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How Clean Is Your Capture? Co-Emissions from Planned US Power Plant Carbon Capture Projects

Sanjay Purswani and Daniel Shawhan

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About the Authors

Sanjay Purswani, a Senior Knowledge Analyst at Boston Consulting Group (BCG), is an experienced professional with a background in the clean energy and low carbon fuels sectors. With over 7 years of industry expertise, he actively contributes to BCG's endeavors in engineering, economics, and policy study related to low carbon hydrogen and renewable natural gas (RNG). Throughout his career, he has held various engineering positions with a focus on low emission power generation and emission control technologies. He has successfully led grant applications offered by California Energy Commission (CEC) and Michigan Public Service Commission (MPSC). Furthermore, Sanjay has played a key role in the development of local government waste-to-energy projects that have made significant strides in reducing emissions at a state level.

Daniel Shawhan is a fellow at Resources for the Future (RFF), an adjunct faculty member at Cornell University, and a member of the Environmental Advisory Council of the New York Independent System Operator. Much of his research focuses on predicting and estimating the effects of electricity policies, including environmental ones. He leads the development and application of the Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST), a detailed US and Canadian power sector model for simulating how power grids, power plants, air quality, and public health will respond to potential changes in policy and infrastructure. He also works on electricity market design and environmental policy design. Shawhan has helped state governments craft electricity market reforms and first-in-the-nation policies for hybrid vehicles, energy efficiency, green buildings, and renewable energy.

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Abstract

We use information from the public engineering studies of six planned power plant CO_2 capture retrofit projects to interpret and summarize their expected emission rates of four co-emission types: sulfur dioxide, nitrogen oxides, fine particulate matter, and ammonia. We also estimate the health damage per MWh that will result from operating these power plants with CO_2 capture projects while comparing it with the health damage per MWh for power plants without CO_2 capture. Three of the power plants use coal and the other three use natural gas. The coal plants will cause estimated co-emission damage of \$7.21 per MWh after adding CO_2 capture, compared with \$31.11 before adding CO_2 capture and compared with an average of \$65.85 across all US coal-fueled power generation. For the natural gas-fueled plants, the estimates are \$3.09 after, \$3.52 before, and \$21.13 across all US natural gas-fueled generation. The large improvement at the coal plants is chiefly because the capture of CO_2 requires the capture of almost all sulfur dioxide as well.

1. Introduction

Power plants and other facilities powered by the burning of coal and natural gas are significant sources of harmful emissions to the air, both greenhouse gases and other harmful pollutants that are sometimes called “co-pollutants” or “co-emissions.” It is well established that CO_2 capture technologies can typically capture at least 90 percent of the CO_2 produced by large fuel-burning facilities. It is much less certain what effect CO_2 capture will have on the co-emission rates. For example, per MWh of net electricity production, Varela et al. (forthcoming) find that adding CO_2 capture could reduce the $PM_{2.5}$, NO_X, NH_3, and SO_2 emission rates of new natural gas-fueled power plants by more than 99 percent, could increase them, or could have an in-between effect. The effects on co-emission rates will depend on the technology used for CO_2 capture and on any changes in co-emission control technologies and practices made by the owners of the generating units as a result of adding CO_2 capture. That depends in part on US power plant emission regulations and the decisions of regulators.

Co-emission rates are major determinants of the public health effects of CO_2-capturing facilities and could determine whether CO_2 capture and sequestration (CCS) is developed and widely deployed. CCS has the potential to greatly deepen greenhouse gas emission reductions generally because many energy applications are difficult to satisfy without fossil fuels, because capturing the CO_2 from biomass and waste energy can produce net negative greenhouse gas emissions, and because allowing CCS may considerably broaden the political support for deep decarbonization. Decisions in the US about advancing CCS could be decisive globally because the US government is the world’s main funder of CCS research and development, more so than for other clean energy technologies (Global CCS Institute 2021).

Most of the US environmental justice advocacy community is opposed to CCS, as indicated by the White House Environmental Justice Advisory Council statement that CCS would not be beneficial to communities (White House Environmental Justice Advisory Council, 2021). If co-emission rates of generators retrofitted with CCS are high, the net benefits of CCS are likely to be lower (possibly negative), opposition is likely to be stronger, and CCS is less likely to become a major greenhouse gas emission reduction technology. If co-emission rates of CCS are low, the opposite statements apply.

At present, only five commercial-scale power plant CO_2 capture projects have operated anywhere on Earth (Global CCS Institute CORE2 2023), and only one in the US in the last decade. Because the technology is relatively new, they are evolving and changing over time. However, we do not need to wait until new CO_2 capture facilities are operating to have information about what their co-emission rates will be, because the developers of five power plant CO_2 capture projects have recently submitted front-end engineering design (FEED) studies to the US Department of Energy, one power plant CO_2 capture project (PetraNovaCFPP, 2017) has submitted a final post-project technical report, and the six studies are publicly available. In this paper, we interpret and summarize what those studies say about the co-emission rates of the six projects, which all involve retrofitting CO_2 capture onto existing electric generating units. Additionally, we estimate the health damages associated with those co-emission rates and compare them with the estimated health damage of coal- and natural gas-fueled generating units (CFPPs and NGPPs) without CO_2 capture.

While all of the six CO_2 capture projects in the engineering studies are retrofits, the analysis can also be useful for better understanding the likely co-emission rates of new generating units that might be built with CO_2 capture incorporated in the design from the start. There are some additional technologies that could be used for a new generating unit and probably not for a retrofitted one, such as supercritical CO_2-cycle technologies and fuel cells, but the technologies that are strong candidates for retrofitting existing EGUs are also strong candidates for new EGUs. Those technologies are amine-based CO_2 capture and membrane-based CO_2 capture, which is new. Both types are represented in the six engineering studies. New generating units that shared a fuel type and basic CO2 capture method (amine-based or membrane-based) with one (or more) of the six generators in the engineering studies and were in a state with similar state and federal emission regulations, would face similar requirements, incentives, and options for control of co-emissions. Emission controls are generally less costly for new generating units, so the new generating unit with CO_2 capture might have lower co-emission rates than the generating unit in the engineering study, but it would have little reason to have higher co-emission rates.

Table 1 shows the basic characteristics of the CO_2 capture projects as described in the engineering studies. The engineering studies did not have all the information necessary to calculate the increase in heat rate associated with a CCS retrofit, hence increases of 27.9 percent for coal and 12.6 percent for natural gas were taken from NETL (2022), based on typical designs for power plants with and without CO_2 capture. These increases in heat rates are mainly due to increased natural gas or coal use to power the CCS process and the compression of the CO_2 for pipeline transport.

