-specific data for recently installed and proposed projects, supplemented with estimates from recent studies when project data were limited or unavailable:

- **Commodity costs.** We do not include the EIA's projected changes in commodity costs, which result in a 9-percent reduction in capital costs by 2040 for all technologies, because of the high level of uncertainty involved in projecting these costs (EIA 2013b).

- **Learning.** We do not use the EIA's learning assumptions, which lower the capital costs of technologies over time as the penetration of these technologies increases in the United States (EIA 2013b). The EIA's approach does not adequately capture growth in international markets and potential technology improvements resulting from research and development;

both are important drivers of cost reductions. Instead, we assume that costs for mature technologies stay fixed over time and we input specific cost reductions for emerging technologies into the model.

- **Natural gas and coal.** For plants lacking carbon capture and storage (CCS), we use the EIA's initial capital costs. But we do not include the EIA's projected cost reductions due to learning because we assume that these plants represent mature technologies. For new integrated gasification combined cycle (IGCC) and supercritical pulverized coal plants, we use the EIA's higher costs for single-unit plants (600–650 megawatt (MW)) instead of the EIA's costs for dual-unit plants (1200–1300 MW); our assumptions are more consistent with data from proposed and recently built projects (SNL Financial 2013). For plants with CCS, we assume (1) higher initial capital costs than the EIA did, based on mid-range estimates from recent studies (EIA 2013c; Lazard 2013; Black & Veatch 2012; NREL 2012); (2) no cost reductions through 2020, as very few projects will be operating by then; and (3) the EIA's projected cost reductions by 2040 will be achieved by 2050 (on a percentage basis).

- **Nuclear.** Based on mid-range estimates from recent studies and announced cost increases at nuclear projects in the United States that are proposed or under construction (Henry 2013; Lazard 2013; SNL Financial 2013; Black & Veatch 2012; Penn 2012; Vukmanovic 2012; Wald 2012), we assume higher initial capital costs than the EIA did for new plants. We do not include the EIA's projected capital cost reductions, given the historical and recent experience of cost increases in the United States. We also assume that existing plants will receive a 20-year license extension, allowing them to operate for 60 years, and will then be retired due to safety and economic issues. In addition, we include 4.7 gigawatts (GW) of retirements at five existing plants (Vermont Yankee, Kewaunee, Crystal River, San Onofre, Oyster Creek) based on recent announcements and 5.5 GW of planned additions (Vogtle, V.C. Summer, and Watts Bar).

- **Onshore wind.** In forecast years, we assume lower initial capital costs than the EIA did, based on data from a large sample of recent projects included in the DOE's 2012 *Wind Technologies Market Report* (Wiser and Bolinger 2013). This report shows that installed capital costs declined 13 percent from 2009 to 2012 for U.S. projects. While costs for new wind projects built in 2013 and 2014 were lower than in 2012, these projects are heavily weighted toward lower cost projects in the interior region of the U.S. Thus, we conservatively assume capital costs will stay fixed at 2012 levels over time as the wind industry invests in technology improvements that result in increases in capacity factors. We base current capacity factors on data from recent projects and studies that reflect recent technology advances (Wiser et al. 2012). Based on mid-range projections from 13 independent studies and 18 scenarios (Lantz, Wiser, and Hand 2012), we assume capacity factors will increase over time to achieve a reduction in the overall cost of electricity. We also assume higher fixed O&M costs than the EIA did, based on mid-range estimates (EIA 2013c; Wiser et al. 2012; Black & Veatch 2012; NREL 2012).

- **Offshore wind.** We base initial capital costs on data from recent and proposed projects located in shallow water in Europe and the United States included in NREL's offshore wind database (Schwartz et al. 2010). We assume that capital costs decline and capacity factors increase over time, based on mid-range projections from several studies (EIA 2013c; Prognos AG and Fitchner Group 2013; Black & Veatch 2012; BVG Associates 2012; Lantz, Wiser, and Hand 2012; NREL 2012). We also assume higher fixed O&M costs than the EIA did, again based on mid-range estimates (EIA 2013c; Black & Veatch 2012; NREL 2012; Wiser et al. 2012).

- **Solar photovoltaic (PV).** We assume lower initial capital costs than the EIA did during forecast years, based on data from a large sample of recent utility-scale and rooftop PV projects installed in the United States through the third quarter of 2013 (SEIA 2013). We base our assumptions of declining PV costs for utility-scale, residential, and commercial systems on mid-range projections from several studies and scenarios (EIA 2013c; Black & Veatch 2012; DOE 2012; NREL 2012). These mid-range projections are roughly consistent with the DOE *Sunshot Vision Study* 62.5-percent price scenario and the NREL *Renewable Electricity Futures Study* Evolution Technology Improvement scenario. After 2020, our assumed costs for utility-scale systems are lower than the EIA's. Because the EIA's projections for residential and commercial systems are consistent with these mid-range projections, we do not change those assumptions. In addition, we use slightly lower capacity factors for PV, based on NREL (2012) data.

