Greenhouse Gas Initiatives Analysis using the National Energy Modeling System

A Study Performed for the Natural Gas Council
by Science Applications International Corporation (SAIC)

NATURAL GAS COUNCIL

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EXECUTIVE SUMMARY

Introduction

The Natural Gas Council[1] (NGC), composed of the four natural gas industry trade associations, firmly believes that natural gas will be a critical component in achieving greenhouse gas emission reductions under any climate change legislation. The various pieces of legislation that have been introduced or may be introduced will be modeled using the National Energy Modeling System (NEMS) for analyzing environmental-energy initiatives. As with any model, input assumptions are the best judgment of the entity requesting the study or the staff of the U.S. Energy Information Administration (EIA), which relies on NEMS to project the impact of greenhouse gas reduction policies on our energy markets and the U.S. economy.

The NGC engaged the NEMS model, using more conservative assumptions than EIA. NGC's model runs placed constraints on the number of nuclear facilities and powerplants utilizing renewable fuels that realistically can be built to achieve the emission reductions mandated under the bill introduced by Senators Joseph Lieberman and John McCain (S. 280). The NGC did not believe it likely that 145 new nuclear plants would be built in United States by 2030, which was the result of the assumptions in an EIA July 2007 analysis of S. 280.

The NGC engaged in this exercise to ensure that any greenhouse gas (GHG) legislation that ultimately may be enacted is sufficiently flexible to address the environmental, economic and energy security implications of a range of possible outcomes that may occur as the energy economy adjusts to mandatory carbon constraints. This project is designed to assist Congress in this effort. While the NGC study focused on S. 280, the findings and lessons learned are applicable to other climate change proposals that have been introduced or may be introduced.

Background

During this past year, members of Congress have proposed a number of new, significantly more aggressive plans for the reduction of greenhouse gases in the United States. Many of these proposals require reductions of 30% below the "business as usual" scenario by 2020 and 60-80% reductions from current levels by 2050. While it is clear that achieving these proposed reductions will require major changes in the U.S. energy infrastructure, it is only recently that quantitative analyses of the potential implications have become available. One of the critical questions to be addressed is the implications for clean-burning fossil fuels such as natural gas. The NGC has prepared a study analyzing legislation introduced by Senators Lieberman and McCain to reduce GHG emissions, S. 280, the Climate Stewardship and Innovation Act of 2007. The study utilizes the publicly available NEMS, the principal model used by EIA[2] to report to Congress regarding the projected economic impacts of proposed GHG legislation.[3] The NGC considered it to be very important to understand the economic impacts of major climate change policy on the U.S. economy and natural gas markets.

While generated independently, the NGC study builds on and extends the recently issued report by EIA on S. 280[4]. The NEMS model is the most robust model of the U.S. economy for energy forecasting, but

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[1] NGC founding members: American Gas Association (AGA), Independent Petroleum Association of America (IPAA), Interstate Natural Gas Association of America (INGAA), Natural Gas Supply Association (NGSA).

[2] NEMS is a national, economy-wide, integrated energy model that analyzes energy supply, conversion, and demand. EIA uses NEMS to provide U.S. energy market forecasts through 2030 in its flagship publication, the *Annual Energy Outlook.*

[3] The contractor, Science Applications International Corporation (SAIC), is a leading consultant to EIA on the design and implementation of NEMS, and has over 100 staff years supporting the model.

[4] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* issued July 2007 by EIA; Report #: SR-OIAF/2007-04

as such, it only forecasts economic decisions and does not predict technical, societal and political decisions. Hence these technical, societal and political decisions must be supplied by the modelers as assumptions. In its report, EIA emphasizes the "sensitivities" and "uncertainties" regarding several assumptions for program implementation, particularly uncertainties with respect to the level of penetration that could be achieved relative to the "business as usual" scenario forecasted by EIA's *Annual Energy Outlook 2007 (AEO2007)*[5] by the following technologies and market mechanism by 2030: (1) newly-built nuclear generation units, (2) renewable generation (bio-power and wind power), (3) the technological development and availability of carbon capture and storage (CCS), and (4) the availability of emission offsets.

These uncertainties merit emphasis. While the technologies and market mechanisms (such as carbon offsets) anticipated for achieving GHG emission reductions *may* be fully deployed and cost effective by 2020-2030 (the key interim target dates in S. 280 examined by EIA), *there is a very real possibility that they may not*. The NGC suggests that Congress examine alternative scenarios and be fully informed of the consequences should the anticipated technologies and market mechanisms not be fully available by 2020-2030. Engaging in this exercise will ensure that any GHG legislation that ultimately may be enacted is sufficiently flexible to address the environmental, economic and energy security implications of a range of possible outcomes that may occur as the energy economy adjusts to mandatory carbon constraints.

The analysis performed in this study uses NEMS to examine the impacts of these uncertainties in greater depth. The NGC study applies reasoned judgment on the *likely* penetration levels of the three technologies - levels that assume lower market penetration by 2030 than reflected in EIA's "S. 280 Core case", yet entirely consistent with EIA's cautions on the uncertainty associated with these technologies. This study also analyzes the impact if only half of the offsets authorized by S. 280 (15% versus 30%) actually are available to be used in the United States as an alternative for carbon reduction.

Primary Comparisons and Results

The study reports results from NEMS model runs for seven focus areas: (1) U.S. CO_2 Emissions, (2) Installed Electric Generating Capacity, (3) Produced Electric Energy, (4) Natural Gas Consumption, (5) Natural Gas Supply, (6) Natural Gas Prices, and (7) Electricity Prices and Prices of CO_2 Offsets and Permits. While the study ran seven scenarios for each focus area, three scenario runs provide the most meaningful comparisons:

- Scenario 1. Base Case S. 280 ("EIA-S. 280 – Core Case")
- Scenario 6. Constrained nuclear and renewable generation with 30% max offsets and updated capital costs ("NGC-S. 280 – 30%")
- Scenario 7. Constrained nuclear and renewable generation with 15% max offsets and updated capital costs ("NGC-S. 280 – 15%")

The study report summarizes and compares the results of the three scenarios for each focus area. While Scenario 6 reflects the provisions of S. 280, it is unlikely that the maximum 30% offsets will be available. A more realistic scenario is depicted in Scenario 7, which assumes a maximum of 15% offsets. Therefore, the key findings are based on Scenario 7. The outcomes under Scenario 6 are described in the full report.

1. U.S. CO_2 Emissions

Key Findings:

- *S. 280 would compel very dramatic steps to de-carbonize the power sector unless efficiency*

[5] *Annual Energy Outlook 2007 with Projections to 2030*; EIA http://www.eia.doe.gov/oiaf/aeo/index.html

improvements, low carbon emission technologies outside the electric sector and transportation CO_2 emission reductions are mandated or incentivized.

- *The number of offsets available will make a very large difference in domestic impacts, almost as much as the choice of technologies used to curb emissions.*
- *The market utilization of banked carbon allowances can significantly affect choices on the deployment of technology to achieve GHG emissions reduction targets.*
- *Significant step function changes in CO_2 emissions limits, such as those that occur in 2020 and 2030 under S. 280, are more likely to cause economic dislocation (e.g., price spikes) than more gradual, linear implementation of emissions reduction limits.*

2. Installed Electric Generation Capacity

Key Finding:

The introduction of carbon capture and sequestration infrastructure under Scenario 7 allows gas-fired and coal-fired generation to play leading roles in reducing CO_2 emissions as compared to Scenario 1, where unconstrained nuclear plant construction dominates the new electric generation mix.

3. Produced Electric Energy

Key Finding:

Widespread political acceptance of new nuclear energy sources and the ability to permit, finance and build new plants (Scenario 1) result in nuclear power plants supplying a predominant share of electricity to consumers under the present EIA cost assumptions. More modest assumptions about nuclear growth in Scenario 7 result in electricity supply from a mix of technologies to meet CO_2 emissions reduction targets.

4. Natural Gas Consumption

Key Findings:

- *Scenario 1 results in less growth in natural gas consumption than AEO2007 through 2020, followed by declining consumption due to the unconstrained deployment of nuclear generation after 2020.*
- *Scenario 7 results in high levels of gas use in the power sector, because gas is the cleanest alternative in the face of constraints on the ability to deploy other generating technologies widely and limits on the availability of offsets. Industrial gas consumption falls somewhat due to high gas prices. Under this scenario, consumption is on average 3.6 Tcf/yr higher than in AEO2007 (no climate change legislation) from 2020 through 2029, spiking to 5.9 Tcf/yr higher in 2030.*

5. Natural Gas Supply

Key Finding:

All cases demonstrate the need for additional gas supplies as part of a GHG emissions reduction strategy. This is true, both if gas is a transition fuel and if gas is a critical part of a longer-term compliance strategy. Supply and demand must balance in the NEMS model, and it is assumed that LNG and unconventional gas resources will provide the backstop that enables this balancing to occur[6] since supply basin access is limited in both the EIA and NGC assumptions. Given the uncertainty associated with foreign gas supplies and the environmental limits that affect unconventional gas production, neither can be wholly relied upon, suggesting that new conventional sources of natural gas located in currently-restricted basins should be developed.

[6] Unconventional gas includes gas from coal bed methane, tight sands, and gas shales.

6. Natural Gas Prices

Key Findings:

- *With nuclear options constrained, overall natural gas demand increases due to incremental demand created by the need to comply with CO_2 emissions limits, increasing upward pressure on wellhead prices. This pressure is alleviated to some degree by importing LNG and finding new domestic gas supplies.*
- *Higher wellhead gas prices will affect all natural gas consuming sectors, but will have an even greater impact on prices to the electric sector and industrial sectors due to the added cost of CO_2 allowances that must be acquired in order to consume the fuel.*
- *Scenario 7 indicates both wellhead and residential natural gas prices increase relative to AEO2007 prices (no climate change legislation) by an average of roughly $1.03 per Mcf from 2020 through 2029, spiking to about $3.60 per Mcf in 2030.*
- *To the extent that the actual supply response, particularly from LNG and unconventional domestic gas sources, is less robust than assumed in NEMS, there would be more upward pressure on natural gas prices compared to these model results.*

7. Electricity and CO_2 Prices

Key Findings:

- *The price of CO_2 is affected by the cost of CO_2 reduction technologies and the number of offsets available and by the prices at which such offsets are available. The market for offsets, in turn, is a function of the technologies available to mitigate CO_2 emissions and the number of CO_2 permits available.*
- *The electricity price will incorporate the price of CO_2 and generally rises dramatically after 2020. Although S. 280 excludes direct energy use by the residential sector, the sector nevertheless will see higher electricity prices as the costs incurred by electric generators are passed through in the price of electricity.*

General Insights and Lessons Learned Applicable to any GHG Legislation

While the NGC study focused on S. 280, the analysis yielded a number of insights and lessons learned that should be applicable to the examination of other bills to establish a comprehensive program for mandatory reductions of U.S. GHG emissions:

1. Solutions to achieve GHG emissions reductions are very complicated with many interdependencies and uncertainties.
2. Results are heavily dependent on the features and functionality of legislative provisions providing market mechanisms, such as carbon offset projects and the development of a tradable carbon allowance market.
3. Results are heavily dependent on the actual availability of carbon offsets and allowances. For example, global demand for offsets could limit their availability to U.S. purchasers and also affect the price.
4. The number of offsets available will make a very large difference in outcomes, almost as much as the choice of technologies used to curb emissions.
5. The choice by the market of when to use banked emissions can significantly affect both the rate at which key technologies are deployed (e.g., nuclear generation) and the level of actual emission reductions achieved in the United States.
6. While CO_2 cap-and-trade legislation may impose economy-wide restrictions, the impact falls primarily on the electric generation sector through 2030. Minimal additional carbon emission cuts are available from the electric sector after 2030, especially if offsets are limited.
7. Economic impacts are heavily dependent on the successful commercialization of technologies (such as use of renewable generation and sequestration) and the rate at which they are adopted.
8. Legislation mandating significant step function changes in CO_2 emissions limits is more likely to cause economic dislocation (e.g., price spikes) than more gradual, linear implementation of emission reduction limits.
9. It is unlikely that legislative goals for reducing domestic man-made GHG emissions by 2050

will be achieved through the electric generation sector alone. Reductions will be needed from other economic sectors, such as transportation and industry, which are less sensitive to the level of carbon prices.

10. The NEMS modeling (EIA and NGC) assumes that there is a set of technical solutions for CO_2 abatement that is globally consistent and that, as a result, global marginal CO_2 abatement costs are consistent. The balance of trade and industrial capacity in the United States will be affected if there is a divergence between marginal domestic CO_2 abatement costs and costs in the world market.
11. Under the Scenario 1 Base Case S. 280 assumptions, NEMS shows that nuclear generation is the most economic solution, but the model cannot account for whether the public will be prepared to accept nuclear resurgence, or any other technology, at the level that would be dictated by economic assumptions provided by EIA.
12. Renewable technologies for generating electricity are competitive in the NEMS scenarios, because they are known low-emissions technologies – an immediate advantage for penetrating a carbon-constrained market. Still, certain renewable technologies require redundant generation or storage capacity to satisfy reliability goals.
13. The use of carbon capture and sequestration in electric generation develops after 2020 in conjunction with integrated coal gasification combined cycle (IGCC) and natural gas combined cycle (NGCC). While both could compete economically, NGC Scenario 6 indicates that "NGCC with sequestration" generally leads "IGCC with sequestration" in adoption due to lower costs and available technology.
14. Investments in new technologies and commercialization to meet GHG targets run the risk of becoming stranded if more economic alternatives for meeting GHG targets become available. For example, private sector investments in expensive sequestration technologies or renewable generation could be rendered uneconomic if nuclear generation achieves the level of market penetration indicated by the EIA or NGC base case scenarios.
15. There is some reduction in GHG emissions from improvements in efficiency in all sectors, but those changes forecasted by NEMS reflect only the continuation of the historical trend that increased delivered energy prices are an impetus for improvements in energy efficiency.
16. The NEMS model (EIA, NGC), as presently configured, does not address the complete timeframe (2010-2050) of the climate change bills being discussed. Given the significant emission reductions desired after 2030, it is very important to understand the implications to the economy and society and what solutions may be available to affect that change.

Conclusions

The NEMS model results demonstrate the importance of considering the likelihood that the technologies and market mechanisms envisioned for GHG emission reductions may not be fully developed and deployed in time to achieve the emission reduction goals under legislation that would establish deadlines for mandatory GHG emissions reductions (e.g., 2020 and 2030). Using alternative assumptions about the level of contribution to GHG emissions reductions that key technologies and market mechanisms are *likely to make*, the model results show the strong possibility that there will be greater reliance on natural gas to achieve the emission reduction targets established for 2020 and 2030. Given the importance of achieving the emissions reduction targets that Congress ultimately may legislate, the natural gas industry would like to explore with Congress policies that can facilitate optimizing the contribution that natural gas can make, at minimum, as a bridge fuel for electric generation, until the other technologies and market mechanisms for GHG emission reductions can be commercialized and fully deployed.

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METHODOLOGY & RESULTS

Background

In April 2007, the four major natural gas industry trade associations comprising the Natural Gas Council (NGC)[7] contracted with Science Applications International Corporation (SAIC) to analyze pending legislative initiatives for mandatory greenhouse gas (GHG) emission controls. This study utilizes the National Energy Modeling System (NEMS), the model on which Congress and federal agencies rely to analyze environmental-energy initiatives.

NEMS is a publicly available, national, economy-wide, integrated energy model that analyzes energy supply, conversion, and demand. It is used by the U.S. Energy Information Administration (EIA) to provide U.S. energy market forecasts through 2030 in its flagship publication, the *Annual Energy Outlook*. NEMS is also the principal energy policy analysis tool used by EIA to report to Congress regarding the projected impact on U.S. energy markets and the economy of GHG policies in proposed legislation. SAIC is a leading consultant to EIA on the design and implementation of NEMS, and has over 100 staff years supporting the model. The diagram below shows the 12 energy industry sectors/sub-modules modeled by NEMS.

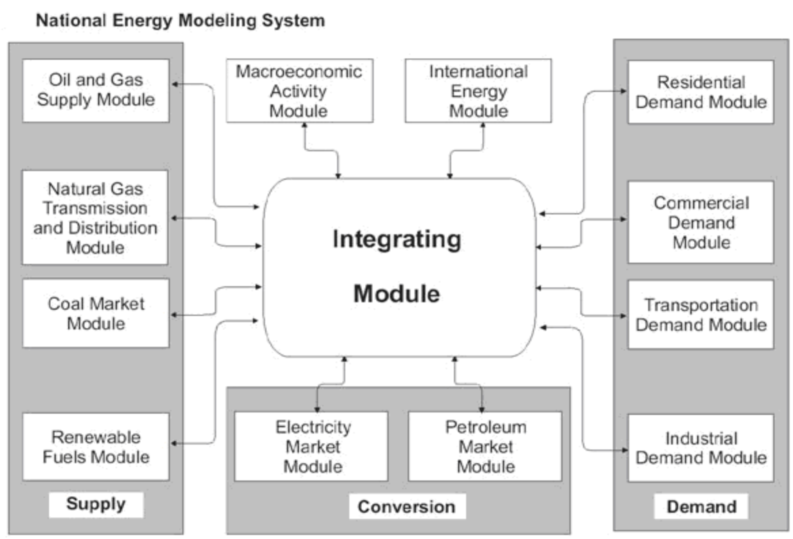

Figure 1: National Energy Modeling System

NEMS provides a common analytical tool for gaining valuable insights into the likely implications of alternative GHG reduction policy options. Using the model relied on by Congress also ensures that the discussion will focus on the merits of assumptions and policy choices rather than methodology. In the end, the use of NEMS in this project supports and supplements congressional consideration of alternatives and enhances opportunities to identify commonalities, strengthen the legislation, and find solution paths.

NEMS results are dependent on model input assumptions related to technology, cost, performance, and other factors. EIA generally performs NEMS runs using its own assumptions, or those in congressional or federal agencies' requests. In its analyses, EIA runs NEMS under current government policy as specified in the *Annual Energy Outlook (AEO2007)*. As with any forecast, these assumptions are the best judgment[8] of the requestor or EIA staff, but may not necessarily be the same assumptions that would be used by others interested in an issue. (Appendix 1 provides examples of analyses performed by EIA for Congress and additional details regarding NEMS.)

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[7] The American Gas Association (AGA), the Independent Petroleum Association of America (IPAA), the Interstate Natural Gas Association of America (INGAA), and the Natural Gas Supply Association (NGSA).

[8] Appendix 3 *Outstanding Issues with the NEMS Model and Existing Source Data as Used for this Modeling Exercise*

Underpinning this project is the concern that, while the technologies and market mechanisms (such as carbon offsets) anticipated for achieving GHG emission reductions *may* be fully deployed by the 2020-2030 interim and final target dates in most bills, *there is a very real possibility that they may not.* The NGC suggests that Congress examine alternative scenarios and be fully informed of the consequences should the anticipated technologies and market mechanisms not be fully available by 2020-2030. Engaging in this exercise will ensure that any GHG legislation that ultimately may be enacted is sufficiently flexible to address the environmental, economic and energy security implications of a range of possible outcomes that may occur as the energy economy adjusts to mandatory carbon constraints. This project is designed to assist Congress in this effort.

This analysis does not address the outcomes that may occur during 2030-2050. Nonetheless, it appears that meeting the increasingly stringent post-2030 emissions reduction targets that would be prescribed under most bills will be a challenge.

Analysis of the McCain-Lieberman Bill

The McCain-Lieberman bill (S. 280[9]) to reduce GHG emissions is the first bill to be analyzed by this project. EIA has analyzed S. 280 at the request of the Congress, and the Environmental Protection Agency (EPA) also has completed an analysis of this bill. Key provisions of S. 280 include:

1. Economy-wide, downstream scope; begins 2012
2. Emission reduction targets for entities with facilities with over 10,000 Metric Tonnes CO_2 equivalent/year imposed in "steps": 1990 level by 2020; 20% below 1990 level by 2030; 60% below 1990 level by 2050
3. Up to 30% offsets allowed from international credits, domestic reductions and sequestration; allowance trading and banking are permitted
4. No "safety valve", i.e., no price caps on carbon

The natural gas industry selected S. 280 for the initial analysis because it has an aggressive emissions reduction target and contains all of the key elements likely to be given strong consideration in developing final GHG legislation. Consequently, the framework of this analysis, the questions asked and the lessons learned should be relevant to analyzing any GHG legislation. As summarized below, the analysis of S. 280 has provided general insights and takeaways regarding the nuances, inter-relationships and relative importance of the key elements that are likely to be included in comprehensive GHG legislation.

Base Case Analysis:

The project established a temporary Base Case for S. 280 by running NEMS under the assumptions contained in *AEO2007* and NGC's interpretation of the bill. Once EIA published its analysis in July 2007, the project adopted the "EIA-S. 280 Core Case" as the S. 280 Base Case[10] (Scenario 1).[11] SAIC identified no significant discrepancies between the temporary Base Case and the EIA-S. 280 Core Case. Appendix 4 compares the temporary Base Case and EIA-S. 280 Core Case, including minor analytical differences. These differences are inconsequential for purposes of the analyses performed during this project, including those described in Scenarios 6 and 7 below.

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[9] The Climate Stewardship and Innovation Act of 2007

[10] Energy Information Administration, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007", July 2007

[11] The temporary Base Case used the best judgment of the contractor on how EIA would proceed. It allowed initial comparisons when alternative scenarios were run, thus allowing the project to proceed in a timely fashion without waiting for completion of the EIA analysis, and provided a fall-back, reference comparison in the event that EIA had not completed its analysis by the time the project was presented to Congress. EIA's completion of its analysis allows the "EIA-S. 280 Core Case" to serve as Scenario 1 for this study. Once adjusted to use the NEMS run that applies banked emissions prior to 2030, as EIA did, SAIC has identified no significant discrepancies between the temporary Base Case and the EIA-S. 280 Core Case.

