Carbon Dioxide Emissions Intensity Reduction in the U.S. Power Sector

Jeffrey Anderson

Department of Engineering & Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, Pennsylvania 15213, U.S.A.
Author's email address: jja1@andrew.cmu.edu

Abstract

The framework of the Clean Air Act (CAA) enables the U.S. Environmental Protection Agency (EPA) to regulate hazardous air pollutants that jeopardize the health and welfare of the American public. While only six criteria pollutants are directly named in the legislation, provisions are included that outline the processes for establishing new regulations for other air pollutants, as evidence becomes available to support the necessity for regulation in both the scientific community and the judicial system. One such new pollutant of international relevance that is now regulated is carbon dioxide (CO_2). This chapter examines the evolution for CO_2 regulation in the electric power sector and the associated changes in the historical and future emission intensity. An overview of the processes by which CO_2 emissions from mobile and stationary sources can be regulated in the U.S. is provided with a context of how judicial decisions shaped the regulations. Historical data on CO_2 emission intensities for the electric power sector are also presented to indicate the impact of market-based forces on the intensity reduction of these emissions created in part by decreasing natural gas prices and increased natural gas combined cycle capacity and generation. Finally, Energy Information Administration models for projections of the electric power sector's composition, output, and CO_2 emissions in 2020, 2025, and 2030 are used in conjunction with the projected natural gas prices to determine the variation in CO_2 emissions and emission intensity, with and without the EPA's Clean Power Plan (CPP) regulation. When these findings are applied to the power sector's contributions to the U.S. nationally determined contribution (NDC) targets for 2020 and 2025 CO_2 reductions in the Paris Agreement, as defined by the CPP targets for those years, we find that these contributions may be reached in 2020 and in 2025, if the natural gas price is at or below the projected prices. However, natural gas prices will need to be substantially below the projection to meet any possible future NDC that may be based upon meeting the 2030 CPP emission target.

Linking paragraph to CAA, EPA and legal path to CO_2 regulation. Mention climate change, IPCC, usual stuff.

Introduction Legal Precedence

The 1970 amendments to the Clean Air Act (CAA) created the authority under/by which the federal government is authorized to establish national regulations for hazardous air pollutants that affect public health and safety, to direct the states to develop implementation plans (SIPs) to meet these regulations,[1] and to authorize said plans [1, 2]. The establishment of these National Air Quality Standards (NAAQS) is not limited to the six criteria pollutants named in the CAA under section 108(a): Section 112(b) authorizes the federal government to identify toxic air pollutants from categories of industrial sources and to establish technology-based standards to control emissions from major sources. Additionally, the federal government under section 111(b) has the authority to set a New Source Performance Standard (NSPS) for other hazardous air pollutants that are not listed in the previous sections and/but are emitted from both mobile and stationary sources. Once this NSPS regulation is in place, a performance standard for existing sources of the regulated pollutant may then be introduced under section 111(d).

In December 1970, President Richard Nixon signed an executive order that created the Environmental Protection Agency (EPA) as the federal agency to carry out the directives in the CAA [3]. While the directives as described appear to make the EPA the overseer for state and industrial emissions, it also allows the states, industries, non-government organizations, and private citizens to sue the EPA for failure to carry out the directives. One example of this occurred in 1999, when private organizations used section 202(a)(1) of the CAA to petition the EPA to impose regulations on carbon dioxide (CO_2) and other greenhouse gas emissions from mobile sources—automobiles [4]. In this petition, the petitioners believed that it was reasonable to expect these emissions to endanger public health or welfare because the emitted gases are associated with climate change, thereby requiring regulation. However, the EPA denied the petition, it interpreted the CAA as not giving the Agency the authority to regulate greenhouse gas emissions for climate change purposes [5]. Furthermore, the EPA cited that there was uncertainty about the role of greenhouse gas in climate change; and that regulatory actions were currently not required by the EPA, because other parts of the federal government were taking actions domestically and abroad to reduce greenhouse gas emissions.

In response, the private organizations (along with the Commonwealth of Massachusetts and a coalition of other states, cities, and organizations) sued the EPA in a case that was decided by the U.S. Supreme Court in 2007 (Massachusetts v. EPA) [6]. The Court's finding in favor of the plaintiffs determined that the greenhouse gases can be classified as air pollutants and regulated

[1] In the absence of a SIP, the plan created by the federal regulating agency is implemented.

under the CAA as such. However, the decision did not order the EPA to take such action; but only to do so if the EPA determined that these gases cause or contribute to climate change, or otherwise that the Agency had a "reasonable explanation" as to why regulation should not occur under the CAA [5].[2] Upon further study, the EPA did find in 2009 that well-mixed greenhouse gas emissions from new motor vehicles threaten current and future public health and welfare related to climate change [7].

This linkage between motor vehicle emitted GHGs, climate change, and detrimental affects on the public led the EPA and the Department of Transportation to issue regulations that limited tailpipe emissions for CO_2, nitrous oxide (N_2O) and methane (CH_4), and limited hydrofluorocarbon (HFC) from air conditioning systems for model year 2012 through 2016 passenger cars, light-duty trucks, and medium-duty passenger vehicles [8-10]. Emissions of these GHGs from such light-duty vehicles accounted for over 70% of Section 202(a) mobile source GHGs in 2007 [10]; therefore, the objective of the 1999 petition was achieved.

The regulation of these emissions from new, mobile sources also allowed the EPA to regulate GHGs from new, modified,[3] and reconstructed,[4] stationary sources. One obstacle that the EPA needed to overcome to regulate GHG emissions in stationary sources, such as fossil-fuel power plants, is a restriction in the CAA concerning source exemptions from requiring construction, modification and operation permits. The CAA requires stationary facilities emitting as little as 100 tons of "any air pollutant" to obtain a permit prior to construction or modification, and operation, under the Prevention of Significant Deterioration (PSD) and Title V provisions [11-13].[5] The EPA felt that a change to this limit was necessary because GHGs are emitted in much larger quantities than traditional pollutants, and that such a small threshold would force the EPA to regulate GHG emissions from many small facilities, such as schools and business. The "absurd result of the inclusion of so many possible sources from this limit would make

[2] The phrase "reasonable explanation" is open to legal interpretation and goes beyond a statement of "Finding of No Significant Impact."
[3] Modified plants are those that undergo a physical or operational modification that increases the maximum achievable hourly rate of air pollutant emissions [11].
[4] Reconstructed plants are those in which components are replaced that exceed 50% of the cost of an entirely new and similar plant [11].
[5] A PSD permit pertains to construction and modification of the stationary source, while a Title V permit pertains to the operation of the source.

enforcement of any such regulation nearly impossible, and force undue financial burdens on many industries, commercial and residential sources that would be unintentionally covered by the regulation [13]. The EPA felt that this was not Congress' intention in legislating the CAA; therefore, as the EPA had the authority to issue legal binding rules, the EPA followed the *Chevron* two-step framework[6] [14] to circumvent the enforcement the financial problems with a "tailoring" rule [13]. Here, the EPA suggested limiting the regulation to cover stationary sources that emitted more than 100,000 tons per year—capturing 86% of the CO_2 emissions [13].

Seventeen states and various industry groups challenged the EPA on this regulation concerning the EPA's determination that stationary sources emit GHGs that are detrimental to the public, that regulations for mobile sources automatically necessitates regulations for stationary source, and the EPA's interpretation of the legislated limits [11, 12, 15]. While lower courts found in favor of the EPA, in 2014 the U.S. Supreme Court ruled that the EPA could not compel an emitting source to obtain a PSD or Title V permit, if it did not already need to do so, nor did the EPA have the authority to interpret the CAA legislation to allow for tailored limits to make enforcement of a regulation manageable, as Congress was not ambiguous about the limits or procedures.[7] However, the Court did rule that the EPA could use these permit provisions to enforce the GHG regulation for stationary sources, if the source was already required to obtain such permits for conventional pollutants. This allowed the EPA to regulate GHGs from stationary sources, and effectively gave the Agency a tool that made enforcement manageable: thereby limiting the regulation to the larger-emitting sources that generated 83% of the GHG emissions [12].

Another important outcome of this case concerns how these harmful emissions are limited. To acquire the permit under the PSD provision, the emitter must use the best available control technology (BACT) to limit these emissions. While this end-of-stack control approach is considered acceptable for traditional pollutants, the Court allowing the EPA to apply BACT

[6] The two-step framework first requires that the intent of the legislation is silent or ambiguous on the issue in question for the agency to have authority to resolve the issue. The second step is that the agency's resolution of the issue is in keeping with the legislation and is reasonable rather than arbitrary and capricious.
[7] In the majority opinion of the Court, Judge Scalia wrote that the first step of the Chevron doctrine did not hold, and that the EPA's action to change the permitting limit was unreasonable [11].

analysis to GHGs in the regulation meant that end-of-stack emission control for GHGs was also applicable. As such, the EPA's suggestion that carbon capture and storage (CCS) should be considered alongside energy efficiency as comparable BACT controls for CO_2 emissions indicates that CCS is reasonable mitigation technology to consider [11], even though this technology had limited use in 2010 [16].

Based on the Court's findings, the initial version of the final regulation to limit CO_2 emission from these fossil-fuel sources, the Carbon Pollution Standards regulation, was entered in the Federal Register in January 2014 as part of the Obama administration's Climate Action Plan; a modified version was entered in August 2015 [17]. In the regulation, CO_2 emission limits are set for base load natural gas combined cycle (NGCC) plants and for coal-fired steam generators, according to limits achievable with the EPA defined best system of emission reduction (BSER). For new and reconstructed NGCC plants, CO_2 emission rates are limited to 1,000 lbs/MWh-gross, which is achievable with the current generation of efficient NGCC base load plants [17]. However, new coal-fired steam generating units must have a CO_2 emission intensity that is below 1,400 lbs/MWh-gross, which is lower than the emission rate for current generation coal-fired plants.[8] The EPA suggests that the BSER to achieve this level of emission intensity is a new, efficient supercritical pulverized coal (SCPC) boiler with a post-combustion CCS subsystem that captures 20% of the CO_2 emissions [17]. While 38% of the power sector net summer capacity in 2015 was derived from SCPC units, none of this capacity used CCS [19].[9] With the initial version of the final Carbon Pollution Standards entered in the Federal Register, the EPA was then allowed to propose a regulation for existing stationary sources, under CAA Section 111(d), which the Agency did in June 2014. After a six-month public comment period that resulted in 4.3 million comments [20], the EPA publish the final rule for the Clean Power Plan in the Federal Register in October 2015 [21]. *Talk about CPP particulars.*

Talk about court judgement and new administration policy

[8] The EPA estimates that the CO_2 emission intensity for a new, supercritical, pulverized coal-fired EGU using bituminous coal is 1,681 lbs/MWh-gross [18].
[9] The standards for the remaining plants are less stringent [20]. Modified gas-fired combustion turbines are not required to meet an emission intensity standard. Emission intensity limits are set for modified and reconstructed coal-fired power plants, and are based on the level of modification or the rate of energy input. For each of these cases, the BSERs are upgrades to equipment and implementation of best practice operations.