- **Concentrating solar power (CSP) plants.** The EIA assumed that CSPs lack storage. We assume CSPs will include six hours of storage. We therefore include higher costs and capacity factors than the EIA did. We base our assumptions on data developed by Black & Veatch (2012) for NREL's *Renewable Electricity Futures Study*.

- **Biomass plants.** We use the EIA's initial capital costs for new fluidized bed combustion plants but do not include its projected cost reductions due to learning because we assume that this is a mature technology. However, we assume that the technology will transition to more efficient IGCC plants, resulting in a gradual decline in the heat rate from 13,500 British thermal units per kilowatt-hour (Btu/kWh) in 2010 to 9,500 Btu/kWh by 2035. For biomass co-firing in coal plants, we reduce the EIA's co-firing limit from 15 percent to 10 percent to reflect potential resource supply constraints near clusters of coal plants, and we assume higher capital costs based on data from Black & Veatch (2012). We also use a slightly different biomass supply curve than the EIA did, based on a UCS analysis of data from the DOE's *Updated Billion Ton Study*, which includes additional sustainability criteria resulting in a potential biomass supply of 680 million tons per year by 2030 (UCS 2012; ORNL 2011).

- **Geothermal and hydro.** We do not change any of the EIA's assumptions for geothermal and hydro, which are site specific. The EIA based its geothermal supply curve on a 2010 NREL assessment.

Calculation of energy efficiency costs and savings. In a separate analysis from our use of NEMS, we estimate the costs and electricity savings resulting from implementing a federal EERS of 15 percent by 2025 (based on S. 1627: The American Renewable Energy and Efficiency Act). We calculate the electricity savings by multiplying the EIA's electricity sales projection by the annual EERS targets, which we adjust to remove small utilities (per S. 1627) and to account for existing state EERS policies. We also estimate the investment and program costs of achieving these savings, based on recent studies by the American Council for Energy Efficiency Economy (ACEEE) (Hayes et al. 2014; Molina 2014). We assume national average first-year costs of $0.46 $ per kWh, based on the ACEEE's survey of utility energy efficiency programs. We split these costs equally between utilities and consumers, with 20 percent of the utility costs allocated to administering the programs and 80 percent allocated to investment in more efficient technologies and measures. We also assume that 50 percent of utility and consumer investment costs and 100 percent of utility program costs are financed over an average measure lifetime of 11 years. In addition, we include the costs of replacing half the efficiency measures after their average lifetime and assume customers would replace the other half without utility incentives. We then add the total annual costs of efficiency investments to the electricity sector compliance costs and consumer electricity bills projected by NEMS.

Calculation of the monetary value of carbon dioxide (CO_2) reduction benefits. To calculate the monetary value of CO_2 reductions, we use the U.S. Government's estimates for the social costs of carbon (SCC) (IWGSCC 2013). The SCC is an estimate of the dollar damages resulting from adding a metric ton of CO_2 to the atmosphere in a given year. We multiply the metric tons of CO_2 reduced in our scenarios by the SCC to derive the CO_2 reduction benefits, or avoided damages.

We use the November 2013 updated SCC values (Table 1). The SCC values are available in 2007$ per metric ton of CO_2 in five-year increments at different discount rates. We use the values that assume a 3-percent discount rate.

TABLE 1. **Social Costs of Carbon Values**

Year	Social Cost of Carbon (2007$ per metric ton of CO_2)[1]
2010	32
2015	37
2020	43
2025	47
2030	52
2040	61

1 Assuming a 3 percent discount rate.

SOURCE: IWGSCC 2013.

Finally, we convert the dollar amounts to 2013$ for consistency with other dollar values in our analysis.

Calculation of the monetary value of sulfur dioxide (SO_2) and nitrogen oxides (NOx) reduction benefits. To value SO_2 and NOx emissions reductions, we use data from an EPA technical support document that calculates the dollar value of the health benefits per ton of SO_2 and NOX reduced by different sectors, including the electricity sector (EPA 2013).

In particular, for the 2020 emissions reductions generated in our models, we use the Krewski et al. values in Table 7 for electric generating units (EGUs): $37,000 per ton of SO2 and $5,400 per ton of NOx. These values are in 2010$ using a 3-percent discount rate. We convert them to 2013$ to be consistent with other dollar values in our analysis. For 2030 and 2040, we use the Krewski et al. values in Table 11 for EGUs: $43,000 per ton of SO_2 and $6,200 per ton of NOx. These values are also in 2010$ using a 3-percent discount rate. Again, we convert them to 2013$ for consistency.

Calculation of variability of total system costs. As noted in the main report, we quantified the benefits of reducing reliance on natural gas by comparing the total system costs of the scenarios. This approach follows the methodology used in a recent Department of Energy report, *Wind Vision* (DOE 2014).

We first calculated the present value of total system costs, which are the total capital and operating expenditures in the power sector, for the Business as Usual Scenario and the Carbon Standard plus Renewables and Efficiency Policies Scenario. In the Business as Usual Scenario, we found that total system costs varied from +4.54 percent to –6.03 percent under the high and low natural gas price sensitivities. In the Carbon Standard plus Renewables and Efficiency Policies Scenario, which leads to more renewables deployment, the variability in total system costs is reduced to +3.52 percent to -5.57 percent. This narrowed range of cost fluctuation helps reduce price risks to consumers. By replacing gas- and coal-fired generation with wind generation, the Carbon Standard plus Renewables and Efficiency Policies Scenario results in a total portfolio that is 14 percent less sensitive to long-term fluctuations in fossil fuel prices and therefore provides some insurance value against rising costs to consumers due to higher-than-expected fossil fuel prices.