EPA has also modeled the S. 280 Bill[12] utilizing different economic computer models and utilizing slightly different assumptions. While not directly comparable to these two NEMS modeling efforts, that exercise did attempt to quantify the global concentration of CO_2 in the atmosphere if S. 280 was implemented and that effort was integrated into a global CO_2 emission abatement architecture. Their conclusion was that the CO_2 concentration in the atmosphere would reach ≈ 480 ppm by 2095, but would not be on a stabilization trajectory.

Analysis using Alternative Assumptions:
The NEMS model is the most robust model of the U.S. economy for energy forecasting, but as such, it forecasts only economic decisions and does not predict technical, societal and political decisions. Hence these technical, societal and political decisions must be supplied by the modelers as assumptions. In its report, EIA emphasizes the "sensitivities" and "uncertainties" regarding several assumptions for program implementation, including in particular, uncertainties with respect to the market penetration achieved by the following technologies and market mechanism by 2030: (1) newly-constructed nuclear generating units; (2) renewable generation (bio-power and wind power); (3) the technological development and availability of carbon capture and storage (CCS); and (4) the availability of emission offsets. Because of the uncertainties, EIA examined several alternative policy sensitivity cases in addition to the "EIA-S. 280 Core Case". EIA states that "[s]ensitivity analyses suggest that the economic impacts can change significantly under alternative assumptions regarding costs and availability of new technologies . . . [and] offsets outside of the energy sector".[13]

As noted above, and as suggested by EIA's statement, there is uncertainty regarding the market penetration that will be achieved by these key technologies and the carbon offset market mechanism by 2030. Accordingly, the NGC project conducted a series of NEMS runs using "alternative assumptions" regarding the contribution that these technologies and this market mechanism (nuclear, renewable generation, integrated coal gasification with combined cycle (IGCC) with sequestration and carbon offsets) - the same as those referenced by EIA - are likely to make by the 2020 and 2030 target dates. EIA's analysis establishes highly useful parameters for examining these questions. The analysis performed in the NGC study uses NEMS to examine the impacts of these uncertainties in greater depth and detail.

The NGC study also includes important "alternative assumptions" about the availability of natural gas supply. The NGC study limited projected increases in LNG imports and unconventional gas and imposed a two-year delay on the in-service date for the Alaska Gas Pipeline beyond that assumed by EIA.

The alternative assumptions relied on insights provided through sequential runs of the NEMS model, combined with the collective, reasoned judgments on the uncertainties surrounding the development and public acceptance of the technologies and market mechanism. These assumptions were based on inputs from natural gas industry analysts, informal consultation with informed sources representing other segments of the energy industry, and information available from federal agencies and other sources. (The appendices include details about these alternative assumptions.)[14]

For example, the level of market penetration achievable by nuclear generation is one of the major uncertainties. EIA's analysis of S. 280 projected that nuclear generating capacity would increase from the current level of 100 GW to 245 GW by 2030, an increase of 145 GW in little more than two decades.[15] Experts consulted by the NGC project characterized that outcome as too aggressive and suggested a more modest increase of 25 nuclear generating units (25 GW) was more likely to occur by 2030. Accordingly,

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[12] EPA Analysis of the Climate Stewardship and Innovation Act of 2007
http://www.epa.gov/climatechange/economicanalyses.html
[13] EIA Report #: SR-OIAF/2007-04, page 60.
[14] In providing these alternative assumptions, the NGC is not being critical of the projections in *AEO 2007*, or EIA's use of them in its EIA-S. 280 Core Case.
[15] EIA-S. 280 Core Case

the assumption used in the NGC Alternative Assumption Case was to project a more modest increase of 25 units (25 GW) for nuclear generation by 2030. The EIA-S. 280 Core and NGC Alternative Assumptions Cases are summarized in Table 1. This level of estimated new nuclear builds falls between the estimates in the "EIA-S. 280 Core Case" and the EIA "No Nuclear" Alternative Policy Case (145 GW and 12 GW respectively).

Table 1: Summary of EIA-S. 280 Core Case and NGC Alternative Assumptions Case

Technology Area	EIA S. 280 Core Case	Assumptions used for the "NGC Alternative Assumptions Cases"
Nuclear	Nuclear capacity will increase from current 100 units to 245 units by 2030	Assumed 25 GW (25 units) new capacity by 2030 starting in 2015. See nuclear build profile in the Appendix 2
IGCC with Sequestration	Not built	150 GW nationwide maximum allocated across regions
Wind*	Wind generating capacity grows from 12 GW currently to 38 GW by 2030	Assumed 3 GW/year national constraint (2x historical build rate, 2.5 GW installed in 2006)
Biomass*	Biomass generating capacity grows from 2 GW currently to 112 GW by 2030	Assumed 3 GW/yr national constraint (equivalent to 40 biomass gasification combined cycle power plants)
Offsets	Used offset supply curves provided by EPA. Demand for offsets determined by NEMS.	1. Used supply and price of offsets based on EPA analysis and demand for offsets determined by NEMS 2. Assumed that only 15% of the offsets actually would be available. Did not use the EPA analysis
Natural Gas Supply	In the Base Case, sources of natural gas supply are lower than *AEO2007* due to falling demand from the power sector, which after 2020 relies increasingly on nuclear power and renewable generation	Assumed LNG imports at *AEO2007* levels, plus 500 Bcf Assumed lower price to unconventional producers (gas price minus $2.50 ramped in over 15 years at 20 cent increments) Assumed Alaska Gas Pipeline in service in 2020, rather than 2018 in *AEO2007*

* Based on technology costs in NEMS, wind and biomass are the dominant forms of renewable electricity generation available to the U.S. economy and are preferred over other renewable generation such as photovoltaic.

SAIC ran NEMS for seven total scenarios. The first scenario (temporary Base Case) ran NEMS under the assumptions contained in *AEO2007* and NGC's interpretation of the bill. As noted, the project now uses the EIA "S. 280 Core Case"[16], as the Scenario 1 Base Case. The remaining six scenarios used the NGC "Alternative Assumptions" described in Table 1. Table 2 sets out the sequential use of the EIA Base Case and NGC Alternative Assumptions in the NEMS runs.

[16] Energy Information Administration, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007", July 2007 http://www.eia.doe.gov/oiaf/aeo/index.html

Table 2: NGC Assumption and Scenarios for S. 280 Analysis Using NEMS

Assumptions	Scenario						
	1	2	3	4	5	6	7
Unconstrained *AEO2007* assumptions							
Nuclear Capacity additions limited to 25GW by 2030 (App. 2.1)		X	X	X	X	X	X
IGCC with sequestration limited to 150GW by 2030 (App. 2.5)			X	X	X	X	X
Biomass additions limited to 3GW/yr maximum (App. 2.2)				X	X	X	X
Wind additions limited to 3GW/yr maximum (App. 2.3)				X	X	X	X
Updated capital and O&M costs for IGCC and IGCC w Sequestration and NGCC and NGCC w Sequestration (App. 2.4)					X	X	X
Alaska Gas Pipeline in 2020 (App. 2.8)						X	X
LNG imports constrained relative to *AEO2007* +500 Bcf (App. 2.6)						X	X
Unconventional Gas Cost increased $1.50 (2030) (App. 2.7)						X	X
15% offsets available				X	X		X
30% offsets available	X	X	X			X	
S. 280 Cap Straight lined	X	X	X	X			
S. 280 Cap Step					X	X	X
EPA Estimates of Offset Costs (App. 2.9)						X	X

Summary of the Results

After running the seven scenarios, two scenarios - Scenarios 6 and 7 - were determined to provide the most meaningful results and outcomes for purposes of comparison with the EIA-S. 280 Core Case. These scenarios can be summarized as follows:

1. Scenario 6 Alternative Assumptions Case: Constrained nuclear and renewable generation with 30% offsets ("NGC-S. 280 – 30%")
2. Scenario 7 Alternative Assumptions Case: Constrained nuclear and renewable generation with 15% offsets ("NGC-S. 280 – 15%")

The comparison between the forecasted outcomes for Scenarios 6 and 7 and the EIA-S. 280 Core Case (designated as Scenario 1) is presented in terms of eight focus areas.

- U.S CO_2 Emissions
- Installed Electric Generation Capacity
- Produced Electric Energy
- Natural Gas Consumption
- Natural Gas Supply
- Natural Gas Prices
- Other Fuel Prices
- Electricity and CO_2 Allowance Prices

General Insights and Lessons Learned Applicable to any GHG Legislation per NEMS Model Runs and Analysis

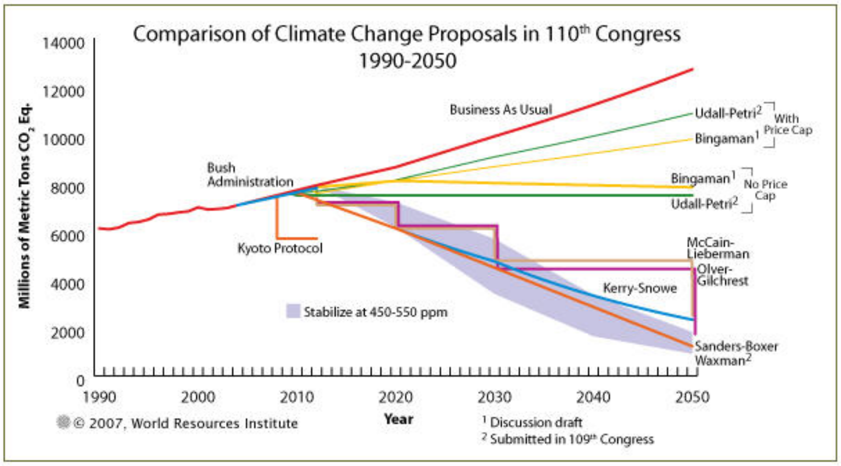
1. Solutions to achieve GHG emissions reductions are very complicated with many interdependencies and uncertainties.
2. Results are heavily dependent on the features and functionality of legislative provisions providing market mechanisms, such as carbon offset projects and the development of a tradable carbon allowance market.
3. Results are heavily dependent on the actual availability of carbon offsets and allowances. For example, global demand for offsets could limit their availability to U.S. purchasers and also affect the price.
4. The number of offsets available will make a very large difference in outcomes, almost as much as the choice of technologies used to curb emissions.
5. The choice by the market of when to use banked emissions can significantly affect both the rate at which key technologies are deployed (e.g., nuclear generation) and the level of actual emission reductions achieved in the United States.
6. While CO_2 cap-and-trade legislation may impose economy-wide restrictions, the impact falls primarily on the electric generation sector through 2030. Minimal additional carbon emission cuts are available from the electric sector after 2030, especially if offsets are limited.
7. Economic impacts are heavily dependent on the successful commercialization of technologies (such as use of renewable generation and sequestration) and the rate at which they are adopted.
8. Legislation mandating significant step function changes in CO_2 emissions limits is more likely to cause economic dislocation (e.g., price spikes) than more gradual, linear implementation of emission reduction limits.
9. It is unlikely that legislative goals for reducing domestic man-made GHG emissions by 2050 will be achieved through the electric generation sector alone. Reductions will be needed from other economic sectors, such as transportation and industry, which are less sensitive to the level of carbon prices.
10. The NEMS modeling (EIA and NGC) assumes that there is a set of technical solutions for CO_2 abatement that is globally consistent and that, as a result, global marginal CO_2 abatement costs are consistent. The balance of trade and industrial capacity in the United States will be affected if there is a divergence between marginal domestic CO_2 abatement costs and costs in the world market.
11. Under the Scenario 1 Base Case S. 280 assumptions, NEMS shows that nuclear generation is the most economic solution, but the model cannot account for whether the public will be prepared to accept nuclear resurgence, or any other technology, at the level that would be dictated by economic assumptions provided by EIA.
12. Renewable technologies for generating electricity are competitive in the NEMS scenarios, because they are known low-emissions technologies – an immediate advantage for penetrating a carbon-constrained market. Still, certain renewable technologies require redundant generation or storage capacity to satisfy reliability goals.
13. The use of carbon capture and sequestration in electric generation develops after 2020 in conjunction with IGCC and natural gas combined cycle (NGCC). While both could compete economically, NGC Scenario 6 indicates that “NGCC with sequestration” generally leads “IGCC with sequestration” in adoption due to lower costs and available technology.
14. Investments in new technologies and commercialization to meet GHG targets run the risk of becoming stranded if more economic alternatives for meeting GHG targets become available. For example, private sector investments in expensive sequestration technologies or renewable generation could be rendered uneconomic if nuclear generation achieves the level of market penetration indicated by the EIA or NGC base case scenarios.
15. There is some reduction in GHG emissions from improvements in efficiency in all sectors, but those changes forecasted by NEMS reflect only the continuation of the historical trend that increased delivered energy prices are an impetus for improvements in energy efficiency.
16. The NEMS model (EIA, NGC), as presently configured, does not address the complete timeframe (2010-2050) of the climate change bills being discussed. Given the significant emission reductions desired after 2030, it is very important to understand the implications to the economy and society and what solutions may be available to affect that change.

NEMS Modeling Scenarios

Selection of the McCain-Lieberman Bill (S. 280) for Modeling

A number of Members of Congress either have introduced bills or circulated drafts of legislation that would mandate reductions in U.S. emissions of greenhouse gases. Figure 2 compares some of these proposals.

Figure 2: Comparison of Climate Change Proposals[17], 1990 - 2050



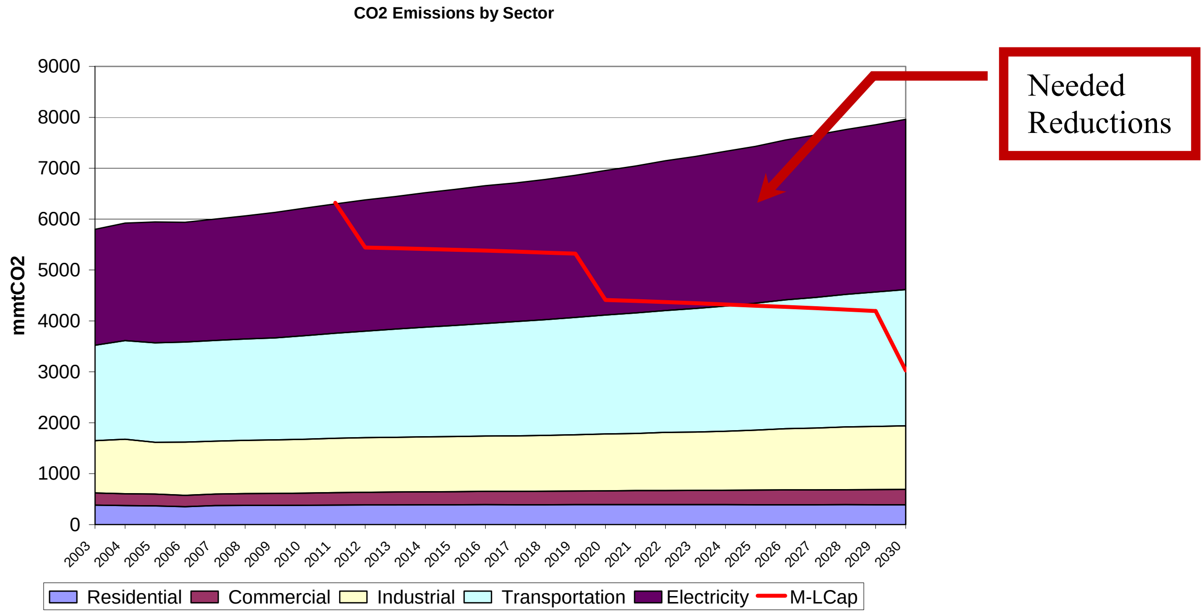
Under a business as usual scenario, with forecasted growth in the economy, it is expected that the United States will emit almost 9,000 million tonnes of CO_2 equivalent ($MMTCO_2e$) by 2020 and over 10,000 $MMTCO_2e$ by 2030.[18] Proposals from Udall-Petri and Bingaman would mandate the least cuts in CO_2 emissions (to approximately 8,000 $MMTCO_2e$ by 2020), while the largest cuts would be mandated by proposals from Sanders-Boxer, Waxman and Kerry-Snowe (to approximately 2,000 to 3,000 $MMTCO_2e$ by 2050). Proposals from McCain-Lieberman and Oliver-Gilchrest would require quite substantial CO_2 emission cuts from around 7,000 $MMTCO_2e$ currently to around 3,000 $MMTCO_2e$ by 2050.

S. 280 was selected as the "straw man" for this modeling exercise, because it provides for aggressive reductions in CO_2 emissions and contains most, if not all, of the key elements likely to be given strong consideration in the development of any final GHG legislation. It was also anticipated that if S. 280 was integrated into a global GHG abatement strategy, the eventual environmental goal would be achieved. Analysis of the components of S. 280 provides not only specific feedback with respect to the impact of S. 280 itself, but also general insight and takeaways regarding trends, influences, inter-relationships and relative importance of these key elements. As such, the framework of this analysis, the questions asked, and the lessons learned will be relevant to the design and analysis of any GHG legislation.

Figure 3 shows CO_2 emissions by sector forecasted by EIA using NEMS and published in the *AEO2007*. This depicts CO_2 emissions under current laws and regulations with S. 280 targets superimposed. Currently, the power sector is the largest contributor of CO_2 emissions, emitting approximately 2,400 $MMTCO_2$ per year. This is followed closely by the transportation sector, which emits a little less than 2,000 $MMTCO_2$ per year. Industry is the third largest emitter (1,050 $MMTCO_2$ per year), followed by the residential sector (375 $MMTCO_2$ per year) and the commercial sector (225 $MMTCO_2$ per year).

[17] World Resource Institute; http://www.wri.org
[18] These estimates include emissions from non-energy sources.

Figure 3: *AEO2007* CO_2 Emissions by Energy Consuming Sector with S.280 Cap Overlaid



Overall CO_2 emissions from energy production and consumption grow to almost 8,000 $MMTCO_2$ by 2030. Targets proposed under S. 280 would constrain emissions to a path shown as the descending red line in Figure 3. The path follows a series of step-downs, first in 2012, followed by steps in 2020, 2030 and 2050. Based on analysis of S. 280, emissions would need to be cut to 5,442 $MMTCO_2$ by 2012, another 4,412 $MMTCO_2$ by 2020, and another 3,027 $MMTCO_2$ by 2030. Entities emitting more than 10,000 tonnes of CO_2 would be covered by S. 280; the residential sector is exempt from direct regulation.

Regulated entities will have a number of options for achieving CO_2 emissions reductions, including zero CO_2 emitting technologies such as nuclear or wind generation, new technologies such as CCS, carbon offset projects that reduce CO_2 emissions by an amount equivalent to that emitted, or purchasing CO_2 emissions permits on a tradable market. S. 280 allows companies to invest in carbon offset projects or to purchase CO_2 emissions up to 30 percent of the targeted emissions. Consequently, it would be possible for the economy to generate 30 percent more emissions than targeted by S. 280 as long as such emissions are offset by carbon sinks.

McCain-Lieberman (S. 280) Analysis
NEMS was used to analyze the impact of S. 280 under scenarios that vary the availability of energy technologies, natural gas supply, and carbon offsets.

*McCain-Lieberman (*S. 280*) Base Case – "NGC-S. 280 Base Case"*
The first step in SAIC's analysis was to use NEMS to establish a temporary NGC "Base Case" for S. 280. SAIC used *AEO2007* assumptions that were considered to be the most likely assumptions that EIA would use in analyzing S. 280. Since EIA had not yet completed its S. 280 analysis when this project was launched, the natural gas industry tasked SAIC to use its best judgment with respect to the operational nuances, assumptions, etc. that might be required in performing a NEMS analysis of S. 280. Emission banking was allowed, but the yearly cap could not exceed the 30% offset limitation. The temporary NGC Base Case allowed initial comparisons when alternative scenarios were run, thus allowing the project to proceed in a timely fashion without waiting for completion of the EIA analysis. When EIA published its analysis in July 2007[19], the project adopted the "EIA-S. 280 Core Case" as the S. 280 Base Case. Once

[19] Energy Information Administration, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007", July 2007

adjusted to use the "sweep" of the banked allowance account in 2028, prior to the end of the 2030 modeled period, as EIA did in their case, SAIC identified no significant discrepancies between the temporary NGC Base Case and the "EIA-S. 280 Core Case". Sweeping the banked emissions results in less need for low GHG emission power plants (e.g., nuclear plants in Scenario 1), but increases the GHG reductions needed post 2030.

Analysis of the McCain-Lieberman Bill using NGC "Alternative Assumptions" to those in the EIA-S. 280 Core Case

As noted above, while it is possible that the technologies, market mechanisms and public acceptance anticipated to be available for achieving GHG emission reductions *may* be fully developed and deployed by the 2020 and 2030 interim and final target dates in most bills, *it is also possible that they may not.* NEMS runs for S. 280 using NGC "alternative assumptions" were performed in order to appreciate the implications should these technologies achieve lower levels of market penetration than anticipated in the EIA-S. 280 Core Case:

Starting with the EIA-S. 280 Core Case and then in sequential NEMS runs, uncertainties surrounding the technologies, market mechanisms and public acceptance identified by NEMS to meet the S. 280 GHG emission reductions targets were examined and alternative assumptions were chosen to be used in NEMS runs. The process for identifying the alternative assumptions relied on sequential NEMS model runs, combined with a collective estimate about the uncertainties surrounding the technologies and market mechanisms in question. This collective estimate was based on input from both natural gas industry experts and informal consultation with informed sources from other segments of the energy industry. These alternative assumptions represented the best judgment regarding the more likely level at which these technologies and market mechanisms would contribute to achieving emissions reductions by the 2020 and 2030 target dates.

SAIC performed NEMS runs assuming lower market penetration than in the EIA-S. 280 Core Case for the key existing generation technologies (such as nuclear generation), new generation technologies (such as advanced coal technologies with sequestration and renewable generation - wind and biomass), and uncertainties with respect to the availability of carbon offsets (i.e., assume that only 15 percent rather than 30 percent in offsets allowed in S. 280 actually would be available).

