adopted the procedures on their own.[95] Under the proposed rule, states may meet EPA's emissions goals under individual plans as well as multi-state ones, albeit that the latter may capitalize on efficiencies. This is no different than what the Court permitted in *Multistate Tax*.

Finally, while the federal government is undoubtedly interested in climate policy on an international scale, interstate compacts that merely speak to federal *interests* do not necessarily encroach on federal *supremacy*.[96] The Court emphasized that the regulatory organization in *Multistate Tax* did not interfere or foreclose federal action, and therefore did not encroach on federal supremacy.[97] Moreover, even the fact that the member states were acting in concert to enhance their capacity to lobby for legislation did not constitute encroachment.[98] In comparison, multi-state plans are mere instruments for states to implement regulatory goals; they do not lend the member states any additional political power and certainly do not foreclose additional federal action, both from a domestic standpoint and if the United States were to enter into any international agreements on climate change.

In sum, for the multi-state plans to violate the Compact Clause, they would have to increase state power *at the expense of* federal supremacy. Ultimately, the primary difference between multi-state plans and single state plans is one of form, rather than function. The multi-state plans do not enhance state power any more than single state plans do. It is therefore unnecessary to receive congressional approval for these plans, which are merely one option that EPA has developed—an innovative and efficient method for additional emissions reduction that is well within the confines of the Agency's statutory authority. Indeed, it is the type of interstate cooperation that Congress envisioned and provided for when drafting the Clean Air Act.

Even though it is not our view that the Compact Clause argument is valid, the argument would be annulled if EPA were to make clear through a model rule the approvable elements of a multistate plan, including such plans intended to adopt multi-state mass-based allowance trading systems. In that case, multistate plans could not arguably be increasing political power in the States, or "encroach[ing] upon or interfere[ing] with the just supremacy of the United States," indeed they would be in furtherance of the Clean Air Act's directives, and the federal government's policy on pollution control.

III. EPA's rate-based targets are reasonable, indeed some of the assumptions underlying the supporting BSER analysis are overly conservative.

EPA developed state targets using a BSER that includes measures that are adequately demonstrated, and achieve significant CO_2 emissions reductions from existing subpart Da and KKKK designated facilities. EPA provides the states with a great deal of flexibility, but its

[95] *Id.*

[96] *See id.* at 479 n.33 ("Absent a threat of encroachment or interference through enhanced state power, the existence of a federal interest is irrelevant.").

[97] *See id.*

[98] *See id.*

BSER estimates reasonable rather than maximum practicable emissions reductions available from each measure included in the four building blocks.[99] Due to conservative assumptions, some measures within the building blocks are available to a greater extent than EPA determined, and additional measures, which EPA did not include in the building blocks at all, are available at reasonable cost. We describe ways to strengthen the building blocks below.

a. Building block 1 is reasonable, but it should be strengthened.

As currently configured by EPA, building block 1 is solely focused on Heat Rate Improvements ("HRI"). However, HRI is just one element of a larger group of measures we refer to as Unit Specific Measures ("USM") – those control options that can be applied directly to an affected source to reduce CO_2 emissions, including (in addition to HRI), retrofit carbon capture and sequestration ("CCS"), natural gas co-firing in coal units, and affected unit retirements. Reconceiving building block 1 as a bundle of potentially available Unit Specific Measures, and determining the potential CO_2 reductions available state by state not only achieves the maximum practicable reductions directly from affected sources, but also even satisfies EPA's stated interest that the building blocks be "broadly applicable"[100] to existing fossil-fueled power plants. For example, even if one particular option cannot be applied to a specific unit or group of units within a state, the target rate would be supported by other options within the basket. For example, a Massachusetts-based plant might not have access to enhanced oil recovery ("EOR") sequestration and so CCS might not be a reasonable option for use in deriving the USM building block 1 portion of Massachusetts' target rate. But co-firing with natural gas is potentially available to existing designated facilities in Massachusetts. While EPA's proposed approach to the BSER nowhere precludes states from doing this analysis as they plan their compliance, the state-specific targets can be strengthened if they are based on a BSER that more accurately reflects the suite of compliance options available to reduce CO_2 directly from existing affected sources.

This "bundling" approach to building block 1 moreover is consistent with the approach EPA is already taking in building block 3 (renewables).[101] And it is consistent with EPA's longstanding regulations – as EPA appreciated in 1975, section 111(d) performance standards or "guidelines" necessarily reflect differences in controls based on location.[102] EPA in the CPP

---

[99] 79 Fed. Reg. at 34,859.