Table 1. Basic characteristics of the projects in the six-power plant CO_2 capture engineering design studies

Name	Year of engineering study	Fuel	CO_2 capture technology type	Planned percent of CO_2 capture
San Juan CFPP	2022	Coal	Amine	95
Basin Fork CFPP	2022	Coal	Membrane	70
Petra Nova CFPP	2020	Coal	Amine	85
Panda Sherman NGPP	2021	Natural gas	Amine	85
Elk Hills NGPP	2022	Natural gas	Amine	90
Daniel NGPP	Amine	Natural gas	Amine	90

Table 1 includes the estimated percentages of the CO_2 to be captured. Future projects using similar capture technology might plan for higher capture rates, after uncertainties have been reduced and the incremental costs of a higher capture percentage have decreased. Alternatively, they might plan for lower capture percentages if regulations require capture but only low percentages of capture, as proposed US EPA regulations might. However, the changes in co-emission rates, which we examine in this paper, are unlikely to be greatly affected by CO_2 capture percentage, for reasons we explain in context at the end of Section 3.

The changes in co-emission rates are not complete measures of the co-emission changes that CO_2 capture retrofits would cause. Retrofits would also be likely to change the capacity factor of the generating unit, its remaining lifespan, and the generation, lifespans, and co-emissions of other generators. The retrofit could extend the lifespan of the unit, which could reduce or increase industry-wide emissions, depending on the emission rates of the other generation that is displaced by the unit's extended operation. Those effects will be partially determined by policies. Varela et al. (forthcoming) and Grubert and Sawyer (2023) examine these effects. However, the changes in co-emission rates of the retrofitted units are an important part of the overall co-emission effects.

2. Study Approach

For this paper, we analyzed the six power plant CO_2 capture engineering studies that have been most recently submitted to the US Department of Energy (DOE), since 2017. These engineering reports provide some detailed information on technical aspects of adding CCS to existing coal and natural gas power plants. They include some information on the design of the CCS, the emissions rates, and the costs associated with implementing the technology. Our main purpose is to report what they say and imply about the effects of CCS on the major co-emissions of concern: SO_2, NO_X, $PM_{2.5}$, and NH_3. We examine the design and technology of the CCS, the type of fuel used, and the operational characteristics of the power plant in order to understand change in emissions rates once retrofitted with CCS. We also estimate the value of the health damage caused by the emissions of SO_2, NO_X, $PM_{2.5}$, and NH_3.

The engineering reports examined in this paper are from a variety of power plants and therefore have a variety of different estimation methods, study boundaries, product qualities and feedstocks. Some of the emission rates are directly extracted from engineering studies whereas others are converted from different units to lbs/mmbtu. These conversions are further explained in section 3 of this working paper.

3. Emissions per Unit of Heat Input

For each of the six generating units, we sought data on its emission rates before and after the retrofit with CO_2 capture equipment. The emission rates per unit of heat input, measured in pounds per million British thermal units (lbs/MMBtu) were extracted from each engineering study for this analysis and standardized in terms of units. In some cases, the study reported them directly. In other cases, the study reported emission rates only in parts per million (ppm). To convert those to lbs/MMBtu, ppm values that were not already measured with a concentration of 15 percent O2 were converted to gas being measured with 15 percent O2 for a consistent comparison. We then converted to pounds per dry cubic feet (lbs/dscf) by using molecular weight of the emission type. Using EPA method 19 F^d factor, pounds per dry cubic feet was converted into pounds per mmbtu (EPA M19, 2003)

The F^d factor, used to calculate emissions, was determined differently for various power plants. The F^d factor is the volume of dry combustion components per unit of heat produced by the fuel. For Panda Sherman NGPP, Petra Nova CFPP, and San Juan CFPP, the F^d factor was calculated using the lower heating value (LHV) specified in the engineering study (PandaShermanNGPP, 2021) (PetraNovaCFPP, 2017) (SanJuanCFPP, 2022). Conversely due to the lack of LHV data, the higher heating value (HHV) was utilized for Dry Fork coal fired generating unit (CFPP) and Daniel

NGPP (BasinForkCFPP, 2022) (DanielNGPP, 2022). HHV is approximately 4 percent higher than LHV for coal and 9 percent higher for natural gas. Additionally, the EPA's method 19 was employed to derive the F^d factor for Elk Hills NGPP (ElkHillsNGPP, 2022).

All ppm values in this study have been converted to be consistent with the assumption of 15 percent O2 concentration in the final emitted flue gas stream.

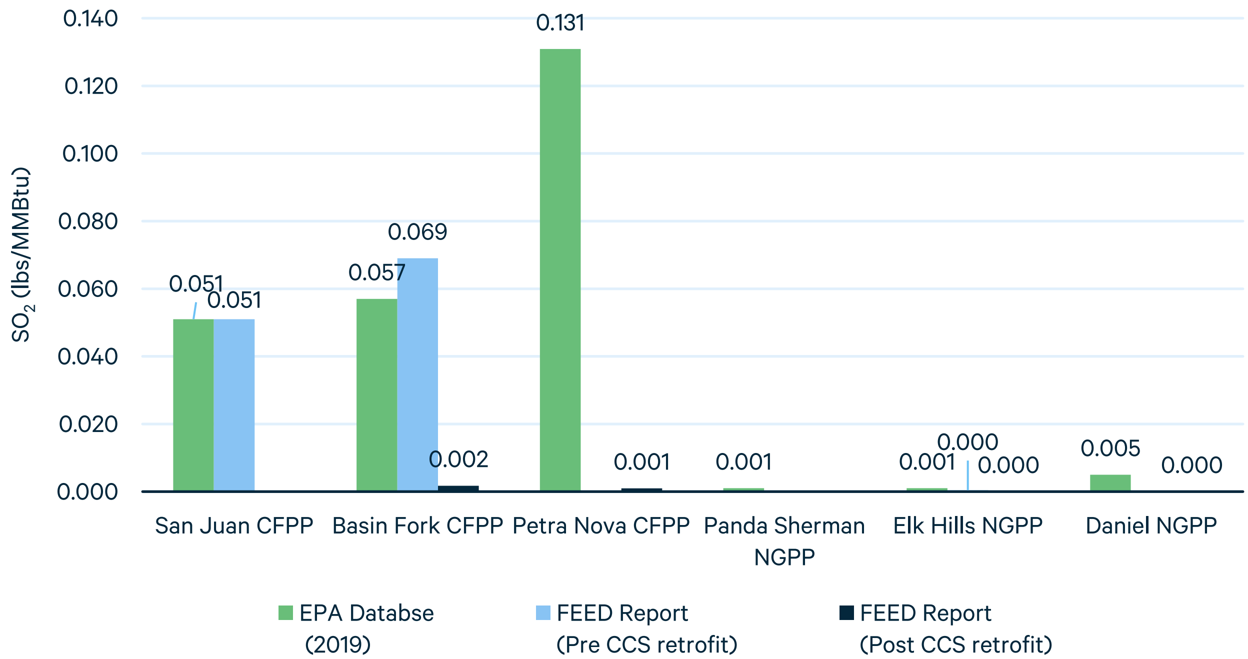
Some engineering studies provide emission rates for different types before and after retrofit with CCS. For the ones which do not provide before retrofit, historical data are an alternative source of emission rates before the retrofit with CO_2 capture. We used EPA's eGRID data from 2019 for all engineering studies except Petra Nova CFPP (EPAeGRID2019, 2020). For Petra Nova CFPP, the pre-CCS SO_2, NO_X, and NH_3 historical emission rate data from EPA that we use is from 2014 (EPAeGRID2014, 2015). The CO_2 capture at that facility started operating on January 10, 2017. The emissions rates for of those three pollutants might have been affected already in 2016, and there is no eGRID data for 2015.