Reference

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[13] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, 40 C.F.R. Parts 51, 52, 70, et al. 2010.

[14] *Chevron U.S.A. Inc.* v. *NRDC*, 467 U.S. 837 (1984).

[15] SCOTUSblog. *Utility Air Regulatory Group v. Environmental Protection Agency*; www.scotusblog.com. n.d. n.p. Web. 9 November. 2017. < http://www.scotusblog.com/case-files/cases/utility-air-regulatory-group-v-environmental-protection-agency >.

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Introduction Historical Data

The path to future CO_2 emission intensity reduction is partially directed by the path already taken, as observed from the reduction goal that is based upon the intensity for a previous year. In 2005, 2,663 million tons of CO_2 were emitted by the electric power sector to produce 3,895 TWh of electricity [1]. This intensity, 1,365 lbs/MWh, is a historical high for subsequent years, Figure X1; therefore, there is already a 21% reduction in intensity by 2015, relative to 2005 (*link to intro about target for intensity reduction, maybe show back to 2000 to demonstrate 2005 max*). This reduction may be due to factors related to within generation source (mitigation, retirement, improved efficiency, added low or zero emission intensity capacity), across generation source, (fuel switching), or a combination of both. Plotting the historical emission intensity for the two dominant fossil fuel sources—coal and natural gas (EIA citation?) shows that the emission intensity for the coal-fired fleet is substantially the same, at an average of 2,205 lbs/MWh [1] over this period, Figure X2. Conversely, the emission intensity for the natural gas fleet decreases by approximately nine percent to 938 lbs/MWh.

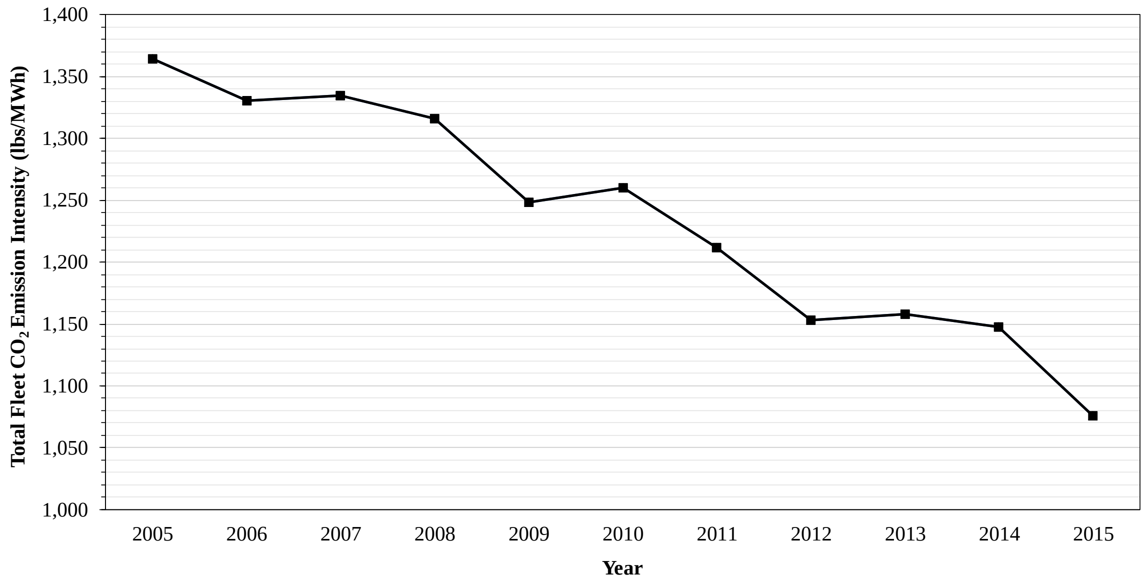

Figure 1. Historical U.S. power sector CO_2 emission intensity rate (lbs/MWh) [1].

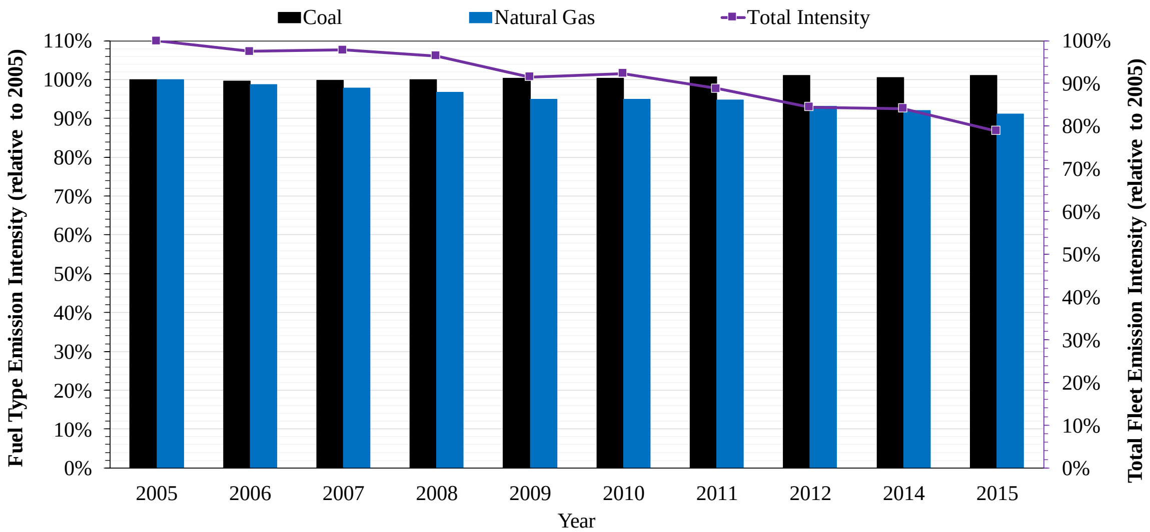

Figure X2. Historical CO_2 emission intensity rate (lbs/MWh) for U.S. power fleet by fuel type, relative to 2005 values [1].

The difference in emission intensities for the two fossil fuel types and the continued decrease in emission intensity for natural gas generation, while the fleet emission intensity continues to decrease, suggests that the profile of the fuel type for the fleet generation mix is changing (*already have something about intensity for different sources earlier in intro?*). From 2005 to 2015, coal-fired EGUs are the primary source of the almost constant net generation, Figure X3. Generation from this source decreases from 51% to 34% over this decade and is primarily replaced by natural gas sources, however. Over this same period, natural gas generation grows (*check consistency in tense throughout text*) from 18% to 32% of net generation. Furthermore, while nuclear generation is constant, renewable energy generation, inclusive of hydropower, increases five percent to further offset coal-fired generation [1]. This increase in renewables relates to an increase in wind and solar capacity from incentivized programs such as the PTC and ITC programs, state RPS and carbon markets, and reductions in capital costs (*cite and give policy details, if not done earlier*). Therefore, much of the 21% emission intensity decrease relates to a change in the fleet net generation profile from a predominantly coal-based fleet to one equally dependent upon natural gas generation that has a lower emission intensity (*calculate percent contribution given generation and intensity numbers from sources?*).

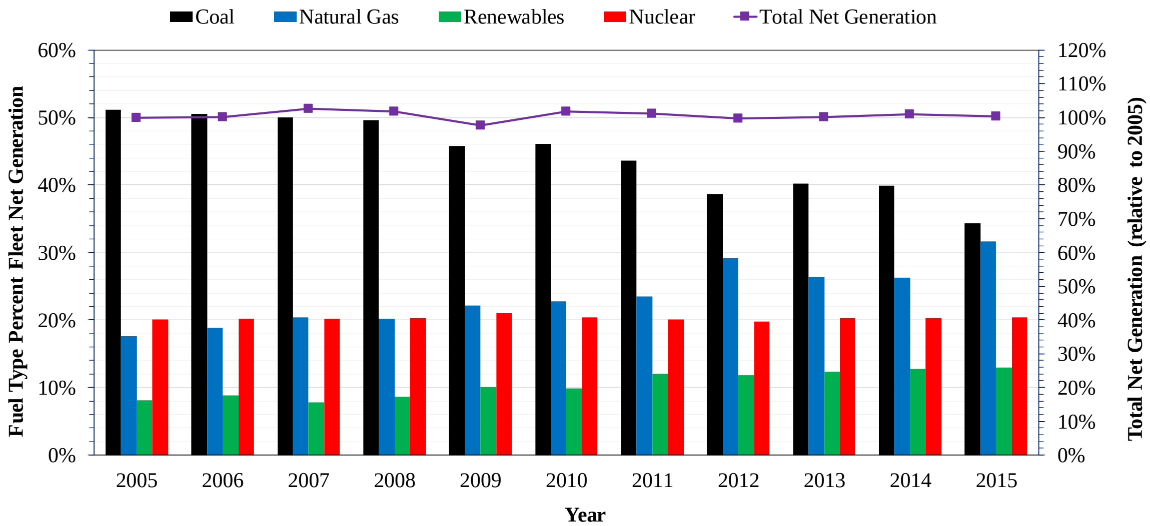

Figure X3. Historical U.S. power sector net generation mix and total net generation, absolute and relative to 2005 value [1].

The increase in generation from natural gas sources can derive from two factors: increasing capacity and increasing capacity factor (*define here or earlier*). Natural gas capacity, in turn, can come from two generation source categories: NGCC plants and other natural gas generators, such as combustion turbines, steam turbines, and internal combustion engines. Each of these categories of natural gas generators has different function and performance characteristics. For a NGCC plant that might be used to supply base load or intermediate load (*define each?*) generation for the grid, the historical fleet average efficiency of the plant is 45% (*heat rate better?*) and results in an average CO_2 emission intensity of 891 lbs/MWh [2, 3] (show calculation?). The other natural gas generators, which are used to provide peak generation, have lower historical fleet average efficiencies, (30 to 35%) and a collective average emission intensity over this period of 1,406 lbs/MWh [2, 3] (*footnote how calculated*?).