[100] 79 Fed. Reg. at 34,905 n.74 (noting that for "inclusion in the building blocks, the EPA considered only those emission abatement measures that are technically feasible and broadly applicable, and can provide reductions in CO[2] emissions from affected EGUs at reasonable cost"). We note that the phrase "broadly available" is not the statutory test or even a factor in the statutory test for determining the "best system of emissions reduction." See 42 U.S.C. §7411(a)(1). Nor is it found in the relevant case law.

[101] EPA adopted a broad interpretation of RE generation to include any non-fossil renewable type, with the exception of generation from existing hydroelectric power facilities. U.S. EPA, *Technical Support Document: GHG Abatement Measures*, at 4-5, Docket ID No. EPA-HQ-OAR-2013-0602-0437 (June 2014) [hereinafter *GHG Abatement Measures TSD*].

[102] 40 Fed. Reg. 53,340, 53,341 (Nov. 15, 1975).

proposal describes building block 3 renewables as including a portfolio of particular technologies showing clear dominance in specific regions:

> North Central and South Central regions have strong on-shore wind resource potential. The East Central and Southeast regions show moderate to strong resources in both biopower and rooftop PV potential. The West has notable potential in geothermal (hydrothermal) power and concentrating solar power, in addition to potential for increased hydropower generation. The Northeast has strong resources in off-shore wind and moderate biopower and solar resources available.[103]

By bundling these options together as "renewables" and not as separate building blocks for geothermal, off-shore wind, on-shore wind, landfill gas combustors, etc., EPA avoids having to decide whether a single technology option is 'broadly available' (as the Agency puts it) for application at all affected units. Regardless whether 'broad availability' is in fact a relevant factor in EPA's determination as to what constitutes the BSER for existing sources (and we assert it is not), it is inconsistent with the position EPA has taken on renewables. EPA's building block 3 category "renewables" contains a number of technologies that the Agency includes in the BSER determination are *not* everywhere available.

At a minimum, building block 1 should include the following components:

- Heat Rate Improvements at Affected Units;
- Natural Gas Co-firing in Affected Coal Units;
- Retirements of Affected Sources, after 2012 and as of the Date of State Plan Submittal; and
- Carbon Capture and Sequestration Retrofits.

i. **Heat rate improvements.** In a simplified analysis of HRI, EPA estimates the contribution from a 6 percent heat rate improvement to be about 97 million metric tons per year.[104]

ii. **Natural gas co-firing in coal plants is a unit specific CO_2 control measure that should be included in building block 1.**

EPA identifies redispatch of existing natural gas combined cycle generation ("NGCC") as the most cost-effective strategy to incorporate the use of lower carbon-emitting natural gas into the BSER and state goal calculation process. But, the Agency declines to identify natural gas *co-firing* in coal boilers as BSER or to make it part of the state goal calculation methodology. EPA asked for comment on ways that the building block analysis could be expanded, including natural gas co-firing in existing coal-fired boilers,[105] and spotlighted this request in the recent

[103] *GHG Abatement Measures TSD*, at 4-12.

[104] *Id.* at 2-39.

[105] 79 Fed. Reg. 34,876.

NODA.[106] In requesting comment, EPA acknowledged that there might be other important considerations that can shape the relationship of the BSER to natural gas consumption, such as the flexibility that co-firing could provide.[107]

Specifically, EPA requests comment on the additional suite of potential benefits from gas co-firing that could justify inclusion of co-firing in the BSER and state goal calculation process, asserting that:[108]

> 1. Co-firing can reduce emissions of nitrogen oxides (NOx); sulfur dioxide (SO2); particulate matter; and hazardous air pollutants, including mercury. Co-firing could also reduce some portion of the costs related to control of these pollutants (depending on the extent of co-firing).
>
> 2. Co-firing might also provide additional operational flexibility, particularly for coal-fired units that are regularly used at less than full load or that cycle regularly. Co-firing may allow units to ramp up and down more quickly, which could give a company the opportunity to take advantage of low fuel prices, when they occur, to achieve cost savings.
>
> 3. Co-firing could allow additional time for implementation of strategies in state plans that have a lengthier implementation timeframe, such as building up a robust energy efficiency program.
>
> 4. Further, co-firing could provide an opportunity to achieve emission reductions at existing higher emitting units with relatively low levels of capital investment, thereby addressing companies' concerns about stranded assets. It should also be noted that utilities continue to announce conversions or plans to convert coal-fired steam boilers to natural gas.