Examining emission rates per unit of energy input, as we do in this section, is informative because it reveals whether there is an improvement associated with the installation of capture technology, and if so, how large that improvement is. However, after the retrofits, some of the generating unit's produced energy would be used to power the capture process. If there is no change in emissions per unit of energy input, this increases emissions in proportion to the increase in heat rate (i.e., in proportion to total energy input required per MWh delivered to grid). This section of the text focuses on emissions rates per unit of heat input; the effects of CCS on emissions and estimated damage per unit of energy delivered is section does not show this since it reports emissions per unit of energy input. to the grid are explored in Section 4.

3.1. Sulfur Dioxide Emissions

Figure 1 shows the reported or calculated SO_2 emission rates (lbs/MMBtu) at each of the six generating units. The green columns show historical pre-retrofit emission rates according to EPA's eGRID data. The blue columns show the emission rates before retrofit according to the engineering study. The black columns show the projected emission rates after the retrofit. Where there is no column and no number, we have no value because data were unavailable. No SO_2 emission information was given for before or after retrofit in the Panda Sherman NGPP FEED study. Only pre-CCS retrofit SO_2 emission data was given in the San Juan FEED study. Only post CCS retrofit SO_2 emission data was given in the Petra Nova CFPP and Daniel NGPP engineering studies.

Figure 1. Estimates of SO_2 emission rates before and after retrofitting with CCS



As shown in Figure 1, across the three coal-fueled generating units, the highest SO_2 emission rate before retrofit is 0.131 lbs/MMbtu, and the highest reported projected rate after retrofit is 0.002 lbs/MMBtu.

Natural gas has a much lower concentration of sulfur compared to coal, resulting in lower SO_2 emissions from natural gas than from coal. Across the three natural gas-fueled generating units, the highest SO_2 emission rates are 0.005 lbs/MMbtu before retrofit (perhaps because of some use of oil as a fuel) and 0.000 lbs/MMBtu, meaning less than 0.0005 lbs/MMBtu) after retrofit.

Amine-based CO_2 capture systems, used in five of the six projects, are fouled by SO_2, as SO_2 reacts with the solvent, which leads to the formation of salts and to costly solvent loss. As a result, the use of an amine-based CO_2 capture system requires extremely low concentrations of SO_2 in the inlet gas of the CO_2 capture system. Consistent with the reductions in the coal engineering studies, Iijima et al. (2007) and Kishimoto et al. (2008) reported for a demonstration project, removal of a minimum of 98 percent of the SO_2 from the gaseous effluent stream before it entered the CO_2 capture process, in CO_2 capture from coal in earlier projects. This SO_2 removal is accomplished almost entirely by the installation of a desulphurization SO_2 scrubbing system by the time the CO_2 capture system comes online. In addition, a portion of the remaining SO_2 entering the amine-based CO_2 capture system is captured by the CO_2 capture system.

Figure 1 shows that the desulphurization SO_2 scrubbing system and CO_2 capture system added to the Petra Nova unit are estimated to result in a 99 percent reduction of Petra Nova's SO_2 emission rate. This reduction is based off the 2014 historical data pre-CCS taken from EPA.

The San Juan CFPP FEED study does not report an expected post-retrofit SO_2 emission rate, only a rate for permitting purposes that is based on its pre-retrofit rate (San Juan, 2023). As a result, we do not know what SO_2 emission rate the project designers expected after the retrofit. The San Juan FEED report highlights the inclusion of a caustic scrubber for SO_2 reduction prior to its release through the stack. The design of the SO_2 control and CO_2 capture system is based on Petra Nova CFPP. Given that San Juan CFPP will adopt the same technology as Petra Nova, it is reasonable to anticipate a similar post-CCS SO_2 emission rate. However, we have left the post-retrofit SO_2 emission rate unspecified in Figure 1 and in later sections of this paper.

The Basin Fork CFPP is unique among the six projects in that it does not involve an amine-based CO_2 capture system. It instead involves a membrane-based capture system, using technology from the company MTR. The project is expected to produce an estimated per-MMBtu SO_2 emission rate reduction of 97 percent compared with controlled SO_2 emission rate prior to retrofit. The direct contact cooler that would be part of this project between the combustion and membrane stages would, in addition to cooling the gases, also increase the capture of SO_2. A maximum concentration of 5ppm for SO_2 is required before entering the membranes in order to have a clean CO_2 product with sufficiently low SO_2 impurities.