When the net summer capacities for these natural gas generation sources are plotted with the coal capacity from 2005 to 2015, Figure X4, there is a four percent net increase in the total natural gas and coal-fired EGU capacity. For the natural gas capacity, the other natural gas generation capacity remains constant at approximately 195 GW [3, table 4.2a], while the NGCC capacity increases by 34% to 226 GW [4, reference cases table A9]. Unpacking the natural gas net generation reveals that the other natural gas generation remains constant at approximately 150 TWh from 2005 to 2015, while the NGCC generation increases over 100% to 1,073 TWh, Figure

X5. Therefore, the decrease in natural gas emission intensity comes from an increase in the lower intensity NGCC capacity and from the increase in net generation from the existing and new NGCC capacity, rather than from changes in the operation of the peaker generation sources. For coal-fired EGUs, there is a net decrease in capacity by 10% to 277 GW [15, Form 860], as some of the capacity is retired by 2015. A 34% decrease in coal-fired net generation to 1,333 TWh is associated with this capacity decrease.

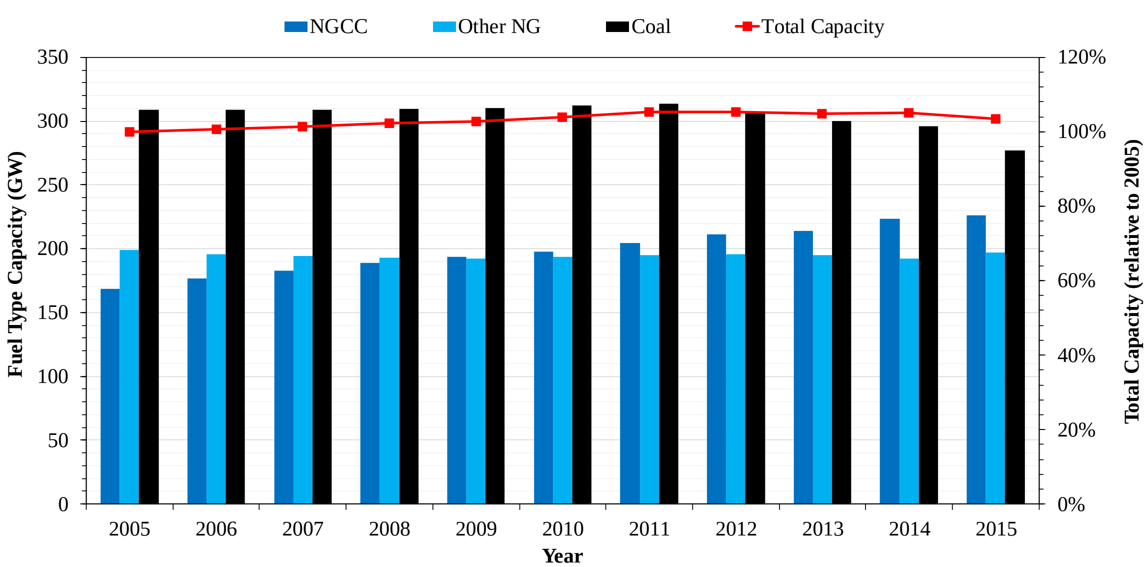

Figure X4. Historical U.S. power sector net summer capacity mix by fuel and generator type for coal and natural gas, absolute and relative to 2005 value [5-14].

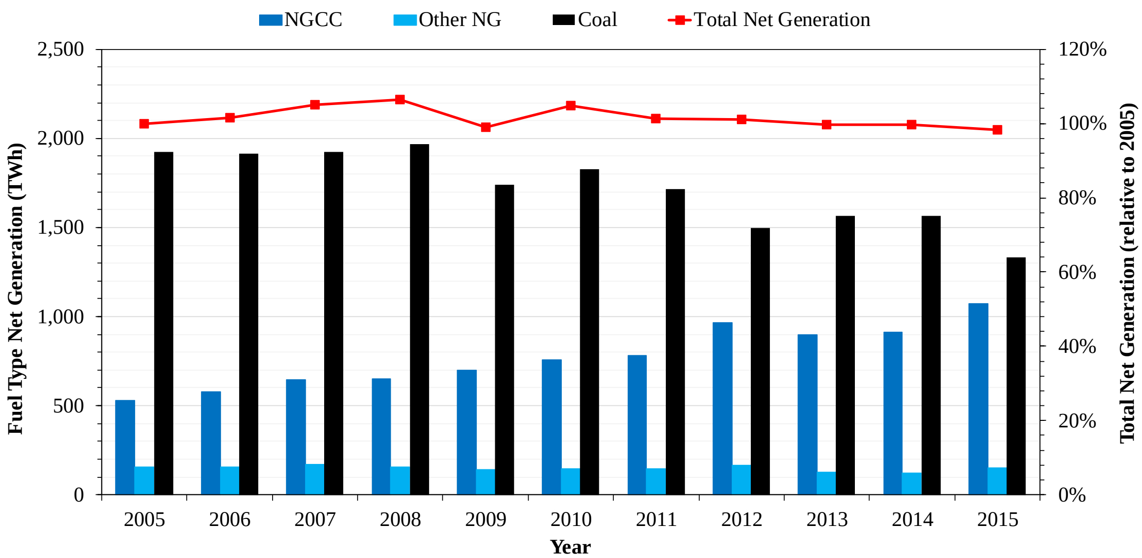

Figure X5. Historical U.S. power sector net generation mix by fuel and generator type for coal and natural gas, absolute and relative to 2005 value [5-14].

The capacity curves for each EGU type are *smooth* in comparison to the net generation curves, Figure X6, when the annual deviations in NGCC and coal capacity and net generation are normalized with 2005 quantities. These fluctuations in net generation relate not only to changes in capacity, but to changes in the operation of existing and new capacity, as *determined in* the capacity factor. Over time, the capacity factor of the coal-fired EGUs decreases from approximately 70% to 55%, while that for the NGCC plants increases from 36% to 55%, Figure X7.

These capacity factors are correlated with the natural gas price through power source dispatch.[10] In deregulated electricity markets, an EGU's generation is typically dispatched according to the merit order for the EGUs in that market, when transmission constraints and other factors that might cause out of merit order dispatch are not present *(explain merit order and cite?)*. The merit order is determined from the prices at which the EGUs in the market offer various amounts of electricity—prices for an EGU are typically set at the short-run variable cost that is dominated by the cost of the fuel. Therefore, an EGU with lower fuel costs will likely be dispatched before an EGU with higher fuel costs is dispatched, thereby possibly increasing the overall utilization of

[10] Commodity prices from reference 17 are adjusted to 2010 dollars with the consumer price index. Source: https://www.bls.gov/cpi/cpid1705.pdf.

the lower variable marginal cost EGU. Over the long-run, the capacity factor of a generator type for one fuel may then change in relation to the relative changes in commodity prices for a competing generator type using a different fuel. For the NGCC plants, the capacity factor is inversely correlated with the natural gas price, while the capacity factor for the coal-fired EGUs is directly correlated, given constant coal prices. These relationships are seen post 2010, Figure X8. Prior to 2011, these relationships are not seen because the natural gas price is too high to significantly affect the dispatch order. The effect of natural gas price on capacity factor is observed between 2008 and 2009, during the Great Recession, when the natural gas price decreases by 47% and causes an 8.5% decrease in the coal capacity factor. (*mention capacity planning here rather than later? Regulated markets?*)

[*This equivalence in capacity factors indicates a future juxtaposition in the dispatch roles of the two generation sources where more NGCC plants will be used for baseload generation. This trend will result in lower the levelized cost of the NGCC plant and increasing the LCOE of the coal-fired EGUs, if capital costs remain. Such a trend will also increase LCOE for new coal, increase intensity for existing coal, hasten retirement because increase aging from cycling. (mention in discussion for ISOMAP)*]

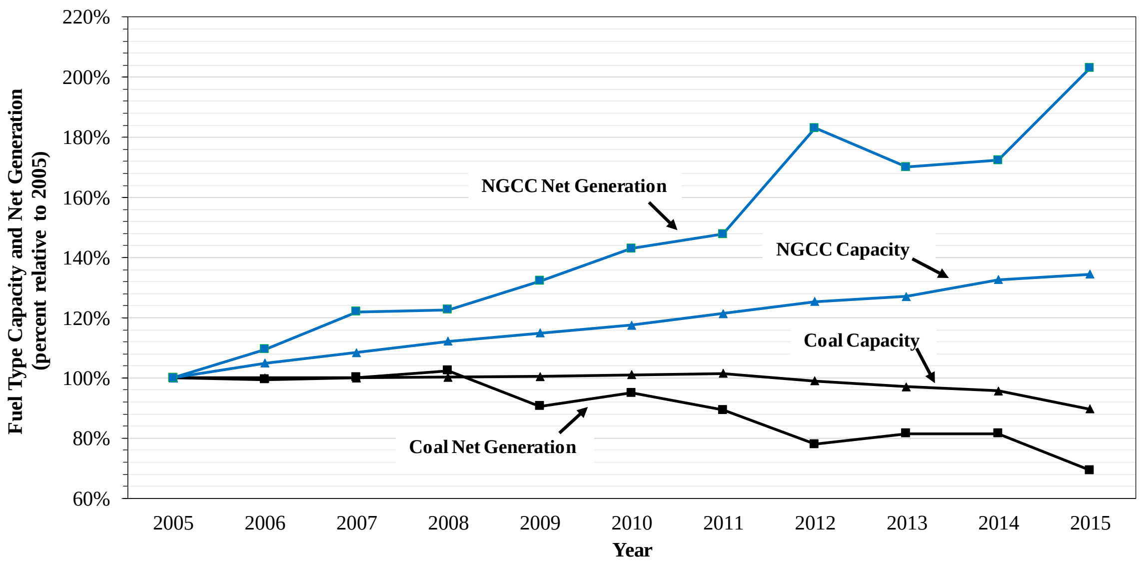

Figure X6. Historical U.S. power sector net generation and net summer capacity for coal-fired power plants and NGCC plants relative to 2005 values [15, 16].