EPA concludes:

> We are requesting comment on these aspects of the costs and potential benefits (or offsetting cost advantages) of co-firing natural gas at existing coal plants, to the extent they were not considered or presented for comment in the proposed rule, along with any other additional costs and potential benefits of such co-firing that could be considered in goal setting. In addition, we are requesting comment on other factors or variables that might affect the decision to use natural gas in co-firing at a particular unit (e.g., type, age, or size of a boiler), as well as factors that could limit the amount of co-firing that could be done. For units currently co-firing with natural gas, we request comment on the benefits experienced and the

---

[106] 79 Fed. Reg. 64,546.

[107] 79 Fed. Reg. 34,875 and 79 Fed. Reg. 64,550.

[108] 79 Fed. Reg. at 64,550-51.

> extent to which co-firing is being done.[109]

Yet, EPA declined to identify natural gas co-firing as BSER or to make it part of the state goal calculation methodology solely on the basis that its costs were relatively higher than redispatch of existing gas facilities in achieving carbon dioxide reductions (\$/ton CO_2).[110] In so doing, however, EPA failed to take into account the requisite statutory factors in determining BSER and identifying which measures should be included in the state goal calculation methodology.

EPA has proposed to limit the state goal calculation from onsite modifications to fossil steam units in building block 1 to heat rate improvements only. Further, EPA declined to identify natural gas co-firing as part of the state goal calculation under building block 2 on the basis that:

> Switching from coal to gas is a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements and redispatch of generation supply to other existing capacity with lower CO_2 emission rates. Moreover, we concluded that coal-to-gas conversion of an existing boiler is less efficient than constructing a new natural gas combined cycle (NGCC) turbine in its place.[111]

To the contrary, CATF recommends that the BSER for existing fossil steam units should include co-firing with natural gas, because this well-demonstrated measure would yield significantly greater emission reductions directly at the affected unit, than would EPA's proposed heat rate-only approach while satisfying the other statutory factors for BSER. Rejecting gas co-firing on the sole basis that its \$/ton cost of carbon dioxide reduced is likely to be relatively higher than that for other strategies fails to appropriately characterize the full benefits of gas co-firing or reflect full consideration of the statutory BSER factors.[112] Careful examination of these factors demonstrates gas co-firing fits the statutory criteria for BSER.[113]

---

[109] 79 Fed. Reg. 45,550-51.

[110] 79 Fed. Reg. 34,875 and *GHG Abatement Measures TSD*, at 6-9.

[111] *GHG Abatement Measures TSD*, at 6-9. *See also*, 79 Fed. Reg. at 34,875.

[112] Section 111(a) explicitly instructs EPA to balance multiple concerns when promulgating a NSPS:

> [A] standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which *(taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements)* the Administrator determines has been adequately demonstrated.

[113] EPA specifically requested comment on ways that building block 2 could be expanded to include gas co-firing. However, CATF observes that gas co-firing – as a unit-specific control measure, more properly belongs within building block 1 as a strategy that can be accomplished by modifications at an existing fossil steam unit.

1. Co-firing coal boilers with natural gas is adequately demonstrated, technically feasible, and available.

The technology for a fossil steam unit to co-fire with natural gas is well demonstrated and commercially available, as EPA acknowledges.[114] In October, SNL Energy, which tracks unit fuel conversions, found that nearly 12,000 MW of coal-fired capacity in the U.S. has converted or is slated to convert to alternative fuel sources between 2011 and 2023.[115] According to SNL Energy data, of the approximately 11,288 MW of coal capacity planned to be converted, 10,894 MW is being converted to gas-fired generation.[116] SNL Energy found that the number of coal-to-gas conversions is expected to increase going forward as generators retrofit older coal units or build new gas generation on sites where coal units have been dismantled.[117] The SNL Energy maps in Figure 2 illustrate the planned gas unit conversions and plans for co-firing through 2022.[118]

---

[114] 79 Fed. Reg. at 34,982 ("conversion to . . . natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates"); 79 Fed. Reg. at 64,550-51. *See also GHG Abatement Measures TSD*, at 6-1, 6-2.