The alternative assumptions included constraints on natural gas, as well. The natural gas industry was concerned that EIA-S. 280 Core Case assumptions regarding the availability of both LNG and unconventional natural gas supplies and the projected in-service date for the Alaska Natural Gas Pipeline might present an overly optimistic gas supply picture. Accordingly, more modest availability of these natural gas supplies was assumed. (The appendices to this Report provide more in-depth discussion of reasons for the uncertainties regarding the technologies and market mechanisms, and the alternate market penetration levels selected for 2020-2030.)

NEMS Modeling Results

While NEMS produces 150 tables for each model run, the results from the NEMS model runs are reported for the following focus areas: (1) U.S. CO_2 Emissions, (2) Installed Electric Generating Capacity, (3) Produced Electric Energy, (4) Natural Gas Consumption, (5) Natural Gas Supply, (6) Natural Gas Prices, (7) Other Fuel Prices, and (8) Electricity Prices and Prices of CO_2 Offsets and Permits.

After running seven scenarios, three were determined to provide the most meaningful comparisons.

- Scenario 1 – S. 280 Base Case ("EIA-S. 280 Core Case")
- Scenario 6 – Constrained nuclear and renewable generation with 30% max offsets and updated capital costs ("NGC-S. 280 – 30%")
- Scenario 7 – Constrained nuclear and renewable generation with 15% max offsets and updated capital costs ("NGC-S. 280 – 15%")

Three graphs - one for EIA's S. 280 Core Case and one each for Scenarios 6 and 7 - are provided to illustrate the results for the first five focus areas. Natural Gas Prices, and Electricity Prices and Prices of CO_2 Offsets and Permits are shown on the same graphs.

1. U.S. CO_2 Emissions

Key Findings:

- *S. 280 would compel very dramatic steps to de-carbonize the power sector unless efficiency improvements, low carbon emission technologies outside the electric sector and transportation CO_2 emission reductions are mandated or incentivized.*
- *The number of offsets available will make a very large difference in domestic impacts, almost as much as the choice of technologies used to curb emissions.*
- *The market utilization of banked of carbon allowances can significantly affect choices on the deployment of technology to achieve GHG emissions reduction targets.*

(1) Scenario 1. EIA-S. 280 Core Case shows that, even after the new law becomes binding in 2012, CO_2 emissions continue to rise until 2018. This implies that the target is being met by carbon offsets and allowances. (The area above the S. 280 line reflects the utilization of offsets and allowances.) Cuts occur in the electric sector after 2020, while other sectors are barely affected. Other sectors do not cut emissions, because the price signal transmitted via the cost of carbon credits is not strong enough to compel a meaningful change in fuel consumption patterns. For example, the base case run results in a CO_2 allowance price of around $24/tonne by 2021 and $35/tonne by 2026 (real 2005$). This would increase the price of gasoline by between 20 and 30 cents a gallon, an amount insufficient to affect gasoline consumption significantly.

(2) Scenario 6. NGC-S. 280 – 30% represents a NEMS run with the S. 280 targets as the step function specified by the bill. Even with banking, this step change results in sudden impacts to the economy. The first S. 280 step occurs in 2020, when the target is reduced from 6,121 $MMTCO_2e$ to 5,074 $MMTCO_2e$. This results in immediate cuts in the power sector and modest cuts in the transportation and industrial sectors. A further cut in the S. 280 target in 2030 results in even more severe curtailment of CO_2 emissions from the electric sector.

The number of offsets was determined by analysis of offset curves published by the EPA[20], which depict the relationship between the number of offsets available and the price of offsets. NEMS projects that those offsets will be heavily utilized during the 2020-2030 period. Scenario 6 assumes limits on the ability to deploy nuclear, IGCC, and renewable technologies, and the availability of natural gas via LNG

[20] Appendix 2.9 *Assumptions for CO_2 Emission Abatement Curves input into NEMS*

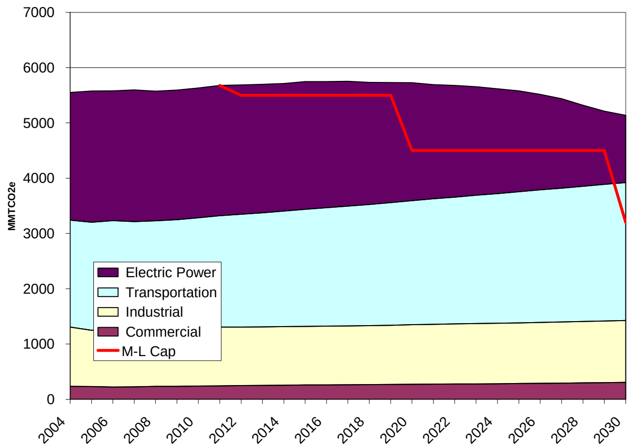
imports. Under this scenario, a full portfolio of electric generating technologies is brought to bear instead of predominant reliance on any one technology.

(3) Scenario 7. NGC-S. 280 – 15% represents the same run as Scenario 6, but with only 15 percent offsets available. This sets the most stringent cap on CO_2 emissions and results in the lowest level of emissions above the S. 280 cap. The limited supply of offsets results in carbon prices high enough to elicit some cuts in emissions from the transportation and industrial sectors.

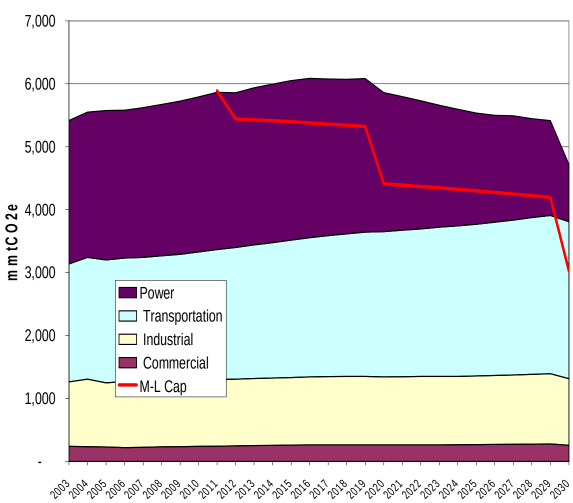
A general lesson is that the number of offsets available will make a very large difference in outcomes, almost as much as the choice of technologies used to curb emissions. For example, 30 percent offsets allow traditional coal to continue to play a major role in power generation through 2030, while 15 percent offsets result in dramatic decreases in coal use and increases in gas use as shown by the results for both generating capacity and electricity generation (Scenarios 6 and 7 in Figure 4).

Figure 4: Comparison of CO_2 Emissions for Various Scenarios

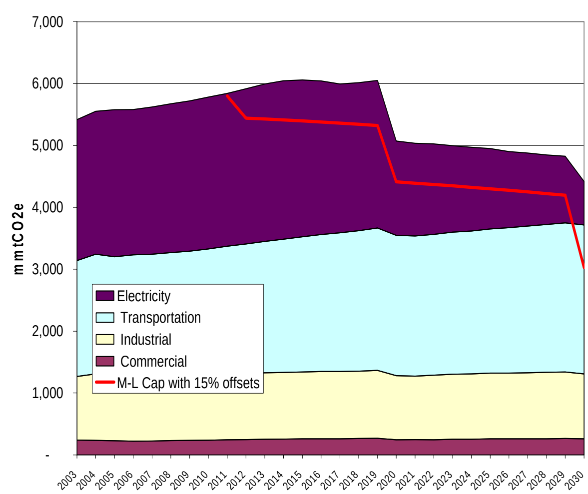
Scenario 1. EIA-S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation with 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation With 15% Offsets



2. Installed Electric Generation Capacity

Key Finding: The introduction of carbon capture and sequestration infrastructure (Figure 5, scenarios 6 and 7) allows gas-fired and coal-fired generation to play leading roles in reducing CO_2 emissions as compared to Figure 5, scenario 1 where unconstrained nuclear plant construction dominates the new electric generation mix.

Scenario 1. EIA-S. 280 Core Case - Unconstrained, NEMS will choose the least expensive technology[21] to meet the S. 280 carbon cap. Consequently, nuclear generation capacity increases from 100 GW currently to 127 GW by 2020, approximately 27 nuclear plants. To meet the 2030 S. 280 step, an additional 118 plants must be built, for a projected total of 145 plants by 2030. Also, renewable generation increases from 100 GW currently to over 242 GW by 2030. Renewable and nuclear generation are the technologies of choice in this scenario. As nuclear and renewable capacity is built:

- Conventional coal capacity falls after 2011, from 317 GW to 228 GW;
- IGCC with sequestration does not get built;
- Other fossil steam, primarily combustion turbines, declines from over 120 GW to around 25 GW capacity; and
- Conventional natural gas fired combined cycle increases from 165 GW to 213 GW by 2030.

Scenario 6. NGC-S. 280 – 30% – Given the assumed constraints on market penetration by nuclear (25 GW total) and renewable generation (3 GW wind and 3 GW biomass annually) and the availability of the full 30 percent offsets permitted under S. 280, coal plays a larger role than in all other cases.

- Conventional coal capacity falls to 200 GW and IGCC with sequestration increases to 116 GW by 2030;
- 155 GW of advanced NGCC with sequestration is added by 2030, with a major jump in 2030 as the more stringent S. 280 cap takes effect; and

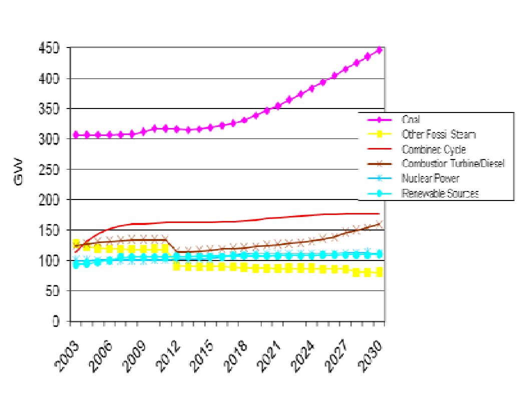
Scenario 7. NGC-S. 280 - 15% represents a case in which no single technology holds a commanding share of the electric generation portfolio. As in Scenario 6 NGC-S. 280 – 30%, market penetration by nuclear and renewable generating capacity is constrained.

- Conventional coal capacity falls after 2020, from 304 GW to a little less that 200 GW.
- Advanced coal with sequestration increases to 81 GW by 2030.
- Conventional NGCC holds steady at 195 GW, with 175 GW of advanced NGCC with sequestration added by 2030.

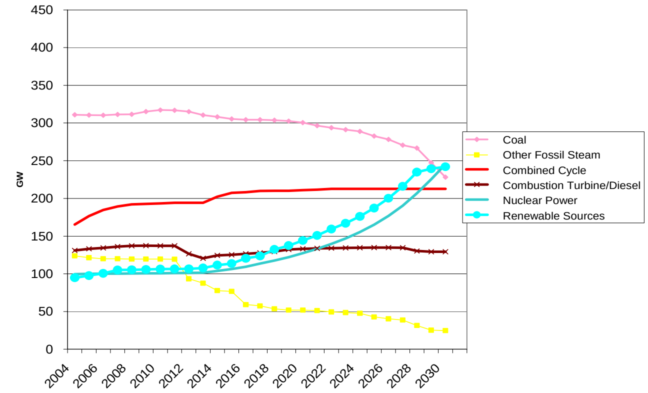
[21] Present NEMS data set does not have updated nuclear capital and operating costs.

Figure 5: Comparison of Installed Electric Generation Capacity for Various Scenarios

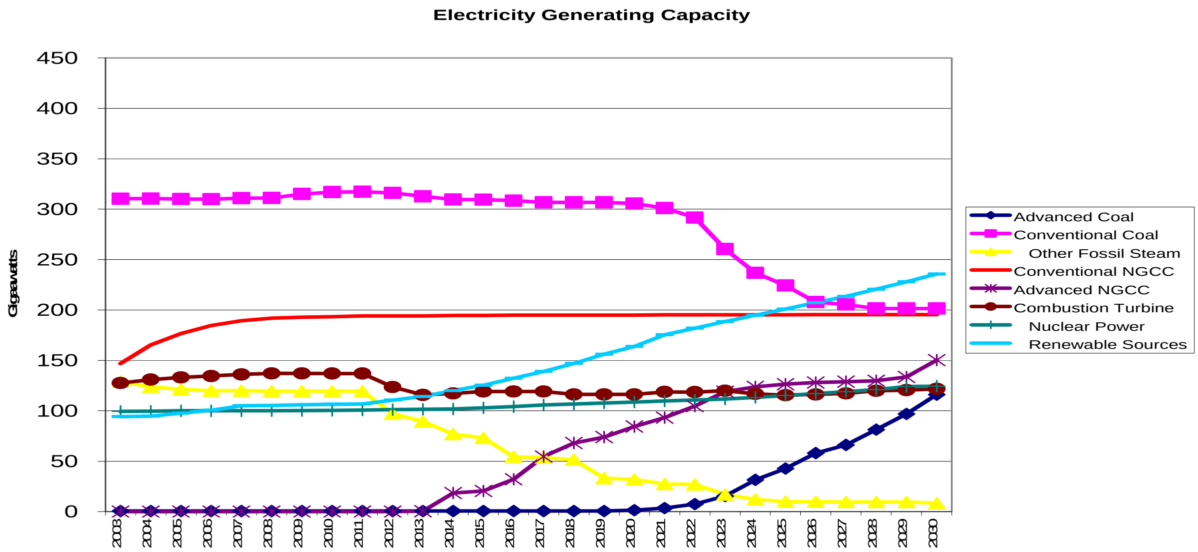
EIA *AEO2007* Business as Usual



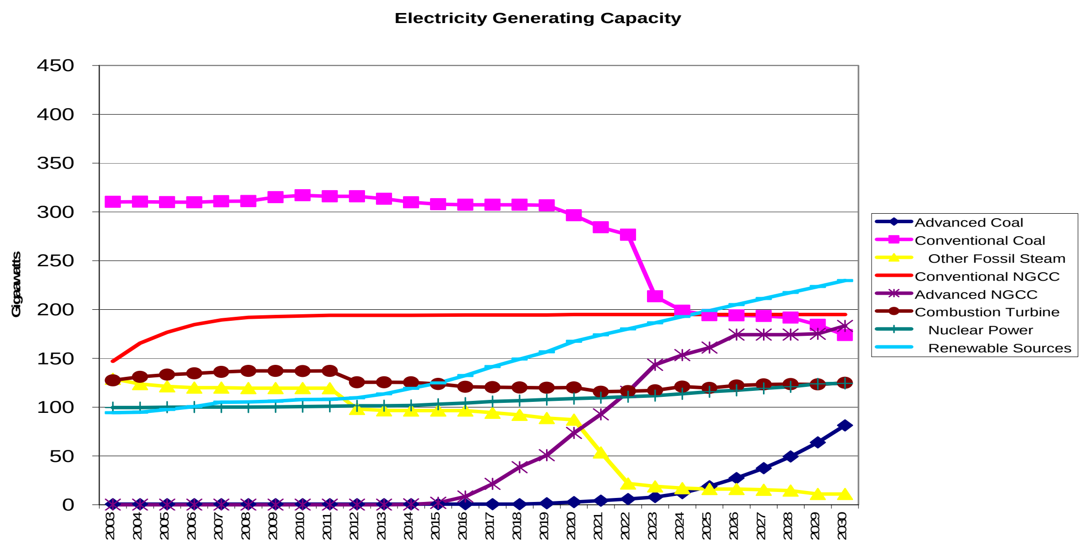
Scenario 1. EIA S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation With 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation with 15% Offsets



3. Produced Electric Energy

Key Finding: Widespread political acceptance of new nuclear energy sources (Figure 6, Scenario 1) results in nuclear power plants supplying a predominant share of electricity to consumers under the present EIA cost assumptions. More modest assumptions about nuclear growth (Figure 6, Scenarios 6 and 7) result in electricity supply from a mix of technologies to meet CO_2 emissions reduction targets.

Scenario 1. EIA-S. 280 Core Case - The increase in nuclear generation capacity results in a similar increase in electricity generated from nuclear power from approximately 790 Billion KWh (BKwh) currently to over 1,909 BKwh by 2030.

- Coal generation begins to fall prior to the retirement of coal capacity, which commences in 2011. Coal fired generation falls from 1,988 BKwh in 2007 to 1,020 BKwh by 2030.
- Natural gas generation peaks at 796 BKwh in 2015, before falling to 438 BKwh by 2030. While natural gas generation units are not retired, the capacity factor falls.
- Renewable generation grows to about 1,441 BKwh by 2030.

Scenario 6. NGC-S. 280 – 30% - Coal generation continues to play a dominant role. Electricity generated using coal declines from 2,086 BKwh in 2019 to 1,644 BKwh in 2023, before recovering to 1,827 BKwh by 2029. It then declines again once the 2030 S. 280 step is reached.

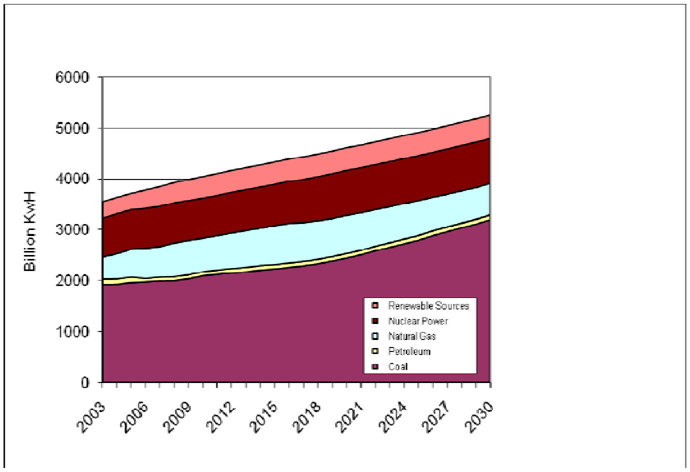
- Natural gas generation grows until coal generation begins to recover in 2023. Natural gas then rebounds when the 2030 step change in S. 280 is reached.
- Renewable generation shows strong growth over the forecast, but is limited by the 3 GW per year additional capacity growth limits on wind and biomass established by the scenario assumptions.
- Nuclear generation is limited to moderate growth due to assumptions regarding the market penetration that can be achieved by new capacity (25 GW maximum).

Scenario 7. NGC-S. 280 - 15% - The S. 280 step-down in 2020 results in a dramatic drop off in electricity generated using coal, falling almost 25 percent. A similar decline occurs in 2030 when the S. 280 cap ratchets down again.

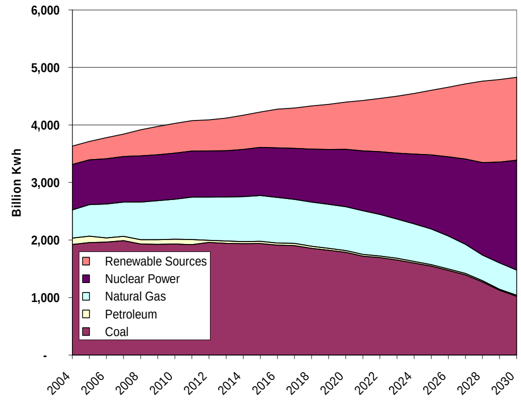
- Natural gas generation steadily climbs and is ratcheted up significantly in 2020 as coal generation falls. A similar ratchet up occurs in 2030.
- Generation from renewable generation and nuclear is similar to Scenario 6 NGC-S. 280 – 30%.

Figure 6: Comparison of Produced Electricity Generation Capacity for Various Scenarios

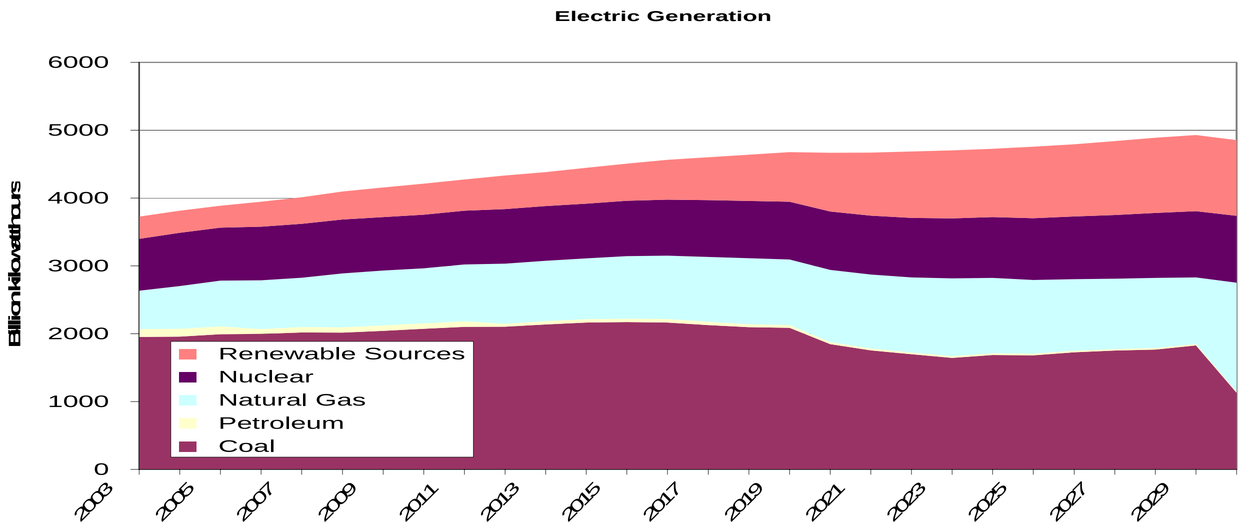
EIA *AEO2007* Business as Usual



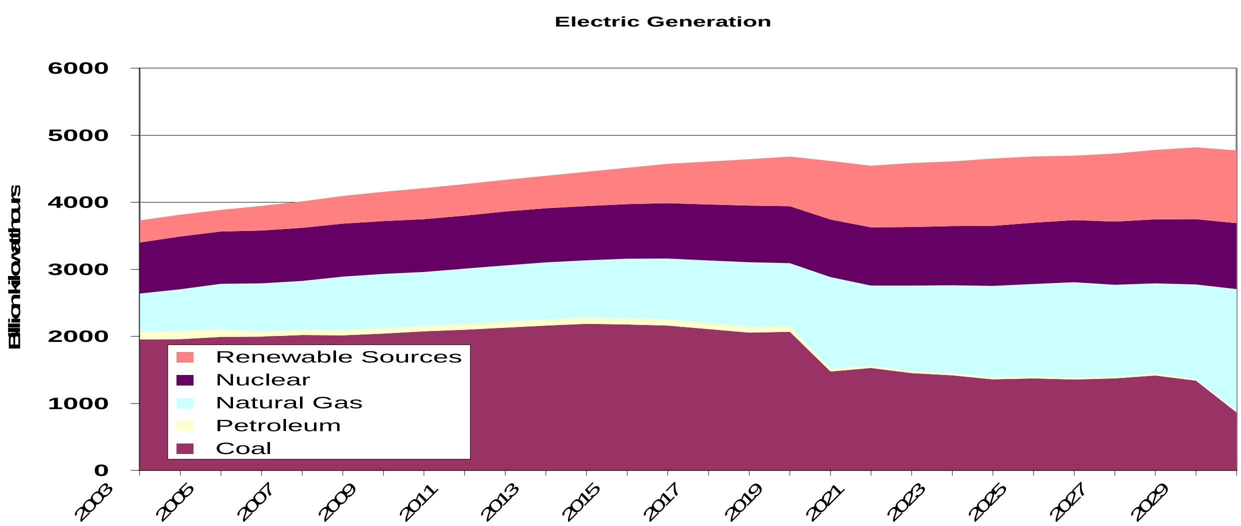
Scenario 1. EIA S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation With 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation With 15% Offsets



4. Natural Gas Consumption[22]

Key Finding: EIA-S. 280 Core Case results in less growth than AEO2007 through 2020, followed by declining consumption due to the unconstrained deployment of nuclear generation after 2020. NGC-S. 280 – 30% (Scenario 6) results in steady gas consumption peaking at approximately 31% over current levels. NGC-S. 280 - 15% (Scenario 7) results in high levels of gas use in the power sector, because gas is the cleanest alternative in the face of constraints on the ability to deploy other generating technologies widely and limits on the availability of offsets. Industrial gas consumption falls somewhat due to high gas prices.