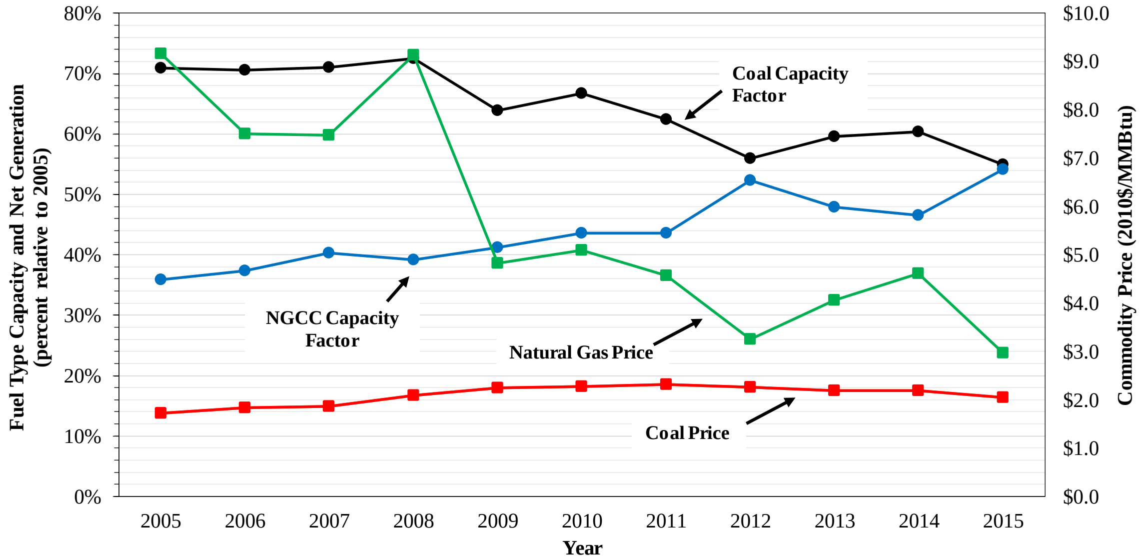

Figure X7. Historical U.S. power sector capacity factor and commodity prices for coal-fired power plants and NGCC plants relative to 2005 values [15-17].

Given the difference in emission intensity between the coal-fired EGUs and natural gas-fired EGUs, lower natural gas prices should lower the fleet emission intensity because these EGUs may be dispatched before the coal-fired EGUs are dispatched and utilized more. (*regulated markets need to be mentioned. Lower fuel price leads to lower LCOE so new capacity may be for lower fuel price or change in capacity factor for EGUs?*) Plotting the yearly reduction as a function of delivered natural gas price to the power sector, Figure X8, shows this linkage between intensity reduction and fuel price. This relationship suggests that market and policy mechanisms to maintain low natural gas prices may be sufficient to affect large intensity reductions, as the natural gas price decreases over the decade generally lead to decreasing intensity. The correlation between price and reduction is not chronologically perfect, however. Coal prices, capacity planning, and inaccuracies in forecasted natural gas price rather than spot price may account for some of the imperfect responses between the natural gas price and the reduction, as occurs from 2006 to 2008 and from 2012 and 2014 when the natural gas prices increase but the emission intensities remain constant (citations to Paul and Bistline's work).

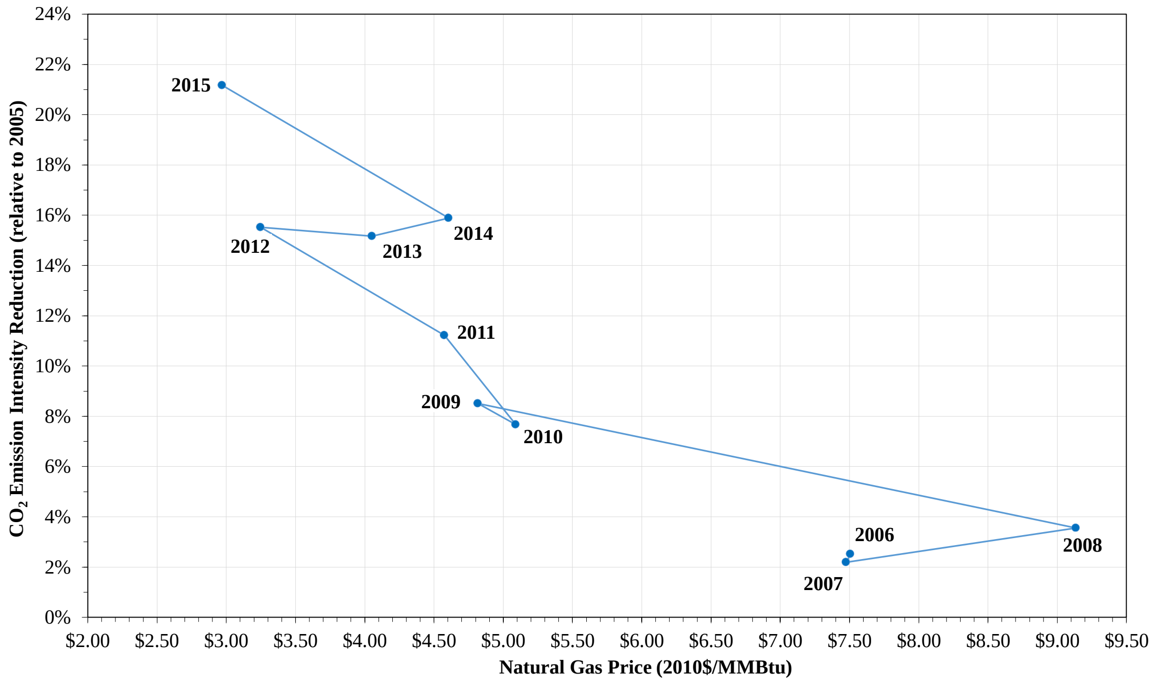

Figure X8. Historical representation of the reduction in CO_2 emission intensity rate (lbs/MWh) relative to 2005 for the U.S. power sector intensity rate in relation to natural gas price for power sector. [1, 17].

Introduction Future Emissions

Projections of future commodity prices, capacities, generation mixes and the resulting changes in fleet emission intensity are some of the information compiled in the Energy Information Administration's (EIA's) *Annual Energy Outlook* [5]. In this report, one of the aspects that the EIA examines in the National Energy Modeling System (NEMS) model is the yearly impact of economic growth, availability of oil and gas resource technological advances, and policy on those variables for the power sector. In all, nine cases are modeled for multiple years concerning variant forms of these parameters [5]. Plotting the projected natural gas price and resulting fleet CO_2 emission intensity reduction for these cases in 2020, 2025, and 2030 with the historical data, Figure X9, shows a continued increase in emission reduction, regardless of the projected natural gas price. However, the variation in the annual case results from the model increases with time, as uncertainty around the parameters also grows. An overall trend of the reduction becoming independent of natural gas price with time emerges from this variation. This is likely due in part to policy implementation related to incentives in the CPP for renewable energy, and to existing programs for wind and solar energy tax credits.

Within each projected year, four case scenarios are identified that help make the distinction between the impact of policy and price, Table X. Scenarios S1 and S1 No CPP tend to fall near the center of the natural gas price distribution for each year and have similar prices; in 2030, the presence of the CPP results in a $0.2 increase in the natural gas price relative to the reference case without the CPP. However, the increase in price is associated with an 11% absolute increase in the intensity reduction in S1. While the lower reduction may be due to lower coal prices in the absence of the CPP, it may also relate to less generation from solar and wind sources due to the absence of the CPP incentives.

Extremes in natural gas price emerge in scenarios S2 and S3 No CPP that relate primarily to the conditions for abundance or scarcity of fossil fuel supply. The range for these extremes increases for each year, as the intensity reduction continues to increase for each case scenario. Prior to 2030, the reduction for S3 No CPP is equal to or greater than that for S2. This relationship changes in 2030 when the CPP policy requirements in S2 result in a four percent greater intensity reduction, even though the natural gas price is $4/MMBtu greater, indicating that in the absence of a policy like the CPP large intensity reductions can be achieved through lower natural gas prices. Using the 2030 S1 No CPP as a baseline, the reduction elasticity is approximately a five percent increase in reduction per one-dollar decrease in natural gas price, which is similar to that for 2020 and 2025.

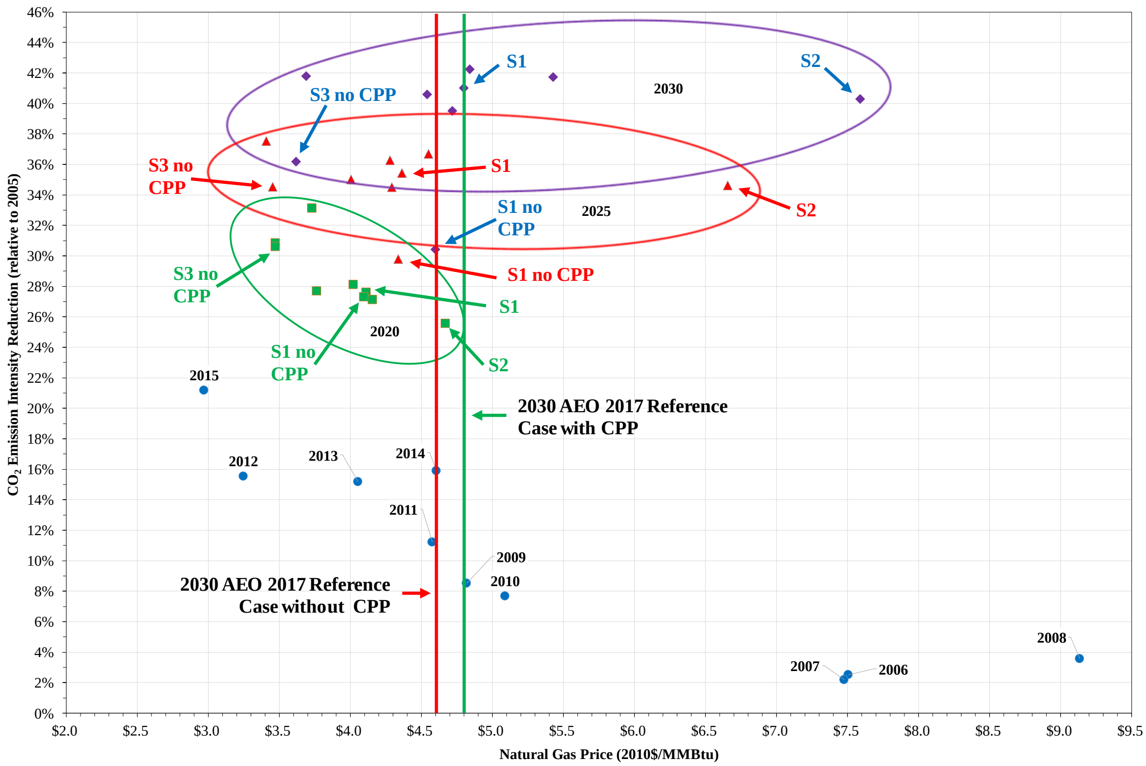

Figure X9. Historical and projected representation of the reduction in CO_2 emission intensity rate (lbs/MWh) relative to 2005 for the U.S. power sector intensity rate in relation to natural gas price for power sector [1, 4, 5]. Projected reductions and gas prices are scenarios in Annual Energy Outlook 2017 relating to economic growth, technology improvements, supply levels for oil and gas, and policy implementations. Ellipses around year groupings of scenarios represent the trend in intensity reduction. The major axes for the ellipses are coincident with the corresponding trend lines for an OLS regression on the intensity reduction in the scenarios for each grouping. Minor axes are set to illustrate the grouping. Natural gas prices from AEO 2017 are converted from 2016 dollars to 2010 dollars with CPI.