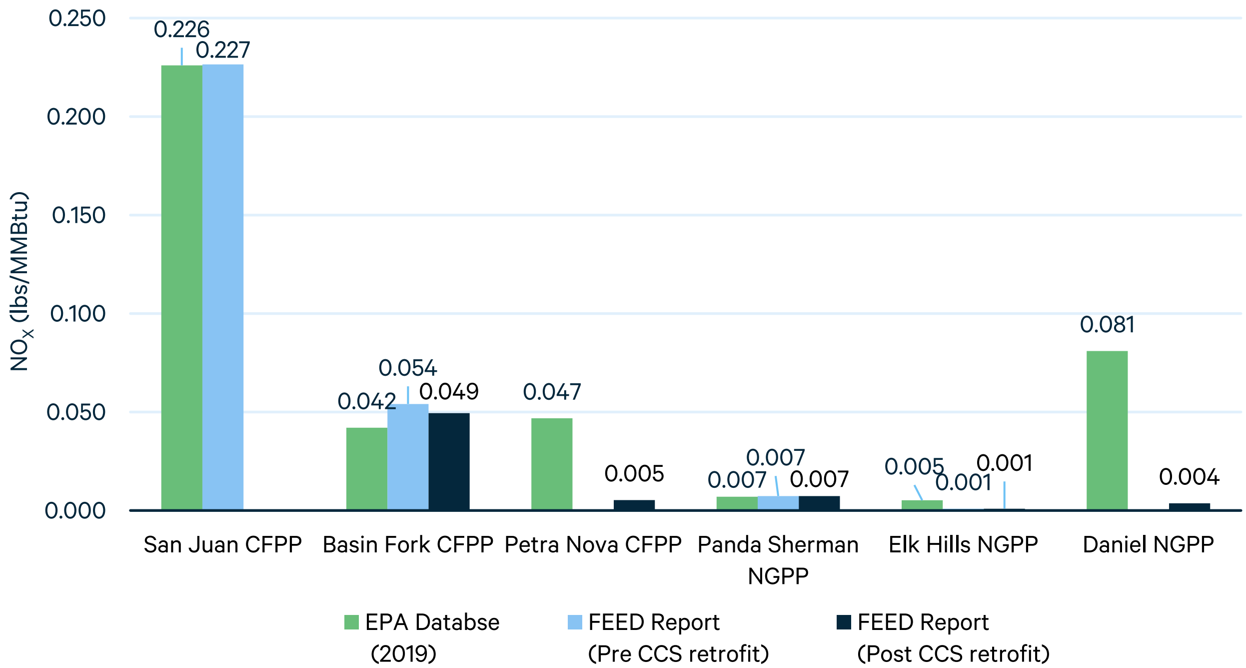
3.2. Nitrogen Oxide Emissions

NO_X can pass through both amine-based and membrane-based CO_2 capture systems without being captured and without causing major problems for the capture systems. As a result, there is no technical need for a CCS retrofit to change the per-MMbtu NO_X emission rate of a generating unit. However, adding CCS could still cause a NO_X emission rate reduction for any of at least three reasons. First, under US law, adding CO_2 capture is a major change that can trigger a requirement for a generating unit to comply with the emission regulations that apply to new generators, while previously that generating units might have been exempt from those regulations (NSPS, 2023). Second, adding CCS is likely to result in increased future operation, increasing the value of having better NO_X emission controls. Third, it could be less costly to add additional NO_X emission controls at the same time as CO_2 capture equipment.

Overall, there are uncertain indications that adding CO_2 capture could reduce the NO_X emission rate considerably at three of the six generating units. Out of the other three generating units, two have slight reduction whereas, one unit is with no change. At one of the units with an uncertain indication of a possible large reduction, there is also an uncertain indication of a possible small increase.

Like Figure 1 did for SO_2 emissions rates, Figure 2 shows estimates of NO_X emissions (lbs/MMbtu) before and after CCS retrofit, to the extent that such information is available. The green, blue, and black columns come from the same sources as they did in Figure 1. The range of NO_X emissions across different power plants and technologies is broad, varying from 0.001 to 0.227 lbs/MMBtu.

Figure 2. Estimates of NO_X emission rates before and after retrofitting with CCS



As mentioned above, it seems that adding CO_2 capture could reduce per-MMbtu NO_X emission rates by 80 percent or more at three of the generating units, but that is uncertain. The Petra Nova CFPP and Daniel NGPP engineering studies report NO_X emission rates only post retrofit. Those rates are at least 80 percent lower than the historical rates (from 2019 for Daniel, from 2014 for Petra Nova), but there are other possible explanations for this difference in emission rates. They could have simply failed to use their NO_X controls fully during the historical data year, they could be basing the post-retrofit NO_X emission projection only on times of optimal operating conditions, or they perhaps have added (or are planning to add) better NO_X controls for a reason other than the CO_2 capture retrofit. The Elk Hills NGPP similarly has an 80 percent reduction between 2019 and the post-retrofit NO_X rate in its FEED study. The potential reasons are the same as for the Petra Nova and Daniel units, but a true NO_X reduction because of the retrofit is more dubious because the Elk Hills FEED study gives a pre-retrofit NO_X rate, and it is approximately the same as the FEED study's post-retrofit NO_X rate projection. The post-retrofit projected emission rate is actually 6 percent higher.

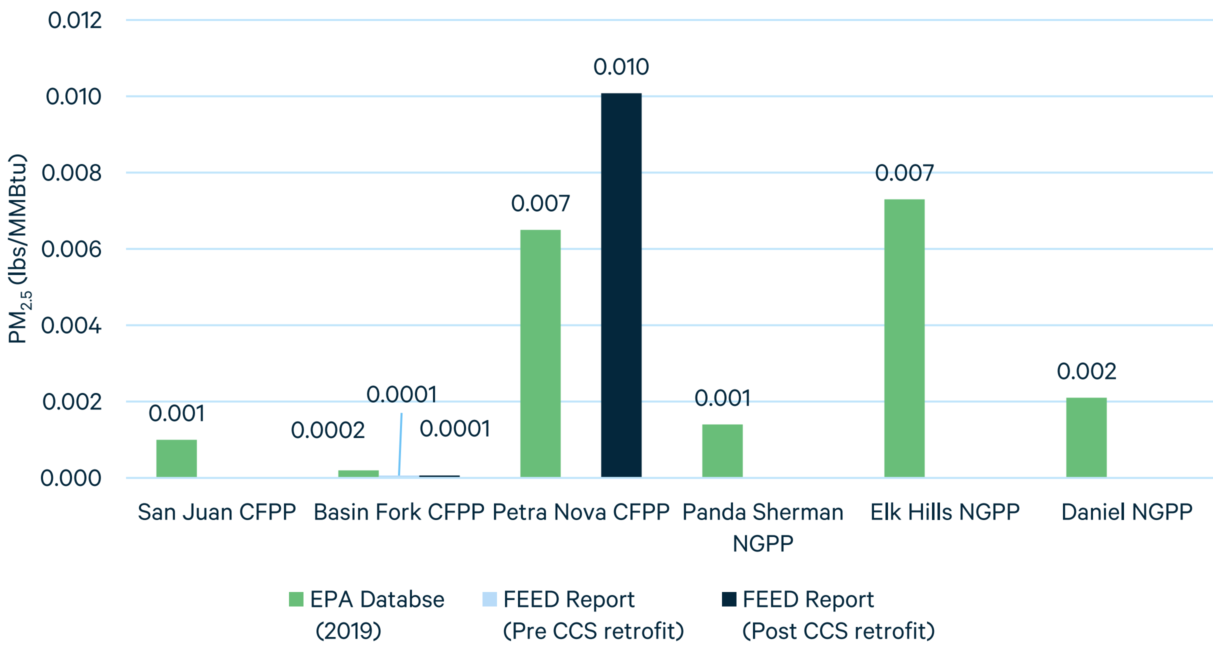
The two units with indications of slight decreases are Basin Fork CFPP and San Juan CFPP. The Basin Fork CFPP FEED study projects approximately a 9 percent NO_X reduction per unit of heat input but does not give any indication of the reason. The San Juan CFPP would add a gas-fueled boiler to provide heat for its capture process. Since NO_X controls are inexpensive to include in new gas-fueled boilers and also might be required by regulations for new boilers, this would likely reduce the NO_X emission rate per MMbtu of the system. The FEED study does not verify that this would reduce the unit's NO_X emission rate and does not mention any other change that would be likely to change its NO_X emission rate.

The sixth FEED study, for the Panda Sherman NGPP, anticipates no significant change in NO_X emission rate per MMbtu. The existing Panda Sherman NGPP already incorporates a selective catalytic reduction (SCR) process for NO_X control. As part of the retrofitting process, the FEED study mentions no plans to introduce additional equipment specifically for NO_X control.