Scenario 1. EIA-S. 280 Core Case - Natural gas grows to 25.6 Tcf by 2021. As nuclear and renewable generation is deployed on an unconstrained basis, natural gas consumption in the power sector begins to decline, with total consumption falling back to 24.3 Tcf by 2030. The impact on prices resulting from diminished gas-fired electric generation facilitates continued growth in natural gas consumption by the industrial, commercial and residential sectors.

Scenario 6. NGC-S. 280 – 30% - This scenario does not show the post-2020 downturn in gas demand under EIA-S. 280 Core Case. Consumption grows to a little less than 27 Tcf by 2025, holding steady until a jump to 29.5 Tcf in 2030 as the next S. 280 step is reached. Compared to NGC-S. 280 – 15%, more moderate gas price increases cause less impact on the industrial and commercial sectors.

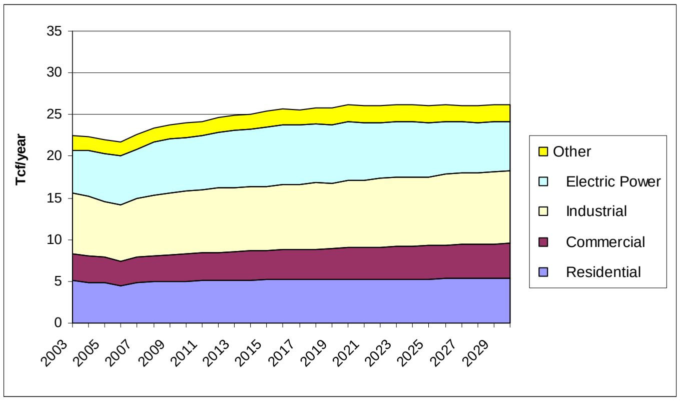
Scenario 7. NGC-S. 280 - 15% - Natural gas becomes the choice fuel for power generation, with overall U.S. consumption rising to 30 Tcf by 2020 and 32 Tcf by 2030. Gas consumption for power generation grows from around 6 Tcf per year currently to over 12 Tcf by 2020 and over 13 Tcf by 2030. In other end-use sectors:

- Industrial consumption of natural gas declines by 1034 Bcf (13%) in 2020 relative to *AEO2007*. A further drop occurs in 2030.
- Commercial gas consumption falls 410 Bcf (11%) in 2020.
- There is little change in residential gas consumption.
- Natural gas prices are generally forecasted to be higher than in either Scenario 1 EIA-S. 280 Core Case or Scenario 6 NGC-S. 280 – 30%.

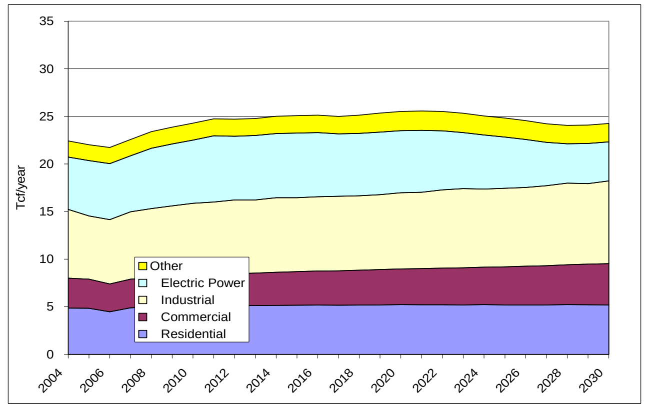
[22] Major markets: residential, commercial, industrial, electric power

Figure 7: Comparison of Natural Gas Consumption for Various Scenarios

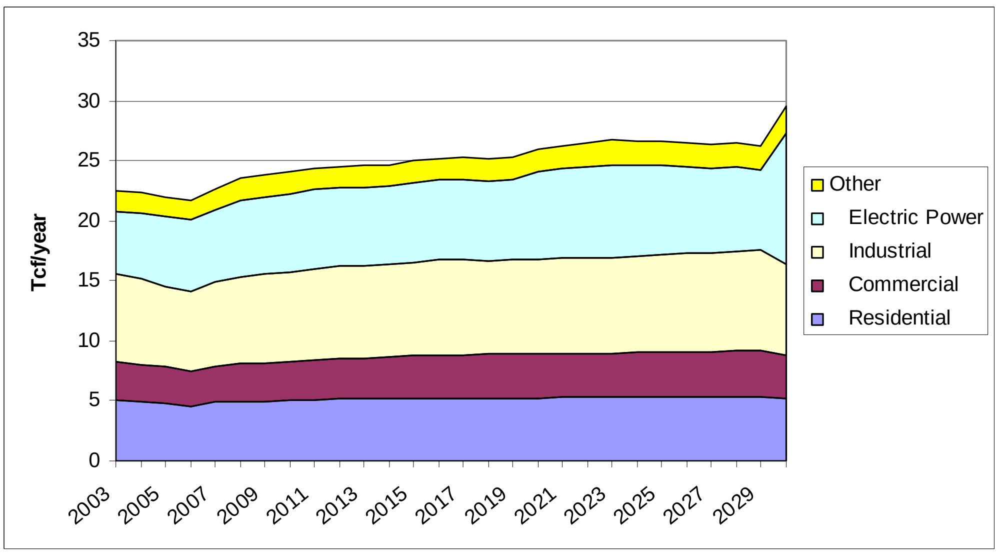
EIA *AEO2007* Business as Usual



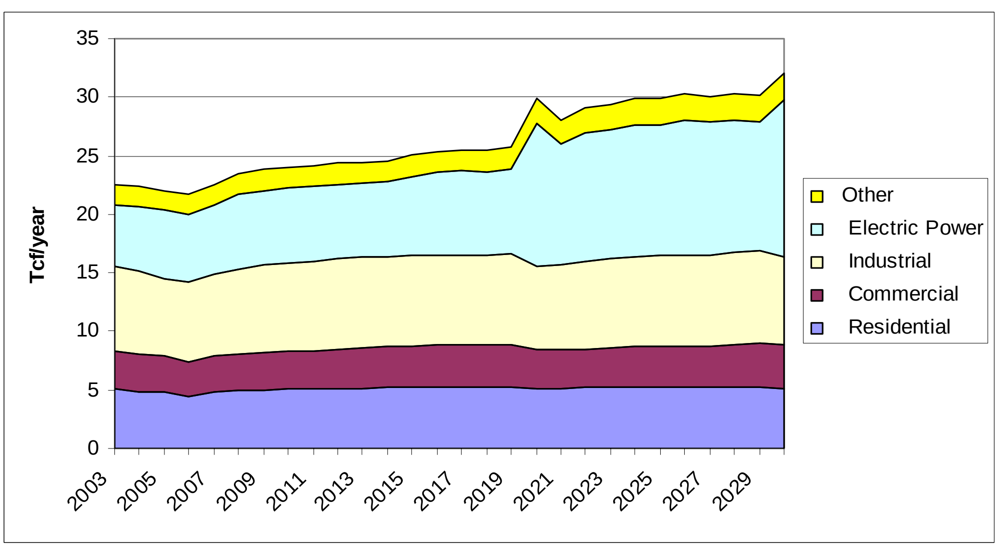
Scenario 1. EIA S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation With 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation With 15% Offsets



5. Natural Gas Supply

Key Finding: All three cases demonstrate the need for additional gas supplies as part of a GHG emissions reduction strategy. This is true, both if gas is a transition fuel and if gas is a critical part of a longer-term compliance strategy. Supply and demand must balance in the NEMS model, and it is assumed that LNG and unconventional gas resources will provide the backstop that enables this balancing to occur since supply basin access is limited in both the EIA and NGC assumptions. Given the uncertainty associated with foreign gas supplies and the environmental limits that affect unconventional gas production, neither can be wholly relied upon, suggesting that new conventional sources of natural gas located in currently-restricted basins should be developed.

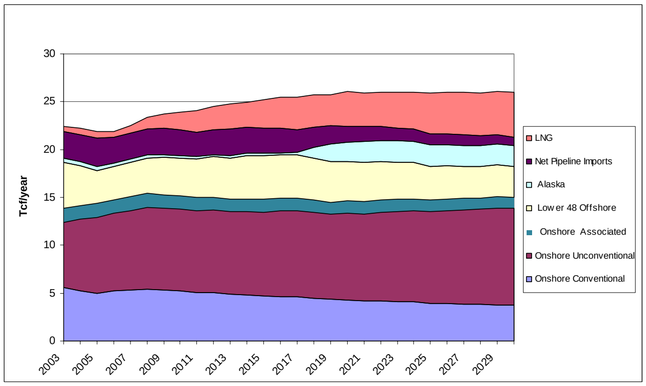
Scenario 1. EIA-S. 280 Core Case - Natural gas supply growth to meet rising demand through 2021 comes from unconventional natural gas sources, LNG and startup of the Alaska gas pipeline in 2018. All other sources of natural gas show long-term decline. After 2022, natural gas supply begins to decline rapidly in response to lower gas consumption from the power generation sector (i.e., price does not support the development of high-cost resources).

Scenario 6. NGC-S. 280 – 30% - This scenario requires an increase in natural gas supply, with this supply mainly coming from LNG imports and unconventional gas sources. LNG imports rapidly hit the Alternative Assumptions upper limit imposed for this run - *AEO2007* values + 500 Bcf (discussed in the Appendix 2.7). Under the Alternative Assumptions, unconventional gas was constrained by increasing production costs (e.g., water disposal and environmental compliance costs, etc.), since this type of gas is generally more expensive to produce than conventional gas sources. The Alternative Assumptions also assumed that the in-service date for the Alaska Gas Pipeline is delayed until 2020. The results suggest that new, cost-effective U.S. natural gas supplies must be found and developed.

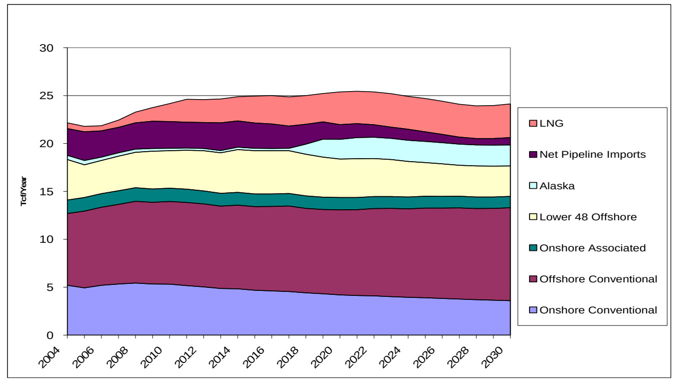
Scenario 7. NGC-S. 280 - 15% - This scenario requires rapid expansion of gas supplies to meet power generation needs. Although NEMS shows incremental supply coming primarily from LNG, the scenario assumes that less LNG will be available to the United States given constraints in the global LNG market. The model also shows mounting pressure for unconventional gas sources to expand, a solution which may be problematic due to the high cost of environmental mitigation for coal bed methane.

Figure 8: Comparison of Natural Gas Supply for Various Scenarios

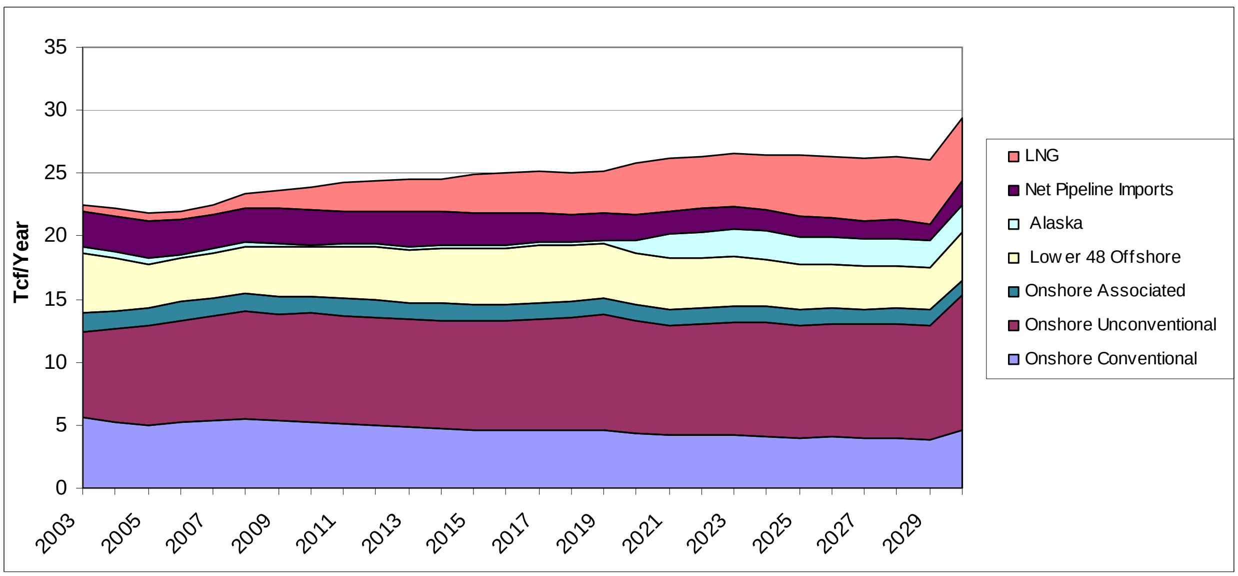
EIA *AEO2007* Business as Usual



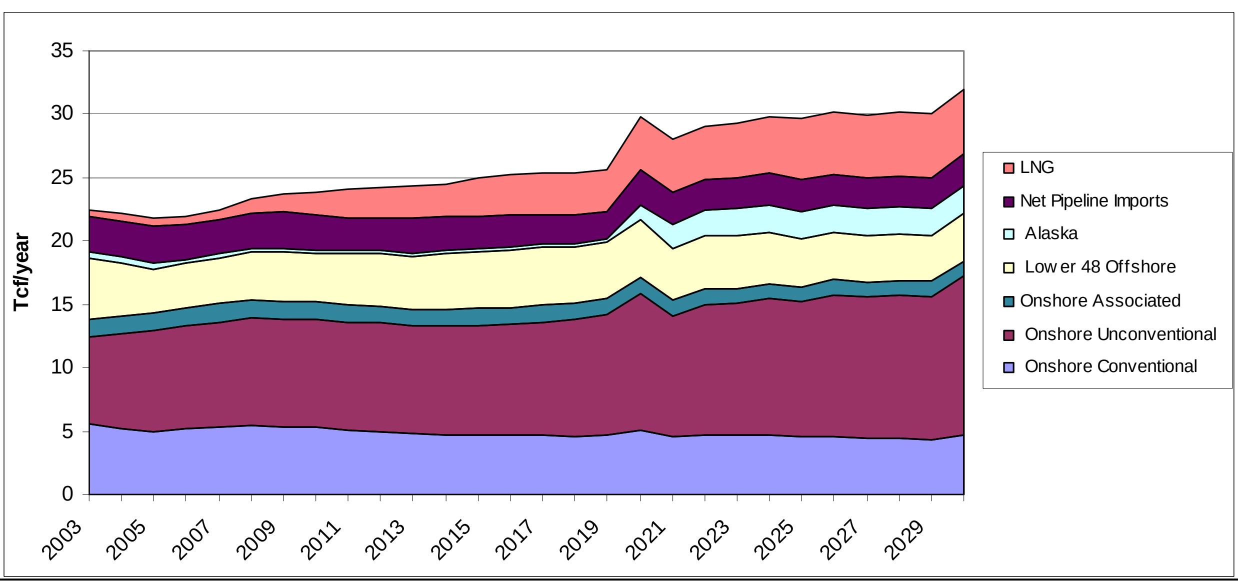
Scenario 1. EIA S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation with 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation with 15% Offsets



6. Natural Gas Prices[23]

Key Finding: With nuclear options constrained, overall natural gas demand increases due to incremental demand created by the need to comply with CO_2 emissions limits, increasing upward pressure on wellhead prices. This pressure is alleviated, to some degree, by importing LNG and finding new domestic gas supplies. With 15% of authorized offsets available, Scenario 7 indicates both wellhead and residential natural gas prices increase relative to AEO2007 prices (no climate change legislation) by an average of roughly $1.03 per Mcf from 2020 through 2029, spiking to about $3.60 per Mcf in 2030.

Natural gas prices are affected by S. 280 both at the wellhead and at the point of consumption. Wellhead prices are affected by changes in the relative natural gas supply/demand balance that results from the fuel use decisions made by the consuming sector as it adjusts to meet the CO_2 cap imposed by S. 280. End use prices to certain users also are affected by the cost of CO_2 mitigation and the price of offsets and allowances.

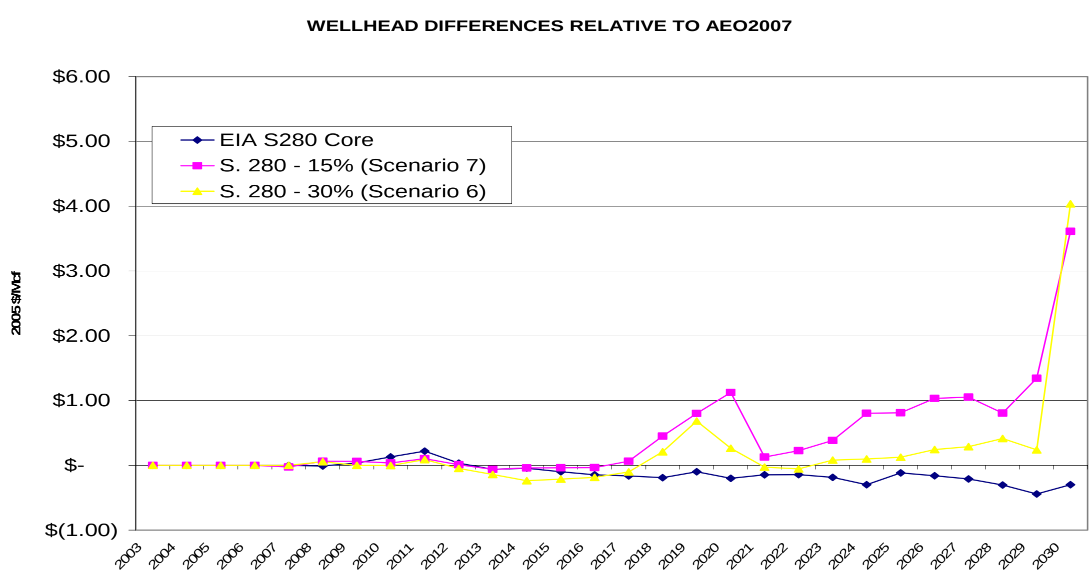
Wellhead gas prices

Wellhead gas prices are affected by the changing supply/demand balance that results from implementing S. 280. Greater natural gas demand results in higher gas prices, which in turn elicit more supply from sources with higher incremental costs of production, particularly imported LNG and high-cost unconventional gas sources.

- *Scenario 1. EIA-S. 280 Core Case* - This scenario results in lower wellhead gas prices compared to the *AEO2007*, due to the assumed unconstrained growth of nuclear power which displaces gas-fired electric generation. Wellhead prices are as much as $0..44/Mcf less than forecasted in *AEO2007*.
- *Scenario 6. NGC-S. 280 – 30%* - This scenario has gas prices between the two extremes of the Scenario 1. EIA-S. 280 Core Case and Scenario 7, NGC-S. 280 - 15%, with prices in 2020 only 40 to 50 cents greater than forecasted under *AEO2007*, and a rapid rise to over $4.00/Mcf greater than *AEO2007* with the 2030 S. 280 step.
- *Scenario 7. NGC-S. 280 – 15%* - With the highest gas demand, this scenario has the highest wellhead price. The post-2020 difference averages $1.03/Mcf greater than forecasted under *AEO2007* and rises to as high as $3.60/Mcf greater than *AEO2007* by the 2030 S. 280 step.