TABLE 2. **Comparison of Assumed Overnight Capital Costs for Electricity Generation Technologies (2011$/kW)**

	UCS 2013					EIA AEO2013			
Technology*	**2010**	**2020**	**2030**	**2040**	**2050**	**2010**	**2020**	**2030**	**2040**
Natural Gas CC	1,000	1,000	1,000	1,000	1,000	1,006	1,000	882	797
Natural Gas-CC-CCS	n/a	2,900	2,628	2,425	2,323	n/a	1,980	1,715	1,504
Natural Gas CT	665	665	665	665	665	664	647	555	497
Coal-Supercritical PC	3,190	3,190	3,190	3,190	3,190	2,883	2,944	2,704	2,472
Coal-IGCC	n/a	4,325	4,325	4,325	4,325	n/a	3,694	3,292	2,960
Coal-PC-CCS	n/a	5,950	5,604	5,354	5,184	n/a	5,087	4,570	4,083
Nuclear	n/a	6,300	6,300	6,300	6,300	n/a	4,733	4,223	3,697
Biomass	4,040	4,040	4,040	4,040	4,040	4,041	3,727	3,370	3,003
Solar PV-Utility	4,150	2,100	1,900	1,835	1,835	3,805	3,217	2,859	2,533
Solar PV-Residential	7,368	3,715	2,724	2,724	2,724	7,368	3,715	2,724	2,724
Solar PV-Commercial	6,316	3,406	2,848	2,477	2,477	6,316	2,848	2,477	2,477
Solar CSP-No Storage	5,083	4,702	4,321	3,939	3,558	4,979	3,732	3,293	2,884
Solar CSP-With Storage	7,318	6,768	5,502	4,871	4,871	n/a	n/a	n/a	n/a
Wind-Onshore	2,200	1,900	1,900	1,900	1,900	2,175	2,220	2,039	1,864
Wind-Offshore	n/a	5,142	4,458	4,100	3,432	6,121	6,108	5,411	4,759

*Abbreviations are as follows: combined cycle (CC), combustion turbine (CT), carbon capture and storage (CCS), pulverized coal (PC), integrated gasification and combined cycle (IGCC), and photovoltaic (PV).

TABLE 3. **Operation and Maintenance (O&M) and Heat Rate Assumptions**

Technology*	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate	
			2010	2050
Natural Gas-CC	15.10	3.21	6,430	6,333
Natural Gas-CC-CCS	31.23	6.66	7,525	7,493
Natural Gas CT	6.92	10.19	9,750	8,550
Coal-Supercritical PC	30.64	4.39	8,800	8,740
Coal-IGCC	50.49	7.09	8,700	7,450
Coal-IGCC-CCS	65.31	4.37	10,700	8,307
Nuclear	91.65	2.10	10,452	10,452
Biomass	103.79	5.17	13,500	9,500
Solar PV-Utility	21.37	0.00	n/a	n/a
Solar PV-Residential	32.47	0.00	n/a	n/a
Solar PV-Commercial	7.62	0.00	n/a	n/a
Solar CSP-No Storage	66.09	0.00	n/a	n/a
Solar CSP-With Storage	66.09	0.00	n/a	n/a
Wind-Onshore	50.00	0.00	n/a	n/a
Wind-Offshore	100.00	0.00	n/a	n/a

* Abbreviations are as follows: combined cycle (CC), carbon capture and storage (CCS), combustion turbine (CT), pulverized coal (PC), integrated gasification and combined cycle (IGCC), photovoltaic (PV), and concentrating solar plants (CSP).

TABLE 4. **Comparison of Assumed Solar Capacity Factors**

Technology*	UCS 2013	EIA AEO 2013
Solar PV-Utility	16–28%	21–32%
Solar CSP-No Storage	19–29%	5–26%
Solar CSP-With Storage	27–54%	n/a

*Abbreviations are as follows: photovoltaic (PV) and concentrating solar plant (CSP).

TABLE 5. **Comparison of Assumed Wind Capacity Factors**

	UCS 2013					EIA AEO2013			
Technology*	**2012**	**2020**	**2030**	**2040**	**2050**	**2010**	**2020**	**2030**	**2040**
Onshore Wind									
Class 3	31%	35%	37%	39%	40%	28%	29%	29%	29%
Class 4	35%	39%	41%	43%	45%	32%	33%	33%	33%
Class 5	40%	45%	48%	50%	51%	39%	39%	39%	39%
Class 6	44%	50%	53%	53%	53%	45%	46%	46%	46%
Offshore Wind									
Class 5	36%	38%	40%	42%	44%	27%	27%	27%	27%
Class 6	45%	47%	49%	51%	53%	34%	34%	34%	34%
Class 7	52%	52%	53%	53%	53%	40%	40%	40%	40%

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