3.3. Fine Airborne Particulate Matter Emissions

As with NO_X, there are legal and economic reasons why the owner of a generation unit might be required to, or choose to, improve $PM_{2.5}$ emission controls at the time of adding CO_2 capture equipment. The engineering studies provide little information about $PM_{2.5}$ emissions, as indicated by the presence of few blue and black columns in Figure 3. The available information indicates little change in $PM_{2.5}$ emission rates per MMBtu of energy input. The Elk Hills NGPP and Panda Sherman NGPP FEED studies mention that their CCS retrofits will have no significant effect on the generating units' per-MMbtu emission rates of total suspended particulate matter. The Basin Fork FEED study reports the same estimated $PM_{2.5}$ emission rate before and after its CCS retrofit. That rate is lower than the historical rate reported by EPA in 2019, but the difference is small. The Petra Nova CFPP's engineering study does not say that its retrofit changed its $PM_{2.5}$ emission rate, and it reports only a post-retrofit $PM_{2.5}$ emission rate. That rate is 0.010 pounds per MMBTu of heat input. That is approximately 50 percent higher than the pre-retrofit historical rate of 0.007 reported by EPA. However, since that CCS project already occurred, and operated from partway through 2017 until partway through 2020, there is also post-retrofit historical emission data. EPA has reported estimated $PM_{2.5}$ emission rates for selected years, including 2016 and 2018. In the EPA estimated $PM_{2.5}$ emission rate data, the Petra Nova 2018 $PM_{2.5}$ emission rate (not shown in chart) is only 3 percent higher than the 2016 emission rate, per MMBtu of energy input. As a result, adding CO_2 capture may have affected the unit's post-retrofit emission rate less than shown in Figure 5.

Figure 3. Estimates of $PM_{2.5}$ emission rates before and after retrofitting with CCS



Only one of the engineering studies mentions that the CCS retrofit will change the generating unit's particulate matter emission rate: Total particulate matter emissions were projected to increase by an unstated amount at San Juan because of the addition of a new cooling tower, which could change PM emissions because some of the dissolved solids in cooling water that escapes and evaporates in the air become airborne particulate matter. The San Juan FEED study does not estimate the extent to which $PM_{2.5}$ emissions would change, but the San Juan project would be similar to the Petra Nova project, which also added a new cooling tower as part of its CCS retrofit project. As mentioned above, a comparison of post- and pre-retrofit $PM_{2.5}$ emission data from Petra Nova indicates a 3 percent increase in emission rate per MMBtu.

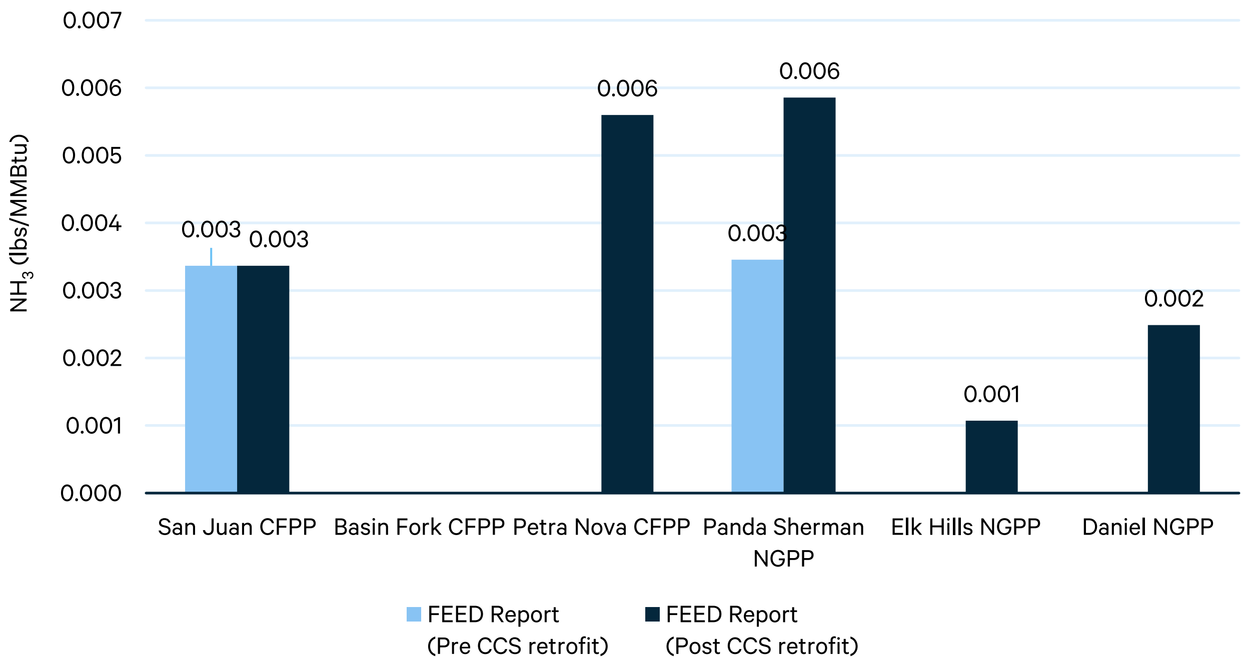
Overall, these findings suggest that retrofitting power plants with CCS technology may not significantly affect their $PM_{2.5}$ emission rates per unit of energy input.

3.4. Ammonia Emissions

Adding CO_2 capture could increase ammonia emissions dramatically, according to Heo et al. (2015), Koornneef et al (2010), and Rao et al. (2006). Heo et al. estimates that ammonia emissions from mono ethanol amine (MEA) degradation in an amine-based capture system could be as high as 0.24 kg of NH_3 per metric ton of CO_2 captured, which is consistent with an NH_3 emission rate of more than 0.04 pounds per MMBtu at a coal-fueled generating unit with 90 percent CO_2 capture. That would be more than ten times the pre-CCS NH_3 emission rate at any of the six generating units considered in this paper. However, that NH_3-forming MEA degradation is also highly controllable down to much lower levels (Heo et al. 2015), so the actual NH_3 emissions may depend on how much is allowed by regulators.

Figure 4 shows the engineering estimates of NH_3 emissions (lbs/MMbtu) that are reported in the engineering studies. No eGRID data was available from EPA for NH_3 emissions.

Figure 4. Estimates of NH_3 emission rates before and after retrofitting with CCS



The five engineering studies for amine-based CO_2 capture projects report estimated NH_3 emission rates after the CCS retrofit. The range of NH_3 emissions across them is 0.001 to 0.006 lbs/MMbtu. Two of these engineering studies also report NH_3 emissions rates pre retrofit: San Juan CFPP reports no expected change. Panda Sherman NGPP reports an expected increase from approximately 0.003 to approximately 0.006 lbs/MMBtu. Even with this increase in ammonia emission rate, it is within the plant's permit limit for ammonia concentration of 10 ppm. The Basin Fork CFPP FEED study does not report NH_3 emission rates before or after its CO_2 capture retrofit, but since it would use membranes instead of amines for its CO_2 capture, there is reason to expect its ammonia emission rate per unit of energy input to remain unchanged.