In both the Scenario 6 NGC-S. 280 – 30% and Scenario 7 NGC-S. 280 - 15% cases, wellhead gas prices rise in anticipation of the 2020 S. 280 emissions reduction step. Prices **increase** rapidly again in anticipation of the 2030 step.

Figure 9: Changes in Wellhead Gas Prices (relative to *AEO2007*) for Scenarios (Real 2005$)

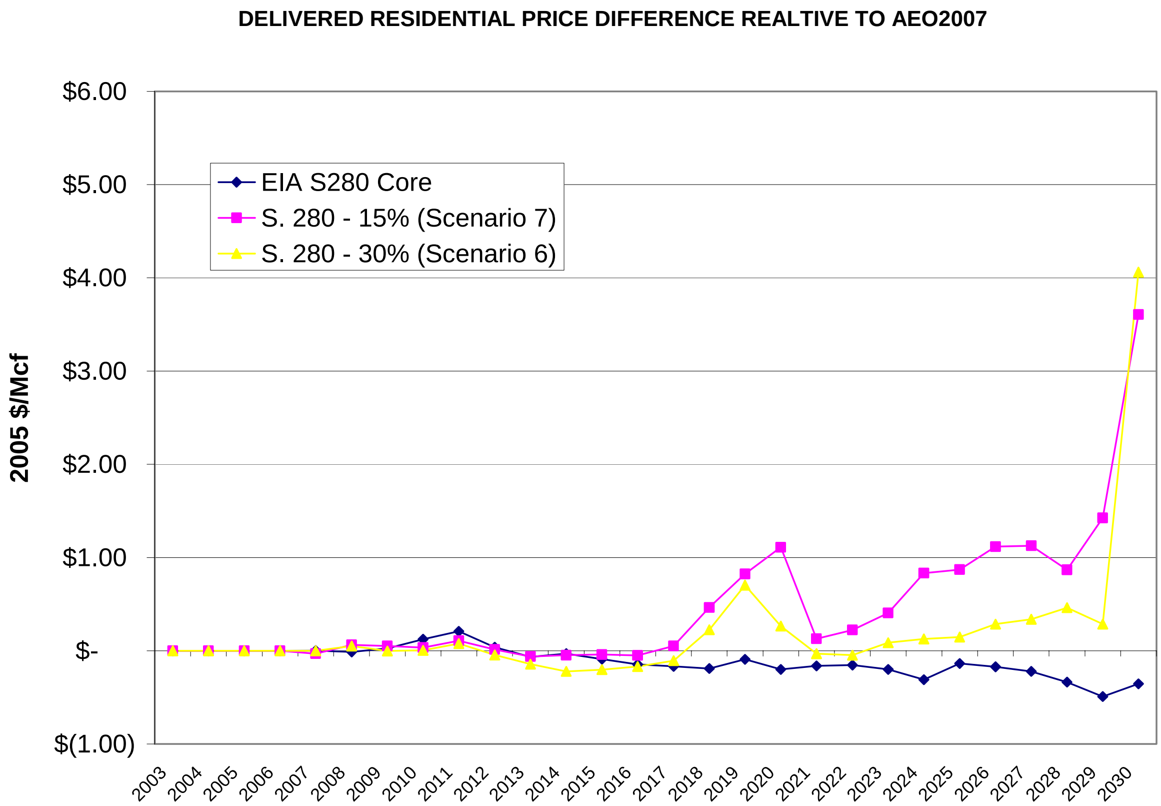


[23] All prices are reported in real 2005$. Observed prices will be higher due to inflation impacts.

Changes in Residential Gas Prices

Because S. 280 exempts the residential sector, residential gas prices are affected only by wellhead gas prices and the cost of transmission and distribution, not by the cost of CO_2 mitigation, offsets, and allowances. Therefore residential gas price changes relative to the prices forecasted by *AEO2007*.

Figure 10: Changes in Residential Gas Prices (relative to *AEO2007*) for Scenarios (Real 2005$)

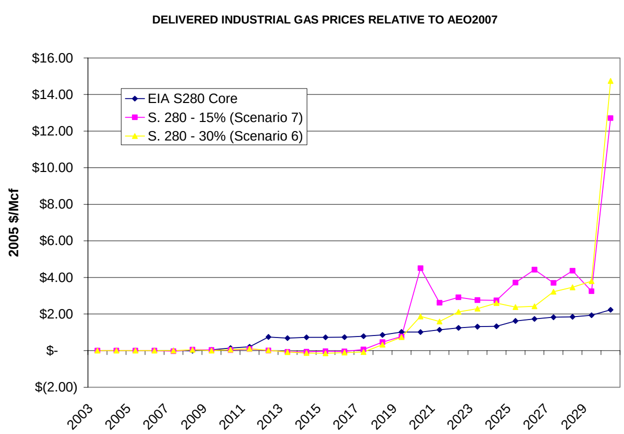


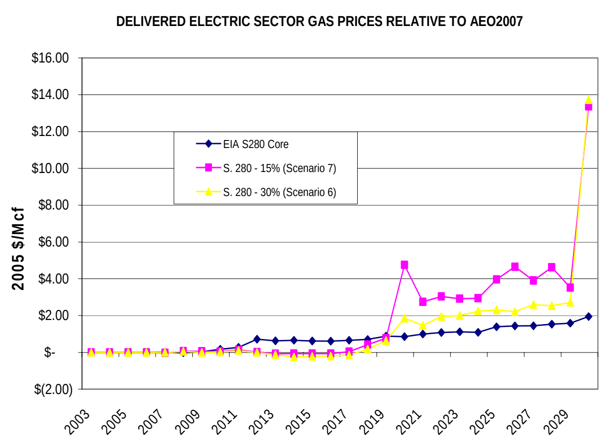
Changes in electric generator and industrial gas prices

Electric generator and industrial gas prices are affected by the wellhead price, the cost of transmission and distribution, and the cost of CO_2 mitigation, offsets, and allowances. The NGC-S. 280 - 15% *(Scenario 7)* has the highest wellhead price, the highest price of CO_2 allowances, and consequently the highest prices paid for gas by industrial and electric generator consumers. Even the EIA-S. 280 Core Case has high end use prices for industrial customers compared to *AEO2007* due to the cost of CO_2 allowances, despite relatively low wellhead prices. In these model runs, it is assumed that carbon emission abatement costs are global in scope and as such provide no competitive advantage among industrial trading partners. But, domestic industrial production that is sensitive to natural gas prices and competes in the global market can be adversely affected, if policy makers inhibit the balance between demand and supply by restricting access to lower cost natural gas resources.

- *Scenario 1. EIA-S. 280 Core Case* - Natural gas prices paid by the electric generation sector increase over *AEO2007*, from \$1.00/Mcf in 2021 to \$1.95/Mcf by 2030.
- *Scenario 6. NGC-S. 280 – 30%* - Between the first step in 2020 and the second step in 2030, gas prices paid by the electric generation sector average \$2.19/Mcf greater than *AEO2007*, and increase dramatically to almost \$14.00/Mcf above *AEO2007* at the second step in 2030.
- *Scenario 7. NGC-S. 280 – 15%* - Between the first step in 2020 and the second step in 2030, gas prices paid by the electric generation sector average \$3.71/Mcf greater than *AEO2007*, and like Scenario 6 NGC-S. 280 – over \$13/Mcf above *AEO2007* at the second step in 2030.

Figure 11: Changes in Electric and Industrial Natural Gas Prices under Three Scenarios (Real 2005$)



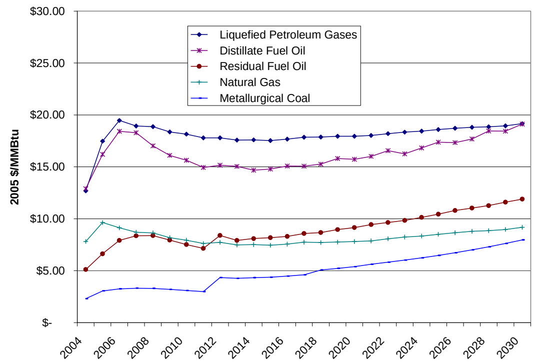


7. Other Fuel Prices

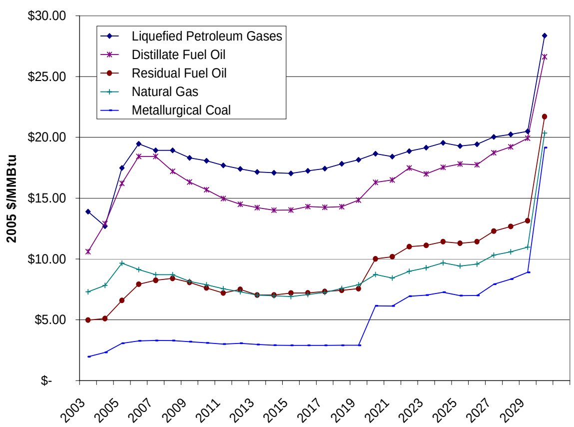
Key Finding: While other fuel prices show the same directional change as natural gas, the changes are greater for fuels with greater carbon content, oil and coal. Under Scenario 6, NGC-S. 280 – 30%, with constrained nuclear and renewable generation, the jump in prices is higher than the EIA-S. 280 Core Case. With only 15% offsets available, all fuel prices spike in 2020 and 2030.

Figure 12: Price Comparison of Fuels Other Than Natural Gas for Various Scenarios (Real 2005$)

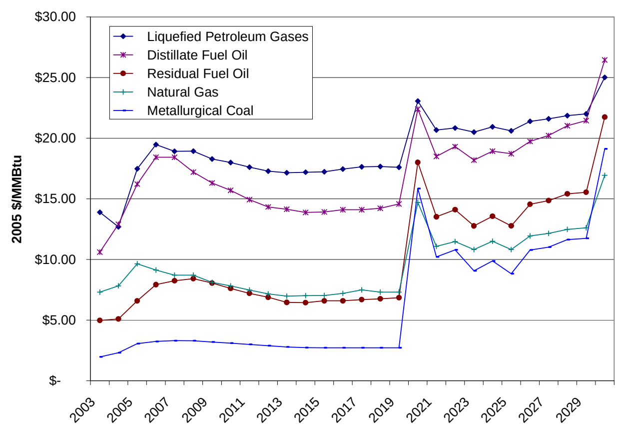
Scenario 1. EIA S. 280 Core Case



Scenario 6. Constrained Nuclear & Renewable Generation With 30% Offsets



Scenario 7. Constrained Nuclear & Renewable Generation With 15% Offsets



8. Electricity and CO_2 Prices

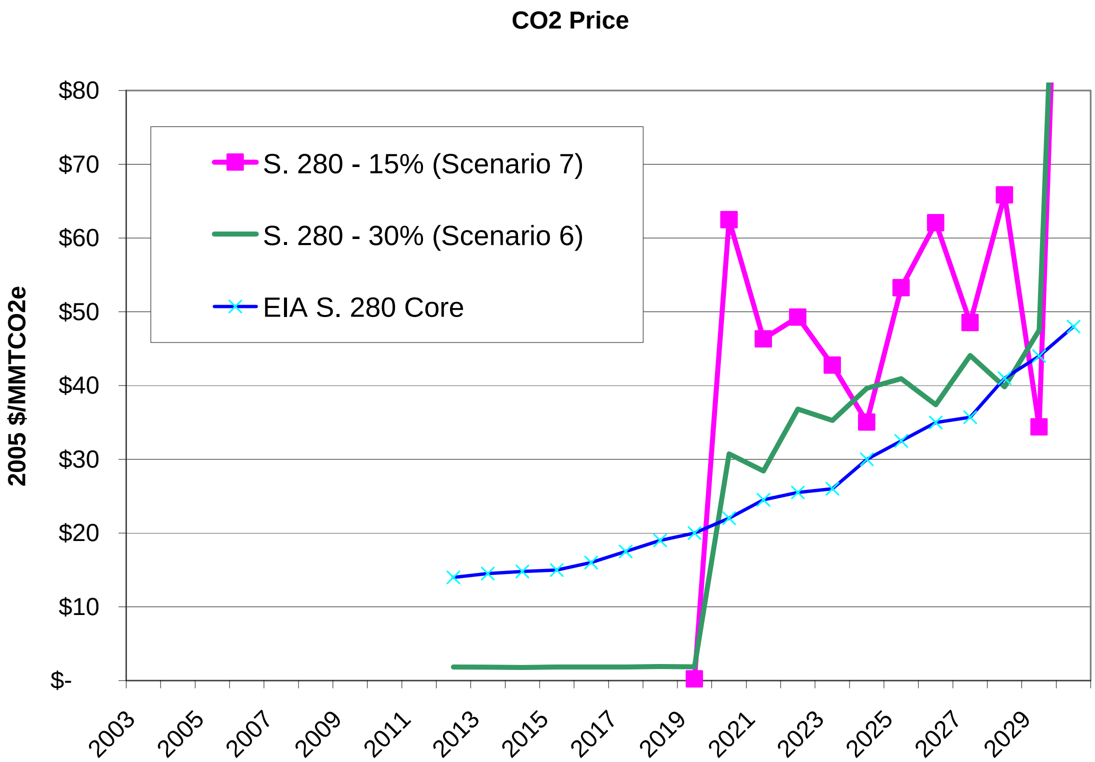
Key Finding: The price of CO_2 is affected by the number of offsets available and by the prices at which such offsets are available. The market for offsets, in turn, is a function of the technologies available to mitigate CO_2 emissions and the number of CO_2 permits available.

The electricity price will incorporate the price of CO_2 emissions and generally rises dramatically after 2020. Although S. 280 excludes direct energy use by the residential sector, the sector nevertheless will see higher electricity prices as the costs incurred by electric generators are passed through in the price of electricity.

CO_2 Allowance Prices

In all three cases, CO_2 allowance prices settle in the \$30 - \$60/$MMTCO_2$ range, although CO_2 allowance prices get very high in 2030 in the Scenario 6 NGC-S. 280 – 30% and Scenario 7 NGC-S. 280 - 15% cases. This occurs because offsets are used up and the emissions reduction step gets much more expensive.

Figure 13: CO_2 Allowance Prices (Real 2005\$)

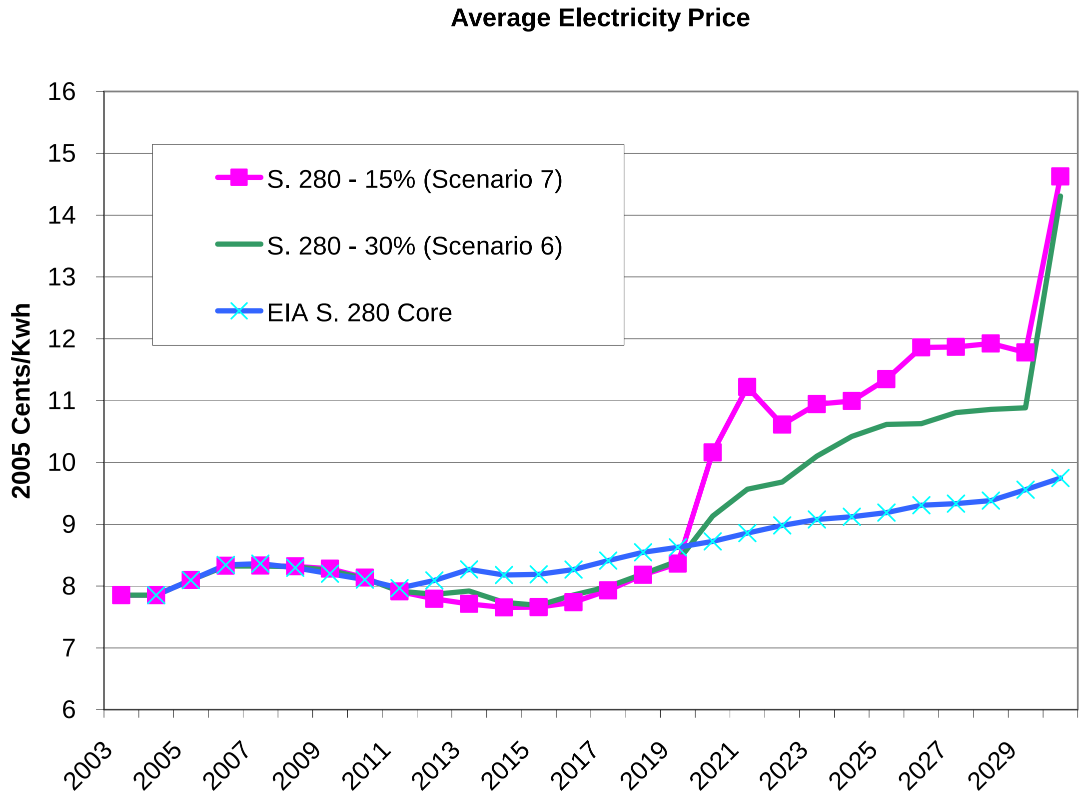


Electricity prices

Electricity prices respond to the rising price of CO_2 allowances and increase in all three cases. S. 280 causes a 25 percent increase in electricity prices at the first major step in 2020 under the Scenario 6 NGC-S. 280 – 30% model runs relative to EIA-S. 280 Core Case. There is an even greater (30 percent increase) in electricity prices under the Scenario 7 NGC-S. 280 - 15% model run.

With the second S. 280 emissions reduction step in 2030, electricity prices in the Scenario 6. NGC-S. 280 – 30% and 15% cases climb an additional 25 to 30 percent.

Figure 14: Average Electricity Prices to all Consumers (Real 2005$)



Conclusions:

The NEMS model runs demonstrate the importance of considering the likelihood that the technologies and market mechanisms envisioned for GHG emission reductions will be fully developed and deployed in time to achieve the emission reduction goals under legislation that would establish deadlines for mandatory GHG emissions reductions (e.g., 2020 and 2030). Using alternative assumptions about the level of contribution to GHG emissions reductions that key technologies and market mechanisms are *likely to make*, the model runs show the strong possibility that there will be greater reliance on natural gas to achieve the emission reduction targets established for 2020 and 2030. Given the importance of achieving the emissions reduction targets that Congress ultimately may legislate, the natural gas industry would like to explore with Congress policies that can facilitate optimizing the contribution that natural gas can make, at minimum, as a bridge fuel for electric generation, until the other technologies and market mechanisms for GHG emission reductions can be commercialized and fully deployed.

Analyses of Climate Change Legislation Performed by the Energy Information Administration (EIA) for Congress

- **Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade System**
  http://www.eia.doe.gov/oiaf/servicerpt/bllmss/index.html
  Forecast Analysis - This report was prepared by EIA, in response to a September 27, 2006, request from Senators Bingaman, Landrieu, Murkowski, Specter, Salazar, and Lugar. The Senators requested that EIA assess the impacts of a proposal that would regulate emissions of greenhouse gases (GHGs) through an allowance cap-and-trade system. The program would set the cap to achieve a reduction in emissions relative to economic output, or greenhouse gas intensity.

- **Energy Market Impacts of a Clean Energy Portfolio Standard – Follow Up**
  http://www.eia.doe.gov/oiaf/servicerpt/emice/index.html
  Forecast Analysis - This analysis responds to a request from Senator Coleman that EIA analyze a proposed clean energy portfolio standard. The proposal requires electricity suppliers to increase the share of electricity sales that is generated using clean energy resources, including: non-hydropower renewable resources, new hydroelectric or nuclear resources, fuel cells, and fossil-fired plants that capture and sequester carbon dioxide emissions.

- **Energy and Economic Impacts of H.R.5049, the Keep America Competitive Global Warming Policy Act**
  http://www.eia.doe.gov/oiaf/servicerpt/economicimpacts/index.html
  Forecast Analysis - This report responds to a May 2, 2006 request from Congressmen Udall and Petri asking EIA to analyze the impacts of their legislation implementing a market-based allowance program to cap greenhouse gas emissions at 2009 levels. The legislation, introduced March 29, 2006, limits the potential economic impact through the sale of additional allowances at a safety-valve price, an allowance allocation program, and allowance credits for carbon sequestration projects.

- **Energy Market Impacts of a Clean Energy Portfolio Standard**
  http://www.eia.doe.gov/oiaf/servicerpt/emice/index.html
  Forecast Analysis - This report responds to a request from Senator Coleman that EIA analyze a proposed clean energy resources policy. The proposal requires retail electric suppliers to account for an increasing fraction of incremental sales growth with clean energy resources, including nonhydro renewable resources, new hydroelectric or nuclear resources, fuel cells, or an integrated gasification combined-cycle plant that sequesters its carbon emissions.

- **Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals**
  http://www.eia.doe.gov/oiaf/servicerpt/agg/index.html
  Forecast Analysis - This report responds to a request from Senator Ken Salazar that EIA analyze the impacts of implementing alternative variants of an emissions cap-and-trade program for greenhouse gases.

- **Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007**
  http://www.eia.doe.gov/oiaf/servicerpt/csia/index.html
  Forecast Analysis - This report responds to a February 5, 2007 request from Senators Lieberman and McCain asking EIA to estimate the economic impacts of S. 280, the Climate Stewardship and Innovation Act of 2007. S. 280 would establish a series of caps on greenhouse gas emissions starting in 2012 followed by increasingly stringent caps beginning in 2020, 2030 and 2050. The report provides estimates of the effects of S. 280 on energy markets and the economy through 2030.