[115] Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3)

[116] *Id.*

[117] *Id.*

[118] *Id.*

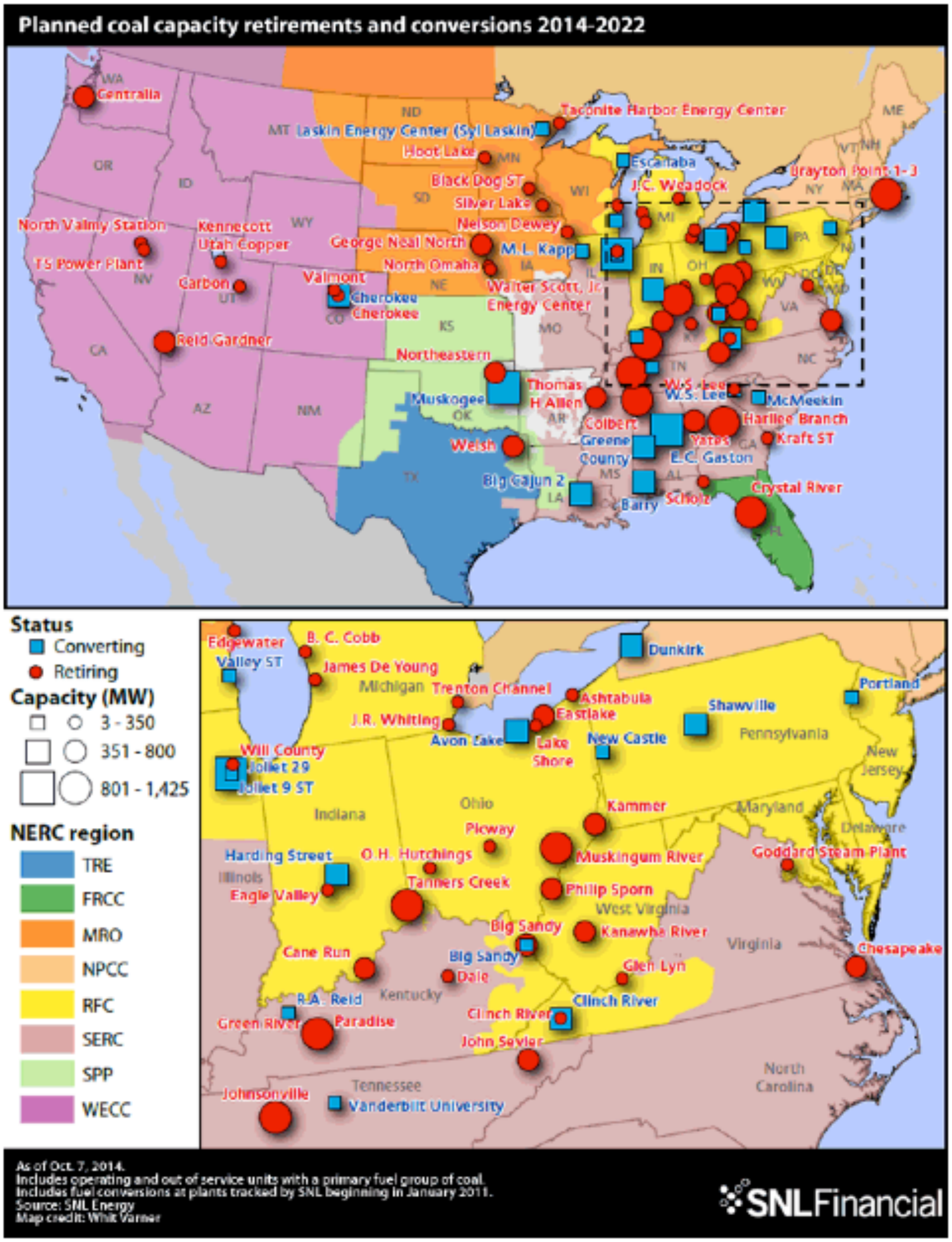


Figure 2: Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3) (showing planned coal capacity and conversions between 2014 and 2022)

In fact, electric utilities have been increasingly co-firing natural gas in coal boilers for at least a decade.[119] The electric power industry is undertaking gas co-firing and full coal-to-gas

[119] *See, e.g.*, Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp (Possum Point Power Station "Units 3 & 4 are fired using natural gas but were converted from coal in May of 2003. Unit 3 generates 96 MW and Unit 4 generates 220 MW.").

conversions at a wide variety of units, including very old EGUs,[120] baseload power plants,[121] and facilities that are over thirty miles from natural gas pipelines.[122] As further evidence of the technical feasibility of gas co-firing, several engineering firms have developed literature outlining economic and technical considerations for utilities that are considering such projects.[123] A recent Black & Veatch paper describes the process for converting a coal-fired unit to run entirely on natural gas.[124]

Although there are unit-specific concerns and costs that may affect decisions about co-firing a given unit, CATF is unaware of any existing coal units for which co-firing with natural gas is technologically infeasible.