Table X: Description of scenarios from AEO 2017.

Scenario	Description
S1	Reference case with CPP using mass-based approach
S1 No CPP	Reference case without CPP
S2	Low oil and gas resource, and technology with CPP using mass-based approach
S3 No CPP	High oil and gas resource, and technology without CPP

Similar intensity reductions or natural gas prices for given cases may not indicate similar power sector requirements or mass reductions, Figure X10. For the cases studied, the required net generation level to meet demand is projected to increase more than 10% by 2030, relative to 2005 levels [1,5]. This increasing generation varies with case, where the scenarios without the

CPP result in greater generation levels than those with the CPP, and approach levels that are 20% greater than the 2005 level. These non-CPP scenarios with higher generation levels and the lower emission intensity reductions, relative to the CPP scenarios, result in a smaller decrease in actual CO_2 emissions in 2030 that fall short of the CPP 36% mass reductions. Therefore, looking at emission intensity reduction without constraining net generation can be misleading when overall mass reduction is needed.

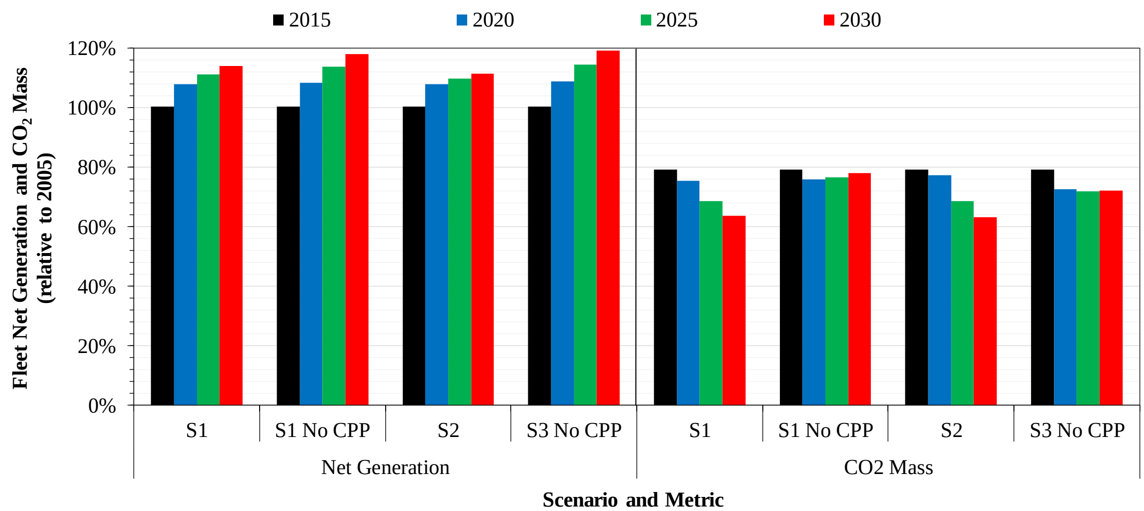

Figure X10. Historical and projected net generation and CO_2 mass for the U.S. power sector for scenarios in AEO 2017, relative to 2005 values [1, 5].

The differences in the natural gas price and intensity reductions over time for these scenarios imply that there is also a difference in the net generation mix by fuel type between the cases, Figure X11. For coal, while the net generation contribution decreases in each scenario, the decrease is scenario dependent. The largest decrease is the reference case, S1, where coal comprises 23% of overall generation. This generation level is 51% of that from coal in 2005 [1, 5]. The coal-fired generation contribution even decreases when there is no CPP or natural gas price is high under the CPP. In these scenarios, the generation levels are 71% and 61% of that from coal in 2005, respectively [1, 5]. Therefore, generation from coal is expected to decrease significantly from 2005 levels with or without the CPP, but the amount is still dependent upon the natural gas price.

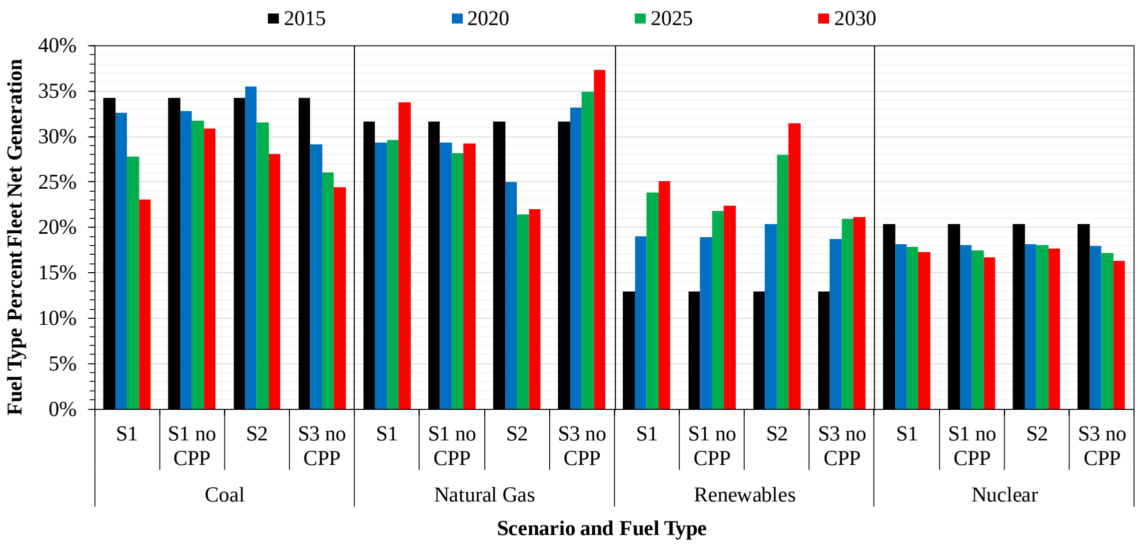

Figure X11. Historical and projected net generation mix for the U.S. power sector for scenarios in AEO 2017 [1, 5].

The generation contribution from natural gas sources, primarily from NGCC plants [4], is more case scenario dependent than the coal-fired generation. Under the CPP reference case, the generation mix increases to 34% by 2030, which is a 21% increase in net generation relative to 2015 levels [1, 5]. When the CPP is not implemented, S1 No CPP, the natural gas generation mix contribution decreases by three percent absolute, even though there is a nine percent increase in natural gas net generation relative to 2015 [1, 5]. In the studied scenarios, the natural gas price needs to be higher, S2, to create a large decrease in natural gas contribution and absolute generation. In S2, the 2030 natural gas, net generation is 23% below the 2015 level [1, 5]. However, when the natural gas price is low, more generation is from natural gas. In this scenario, the 2030 net generation level is 40% greater than the 2015 level [1, 5].

Decreasing capital costs and tax credits increase renewable generation by 2030 for all scenarios [4]. This increase is most profound under the CPP for which the state CO_2 mass allowance set-asides and mass limit requirements encourage renewable energy generation to meet demand. When natural gas prices are high and limit generation from this fuel, S2, these requirements allow for more coal-fired generation because the zero-carbon generation from renewable sources permits more generation from high-carbon coal before the mass limit is reached. Therefore, even at the lowest generation mix, S3 No CPP, generation from renewable energy sources increases 94% from 2015 levels [1, 5].

This large increase in renewable generation is achieved with a corresponding large increase in percent fleet capacity from less than four percent in 2015 to almost twenty-five percent or greater for each scenario in 2030, Figure X12. As such, the increase in renewable source capacity mix creates a misleading decrease in capacity mix from 2015 levels for the other energy sources that might be interpreted as the capacities for the other energy sources greatly decreasing. However, this decrease relates to the projected capacity factor for the renewable fleet only increasing from 37% in 2015 to at most 43% in 2030; thereby requiring a large increase in renewable capacity to supply the projected net generation [5].

Nuclear energy is an important generation source for the CPP because it produces zero-carbon energy. However, high and uncertain capital costs [4, other] and public perception of the nuclear fleet [ahmed and parth?] make it unlikely that new capacity will be added in the future, other than that already under construction. Therefore, the generation contribution from the existing fleet is projected to decrease from 2015 to 2030, as the generation level decreases by four percent over this period [1,4].

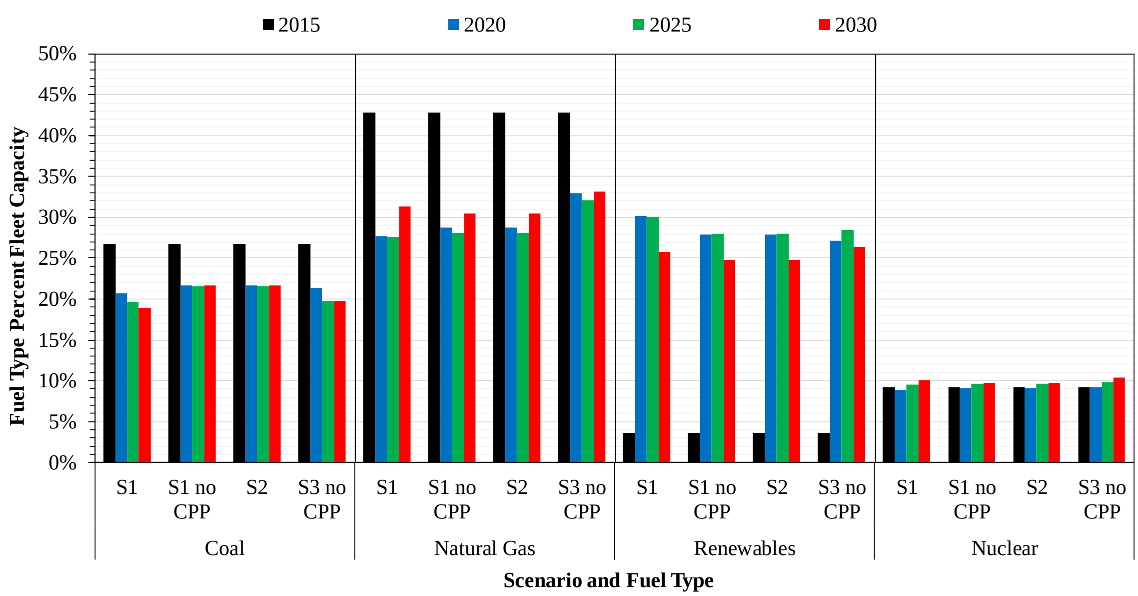

Figure X12. Historical and projected net summer capacity mix for the U.S. power sector for scenarios in AEO 2017 [1, 5]. Largest growth in capacity is in renewable sources. *Put in appendix.*