Index of Alternative Modeling Assumptions

The following assumptions used for NGC Scenarios 2 -7 build off the assumptions embodied in the EIA *AEO2007* http://www.eia.doe.gov/oiaf/aeo/index.html:

1. ***Alternative Assumption for Nuclear Generation Capacity***
2. ***Alternative Assumptions for Biomass Power***
3. ***Alternative Assumptions for Wind Power***
4. ***Alternative Assumptions for Cost and Performance Baselines for Fossil Energy Electric Generation Plants, Nuclear Electric Generation Plants and Biomass Plants***
5. ***Alternative Assumptions for Regional Constraints Placed on Building IGCC with Sequestration***
6. ***Alternative Assumptions for Liquefied Natural Gas imports (LNG)***
7. ***Alternative Assumptions for Unconventional Natural Gas***
8. ***Alternative Assumptions for the completion of the Alaska Natural Gas Pipeline***
9. ***Assumptions for CO_2 Emission Abatement Curves within NEMS***

Alternative Assumption for Nuclear Generation Capacity

Assume that construction of new nuclear generation plants will not exceed 25 gigawatts (approximately 25 new plants) by 2030. All other assumptions are consistent with *AEO2007.*

Factors important for predicting the level of new nuclear plant construction in the United States include:
- Re-licensing of existing plants, since failure to re-license means that more new plants will be needed
- Local resistance to new plant construction
- Length of the regulatory approval process
- Constraints on construction resources

Scenario 1 Assumptions
In this scenario *AEO2007* forecasts that nuclear energy is the lowest cost option and that nuclear powerplant construction is unconstrained.
- Nuclear technology is the most economic form of electric generation to achieve greenhouse gas emission reductions by the target dates of 2020 to 2030 and beyond according to present EIA assumptions.
- Presently, there are 104 nuclear powered electric generation plants in the United States, which were licensed during a 27-year period from 1969 to 1996. (See table below) Of these 104 plants sites, 40 have the ability to install an additional reactor, which would ease plant siting issues for additional capacity.
- The bulk of plants will be re-licensed despite a desire by some local populations to decommission and remove plants that are subject to re-licensing. Ninety three of the 104 presently sited nuclear power plants must be re-licensed by 2030, a procedure that some portion of present plants will likely not complete due to regulatory hurdles and public opposition.
- Under the present regulatory approval process, it will take 10 years to permit and construct a new nuclear plant, limiting the number of new plants that can be built during the period 2008-2020, but allowing considerable expansion after 2020.
- Under *AEO2007*, nuclear power has relatively low forecasted capital costs and maintenance costs. (Note, however, that NEMS has not updated these costs since 2004 and that processed uranium fuel costs have not been updated in NEMS since the recent escalation of market prices from \$10 to \$120 a tonne, due to increasing demand.)

Alternative Assumptions Case
In these scenarios, the development of nuclear power is constrained by a numbers of factors, with social acceptance being the primary impediment.

- Construction of new nuclear generation plants will not exceed 25 gigawatts (approximately 25 new plants) by 2030. This represents net new nuclear generating capacity; as explained below, it also is assumed that there will be no net loss of nuclear generating capacity when plants are retired.
- Similar plants will replace the present plants that are not re-licensed, effectively utilizing some of the open multiple reactor construction sites.
- The number of new nuclear plants built by the industry is a sum of the new capacity nuclear plants plus the replacement nuclear plants. For example, if 30% of the present plants do not get re-licensed, it is assumed that an additional 30 new plants will need to be built to replace the present plants.
- The general public and local authorities will resist “green field” nuclear plant construction, thereby limiting the ability to site new nuclear plants to, primarily, available multiple reactor sites.

- Other countries are interested in developing nuclear power plants, and nuclear plant construction appears to be entering a global renaissance. This will challenge the ability of a resource constrained workforce (engineers, construction workers, regulatory authorities etc.) to keep pace with demand for nuclear power plant construction. Once such plants enter operation, demand also will increase the cost of nuclear fuel. China, with large amounts of available capital, large energy needs, and large labor pools, is predicted to build 25 nuclear plants by 2025.

The table below shows cumulative and annual builds in nuclear power plants used for constraining nuclear.

YEAR	Cumulative Builds, GW	Annual Builds, GW
2003	100.0	
2004	100.0	0.0
2005	100.0	0.0
2006	100.0	0.0
2007	100.0	0.0
2008	100.0	0.0
2009	100.0	0.0
2010	100.0	0.0
2011	100.0	0.0
2012	100.0	0.0
2013	100.0	0.0
2014	100.0	0.0
2015	101.0	1.0
2016	102.0	1.0
2017	103.0	1.0
2018	104.0	1.0
2019	105.0	1.0
2020	106.0	1.0
2021	107.0	1.0
2022	108.0	1.0
2023	109.0	1.0
2024	111.0	2.0
2025	113.0	2.0
2026	115.0	2.0
2027	117.0	2.0
2028	119.0	2.0
2029	122.0	3.0
2030	125.0	3.0

The table below shows the current status of operating licenses for U.S. nuclear plants.

Plant Name	Operating License: Issued	Expires
Arkansas Nuclear 1	5/21/1974	5/20/2034
Arkansas Nuclear 2	9/1/1978	7/17/2018
Beaver Valley 1	7/2/1976	1/29/2016
Beaver Valley 2	8/14/1987	5/27/2027
Braidwood 1	7/2/1987	10/17/2026
Braidwood 2	5/20/1988	12/18/2027
Browns Ferry 1	12/20/1973	12/20/2013
Browns Ferry 2	8/2/1974	6/28/2014
Browns Ferry 3	8/18/1976	7/2/2016
Brunswick 1	11/12/1976	9/8/2016
Brunswick 2	12/27/1974	12/27/2014
Byron 1	2/14/1985	10/31/2024
Byron 2	1/30/1987	11/6/2026
Callaway	10/18/1984	10/18/2024
Calvert Cliffs 1	7/31/1974	7/31/2034
Calvert Cliffs 2	11/30/1976	8/13/2036
Catawba 1	1/17/1985	12/6/2024
Catawba 2	5/15/1986	2/24/2026
Clinton	4/17/1987	9/29/2026
Columbia Generating Station	4/13/1984	12/20/2023
Comanche Peak 1	4/17/1990	2/8/2030
Comanche Peak 2	4/6/1993	2/2/2033
Cooper	1/18/1974	1/18/2014
Crystal River 3	1/28/1977	12/3/2016
D.C. Cook 1	10/25/1974	10/25/2014
D.C. Cook 2	12/23/1977	12/23/2017
Davis-Besse	4/22/1977	4/22/2017
Diablo Canyon 1	11/2/1984	9/22/2021
Diablo Canyon 2	8/26/1985	4/26/2025
Dresden 2	2/20/1991	12/22/2009
Dresden 3	1/12/1971	1/12/2011
Duane Arnold	2/22/1974	2/21/2014
Farley 1	6/25/1977	6/25/2017
Farley 2	3/31/1981	3/31/2021
Fermi 2	7/15/1985	3/20/2025
FitzPatrick	10/17/1974	10/17/2014
Fort Calhoun	8/9/1973	8/9/2013
Ginna	9/19/1969	9/18/2009
Grand Gulf 1	11/1/1984	11/1/2024
Harris 1	1/12/1987	10/24/2026
Hatch 1	10/13/1974	8/6/2034
Hatch 2	6/13/1978	6/13/2038
Hope Creek 1	7/25/1986	4/11/2026
Indian Point 2	9/28/1973	9/28/2013
Indian Point 3	4/5/1976	12/15/2015
Kewaunee	12/21/1973	12/21/2013
La Salle 1	4/17/1982	4/17/2022

La Salle 2	2/16/1983	12/16/2023
Limerick 1	8/8/1985	10/26/2024
Limerick 2	8/25/1989	6/22/2029
McGuire 1	6/12/1981	6/12/2021
McGuire 2	3/3/1983	3/3/2023
Millstone 2	9/26/1975	7/31/2015
Millstone 3	1/31/1986	11/25/2025
Monticello	1/9/1981	9/8/2010
Nine Mile Point 1	12/26/1974	8/22/2009
Nine Mile Point 2	7/2/1987	10/31/2026
North Anna 1	4/1/1978	4/1/2018
North Anna 2	8/21/1980	8/21/2020
Oconee 1	2/6/1973	2/6/2033
Oconee 2	10/6/1973	10/6/2033
Oconee 3	7/19/1974	7/19/2034
Oyster Creek	7/2/1991	4/9/2009
Palisades	3/24/1971	3/24/2011
Palo Verde 1	6/1/1985	12/31/2024
Palo Verde 2	4/24/1986	12/9/2025
Palo Verde 3	11/25/1987	3/25/2027
Peach Bottom 2	10/25/1973	8/8/2013
Peach Bottom 3	7/2/1974	7/2/2014
Perry 1	11/13/1986	3/18/2026
Pilgrim 1	9/15/1972	6/8/2012
Point Beach 1	10/5/1970	10/5/2010
Point Beach 2	3/8/1973	3/8/2013
Prairie Island 1	4/5/1974	8/9/2013
Prairie Island 2	10/29/1974	10/29/2014
Quad Cities 1	12/14/1972	12/14/2012
Quad Cities 2	12/14/1972	12/14/2012
River Bend 1	11/20/1985	8/29/2025
Robinson 2	9/23/1970	7/31/2010
Saint Lucie 1	3/1/1976	3/1/2016
Saint Lucie 2	6/10/1983	4/6/2023
Salem 1	8/13/1976	8/13/2016
Salem 2	5/20/1981	4/18/2020
San Onofre 2	9/7/1982	2/16/2022
San Onofre 3	9/16/1983	11/15/2022
Seabrook 1	3/15/1990	10/17/2026
Sequoyah 1	9/17/1980	9/17/2020
Sequoyah 2	9/15/1981	9/15/2021
South Texas 1	3/22/1988	8/20/2027
South Texas 2	3/28/1989	12/15/2028
Summer	11/12/1982	8/6/2042
Surry 1	5/25/1972	5/25/2012
Surry 2	1/29/1973	1/29/2013
Susquehanna 1	11/12/1982	7/17/2022
Susquehanna 2	6/27/1984	3/23/2024
Three Mile Island 1	4/19/1974	4/19/2014
Turkey Point 3	7/19/1972	7/19/2032
Turkey Point 4	4/10/1973	4/10/2033
Vermont Yankee	2/28/1973	3/21/2012
Vogtle 1	3/16/1987	1/16/2027

Vogtle 2	3/31/1989	2/9/2029
Waterford 3	3/16/1985	12/18/2024
Watts Bar 1	2/7/1996	11/9/2035
Wolf Creek 1	6/4/1985	3/11/2025

Alternative Assumptions for Biomass Power

Construction of new electric generation capacity provided by biomass power is limited to 3 gigawatts of new capacity per year (approximately 37 plants) through 2030.

Scenario 1 Assumptions

There is no limitation in *AEO2007* on the number of biomass projects constructed through 2030 to generate electricity. Still, this scenario assumes that the construction of nuclear power plants is unconstrained and therefore construction of biomass plants is limited.

Alternative Assumptions Case

In these scenarios where the forecasted lowest cost technology, nuclear power, is constrained, the NEMS model forecasts a significant number of new biomass plants.

- Limits the capacity growth (and number) of new of biomass plants to 3 gigawatts per year (37 plants per year that extract sustainable biomass resources within a 100 mile radius per plant). Agricultural biomass resources (residues and energy crops) are assumed to be economically available within a 50-mile radius, and urban wood waste is assumed economically available within a 100 mile radius.
- Biomass capacity addition is non-captive generation (i.e., 80 MW plants not connected with industrial plants) and is assumed to utilize Biomass Integrated Gasification Combined Cycle (BIGCC) technology[24]. Essentially, this is the same technology utilized for the Integrated Coal Gasification Combined Cycle (IGCC) plants, but does not require sequestration to reduce CO_2 discharge. Hence, it is subject to the same forecasted increased costs that affect new coal technology (minus sequestration).
- BIGCC is subject to the same basic technical issues as IGCC, with the exception of feedstock handling, storage, and treatment methods, and will be available in the latter part of the period being modeled. The plants are assumed to have similar operating flexibility as IGCC and would be rated as intermediate-to-base load capacity. Besides the overall national growth rate limit identified above, no other exogenous limitations were placed on biomass plant capacity constructed through 2030 to generate electricity.[25]
- EIA technology costs in NEMS were not updated, hence the actual capital costs for BIGCC biomass plants likely will be greater than predicted by NEMS model runs.
- In the S. 280 – Core Case NEMS model run, other technologies are utilized because of the high cost of biomass. It is economic to construct and operate these biomass plants only with the addition of high carbon prices.
- Transportation costs for biomass are assumed to be the same as *AEO2007*. Fixed transportation rate of $10-12 per dry ton[26] for rural biomass energy sources (wood waste in 100 mile radius) and $0.24 per ton mile[27] for urban biomass sources in the model without any escalators for fuel costs (presumably diesel) that would be dictated by world oil prices and carbon allowance costs. This appears to underestimate the cost of this choice.

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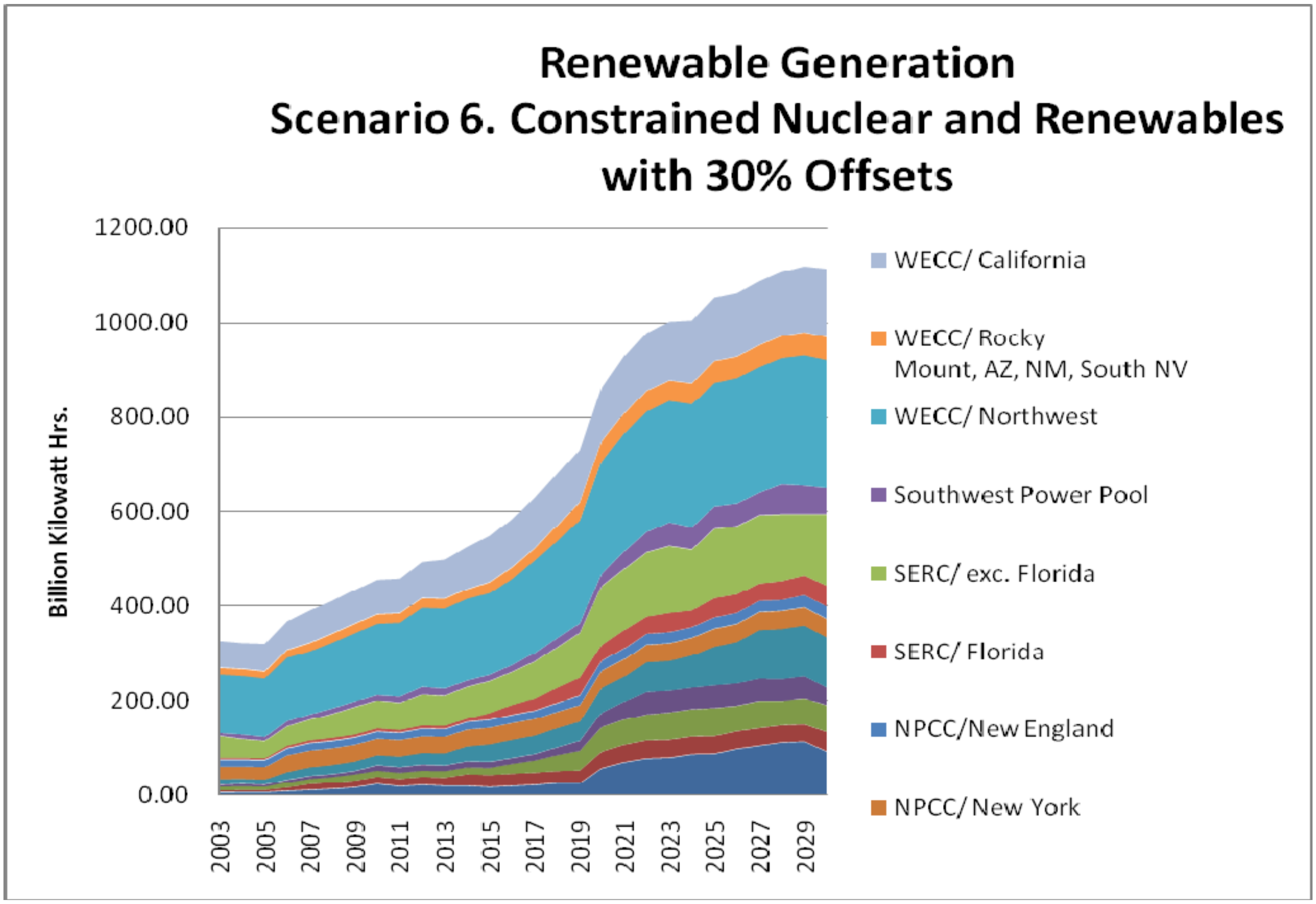
[24] Page 103; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation; EIA DOE 8/1/2006

[25] NEMS Biomass Submodule, within the Renewable Fuels Module, calculates maximum available biomass capacity limit by region based on assumed biomass reserves and consumption data. The underlying assumptions used to calculate the regional capacity limits were not altered.

[26] Page 103; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation; EIA DOE 8/1/2006

[27] Page 103; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation; EIA DOE 8/1/2006

Below is an example of the NEMS model output showing the growth of Renewable Electric Generation by region. While it varies by region, the primary growth in renewable generation is biomass and wind.



Alternative Assumptions for Wind Power

Construction of new electric generation capacity provided by new wind power is limited to 3 gigawatts of new capacity per year (app. 60 plants) through 2030.

Scenario 1 Assumptions

The only limitation in *AEO2007* on the number of wind turbines[28] constructed through 2030 to generate electricity is based on geographic limits due to factors such as wind and land availability. Because this scenario forecasts that the construction of nuclear power plants is unconstrained, the NEMS model does not forecast the construction of a significant number of wind turbines.

Alternative Assumptions Case

Since nuclear plants are limited in these scenarios, there is a rush to develop wind resources. These cases limit the number of new wind turbines to 3 gigawatts per year (60 wind farms, 3,000 one MW turbines). This is roughly twice the construction capacity of the present wind power industry**.** The building rate in these scenarios is limited primarily by local permitting issues, the cost of wind turbines given the predicted worldwide demand for wind turbines, and the ability to integrate remotely located units into the present electric grid.

The NEMS model takes into account the regional availability of wind[29], variable grid connection costs[30], and limited electric generation reserve capacity.[31] These constraints result in lower capacity utilization factors for wind turbines compared to other generation technologies. As a result, a significant amount of alternative generation capacity (e.g., natural gas turbines) must be built, including backup infrastructure facilities to achieve the power delivery when needed (e.g., proposed "plug in" hybrid automobiles). The economic decision in NEMS for building of wind turbines is based on the predicted "BTU values of Wind Energy[32]". Finally, the interconnection costs for wind generation in NEMS are based on 2002 interconnection costs, which have increased significantly since this estimate, due to increases in right of way acquisition, material and labor costs. Due to its distributed nature and remote siting, this factor could limit the market penetration achieved by wind technology relative to other technologies.

[28] Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation ; Energy Information Administration ; 8/1/2006

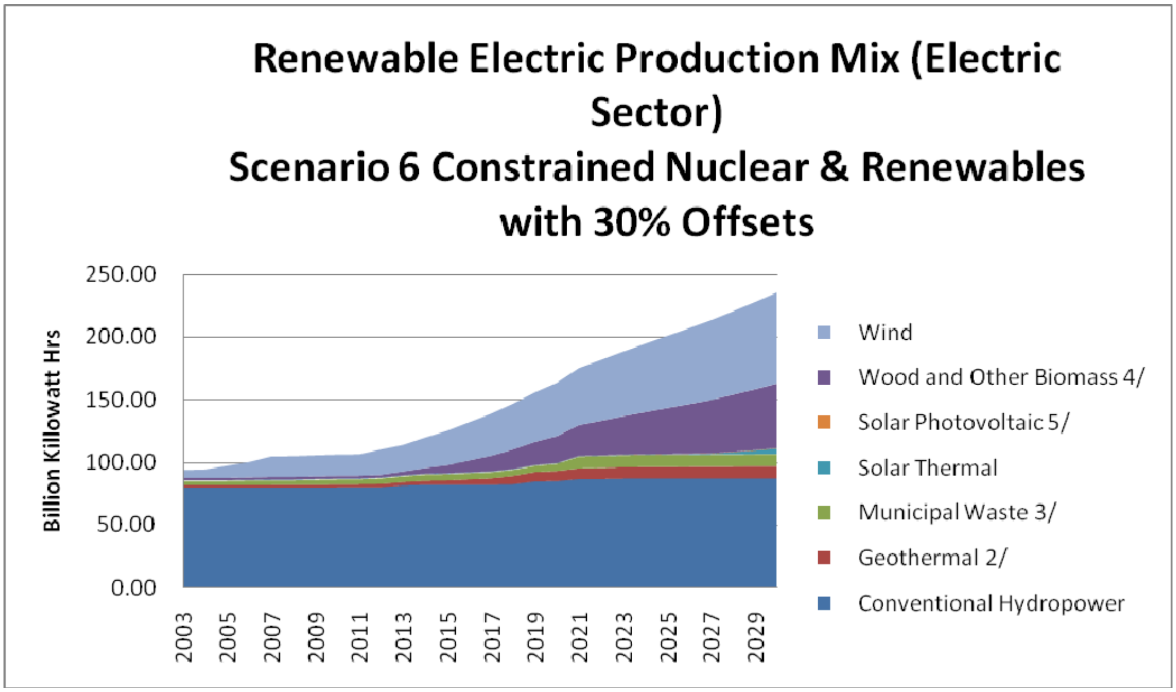
[29] Page 45; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation ; Energy Information Administration ; 8/1/2006

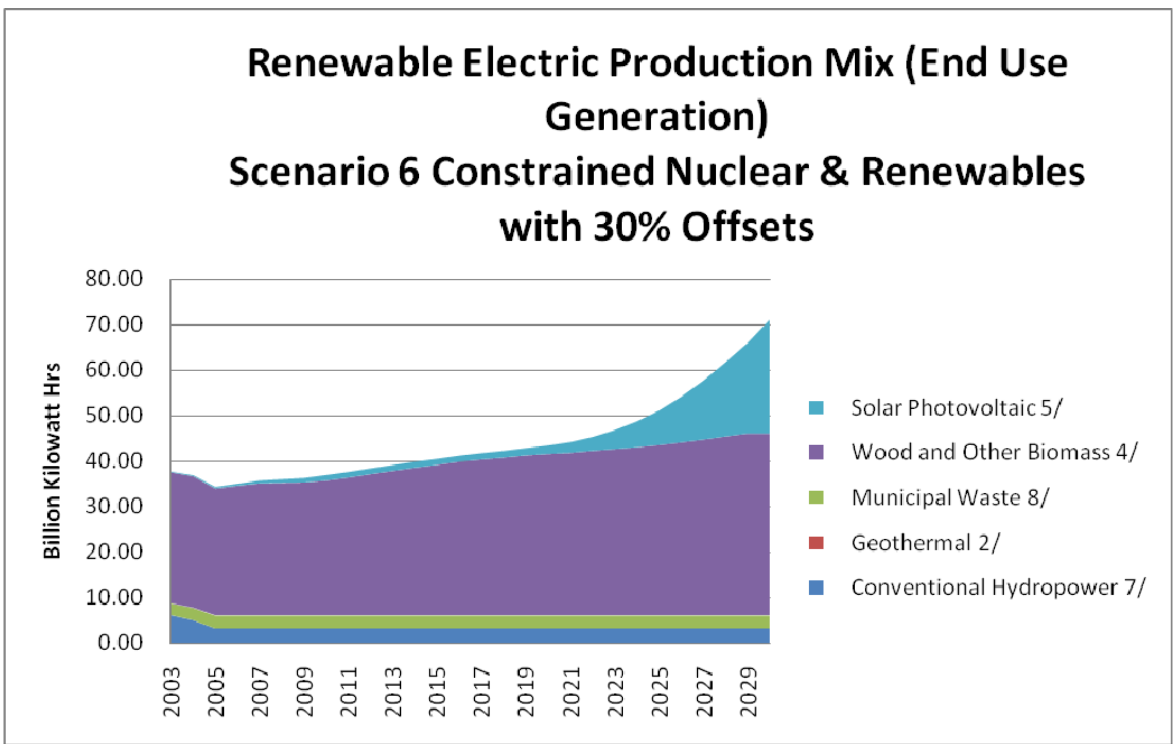
[30] Page 45-46; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation ; Energy Information Administration ; 8/1/2006

[31] Page 47-52; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation ; Energy Information Administration ; 8/1/2006

[32] Page 52; Renewable Fuels Module of the National Energy Modeling System 2006, Model Documentation ; Energy Information Administration ; 8/1/2006

Below is an example of the renewable generation by type for electric energy production for both the Electric Sector and the End Use Sector as forecast by NEMS for Scenario 6. This shows large increases in biomass and wind energy for both the electric generation sector and those who generate their own electricity at on-site facilities.