In summary, the engineering studies indicate that NH_3 emission rates will remain under 0.006 lbs/MMbtu, far below the possible rate of more than 0.04 lbs/MMBtu deemed possible by Heo et al. (2015). The studies also indicate that NH_3 emission rates will not increase at all generating units that adopt CO_2 capture, and that they can be as low as 0.001 lbs/MMBtu at generating unit with an amine-based CO_2 capture system despite the NH_3-forming MEA degradation in amine-based systems.

4. Estimated Value of Damage from Co-Emissions

Release of these emissions from power plants poses a significant threat to the public health, contributing to respiratory illnesses, cardiovascular problems, and environmental degradation. In order to understand what level of damage is caused by release of emissions per unit of net power output before and after retrofitting these power plants with CCS, we estimated damage caused as $/MWh of net power output.

To calculate emissions per unit of net power output (lbs/MWh), we converted the emissions per unit of heat input (lbs/MMbtu) reported above using the estimated heat rate (MMbtu/MWh) of each generating unit. We did this for each generating unit both before and after its retrofit. The engineering studies do not report heat rate after retrofit, so we used the assumption that heat rate increases by 27.9 percent at the coal-fueled generating units and by 12.6 percent at the gas-fueled generating units. These assumptions about heat rate penalty of CO_2 capture and compression come from (NETL, 2022). The actual heat rate penalties could differ somewhat from these assumptions.

To calculate the estimated damage per MWh, we use estimates of health damage value per pound from the US Environmental Protection Agency for the four co-emission types that we consider in this paper (EPA 2023). The estimated health damage is just from the ground-level airborne PM2.5 that results from SO_2, NO_X, $PM_{2.5}$, and NH_3 emissions, since that is estimated to cause much more damage than the SO2, NO_X, and NH_3 themselves. The value of the health damage reflects both premature mortality and illness caused by the resulting airborne $PM_{2.5}$. Premature mortality accounts for most of the estimated damage value. The damage value per pound estimates are national averages for power plant emissions of each of these types, accounting for where they are emitted, based on the locations, emission rates, and smokestack characteristics of US electricity generating units. As a result, what we have estimated is the value of the co-emission damage each of the generating units would cause if the unit were located at a US location that is average in terms of the US health damage it causes. The estimated damage per pound depends on the year because of increasing incomes and increasing population density. We use the values for emissions in 2023. They are respectively 28, 4, 24, and 55 dollars per pound for SO_2, NO_X, NH_3, and $PM_{2.5}$.[1]

[1] We assume that power plant NO_X emissions cause no change in net damage from ground-level ozone because ozone-season NO_X emissions in the states that contain most US combustion-powered electricity generation are constrained by binding ozone-season NO_X emission limits that are unlikely to be changed in response to greater or lesser adoption of CCS.

Valuing the four co-emission types provides an estimate of their relative importance and of the total co-emission damage per MWh from each generating unit before and after retrofit. Tables 1 and 2 show the estimated damage values for each of the six generating units corresponding to the six engineering studies. They also show the estimated average damage per MWh from all US power plants that primarily use the same fuel type, for each co-emission type.

Table 2. Estimated co-emission damage per MWh from the coal-fueled generating units

	SO_2 ($/MWh)	NO_X ($/MWh)	NH_3 ($/MWh)	$PM_{2.5}$ ($/MWh)
San Juan CFPP Pre CCS	14.71	8.85	0.25	0.58
San Juan CFPP Post CCS	No data	No data	0.8	No data
Basin Fork CFPP Pre CCS	16.21	1.62	No data	0.11
Basin Fork CFPP Post CCS	0.69	1.82	No data	0.05
Petra Nova CFPP Pre CCS	37.23	1.81	No data	4.73
Petra Nova CFPP Post CCS	0.40	0.30	1.81	8.30
US Average CFPP	46.35	4.29	0.13	15.07

Note: Estimated US health damage from NO_X, SO_2, $PM_{2.5}$, and NH_3 emissions associated with the three CFPPs before and after adding CO_2 capture.

Table 3. Estimated co-emission damage per MWh from the natural gas-fueled generating units

	SO_2 (\$/MWh)	NO_X (\$/MWh)	NH_3 (\$/MWh)	$PM_{2.5}$ (\$/MWh)
Panda Sherman NGPP Pre CCS	0.18	0.17	0.52	0.49
Panda Sherman NGPP Post CCS	0.22	0.20	0.99	0.55
Elk Hills NGPP Pre CCS	0.22	0.16	No data	3.26
Elk Hills NGPP Post CCS	0	0.03	0.23	3.67
Daniel NGPP Pre CCS	1.12	2.46	No data	0.94
Daniel NGPP Post CCS	0	0.13	0.54	1.06
US Average NGPP	4.79	1.08	0.46	14.80

Note: Estimated US health damage from NO_X, SO_2, $PM_{2.5}$, and NH_3 emissions associated with the three NGPPs before and after adding CO_2 capture.

For these tables, we use the emission rates from the engineering studies if they are available. If pre-retrofit emission rate is not available in the engineering study, we use historical emission rate from EPA eGRID data if it is available as described in Section 3. For NGPPs, the engineering studies do not provide any $PM_{2.5}$ emission rates, however, they do suggest that adding CO_2 capture will not change the $PM_{2.5}$ emission rates per unit of energy input, so we assume that the NGPPs have their 2019 per-MMbtu $PM_{2.5}$ emission rates (from eGRID data) both before and after their retrofits. So, changes as a result of the CCS retrofit are due to heat rate impacts. Some of the emission rates are missing, as indicated by the words “No Data” in the table.

Figure 5. Estimated value of damages due to NO_X, SO_2, $PM_{2.5}$, and NH_3 emissions without and with CCS