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Implication for Paris Agreement

At the December 2009 United Nations Climate Change Conference in Copenhagen, the United States (U.S.) pledged to reduce overall domestic greenhouse gas (GHG) emissions in 2020 by approximately 17% from 2005 levels with the intent to further reduce levels by 2050 by 83% of 2005 levels [1]. An additional early target horizon was set for 2025 with the 2015 Paris Agreement, in which the U.S. nationally determined contribution (NDC) to GHG emission reduction was set at 26–28% below the 2005 levels [2]. To facilitate these reductions, President Obama implemented the Climate Action Plan (CAP) [3] to slow and manage the impacts of climate change. A central element in meeting the CAP's goal to reduce national carbon emissions is the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) that promulgates a reduction in carbon dioxide (CO_2) emissions from existing fossil-fuel power plants to 68% of the 2005 level by 2030 [4].[11] This CPP reduction represents the substantial contribution that the electric power sector makes to meeting the Paris Agreement targets: Intermediate targets in the CPP for 2020 and 2025 represent approximately 47% and 37–40% of the Paris Agreement reduction for the corresponding years [5].

The Trump administration is taking different actions concerning GHG emissions. On 28 March 2017, Executive Order 13783 revoked the Climate Action Plan and started a review of the CPP [6]—a review that is leading to the EPA's proposed repeal of the CPP [7]. The U.S. also notified the United Nations on 4 August 2017 of its intent to withdraw from the Paris Agreement, when it is eligible to do so in 2020 [8, 9]. Notwithstanding the repeal of the CPP and the impetus for the regulation, it may still be possible for the U.S. electric power sector to meet its contribution to the NDC pledge, depending on natural gas prices. To illustrate this point, this note summarizes work done to expand on the EPA's regulatory impact analysis of the CPP review [10] and work documented in Ramseur [5] with further analysis of data from the U.S. Energy Information Administration's (EIA's) 2017 Annual Energy Outlook (AEO) [11].[12] In particular, we examine projected electric power sector CO_2 emissions under different natural gas prices to determine if

[11] The potential regulatory contribution of the CPP to the development of more stringent climate polices for the deeper carbon reduction pledge in the NDC for 2050 is beyond the discussion herein.
[12] The AEO projections assume that the mass-based approach is taken by all states.

the 2020, 2025 and 2030 emission targets set in the CPP can still be met by the U.S. electric power fleet in the absence of the CPP.[13]

In the AEO, projected commodity prices, capacities, generation mixes, and fleet emissions are determined by the National Energy Modeling System (NEMS) model, which incorporates, *inter alia*, the impact of economic growth, resource availability, and regulation [12]. Of the nine cases modeled for these three factors, two are shown with and without implementation of the CPP: one pair is the reference case, and the other is for the high resource availability case (which results in low natural gas prices).[14] When these pairs are compared to the CPP emission targets for the years in question, Table 1, one observes that the CPP cases continue on the decreasing glidepath to the 2030 target, while the emissions for the non-CPP cases remain stable. The 2020 emission target is surpassed without the CPP in both natural gas price cases, and the case pairs are almost indistinguishable given the uncertainty in the CO_2 emission projection [17].[15] This is not true for the 2025 target. While the 2025 target is surpassed for the CPP cases,[16] the target in the other cases is not met in the absence of the CPP. However, the non-CPP case with the lower natural gas price is within 13 million tons of the target, which may be within the uncertainty of the projection. Though the NDC does not extend to 2030, the projections indicate that the 2030 CPP emission target will not be met without the associated emission cap and incentive mechanisms. This indicates the positive role that the CPP has on deeper emission reductions beyond 2025.

[13] Many of the data used and the conclusions reached in this work are highly dependent upon the assumptions made in the referenced literature and made for the calculations. Changing these assumptions can lead to different conclusions. This work is a deterministic presentation that does not directly address the uncertainty in the data used.

[14] The low natural gas price cases used are specified in the AEO 2017 literature [11] as “high oil and gas resource and technology” and “high resource without Clean Power Plan.”

[15] The EIA data for the average, absolute, percent difference between the EIA emissions projection and the actual result for one to six-year projections since 2010 is 3.4% percent [17].

[16] In some cases, the AEO 2017 projections for emission reduction surpass the CPP targets. This over-reduction may be viewed as an overcorrection inefficiency, or as establishing a surplus reduction that may be used to offset other GHG reduction programs that do not meet associated targets for the NDC.

Table 1. Clean Power Plan CO_2 Emission Targets and AEO 2017 Projected CO_2 Emissions with and without the CPP for 2020, 2025, and 2030 [12, 14].[17] Values in boldface indicate that the case surpasses target.

	Annual CO_2 Emissions (million short tons)		
Case/Year	2020	2025	2030
Target	2,073	1,901	1,814
Reference with CPP	**2,007**	**1,829**	**1,694**
Reference without CPP	**2,024**	2,039	2,078
Low Natural Gas Price with CPP	**1,922**	**1,782**	**1,689**
Low Natural Gas Price without CPP	**1,936**	1,914	1,922

When the projected natural gas price[18,19] and the resulting fleet CO_2 emission reduction for these case pairs are plotted with historical data,[20] Figures 1 and 2, one observes that the historical trend for CO_2 emissions decreasing with lower natural gas prices[21] is maintained in each case pair, until the CPP is in full effect in 2030.[22] Furthermore, the emission reductions for each pair are lower than the 2015 level, even though the natural gas prices for these pairs are higher. This decrease in emissions may be due in part to a fuel-switch from coal to renewable and natural gas sources[23] related to policy mechanisms for renewable energy[24] and/or a favorable natural gas price.[25] Therefore, one market-based mechanism to achieve the NDC emissions target for 2025 would be through an increase in fuel-switching to natural gas sources—to natural gas combined

[17] The AEO projections assume that the mass-based approach is taken by all states.

[18] Natural gas prices in dollars per million British thermal units ($/MMBtu) are converted to 2010 dollars with the Consumer Price Index (CPI) [14]. Natural gas prices from the EIA are based upon national averages.

[19] Unless specified otherwise, all dollar values are in 2010 dollars.

[20] Historical data are from EIA *Monthly Energy Review* [15] and are converted to 2010 dollars with the CPI [14].

[21] The correlation between price and reduction is not chronologically perfect, however. Coal prices, capacity planning, regulations and policy mechanisms (such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy), unforeseen events, technology changes, and hedging related lags [16, 17, 18] may account for some of the imperfect responses between the natural gas price and the reduction, as occurs from 2006 to 2008 and from 2012 and 2014, when the natural gas prices increase but the emission intensities remain constant.

[22] Prior to 2030, the annual CO_2 emission target is on a glidepath to reach the 2030 target [4]. From 2030 on, this target is maintained, so further decreased emissions come from monetary incentives rather than from regulatory mandates.

[23] Fugitive methane emissions for natural gas sources are not included.

[24] Such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy.

[25] AEO 2017 projections indicate that the percent net generation from renewable sources increases for the case pairs in 2020, 2025, and 2030, relative to 2015 [11]. The percent-generation from coal decreases in the case pairs for these years, whereas the natural gas generation increase depends upon the gas price and emission target or cap for that year.

cycle (NGCC) plants[26]—that would occur if natural gas prices were below \$3.40/MMBtu.[27] The natural gas price will need to be even lower to meet the 2030 CPP target. Estimating this crossover price with a simple, linear extrapolation of the projected 2030 emissions without the CPP yields a natural gas price at or below \$2.95/MMBtu.

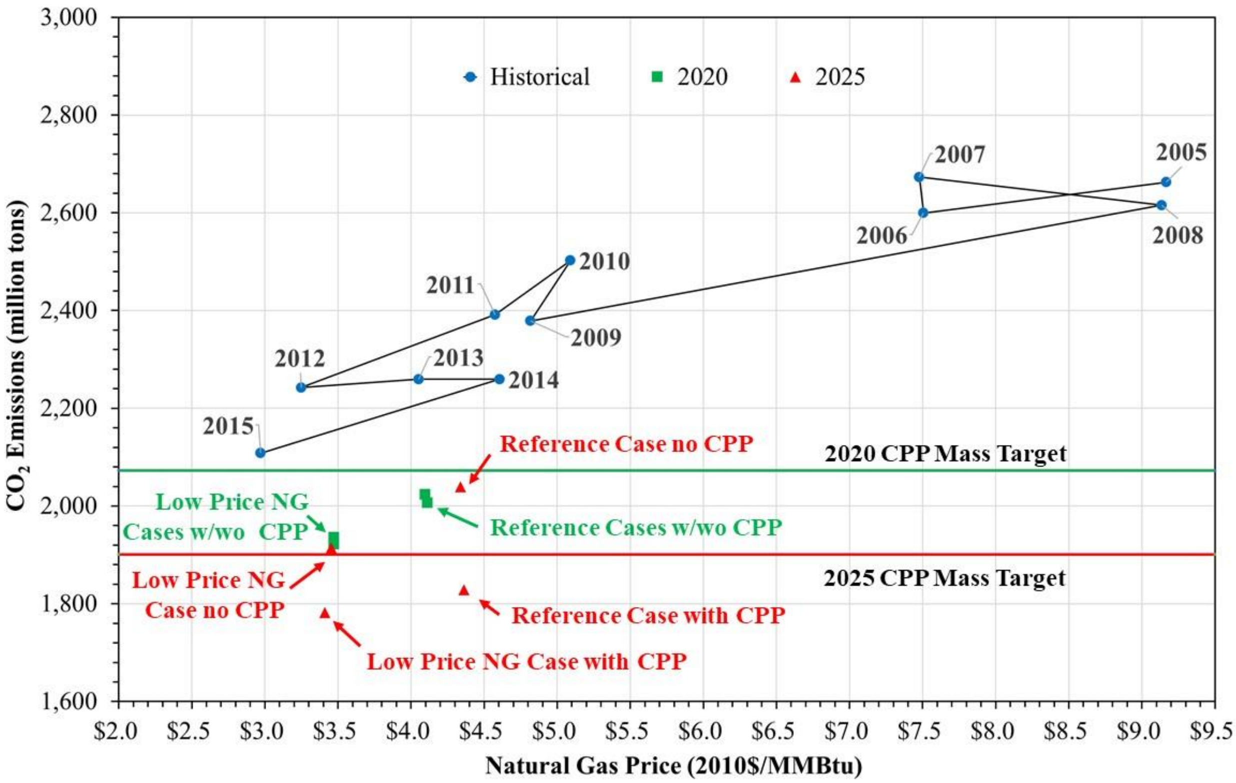

Figure 1. Historical and projected 2020 and 2025 CO_2 emissions from the U.S. power sector in relation to natural gas price [15]. Projected emissions and gas prices are national averages based on scenarios in the Annual Energy Outlook (AEO) 2017 for the reference case, and the high oil and gas resource and technology case [11]. Complementary scenarios in AEO 2017 are shown with and without the Clean Power Plan. Historical and projected natural gas prices from AEO 2017 are converted to 2010 dollars with the Consumer Price Index [14].