Alternative Assumptions for Cost and Performance Baselines for Fossil Energy Electric Generation Plants, and Biomass Plants

Costs for construction and operation of new fossil fuel electric generation capacity (integrated gasification combined cycle, pulverized coal boiler and NGCC with sequestration) were updated utilizing recent DOE-NETL estimates[33]. This resulted in a relative increase in costs for coal based technologies compared to natural gas based technologies in the Alternative Assumptions Case.

Scenario 1 Assumptions

AEO2007 and Scenario 1 utilize construction, operating and maintenance costs that were gathered several years ago for inclusion in NEMS. These costs drive the NEMS model to pick nuclear, coal and natural gas in this order when baseload electric generation is needed.

Alternative Assumptions Case

The alternative assumptions cases use the new fossil fuel generation costs as determined by DOE. The table below provides the new costs for coal- and natural gas-powered electric generation plants. Biomass technology costs have not been updated (much of the gasification technology is the same as IGCC) in the "alternative assumptions case" due to the unavailability of new DOE assumptions.

It appears that there is a general cost estimate for fossil fuel sequestration. Still, this will remain a very general estimate until additional studies are completed about the availability and location of geologic formations for sequestration.

While it appears that biomass plants could utilize sequestration if it was economical, the NEMS model does not now make that that option available.

[33] **Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281 Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report, May 2007**

IGCC COST and performance ($ 2007)

Assumptions: SHELL IGCC;

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M Mills/kW-hr				
	2006	1987	2006	1987	2006	1987	HEAT RATE (Initial & Last)	YEAR	CAPACITY FACTOR
IG	1,977	1,245	35.18	22.17	6.32	3.98	8306	2010	80
							6357	2020	

IGCC w Sequestration COST and performance ($ 2007)

Assumptions: SHELL IGCC;

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M Mills/kW-hr				
	2006	1987	2006	1987	2006	1987	HEAT RATE	YEAR	CF
IS	2,668	1,681	43.75	27.56	8.03	5.06	10674	2010	
							7776	2020	80

NGCC Cost and performance ($ 2007)

Assumptions:

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M Mills/kW-hr				
	2006	1987	2006	1987	2006	1987	HEAT RATE	YEAR	CF
AC	554	349	9.82	6.18	1.32	0.83	6719	2008	
							6200	2015	85

NGCC w Sequestration COST and performance ($ 2007)

Assumptions:

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M Mills/kW-hr				
	2006	1987	2006	1987	2006	1987	HEAT RATE	YEAR	CF
CS	1,172	738	16.64	10.48	2.56	1.61	7813	2010	
							7032	2020	85

Pulverized Coal SUPERCRITICAL COST and performance ($ 2007)

Assumptions:

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M Mills/kW-hr				
	2006	1987	2006	1987	2006	1987	HEAT RATE	YEAR	CF
PC	1,575	992	25.18	15.86	4.87	3.07	8721	2009	
							8500	2015	85

BIOMASS - WOOD-FED IGCC COST and performance ($ 2007)

Assumptions:

	CAPITAL COST $/kW		FIXED O&M $/kW-Yr		VARIABLE O&M (see note) Mills/kW-hr				
WD	2006	1987	2006	1987	2006	1987	HEAT RATE	YEAR	CF
	1,767	1,113	51.71	32.58	5.11	3.22	8,911	2009	
							8,911	2015	83

Variable O&M value overwritten by Renewable Fuels Module (RFM)

Alternative Assumptions for Regional Constraints Placed on Building IGCC with Sequestration

Scenario 1 Assumptions

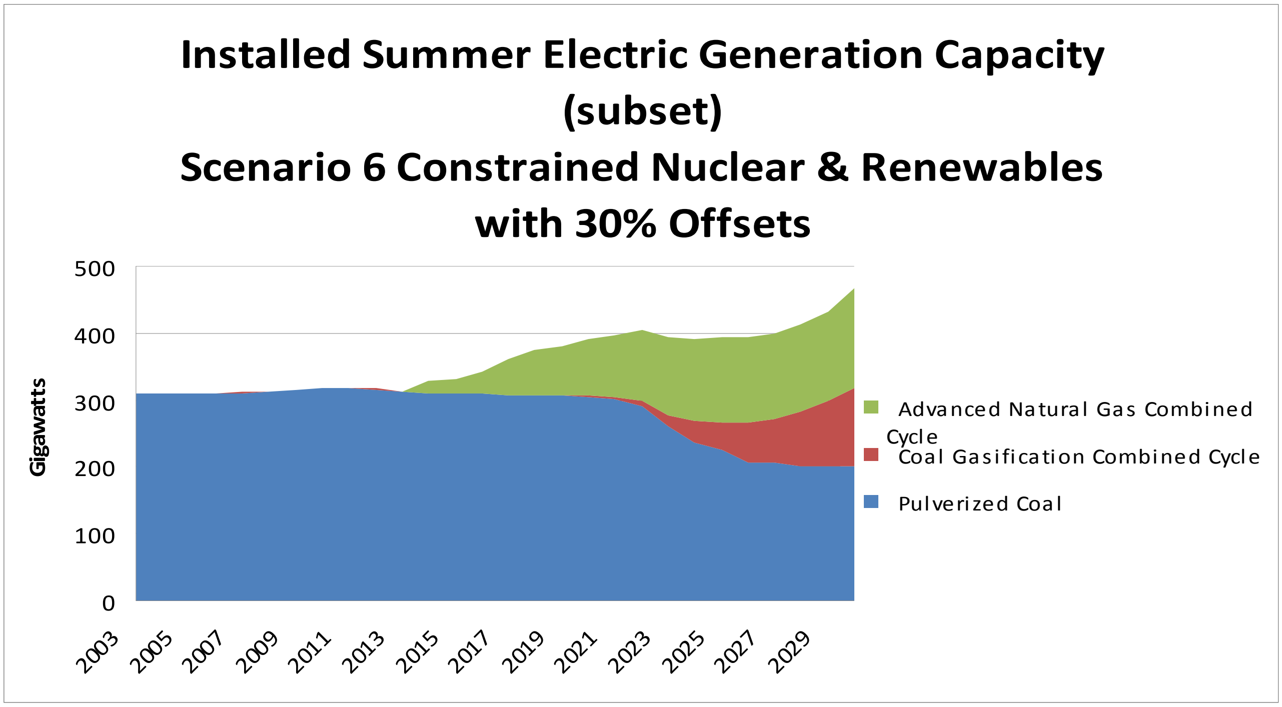
- No limits on IGCC with sequestration (IGCC/S), although only limited capacity was built under Scenario 1 due to the unconstrained construction of nuclear power plants as the least-cost option.

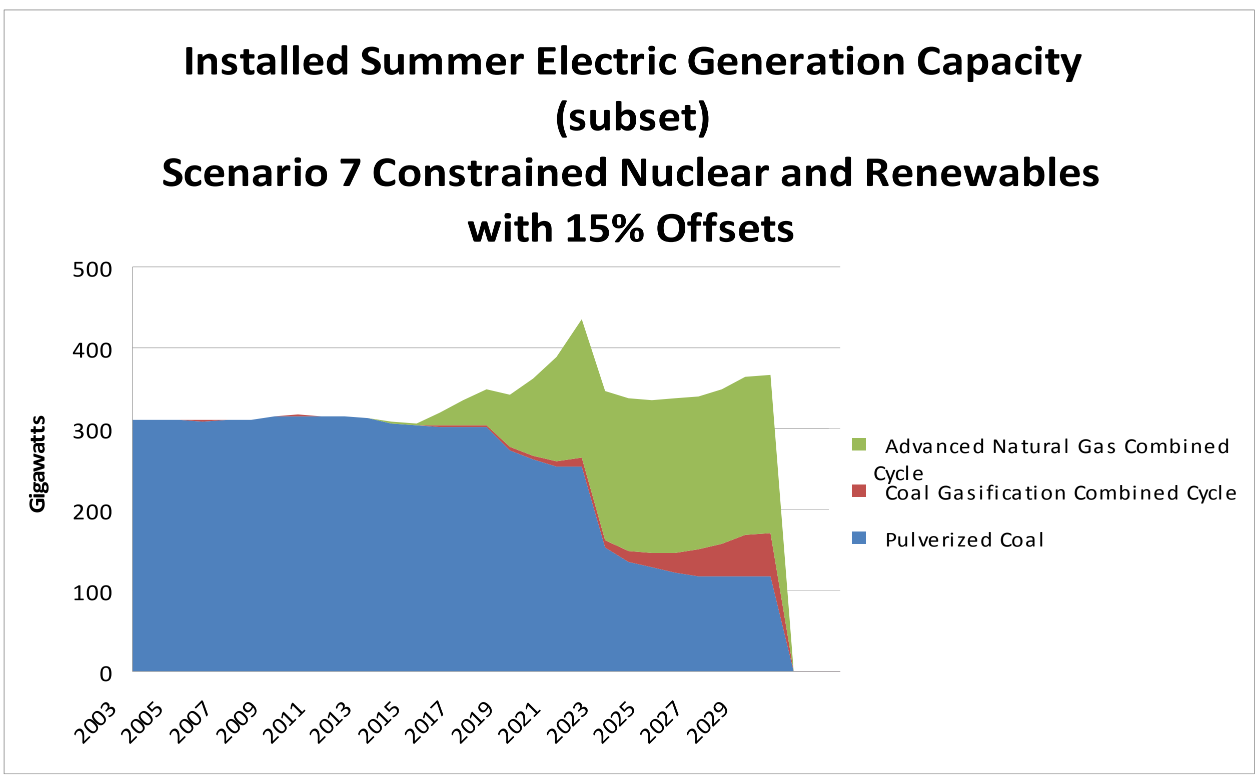
Alternative Case Assumptions

- The table below shows the regional constraints placed on building IGCCs. These limits were imposed in order to constrain maximum IGCC/S build capacity by region starting in Scenario 3 (see Table 2 of main report). In Scenario 2, with nuclear construction constrained, NEMS overwhelmingly chose IGCC technology based on its lower predicted cost. Still, there was concern about whether this represented too rapid a rate of market penetration for a new technology. The regional constraints reflect the same allocation of capacity as would be achieved in an unconstrained case. For example, Florida's upper limit of 4 GW is equivalent to 2.9% of the imposed national total of 150 GW, which is the same percentage projected in Scenario 2 (see Table 2 of main report).
- In subsequent runs (Scenarios 6 and 7), the updated fossil fuel plant costs (*Appendix 2.4*) limited IGCC installations from even reaching the imposed cap of 150 GW, because of the higher cost of IGCC relative to other generation technologies. In those scenarios, the assumed regional constraints were not a factor.

BUILD AND REGIONAL CONSTRAINTS FOR IGCC W Sequestration	
	National Constraint
East-Central Area Reliability Coordination Agreement	**31**
Electric Reliability Council of Texas	**10**
Mid-Atlantic Area Council	**14**
Mid-America Interconnected Network	**6**
Mid-Continent Area Power Pool	**4**
New York	**2**
New England	**1**
Florida	**4**
Southeast Electric Reliability Council	**43**
Southwest Power Pool	**12**
Northeast Power Pool	**2**
Rocky Mountain, New Mexico, Arizona, Southern Nevada	**11**
California/Nevada	**10**
	150

Below are examples comparing the NEMS forecasts for advanced coal and natural gas generation with sequestration capacity with compared to the traditional coal generation capacity.





Alternative Assumptions for Liquefied Natural Gas imports (LNG)

LNG volumes available to the United States are based on a clearing price that is linked to the price of crude oil. This is higher than the cost used by NEMS in *AEO2007*. In NEMS, large volumes of LNG are available as a backstop supply when United States prices exceed the cost of importing LNG (sum of gas production costs at exporting countries, estimated liquefaction costs, estimated transportation costs, and regasification costs). However, except for small quantities of spot market LNG, most long-term LNG contracts in the global market are linked to a basket of crude oil prices. If global LNG prices (based on oil prices) are higher than United States delivered gas prices, the rest of the world will bid LNG away from the United States and reduce the volumes available for import.

Scenario 1 Assumptions[34]

- Gas production costs reflect assumed market prices entering the liquefaction facility from various stranded gas locations.
- Liquefaction costs are based on a declining liquefaction capital cost function for one train (3.9 million metric tonnes of LNG or 186 Bcf per year) starting at $276 per ton of plant capacity in 2004 and gradually declining to $245 per ton in 2030.
- Estimated shipment costs, in 2004 dollars/Mcf, are divided by the route distances to arrive at initial transportation costs. On average these calculations provide a result of $0.000173/Mcf-mile in 2004 dollars (i.e., roughly $0.17/Mcf per 1,000 nautical miles). An assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.
- Regasification costs include a fixed and variable component. Variable costs include administrative and general expenses, operating and maintenance expenses, taxes and insurance, electric power costs, and fuel usage and loss. The fixed costs reflect the expected annual return on capital and are based on the assumed capital cost, 60 percent debt financing, the cost of debt and equity, a 38 percent corporate tax rate, and a 20-year economic life. The capital costs are based on the cost of storage tanks, vaporizer units, marine facilities, site improvements and roads, buildings and services, installation, engineering and project management, land, contingency, and the capacity of the plant. The cost of debt is tied to the AA utility bond rate, and the cost of equity is tied to the 10-year Treasury note yield plus a 10 percent risk premium. A per-unit regasification charge for a given size facility is obtained by dividing total costs by an assumed annual throughput. Region-specific factors are applied to account for differences in costs associated with land purchase, labor, site-specific permitting, special land and waterway preparation and/or acquisition, and other general construction and operating cost differences.

Alternative Case Assumptions

LNG imports were limited to the volume of imports forecasted in the *AEO2007* plus 500 Bcf. An algorithm, described below, was developed to forecast the price point for the availability of large quantities of LNG.

[34] From NEMS documentation.

A floor price was placed on incremental LNG volumes of 500 Bcf/year above the Reference Case at a price equal to 80% of the oil price. This raises the LNG/gas prices by about 70 cents per MMBtu over *AEO2007* (as shown below).

AEO 2007 Oil and Gas Prices
Table 12. Petroleum Product Prices

	2010	2015	2020	2025	2030
Crude Oil Prices (2005 dollars per barrel) Imported Crude Oil 1/	51.20	44.61	46.47	49.57	51.63
Natural Gas Prices (2005 dollars per million Btu) Henry Hub Spot Price	6.28	5.46	5.71	6.14	6.52
Natural Gas Prices (2005 dollars per million Btu) Lower 48 Average Wellhead Price 1/	5.59	4.84	5.07	5.46	5.80
AEO HH as % of Imported Crude Price	71%	71%	71%	72%	73%

Recalculated Gas Price for Incremental LNG (assuming competition from Asia/European buyers paying on oil-price formulae)

0.80	LNG Price as Function of Crude	$ 7.06	$ 6.15	$ 6.41	$ 6.84	$ 7.12
	Additional Cost Over AEO	$ 0.78	$ 0.70	$ 0.70	$ 0.70	$ 0.61

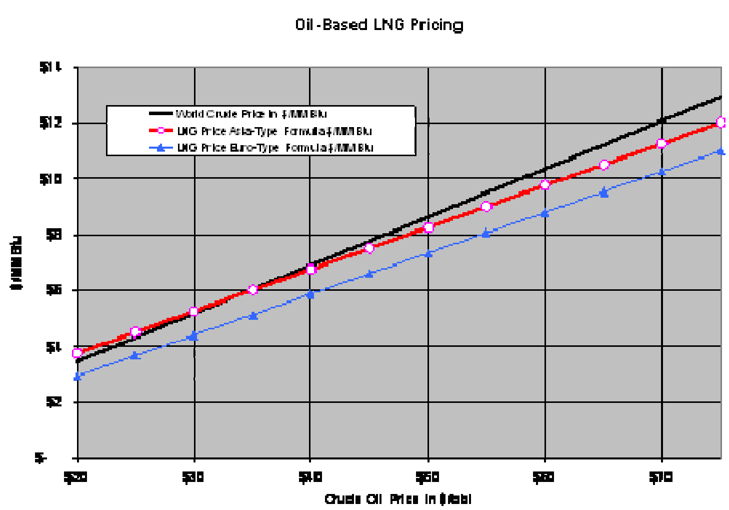
For very large incremental LNG volumes (e.g., the next 4 Tcf per year), the price necessary to attract LNG to the United States would have to equal the price of crude oil on an MMBtu basis. That equates to $8.90 or another $1.78 in 2030.

The logic behind this approach is that Asian and European markets traditionally have priced LNG based on oil price formulae. For example a Japanese contract would typically use the Japanese Crude Cocktail (i.e., mix of imported crudes) in a formula such as:

LNG Price = 0.75 + Crude x .15

Where LNG price is in $/MMBtu and Crude is the JCC in $/bbl.

In Europe, LNG prices often are based on a market basket of oil products (residual oil or distillate), resulting in prices that most often are below Asian prices. The chart and table below demonstrate how these crude-based formulae work.



LNG Pricing Examples Based on Crude Oil Formulae

		0.75 0.15	0.85		
World Crude Price in $/bbl	World Crude Price in $/MMBtu	LNG Price Asia-Type Formula $/MMBtu	LNG Price Euro-Type Formula $/MMBtu	LNG Price Asia-Type Formula % of Crude	LNG Price Euro-Type Formula % of Crude
$ 20.00	$ 3.45	$ 3.75	$ 2.93	109%	85%
$ 25.00	$ 4.31	$ 4.50	$ 3.66	104%	85%
$ 30.00	$ 5.17	$ 5.25	$ 4.40	102%	85%
$ 35.00	$ 6.03	$ 6.00	$ 5.13	99%	85%
$ 40.00	$ 6.90	$ 6.75	$ 5.86	98%	85%
$ 45.00	$ 7.76	$ 7.50	$ 6.59	97%	85%
$ 50.00	$ 8.62	$ 8.25	$ 7.33	96%	85%
$ 55.00	$ 9.48	$ 9.00	$ 8.06	95%	85%
$ 60.00	$ 10.34	$ 9.75	$ 8.79	94%	85%
$ 65.00	$ 11.21	$ 10.50	$ 9.53	94%	85%
$ 70.00	$ 12.07	$ 11.25	$ 10.26	93%	85%
$ 75.00	$ 12.93	$ 12.00	$ 10.99	93%	85%

In the future, such oil-based pricing formula might be replaced by a United States-style index pricing for new contracts for delivery to regions where natural gas markets are competitive (parts of Europe). Still, oil-based pricing is likely to continue for deliveries to markets that are geographically isolated from competition (Korea, Japan), where Russian gas dominates, or where buyers are unwilling to move away from oil-based pricing. Consequently, it is difficult to forecast the circumstances in which the United States can bid away larger incremental volumes of LNG at AEO's prevailing gas prices, which are at a deep discount to oil prices. (Of course, if there was a global LNG oversupply, the United States might succeed in purchasing incremental volumes of LNG at the AEO price, because it would be the market of last resort for LNG suppliers.)

In summary the "LNG price curve" is:
Volumes at or below AEO LNG volumes: same as NEMS prices
Volume 500 bcf/year above AEO LNG Volumes: oil price times 0.80
Volume 4,500 bcf/year above AEO LNG Volumes: oil price times 1.00

Alternative Assumptions for Unconventional Natural Gas

Large volumes of unconventional gas are available to the United States. As presently modeled in *AEO2007*, these supplies appear to be very price elastic (i.e., large volumes of additional gas production can be had for a relatively small increase in gas prices). NGC disagreed with this assumption. In Scenarios 6 and 7, extraction costs were increased to eliminate this implicit assumption. In 2015, an additional $0.20 per Mcf was added to production costs presently used in NEMS. This cost is additive and results in an additional $3.00 per Mcf by 2030. This adjusts the elasticity of this natural gas supply source to be more in line with natural gas production results in the last five years.