2. Gas co-firing and/or conversion would result in greater carbon dioxide emission reductions along with significant reductions of other pollutants and air toxics.

Unlike EPA's proposed heat rate-only approach, co-firing natural gas has very significant potential for reducing the carbon dioxide emissions from coal boilers —a critical factor in the BSER analysis. For example, EPA's analysis of gas co-firing concluded that a reconstructed

---

[120] The Blount Street power plant was first built in 1903 and converted to burn natural gas in 2010. Thomas Content, *MG&E stops burning coal in Madison plant*, MILWAUKEE J. SUN (Mar. 18, 2010), *available at*: http://www.jsonline.com/business/88508257.html.

[121] Darren Epps, *Alabama Power switching to natural gas from coal at 4 Gaston plant units*, SNL (Jan. 17, 2014), *available at*: https://www.snl.com/InteractiveX/Article.aspx?id=26566141.(reporting Alabama Power's application to convert 4 units, each with a capacity of about 250 MW, to burn natural gas); Colorado Department of Regulatory Agencies, Powerpoint, *Colorado's electric grid and the role of base load and "peaker" electric generating units*, *available at*: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=390881&p_session_id= (classifying the 352-Mw Cherokee unit 4 as a baseload plant).

[122] Xcel Energy, Cherokee Repowering & Natural Gas Pipeline Projects, *available at*: http://www.xcelenergycherokeepipeline.com ("The Cherokee Natural Gas Pipeline Project has been completed."); Thomas Spencer, *Alabama Power to connect Shelby plant to natural gas line*, THE BIRMINGHAM NEWS, *available at*: http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html(citing an Alabama Power spokesperson for information that the coal-to-gas conversion project at the Gaston Steam Plant will involve building a gas pipeline to tie into the Transcontinental pipeline, which runs across Alabama about 30 miles south of the plant).

[123] *See generally* Babcock & Wilcox, *Natural Gas Conversions of Existing Coal-Fired Boilers* (2010) available at: http://www.babcock.com/library/documents/ms-14.pdf("This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision."); Black & Veatch, *Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch* (2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch("This paper explores several technically feasible options available on the current market" for retrofitting coal-fired units, including full conversion to natural gas).

[124] Black & Veatch, A *Case Study on Coal to Natural Gas Fuel Switch* (Dec. 12, 2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

utility boiler firing 100 percent natural gas would yield a 40 percent reduction in carbon dioxide emissions relative to 100 percent coal firing.[125]

EPA also must consider the pollution reduction co-benefits that would result from co-firing a coal boiler with natural gas.[126] For example, EPA estimated that converting to 100 percent natural gas would significantly reduce a utility boiler's emissions of SO_2, NOx, and PM2.5.[127] And partial co-firing would reduce these pollutants in amounts directly related to the percent of gas being co-fired. These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between \$67 to \$150/MWh—a factor of at least two times the costs associated with co-firing, as noted below.[128] By promulgating a standard that takes advantage of these pollution reduction co-benefits, EPA can greatly reduce the health burdens on the communities living near these sources.

3. The costs of natural gas co-firing and/or conversion are reasonable and can be further constrained through prudent application in the state goal calculation methodology.

EPA rejected natural gas co-firing because it found that co-firing represents "an inefficient way to generate electricity compared to use of an NGCC" and that CO_2 reductions from this option were "relatively costly."[129] EPA estimated the costs of CO_2 avoided from natural gas co-firing to be \$83 per metric ton.[130] In terms of generation, EPA estimated that co-firing with natural gas would increase the fuel costs of an EGU by approximately \$30/MWh (three cents per kWh), increase capital costs by \$5/MWh, while it would reduce fixed operating costs by 33 percent and variable operating costs by 25 percent.[131] The net costs may be higher than other options EPA has considered, but they are significantly lower than the benefits associated with criteria pollutant reductions from conversion—which as noted above, are approximately \$67-140/MWh. Adding in the benefits of reduced CO_2 pollution (e.g., consistent

[125] *GHG Abatement Measures TSD*, at 6-6, Table 6-1.