[26] The reduction in emissions comes from the difference in the CO_2 emission intensity for the two sources, based upon net generation. The 2015 average CO_2 emission intensity for the U.S. power sector coal-fired fleet was 2,200 lbs/MWh [15]. The CO_2 emission intensity for a new, conventional NGCC plant is 772 lbs/MWh. Therefore, replacing the net generation from the average coal-fired EGU with net generation from a new conventional NGCC plant reduces the total emissions by 65%.

[27] The projected natural gas price for 2030 may need to be lower than the 2015 price to achieve the CPP target, based upon the historical 2014-2015 relationship between natural gas price and CO_2 emission reduction.

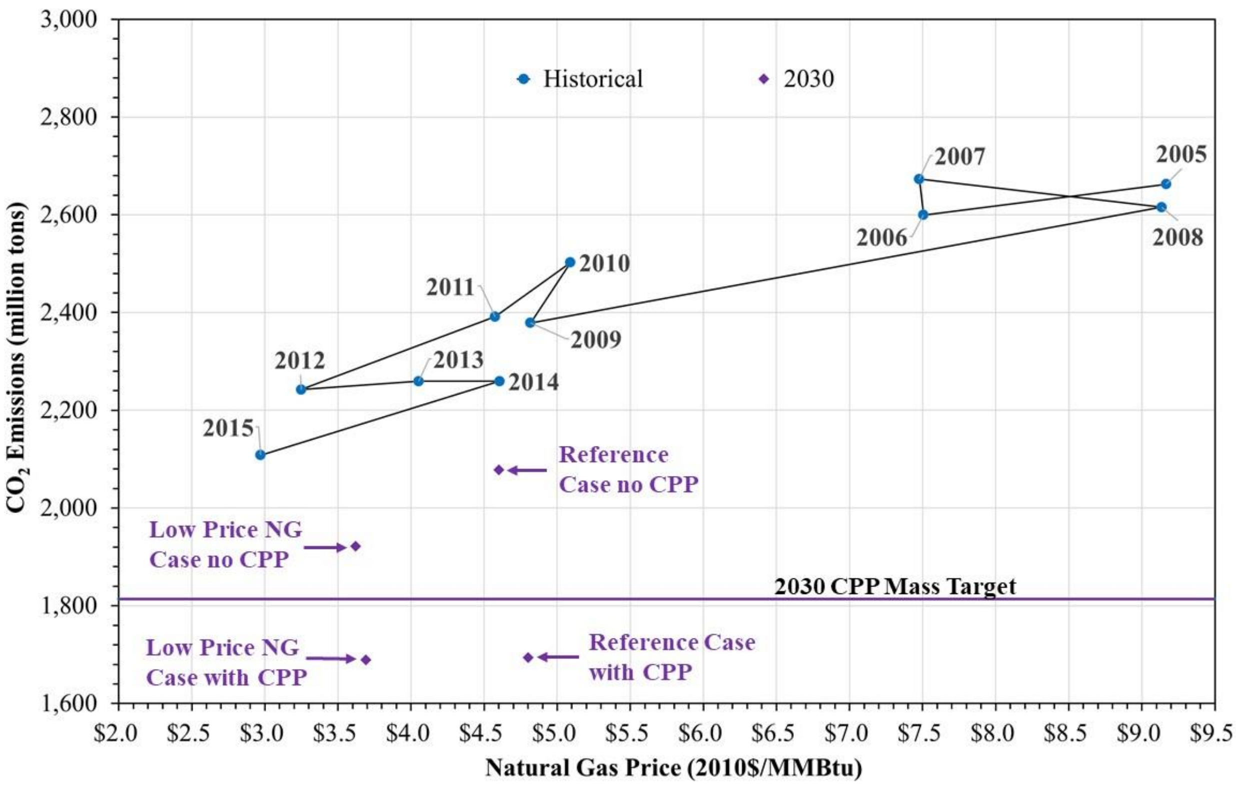

Figure 2. Historical and projected 2030 CO_2 emissions from the U.S. power sector in relation to natural gas price [15]. Projected emissions and gas prices are national averages based on scenarios in the Annual Energy Outlook (AEO) 2017 for the reference case, and the high oil and gas resource and technology case [11]. Complementary scenarios in AEO 2017 are shown with and without the Clean Power Plan. Historical and projected natural gas prices from AEO 2017 are converted to 2010 dollars with the Consumer Price Index [14].

The emission targets can also be met, *ceteris paribus*, by building more NGCC plants and/or onshore wind farms. For the 2025 reference case with NGCC replacement, this will require eliminating 138 million tons of CO_2 by replacing approximately 31.5 gigawatts (GW) of coal-fired capacity with 26.5 GW of NGCC capacity, at a CO_2 avoidance cost of $34.8/ton and a total annual cost of $4.8 billion, Table 2. Reducing the same amount of CO_2 emissions through onshore wind generation will require an additional 56.3 gigawatts (GW) of wind capacity at a CO_2 avoidance cost of $11.2/ton[28] and a total annual cost of $1.5 billion. The required emission reduction to meet the target for the low natural gas price case is almost an order of magnitude less than the reference case; therefore, the associated capacity requirement and cost for each

[28] This assumes the 2025 wind sources enter service in 2022 and are eligible for the current production tax credit valued at $11.6/MWh (2016 dollars) [20].

substitute source is also almost an order of magnitude lower.[29] Thus, it is possible to meet the 2025 NDC emission target through replacing some of the coal-fired fleet with NGCC and/or wind sources. The required capacity of these sources and the total cost of meeting the target is dependent upon the natural gas price and a mechanism to promote this emission reduction.

Table 2. 2025 Cases without CPP for Replacement Sources to Decrease CO_2 Emissions to CPP Target

Parameter	**Units**	**Reference**		**Low NG Price**	
Excess CO_2	Million short tons	138		13	
Retired coal capacity[30]	Gigawatts	31.5		3.2	
Retired coal EGUs[31]	Number	82		8	
Natural gas price[32]	2010$/MMBtu	4.34		3.41	
New Generation Source Cases		NGCC[33]	Wind[34]	NGCC	Wind
New source capacity	Gigawatts	26.5	56.3	2.5	5.4
New sources	Number	38	18,755	8	1,795
CO_2 avoidance cost[35]	2010$/ton	34.8	11.2	26.4	11.2

29 The avoidance cost for the NGCC source in the low natural gas price case is lower than that for the reference case because of the natural gas price.

30 The calculation for the required retirement capacity for the coal-fired fleet is based upon four parameters: (1) the projected profile of the coal-fired fleet in 2020, 2025, and 2030 (the fleet capacity, average emission intensity (lbs CO_2 per megawatt-hour), and net generation), (2) the required reduction in coal-fired generation, (3) the CO_2 emissions emitted from the replacement source to match the reduced coal-fired generation, and (4) the required reduction in CO_2 emissions to meet the target. The projected coal-fired emission intensities are calculated from AEO 2017 coal-fired emission and net generation data [11]. The resulting values for 2020, 2025, and 2030 are 2131, 2143, and 2132 lbs/MWh, respectively. The replaced coal-fired net generation is found by setting the coal-fired emission intensity multiplied by replaced net generation plus the emissions from the replacement source equal to the required reduction in CO_2 emissions to meet the target, and solving for the net generation. The retirement capacity is then determined from the calculated coal-fired fleet capacity factor, based upon the projected capacity and net generation [11], and the coal-fired net generation that needs to be replaced.

31 The required number of coal plants to be retired to reach the emissions goal serves as a reference only, and is based upon the capacity of a proxy coal EGU emitting CO_2 at the emission intensities described in the previous endnote. This capacity of this proxy plant is the average net summer capacity of the 669, operational coal plants with capacity greater than 25 MW that use bituminous, subbituminous, lignite and waste coal, as listed in the August 2017 EIA form 860M [19]. The calculated average capacity is 386 MW. The number of actual plants that might be retired in this scenario will depend upon many factors and is beyond the scope of this work.

32 The EIA data for the average absolute percent difference between the EIA emissions projection and the actual result for one to six-year projections since 2010 is 21% percent [17].

33 The replacement NGCC plant is a conventional NGCC plant that is constructed in 2022 for the 2025 scenario and in 2030 for the 2030 scenario. The capacity is taken as 702 MW net summertime capacity [21]. This plant operates at an 87% capacity factor [20], has a heat rate of 6,600 Btu/kWh and the CO_2 emission intensity is 117 lbs/MMBtu [21].

34 The replacement onshore wind turbine enters into service in 2022 for the 2025 scenario and in 2030 for the 2030 scenario. The capacity is taken as 1.79 MW [20] and operates at a 41% capacity factor [20].

35 The CO_2 avoidance cost is based upon the difference in the generation levelized cost of electricity (LCOE) between the base case and the case to obtain the reduced emissions divided by the associated change in CO_2 emission intensity. The projected baseline generation LCOE for the projected fleet is given in the AEO 2017 [11].

Annual Cost[36]	Billion dollars	4.8	1.5	0.3	0.1

The gap between the projected emissions and the target is greater for the 2030 cases, and requires more alternative source capacity at a greater cost to bridge, Table 3. In the 2030 reference case, almost twice as many excess CO_2 emissions must be replaced as in the 2025 case; therefore, the 2030 retired electric generating units (EGUs), alternative NGCC capacity, and cost requirements are almost twice as large. This scaling is also true for wind replacement; however, the wind avoidance cost is now twice as great as that for 2025 due expiration of the production tax credit. Replacement in 2030, when the natural gas price is low, results in the avoidance cost and overall cost for the NGCC replacement to be lower than that for the wind. This is due to the increased levelized cost of electricity for the wind source in the absence of the tax credit, and to the lower variable cost for the NGCC plant because of the low natural gas price.