Alternative Assumptions

NEMS predicts wide availability of unconventional gas when the clearing price exceeds the cost to deliver the resource (i.e., sum of exploration, production and transportation costs). Unconventional gas production requires additional processes, such as fracturing and de-watering that are not necessary to produce conventional gas. Based on judgment of the group, these costs were increased under the alternative case by decreasing the price and hence profit received by producers of unconventional gas. The final adjustment of $0.20/Mcf per year starting in 2015 was chosen, because it resulted in a lower elasticity than implied by Scenario 1.

Alternative Assumptions for completion of the Alaska Natural Gas Pipeline

Large volumes of Alaskan gas are available at the North Slope but lack a pipeline to transport the supply to the Lower-48 markets. *AEO2007* and the Scenario 1 NEMS runs assume that the Alaska gas pipeline will be completed by 2018. The Alternative Assumptions Case NEMS model runs assume that the pipeline will not be available for natural gas transportation until 2020, two years later than the Scenario 1.

Construction time (design, permitting, material procurement, and construction) for both the Scenario 1 and Alternative Assumptions Case model runs are approximately the same (10 years). The Alternative Assumptions Case runs add additional time to the project to account for delays that may occur.

Assumptions for CO_2 Emission Offset Curves Input into NEMS

NEMS can be run with user-specified carbon offset curves as input. Carbon offset curves were developed for this project using information available from EPA. The EPA offset curves were limited to a maximum number of credits consistent with the S. 280 limitation of 30% offsets. The EPA offsets are a mix of domestic sources that have regulatory approval and 30% of approved international sources. The offsets available at different cost points were used as inputs into NEMS.

- The information for the offset curves is from the 2006 EPA report Global Mitigation of Non- CO_2 Greenhouse Gases (EPA Report 430-R-06-005) http://www.epa.gov/nonco2/econ-inv/international.html. The report only has data for 2010 and 2020, so data were interpolated and kept constant after 2020.
- Carbon prices only reach $60/tonne in the test runs of the model, and prices were not extrapolated beyond that.
- U.S. sequestration offset costs were not changed from the input file available to *AEO2007*.
- International curves are based on non-CO_2 rather than CO_2. Non-annex 1 country data were discounted by 2/3 to estimate the share of international credits that would be available to the United States.
- Post-2020, China, India and Brazil were subtracted on the assumption that they might be coming into an international program. This allows a large quantity of offsets to be available before those countries need to use these credits for their own mitigation
- $5 was added to all of the offset values for modeling to account for certification and project development.
- This table reflects the cost of the offsets, not the price of the offsets in a market. In a fully functioning competitive market, the price of the credits on average should be the cost of the credits plus a reasonable rate of return. If the market is less than perfect, the offset prices can rise to the equivalent discounted cost of domestic CO_2 mitigation.

Appendix 2.9 continued

The following table provides the Offset Supply Curves input into NEMS.

Year for Real $ Prices:	Prices $/Ton	Million Metric Tonnes CO2									
Natural Gas-Related Methane		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	20.57	20.57	22.51	24.46	24.46	24.46	24.46	24.46	24.46	24.46
	$15	24.49	24.49	26.81	29.13	29.13	29.13	29.13	29.13	29.13	29.13
	$25	30.79	30.79	33.70	36.61	36.61	36.61	36.61	36.61	36.61	36.61
	$35	39.01	39.01	42.70	46.39	46.39	46.39	46.39	46.39	46.39	46.39
	$45	45.78	45.78	50.11	54.44	54.44	54.44	54.44	54.44	54.44	54.44
	$55	58.08	58.08	63.57	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$80	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$105	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$130	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$155	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$180	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
	$205	75.91	75.91	83.08	69.07	69.07	69.07	69.07	69.07	69.07	69.07
Coal-Related Methane		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	26.4	26.4	25.2	24.0	24.0	24.0	24.0	24.0	24.0	24.0
	$15	37.7	37.7	35.9	34.2	34.2	34.2	34.2	34.2	34.2	34.2
	$25	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$35	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$45	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$55	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$80	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$105	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$130	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$155	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$180	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
	$205	43.9	43.9	41.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9
Landfill Methane		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	15.2	15.2	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	$15	39.4	39.4	39.1	38.8	38.8	38.8	38.8	38.8	38.8	38.8
	$25	52.9	52.9	52.5	52.1	52.1	52.1	52.1	52.1	52.1	52.1
	$35	52.9	52.9	52.5	52.1	52.1	52.1	52.1	52.1	52.1	52.1
	$45	85.1	85.1	84.5	52.0	83.8	83.8	83.8	83.8	83.8	83.8
	$55	104.0	104.0	103.2	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$80	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$105	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$130	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$155	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$180	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
	$205	109.5	109.5	108.7	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Nitrous Oxide + Ag Methane		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	52.1	52.1	52.9	53.7	53.7	53.7	53.7	53.7	53.7	53.7
	$15	72.8	72.8	74.0	75.1	75.1	75.1	75.1	75.1	75.1	75.1
	$25	90.4	90.4	92.8	75.0	95.2	95.2	95.2	95.2	95.2	95.2
	$35	102.4	102.4	107.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$45	107.4	107.4	111.3	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$55	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$80	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$105	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$130	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$155	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$180	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	$205	109.8	109.8	113.4	75.0	75.0	75.0	75.0	75.0	75.0	75.0
High GWP Gases		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	39.6	39.6	61.3	83.0	83.0	83.0	83.0	83.0	83.0	83.0
	$15	67.2	67.2	102.2	137.3	137.3	137.3	137.3	137.3	137.3	137.3
	$25	84.7	84.7	127.7	170.7	170.7	170.7	170.7	170.7	170.7	170.7
	$35	88.9	88.9	133.0	177.2	177.2	177.2	177.2	177.2	177.2	177.2
	$45	90.0	90.0	134.8	179.7	179.7	179.7	179.7	179.7	179.7	179.7
	$55	90.5	90.5	135.8	181.0	181.0	181.0	181.0	181.0	181.0	181.0
	$80	90.6	90.6	135.8	181.0	181.0	181.0	181.0	181.0	181.0	181.0
	$105	90.6	90.6	135.8	181.1	181.1	181.1	181.1	181.1	181.1	181.1
	$130	90.6	90.6	135.9	181.2	181.2	181.2	181.2	181.2	181.2	181.2
	$155	90.6	90.6	135.9	181.3	181.3	181.3	181.3	181.3	181.3	181.3
	$180	90.6	90.6	136.0	181.3	181.3	181.3	181.3	181.3	181.3	181.3
	$205	90.6	90.6	136.0	181.4	181.4	181.4	181.4	181.4	181.4	181.4
US Sequestration		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	$15	0.0	56.8	58.0	59.2	48.2	18.0	18.0	18.0	18.0	18.0
	$25	0.0	72.9	74.4	76.0	61.9	18.0	18.0	18.0	18.0	18.0
	$35	0.0	84.4	86.1	87.9	71.7	18.0	18.0	18.0	18.0	18.0
	$45	0.0	93.6	95.6	97.5	79.6	18.0	18.0	18.0	18.0	18.0
	$55	0.0	101.4	103.6	139.7	86.3	18.0	18.0	18.0	18.0	18.0
	$105	0.0	130.2	132.9	152.7	110.9	18.0	18.0	18.0	18.0	18.0
	$155	0.0	150.6	153.9	174.1	128.4	18.0	18.0	18.0	18.0	18.0
	$205	0.0	167.0	170.7	191.3	142.5	18.0	18.0	18.0	18.0	18.0
	$230	0.0	174.3	178.1	192.0	148.7	18.0	18.0	18.0	18.0	18.0
	$255	0.0	181.0	184.9	192.0	154.5	18.0	18.0	18.0	18.0	18.0
International Non-CO2 Offsets		2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
	$6	139.2	139.2	166.9	194.6	134.9	134.9	134.9	134.9	134.9	134.9
	$15	287.1	287.1	334.6	382.1	227.7	227.7	227.7	227.7	227.7	227.7
	$20	369.2	369.2	427.8	486.3	279.3	279.3	279.3	279.3	279.3	279.3
	$25	383.7	383.7	446.8	509.8	298.0	298.0	298.0	298.0	298.0	298.0
	$35	412.8	412.8	484.8	556.8	335.4	335.4	335.4	335.4	335.4	335.4
	$45	433.3	433.3	506.7	580.1	355.9	355.9	355.9	355.9	355.9	355.9
	$55	475.2	475.2	554.1	633.1	401.8	401.8	401.8	401.8	401.8	401.8
	$80	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$105	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$130	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$155	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$180	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$205	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1
	$230	538.5	538.5	627.1	715.6	473.1	473.1	473.1	473.1	473.1	473.1

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Outstanding Issues with the NEMS Model and Existing Source Data as Used for this Modeling Exercise

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets for the midterm period through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions, by solving for the prices of each energy product that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and assumed energy policies and regulations that influence market behavior. An overview of the NEMS model is available at http://www.eia.doe.gov/oiaf/aeo/overview/index.html. Documentation of the NEMS model and AEO 2007 assumptions (business as usual) that were used as a basis for this modeling is available at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation.

As a midterm forecasting model, NEMS predictions do not reflect short-term behavior. As such, NEMS predictions tend to smooth out projections, where results are normally cyclical in nature. EIA utilizes another model, the Short-Term Energy Outlook Model (STEO), to forecast short-term trends more accurately (e.g., cyclical behavior such as seasonality in prices).

During the NGC modeling exercise, the following were identified as issues that could affect the results achieved under the assumed scenarios:

- Nuclear power plant construction and operating costs have not been updated concurrently with the update of fossil fuel plant (PC, IGCC, and NGCC) costs in NGC Scenarios 5, 6 and 7. Yet it is safe to assume that the costs of building and operating nuclear plants also have risen. It is unclear whether these cost increases would affect the results achieved in any of the scenarios.
- Biomass Integrated Gasification Combined Cycle (BIGCC) technology construction and operating costs have not been updated concurrently with fossil fuel plant costs in NGC cases 5, 6 and 7. The costs of building and operating biomass plants have risen and are expected to be comparable to the IGCC cost increases.
- NEMS only models out to 2030 in its present implementation. S. 280 (as well as other proposed climate change legislation) would set policy out to 2050 and would mandate additional, post-2030 reductions in carbon emissions.
- The NEMS model sometimes has difficulty solving in years with large step function reductions in the GHP caps, particularly in the year 2030. The uncertainty about the allowance prices in this time period could be alleviated by designing the NEMS model and assumptions to solve out to 2050.

- NEMS presently does not provide an option for biomass plants to sequester carbon emissions. This could be a cost-effective offset.
- The NGC believes that the NEMS forecast that modest increases in domestic natural gas supply prices will attract significant incremental LNG import volumes is suspect and may underestimate the degree to which global LNG demand will affect the availability of LNG to the United States.
- The NGC believes that NEMS forecasts too much additional unconventional gas production at the relatively small increases in the assumed price of natural gas. This may be because NEMS underestimates the costs of producing this resource.
- NEMS does not include natural gas located in production areas that are now off limits. Therefore, this gas supply is not modeled and cannot be included in the alternative scenarios.

Comparison Between NGC Scenario 1(CAP 3BS) and EIA S. 280 Core Case

There are differences between results from the NGC base case run (*Scenario 1*) and the EIA-S. 280 Core Case, even though EIA S. 280 Core is likely the closest to the NGC Base Case run (Scenario 1) out of the seven cases reported by EIA. This Appendix compares results for electric generation and capacity, natural gas consumption and supply, CO_2 emissions, and energy and CO_2 prices.

In addition to underlying differences in assumptions between the NGC Base Case and EIA-S. 280 Core, EIA also changed the NEMS model in ways that were not duplicated in the NGC runs. These changes included:

Renewable Market Model Changes from *AEO2007* Reference Case

- Added offshore wind technology as a capacity expansion option in selected coastal regions, with revised cost and performance estimates.
- Updated corn and biomass feedstock costs consistent with University of Tennessee POLYSYS study.

EIA's estimates of biomass supply curves were taken from the U.S. Department of Agriculture's (USDA's) latest estimates through 2015, which were developed under contract with Dr. Ugarte at the University of Tennessee using an integrated land and crop competition model. EIA contracted with Dr. Ugarte to extend these curves through 2030. The corn supply curves also were developed using POLYSYS and were generally higher-priced than those in *AEO2007* for the same level of demand; however, the maximum availability of corn supply in the new estimate is much larger than the *AEO2007* Reference Case and allows for corn imports when corn prices and demand are sufficiently high. In addition to the Reference Case, a High Yield Case was constructed to evaluate the impact of potentially higher biomass crop yields. Similar to the reference case, the biomass supply curves through 2015 were obtained from the USDA and extended through 2030 by Dr. Ugarte under contract to the EIA.

Electricity Market Models Changes from *AEO2007* Reference Case

- Modified the interregional transmission cost structure to allow renewable capacity additions from one region to serve adjacent regions, with higher associated transmission costs.
- Improved the representation of competition for biomass for electricity generation and cellulosic ethanol production.
- Added offshore wind technology as a capacity expansion option in selected coastal regions, with revised cost and performance estimates.

EIA also made substantial changes to the representation of ethanol in the petroleum market model. Finally, EIA chose to sweep banked emissions before 2030.

A comparison of the results of the NGC modeling and the EIA modeling using the adjusted NEMS follows:

Power Generation

Net Generation by Fuel Type (Billion KWh)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Coal	1,580	1,235	1,786	1,020	-12%	21%
Petroleum	39	23	31	19	24%	20%
Natural Gas	1,146	711	763	438	50%	62%
Nuclear Power	910	2,025	996	1,909	-9%	6%
Renewable Sources	721	871	821	1,441	-12%	-40%
Total	4,395	4,866	4,397	4,828	0%	1%

- CAP 3BS (NGC *Scenario 1*) generates more power with natural gas while S. 280 Core is much more reliant on renewable fuel sources.

Generating Capacity

Generation Capacity (Gigawatts)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Coal Steam	305	261	297	226	3%	15%
Other Fossil Steam	88	36	51	24	72%	50%
Combined Cycle	169	193	179	180	-5%	7%
Combustion Turbine/Diesel	125	131	130	126	-4%	3%
Nuclear Power	116	261	127	245	-9%	7%
Renewable Sources	126	151	144	241	-12%	-38%
Total	952	1,059	950	1,069	0%	-1%

- CAP 3BS (NGC *Scenario 1*) builds less renewable generation than EIA-S. 280 Core (151 GW vs. 241 GW) by 2030.
- CAP 3BS (NGC *Scenario 1*) does not retire as many coal plants as EIA-S. 280 Core.
- Combined cycle plants (NGCC) are comparable in both cases.

Natural Gas Consumption

Natural Gas Consumption (Tcf)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Residential	5.2	5.2	5.2	5.2	0%	-1%
Commercial	3.7	4.3	3.8	4.3	0%	-2%
Industrial	7.9	8.6	8.0	8.7	-1%	0%
Electric Power	6.8	5.3	6.5	4.1	4%	29%
Transportation	0.1	0.1	0.1	0.1	0%	1%
Pipeline Fuel	0.8	0.8	0.8	0.7	0%	4%
Lease and Plant Fuel	1.2	1.1	1.2	1.1	0%	2%
Total	25.7	25.3	25.5	24.3	1%	4%

- Natural gas consumption is lower in EIA-S. 280 Core Case in the electric power sector, reflecting increased reliance on renewable generation as compared to CAP 3BS (NGC *Scenario 1*).

Natural Gas Supply

Natural Gas Supply (Tcf)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Dry Production						
United States Total	20.6	20.3	20.4	19.9	1%	2%
Lower 48 Onshore	14.5	14.9	14.4	14.5	1%	3%
Associated-Dissolved 4/	1.3	1.2	1.3	1.2	0%	0%
Non-Associated	13.2	13.7	13.1	13.3	1%	3%
Conventional	4.2	3.7	4.2	3.6	1%	3%
Unconventional	8.9	10.0	8.9	9.7	1%	3%
Lower 48 Offshore	4.1	3.2	4.0	3.2	1%	1%
Associated-Dissolved 4/	1.0	0.9	1.0	0.8	0%	1%
Non-Associated	3.0	2.4	3.0	2.3	1%	1%
Alaska	2.0	2.2	2.0	2.2	0%	0%
Net Imports	5.0	4.9	5.0	4.3	1%	15%
Pipeline	1.6	0.9	1.5	0.8	3%	13%
Liquefied Natural Gas	3.4	4.0	3.4	3.5	1%	15%

- Natural gas production is similar in both cases, but imports are lower in EIA-S. 280 Core Case due to greater reliance on renewable fuels for electric generation.

CO_2 Emissions

CO2 Emissions (million metric tons carbon dioxide equivalent)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Residential	390	391	389	383	0%	2%
Commerical	256	281	271	303	-5%	-7%
Industrial	1,082	1,139	1,078	1,122	0%	2%
Transporation	2,298	2,525	2,246	2,495	2%	1%
Electric	2,101	1,544	2,133	1,217	-1%	27%
Total	6,128	5,880	6,116	5,520	0%	7%

- Commercial emissions are higher in the EIA-S. 280 Core Case since the EIA assumed that commercial emissions would essentially be exempted[35] due to size.
- Electric generation emissions are lower in 2030 in the EIA-S. 280 Core Case due to increased reliance on renewable fuels.

[35] Regulated entities (companies) are allowed at least one facility over 10,000 tonnes CO_2 emissions per year

Energy Prices

Prices ($2005)

	CAP 3BS 2020	CAP 3BS 2030	EIA - S280 Core Case 2020	EIA - S280 Core Case 2030	Percent difference NGC Base Case vs EIA-S280 2020	Percent difference NGC Base Case vs EIA-S280 2030
Imported Crude Oil Price ($ per bbl)	$ 46.47	$ 51.63	$ 46.47	$ 51.63	0%	0%
Gas Price at Henry Hub ($ / mmBtu)	$ 6.34	$ 6.33	$ 5.46	$ 6.12	16%	3%
Coal Minemouth Price ($ / ton)	$ 23.67	$ 21.76	$ 21.28	$ 23.51	11%	-7%
Electricity (cents / Kwh)	$ 10.04	$ 10.38	$ 8.72	$ 9.75	15%	7%
Natural Gas Prices (2005 $/MMBtu)						
Residential	$ 11.44	$ 11.60	$ 10.62	$ 11.33	8%	2%
Commercial	$ 12.84	$ 12.29	$ 8.70	$ 9.12	48%	35%
Industrial	$ 9.94	$ 9.38	$ 7.05	$ 8.91	41%	5%
Electric Power	$ 10.05	$ 9.00	$ 6.73	$ 8.38	49%	7%
CO2 Prices (2005 $/ton)	$ 60.42	$ 52.26	$ 22.17	$ 47.85	173%	9%

- Wellhead natural gas prices are lower in EIA-S. 280 Core Case due to lower gas demand, particularly from the electric sector.
- End-use gas prices are lower in EIA-S. 280 Core Case due to lower CO_2 prices.
- CO_2 allowance prices are lower in EIA-S. 280 Core Case due to lower price of emission offsets, lower demand for allowances due to increased reliance on renewable generation, and an assumption (made by EIA) that regulation would limit the amount by which allowance prices could increase from year to year. This restriction has a big effect on CO_2 allowance prices and delivered costs in 2020, the year of the second S. 280 step.

Glossary of Terms

Allowance: A government-issued authorization to emit a certain amount. In greenhouse gas markets, an allowance is commonly denominated as one ton of CO_2e per year. See also “permit” and “credits (a.k.a. carbon credits).” The total number of allowances allocated to all entities in a cap-and-trade system is determined by the size of the overall cap on emissions.

Banking: The carry-over of unused allowances or offset credits from one compliance period to the next.

Baseline: The target, usually the historical emissions from a designated past year, against which emission reduction goals are measured. In California, the designated base year is 1990.

Borrowing: A mechanism under a cap-and-trade program that allows covered entities to use allowances designated for a future compliance period to meet the requirements of the current compliance period. Borrowing may entail penalties to reflect the programmatic preference for near-term emissions reductions.

Carbon Dioxide (CO_2): A naturally occurring gas, it is also a by-product of burning fossil fuels and biomass, as well as other industrial processes and land-use changes. It is the principle anthropogenic greenhouse gas that affects the Earth’s temperature. It is the reference gas against which other GHGs are indexed and therefore has a Global Warming Potential of one (1).

Carbon Dioxide Equivalent (CO_2e): The metric used to compare quantities and effects of various GHGs on a common basis. The CO2e of a gas is equal to its emissions, by mass, multiplied by its global warming potential (see "global warming potential") and is commonly expressed in million metric tonnes (MMT CO_2e).

Carbon sequestration: The storage of carbon or carbon dioxide (CO_2) , for example, in plants, soils, or subsurface geologic formations.

Climate: The long-term statistical average of weather-related aspects of a region including typical weather patterns, the frequency and intensity of storms, cold spells, and heat waves. Climate is not the same as weather. A description of the climate of a certain place would include the averages and extremes of such things as temperature, rainfall, humidity, evapotranspiration and other variables that can be determined from past weather records during a specified interval of time.

Climate Change: Refers to changes in long-term trends in the average climate, such as changes in average temperatures.

Credits (a.k.a. carbon credits): Credits can be distributed by the government for reductions achieved by offset projects or by achieving environmental performance beyond a regulatory standard.

Emissions: The release of substances (e.g., greenhouse gases) into the atmosphere. Emissions occur both through natural processes and as a result of human activities.

Greenhouse Gases (GHGs): Greenhouse gases include a wide variety of gases that trap heat near the Earth’s surface, slowing its escape into space. Greenhouse gases include carbon dioxide, methane, nitrous oxide and water vapor and other gases. While greenhouse gases occur naturally in the atmosphere, human activities also result in additional greenhouse gas emissions. Humans have also manufactured some gaseous compounds not found in nature that also slow the release of radiant energy into space.

Offset: Projects undertaken outside the coverage of a mandatory emissions reduction system for which the ownership of verifiable GHG emission reductions can be transferred and used by a regulated source to meet its emissions reduction obligation. If offsets are allowed in a cap-and-trade program, credits would be granted to an uncapped source for the emissions reductions a project (or plant or soil carbon sink) achieves. A capped source could then acquire these credits as a method of compliance under a cap.