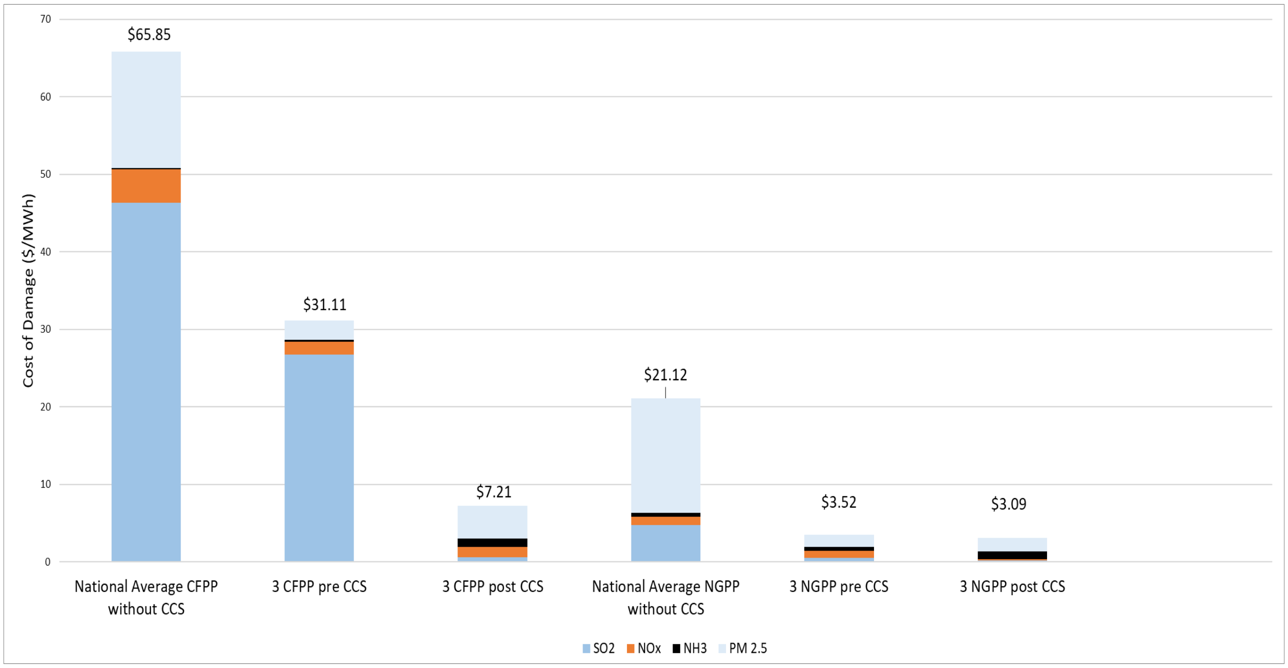


Figure 5 displays estimated average co-emission damage value per MWh for all US CFPPs that do not have CO_2 capture, for the three CFPPs in the engineering studies before their retrofits, and for those three CFPPs after their retrofits. The figure shows the same information for the NGPPs. To calculate the pre-retrofit average and post-retrofit average across each trio of generating units, we used values in matched pairs: we used values only if a pre- and post-retrofit value were both available.

The second and third bars in Figure 5 reveal that the CCS retrofits would reduce average estimated co-emission health damage per MWh from the three CFPPs by more than 77 percent, from $31.11 per MWh to $7.21 per MWh. This is explained almost entirely by the reduction of SO_2 emissions. Before the retrofits, the SO_2 emissions account for 86 percent of the estimated co-emission damage of the three CFPPs. After the retrofit, their estimated average SO_2 emission rate per MWh is 97.5 percent lower. In the case of amine-based CO_2 capture, this is because the CO_2 capture retrofits are accompanied by extremely effective SO_2 capture retrofits motivated by the fact that SO_2 fouls amine-based CO_2 capture systems. In the case of the membrane-based CO_2 capture, this is primarily because the membranes capture SO_2 even better than CO_2, and secondarily because of pre-membrane SO_2 capture improvements motivated by a desire to produce a CO_2 stream with extremely low sulfur content.

There is also a slight reduction in estimated damage from NO_X. There are increases in estimated $PM_{2.5}$ and ammonia emissions, and hence additional damage, per MWh as indicated in the figure by the larger black and light blue segments post retrofit.

The fifth and sixth bars reveal that the estimated average co-emission health damage of the NGPPs before retrofit is already just \$3.52 per MWh. The CO_2 retrofit would reduce this slightly, to approximately \$3.09 per MWh. The reasons for the reduction are the reductions in estimated SO_2 and NO_X emission rates, discussed in Section 3. Those reductions are partially offset by the estimated increases in NH_3 and $PM_{2.5}$ emission rates per MWh.

Figure 5 also reveals that the generating units in the engineering studies, before their retrofits, already have much less damaging estimated average co-emission rates than the industry averages for their respective fuel types. CO_2 capture retrofits could reduce estimated co-emission damage more at generating units with higher co-emission rates, especially those with higher SO_2 emission rates since amine-based and membrane-based retrofits involve reducing SO_2 emission rates to near zero.

For comparison, the projected levelized cost of electricity from a new combined cycle natural gas power plant (with CO_2 capture) is \$70/MWh (Lazard 2023). This is also a proxy for the wholesale price per MWh of electricity and ancillary services. The average co-emission damage from CFPPs is two thirds of the levelized cost of electricity from a combined cycle power plant. The average co-emission damage from NGPPs is more than a fifth of that levelized cost.

The estimated dollar value of net harm from carbon dioxide emissions can also be helpful for comparison. A careful, recent estimate of that based on the research literature is \$230 (year-2020 dollars) per metric ton of CO_2 emitted in 2030 (EPA 2022). Applying that to the average CO_2 emission rates of coal- and natural gas-fueled generation in the US gives average CO_2 damage of \$235 per MWh from coal-fueled generating units and \$101 per MWh from natural gas-fueled generating units.

As mentioned in the introduction, future CO_2 capture projects could capture higher or lower percentages of the CO_2 that they produce than the six projects considered in this paper. CO_2 capture percentage could be unlikely to significantly affect the co-emission rates. For estimated damage, SO_2 is the co-emission type that matters most. SO_2 fouls amine capture systems whether they are capturing 30 percent or 99 percent of the CO_2, so reducing the SO_2 concentration to near zero may be worthwhile even for a system with a low CO_2 capture percentage. The membrane technology used in the Basin Fork project captures SO_2 even more efficiently than it captures CO_2, and future membrane-based projects too may have a desire for nearly zero SO_2 in the final CO_2 stream. For some of the other co-emission types, adding CO_2 capture may prompt better emission controls, and the degree of improvement may be little affected by the CO_2 capture percentage. For example, if adding CO_2 capture requires complying with the NO_X emission standards for new generating units, this may occur whether the CO_2 capture system is designed to capture 30 percent or 99 percent of the CO_2. However, for any emission types whose emission rates per unit of energy input are unaffected by the addition of CO_2 capture, the emission rates per MWh would increase in proportion to the heat rate of the facility, which would be increased more by a larger capture percentage.

5. Conclusions

Coal and natural gas power plants that incorporate carbon capture technology have the potential to significantly reduce CO_2 emissions. However, these power plants also release other harmful pollutants (co-emissions), including SO_2, NO_X, $PM_{2.5}$, and NH_3. The effect of CO_2 capture retrofits on the rates of those emissions is important as well. To preview what those effects are likely to be in the coming years, this study reviews engineering studies submitted to the United States Department of Energy.

The engineering reports indicate that retrofitting existing coal- and natural gas-fueled power plants with CCS will reduce their SO_2 emission rates. The reduction at the coal-fueled generating units is 99 percent at a unit that used amine-based capture and 96 percent at the unit that plans to use membrane-based capture. The third coal-fueled unit does not have a post-retrofit emission rate in its engineering study. At the natural gas-fueled units, the SO_2 reduction might result primarily from reduced use of oil as a fuel.

The retrofits might be accompanied by NO_X control improvements: A comparison of the projected post-retrofit NO_X emission rates with actual pre-retrofit NO_X emission rates indicates reductions of 80 percent or more at three of the six generating units. However, the engineering reports do not verify this. With one exception, they are silent about whether adding CO_2 capture would also cause a large change in NO_X emission rate.

The six engineering reports and historical emission rate data for Petra Nova indicate that adding CO_2 capture would have little effect on $PM_{2.5}$ emission rates per unit of heat input.