Table 3. 2030 Cases without CPP for Replacement Sources to Decrease CO_2 Emissions to CPP Target

Parameter	**Units**	**Reference**		**Low NG Price**	
Excess CO_2	Million short tons	264		108	
Retired coal capacity	Gigawatts	58.9		25.9	
Retired coal EGUs	Number	153		67	
Natural gas price	2010$/MMBtu	4.60		3.62	
New Generation Source Cases		NGCC	Wind	NGCC	Wind
New source capacity	Gigawatts	50.6	107.4	28.6	44.1
New sources	Number	72	35,785	30	14,706
CO_2 avoidance cost	2010$/ton	37.2	29.2	28	29.4
Annual Cost	Billion dollars	9.8	7.7	3.0	3.2

This is adjusted for the replaced coal-fired generation with an assumed generation LCOE for the coal-fired fleet taken from Jean et al [22] as $33/MWh (assumed in 2016 dollars). The coal-fired LCOE is held constant for all years, given a projected maximum 0.6% annual increase in delivered coal price between 2016 and 2050 for the cases [11]. The 2025 and 2030 generation LCOE for the conventional NGCC plant is taken as $57.5/MWh, and is adjusted with the plant heat rate for variation in natural gas price from the 2022 reference case with CPP level [20]. The 2025 generation LCOE for the wind turbines is taken as $41.4/MWh, which is the LCOE for service entry in 2022 inclusive of a $11.6/MWh tax credit [20]. The 2030 LCOE is taken $55.0/MWh, which includes a linear approximation of the LCOE increase between 2022 and 2040 and excludes the tax credit [20]. Dollar values in this endnote are given in 2016 dollars. The replacement LCOEs exclude any additional transmission investments and include the annualized capital investments.

[36] These costs are the annual costs, based upon the avoidance costs and the necessary emission reduction.

While the Paris Agreement NDC is non-binding and the U.S. currently intends to withdraw prior to the target dates, the portion of the target that is represented by the reductions present in the CPP may still be met in 2020 and 2025, even if the CPP is repealed. Projections from the EIA indicate that the CO_2 emission reduction with or without the CPP may be substantially the same in 2020. Furthermore, the 2025 reduction may be met without the CPP if natural gas prices are below $3.40/MMBtu. In lieu of lower natural gas prices, some coal-fired generation can be replaced with generation from NGCC and wind sources to meet the 2025 target and to achieve the 2030 CPP target. In the absence of the CPP's incentives and mechanisms to achieve these deeper reductions, the fuel choice for the replacement source and the cost for future reductions will depend upon the policy maker's decisions on renewable subsidies and mechanisms to incentivize the reductions, and on the actual natural gas price, however.

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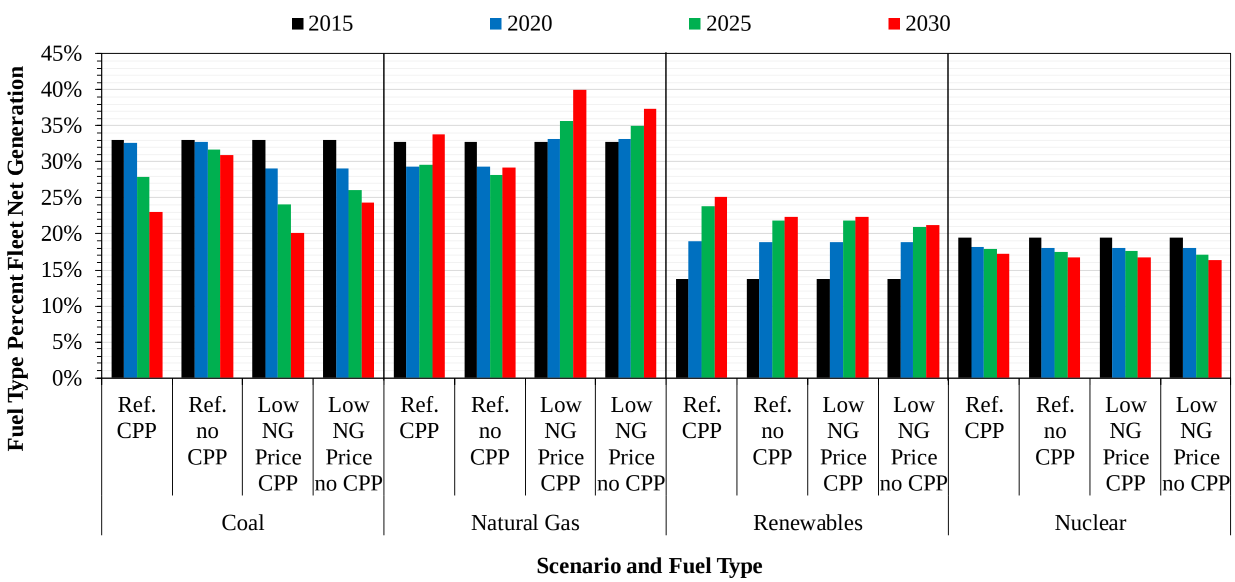

Figure 3. Historical and projected net generation mix for the U.S. power sector for complementary scenarios with and without the CPP in AEO 2017 [11,23].

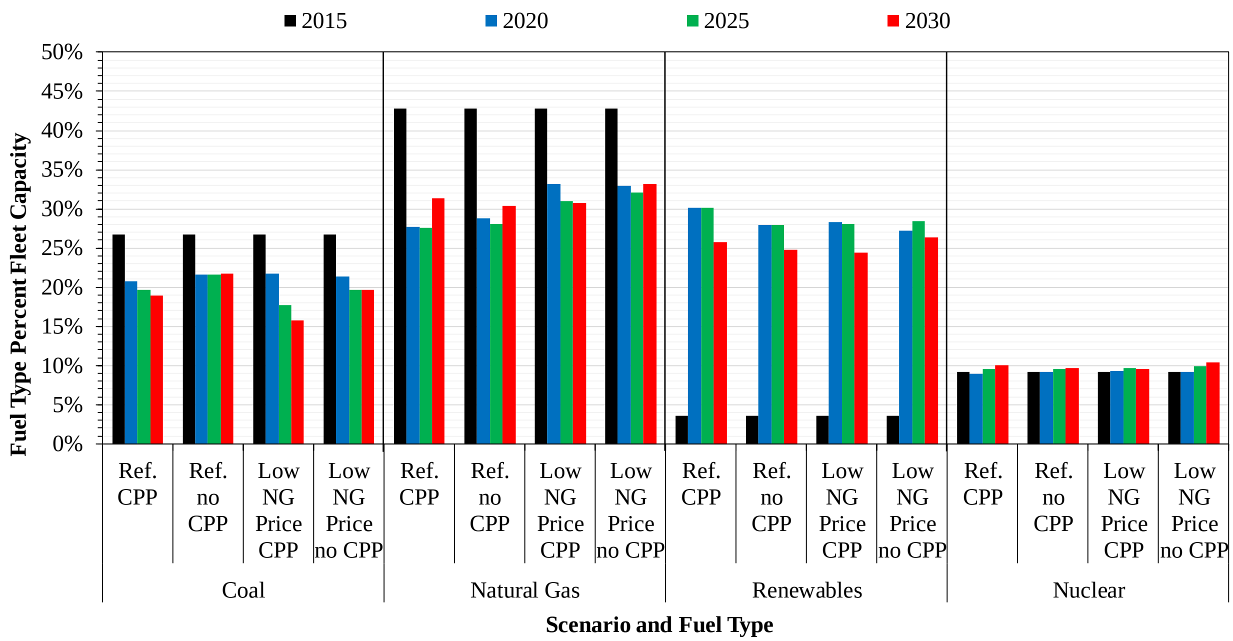

Figure 4. Historical and projected net summer capacity mix for the U.S. power sector for complementary scenarios with and without the CPP in AEO 2017 [11,23].

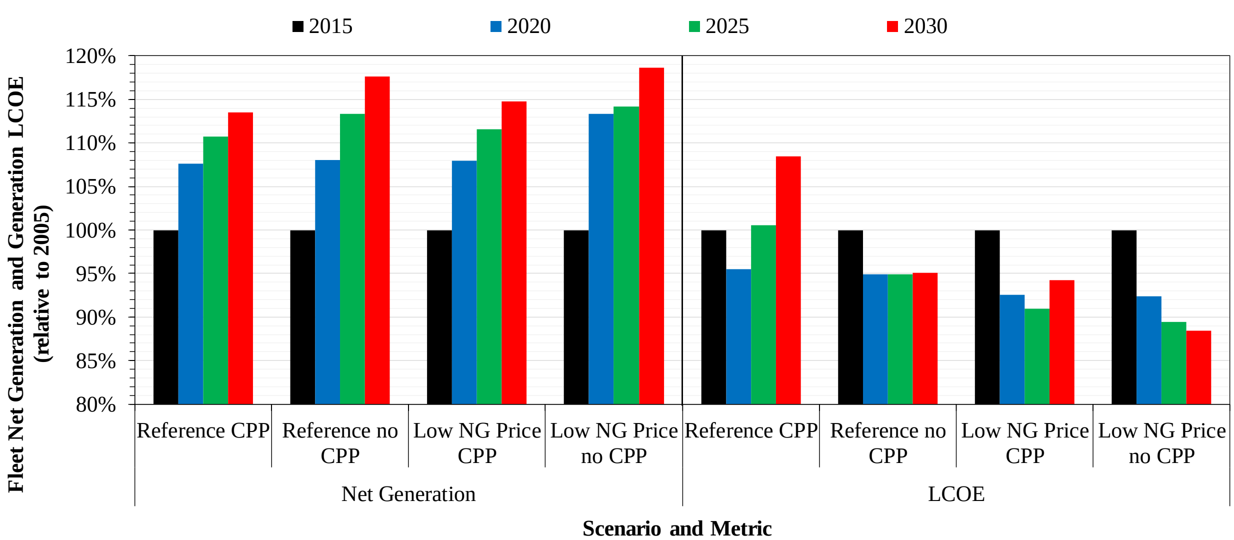

Figure 5. Historical and projected net generation and levelized cost of electricity for the U.S. power sector for scenarios in AEO 2017, relative to 2005 values [11,23].

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