Only two of the engineering studies give both pre- and post-retrofit estimates of ammonia emission rates. One of them projects that ammonia emission rate per unit of heat input will remain unchanged despite the tendency of amine-based capture to produce ammonia, while the other projects that it will increase by approximately 75 percent but remain under the generating unit's current permitted emission rate limit. The engineering studies of the five amine-based CO_2 capture projects report post-retrofit ammonia emission rates. They range from 0.006 pounds per MMBtu of energy input down to a remarkably low rate of 0.001 pounds per MMBTu of energy input. The engineering study of the membrane-based capture project does not report an ammonia emission rate, but the engineering study gives no indication that the membrane-based capture would produce ammonia emissions.

By applying estimated national average per-pound health damage values for the four co-emission types we consider in this study, we can estimate the value of the damage caused by the three coal-fueled and three gas-fueled generating units before and after their retrofits. The retrofits reduce the estimated average damage of the three coal-fueled units from $31.11 to $7.21 per MWh of electricity delivered to the electricity grid. This is mainly because of the reduction in SO_2 emissions, which are the most harmful co-emission type before the retrofits, and which see the largest reductions.

The retrofits have little effect on the estimated co-emission damage per MWh from the three natural gas-fueled generators, which is already less than $4 per MWh before the retrofits. They reduce the estimated SO_2 and NO_X emission rates, and those reductions are partially offset by increases in $PM_{2.5}$ and ammonia per MWh.

The generating units in these engineering studies have pre-retrofit damage-weighted co-emission rates that are considerably lower than the national averages for their respective fuel types, mainly because of lower SO_2 and $PM_{2.5}$ emission rates. Generating units with more typical SO_2 emission rates would be likely to experience larger SO_2 emission rate reductions, since a very low SO_2 concentration must be achieved for CO_2 capture regardless of the pre-retrofit concentration. The emission rate reduction at the generating unit is not the only factor that determines its overall effects on co-emissions, but it is an important factor.

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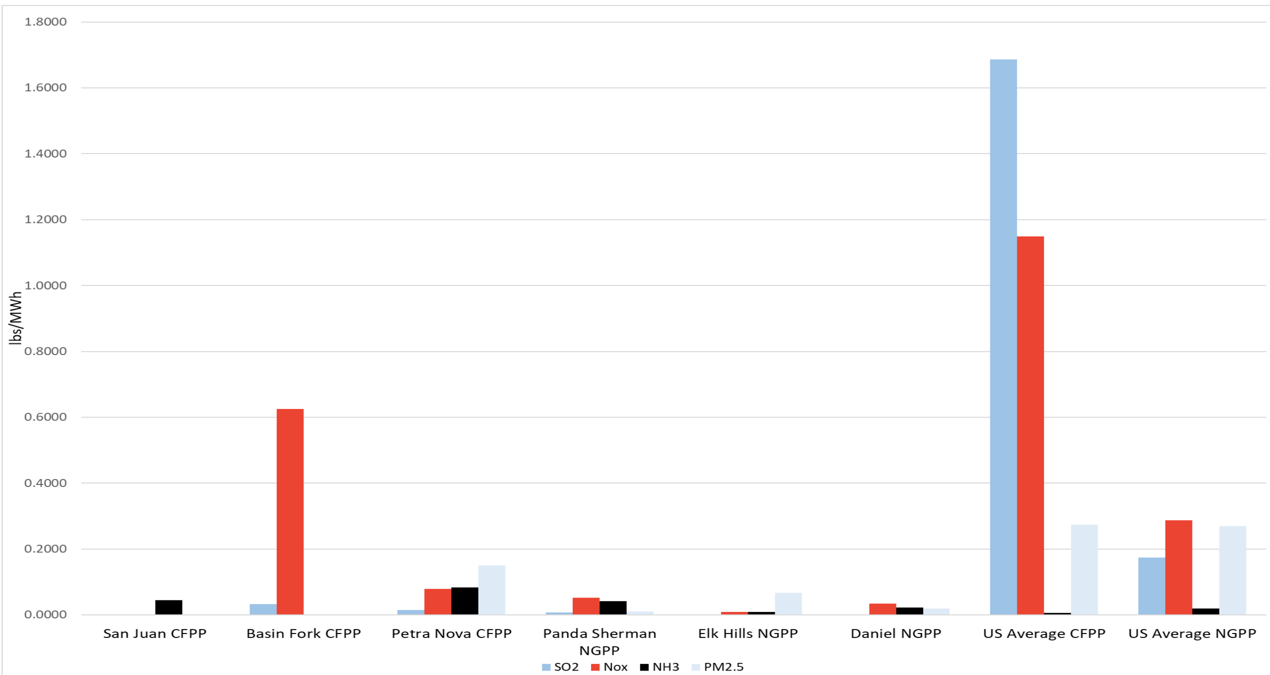
Appendix

In order to understand the impact of estimated emission rates from the engineering study power plants being retrofitted with CCS, we calculated emission rates per unit of net electrical energy generated from these power plants. Additionally, for comparison we also calculated emission rates for an average CFPP and NGPP without Carbon capture technology.

Figure A1. Estimates of NO_X, SO_2, $PM_{2.5}$, and NH_3 emissions associated with CFPPs and NGPPs post CCS



Note: Ranges of estimates of NO_X, SO_2, $PM_{2.5}$, and NH_3 emissions associated with various CFPP's and NGPP's from engineering reports for post CCS and US average CFPP and NGPP.

The calculation of emission rates in lbs/MWh (pounds per megawatt-hour) involved specific methodologies for different power plants and are explained below excluding the standard way;

Petra Nova CFPP and Dry Fork CFPP:

1. To determine the emission rates for these power plants, the net power output of the units undergoing carbon capture and storage (CCS) retrofitting was utilized.
2. Engineering studies provide emissions as annual totals but fail to address amount of energy producing those emission quantities hence, the capacity factor, obtained from the EPA eGrid 2021 data, was applied to calculate the actual power output in MWh (megawatt-hours).

Elk Hills NGPP and Daniel NGPP:

1. Engineering studies did not provide heat rates hence to convert lbs/MMbtu to lbs/MWh, it was multiplied by a factor of 3.413 MMbtu/MWh and divided by natural gas power plant efficiency. The emission rates for these power plants were calculated using the formula provided by the California Air Resources Board (CARB), as outlined in their documentation (**https://ww2.arb.ca.gov/sites/default/files/2020-06/gappc.pdf**).
2. An efficiency of 42 percent was assumed for natural gas power plants (NGPP) (**http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/**).

US Average CFPP and US Average NGPP:

1. Average lbs/MWh for NOx, SO2 and PM 2.5 was taken from EPA eGRID data
2. Average lbs/MMbtu for NH_3 was taken from the EIA 2020 study.

Formula used for Elk hills NGPP above was used to calculate emission rate per unit of power output for all studies without heat rate. Also, an efficiency factor of 33 percent was assumed for coal power plants (CFPP) (**http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/**).