[126] *Cf.* 42 U.S.C. §7411(a)(1) (EPA is to take into account nonair quality health and environmental impact, which we understand include health and environmental benefits due to reductions in other air pollutants beyond the regulated pollutant).

[127] *GHG Abatement Measures TSD*, at 6-6, Table 6-2.

[128] *Id.* at 6-7, Table 6-3. Even given a steep 7 percent discount rate, EPA estimated the health benefits of reducing co- pollutants through natural gas conversion to be between \$61/MWh and \$140/.

[129] *Id.* at 6-9; 79 Fed. Reg. at 34857.

[130] 79 Fed. Reg. 34857.

[131] *GHG Abatement Measures TSD*, at 6-4. According to EIA's most recent estimates of generation costs, fixed O&M costs for an advanced pulverized coal EGU are approximately \$31-38/kW-yr (equivalent to approximately \$5/MWh) and variable O&M costs are approximately \$4.50/MWh. *See* EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013), *available at*: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

with the Social Cost of Carbon) would only increase the obvious value of identifying gas co-firing as a BSER. The fact that so many co-firing and conversion projects have been undertaken or announced shows that the costs are eminently reasonable, certainly as compared with the levels of costs courts have suggested constrain new source performance standard setting under section 111.[132]

Gas co-firing has emerged as a means of complying with emission standards precisely because it is sometimes the most cost reasonable strategy.[133] Several coal-fired units are co-firing with natural gas because it is the units' most economical option for complying with other emission limitations.[134] The cost of converting to natural gas fuel depends on whether the unit was originally designed to be capable of burning natural gas. The cost of fuel-switching in boilers is minimal for units that are already designed to burn gas, but even the cost of more extensive retrofits is still moderate.[135] Even where retrofit costs are significant, the conversion to natural gas is eminently cost reasonable and can be achieved in a manner that enables electricity consumers actually to save money.[136]

---

[132] EPA must "consider" cost in setting section 111(d) existing source performance standards. While no court has opined on an acceptable cost level for existing source standards, courts have determined that costs of *new* source performance standards under section 111 must not be "exorbitant," *see Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive," *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").

[133] Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL DATA DISPATCH (Oct. 14, 2014) (Ex. 3).

[134] Georgia Power Company, *2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6* at 1-18, *available at*: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145981("Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost- effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel."); *see also id.* at 1-11 (requesting favorable amortization of "approximately $14 million of Plant Yates Units 6 and 7 environmental construction work in progress"). Conversion to natural gas is likely to be a cost- effective compliance option for any facility with limited planned service hours. Black & Veatch, *A Case Study on Coal to Natural Gas Fuel Switch* at 7, Table 7.

[135] Ameren Missouri, 2014 Integrated Resource Plan at 4-18, *available at*: https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp.
Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

[136] *See e.g.* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that

For some units, building a pipeline is a cost associated with conversion to natural gas. EPA's cost estimates assumed that a unit converting to natural gas would need to build a 50-mile pipeline at a cost of $50 million.[137] EPA estimated pipeline construction would contribute $100/kW to the capital costs of a 500 MW unit, while capital costs as a whole represented only one-seventh of the cost impact of natural gas conversion.[138] EPA's analysis shows that even building a long pipeline is generally a relatively small part of the cost of converting a reconstructed unit to burn natural gas. Consequently, units can undergo conversion at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. For most units, however, the cost of building a pipeline is likely to be less than EPA assumed. This is because the median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[139]

In calculating costs, EPA also used an average national natural gas price figure. In fact, due to the shale gas development boom, the price of natural gas now varies by region. In particular, fossil units with nearby access to plentiful shale gas supplies may be able to take advantage of relatively lower natural gas prices than EPA assumed. For example, gas customers in the Marcellus shale region (Pennsylvania, West Virginia, and eastern Ohio), now typically pay much less than the Henry Hub gas price, the traditional source of gas price information.[140] As a result, co-firing natural gas in coal units located near the Marcellus Shale e.g., West Virginia and Kentucky, could be significantly less expensive than EPA assumed. In fact, of the ten states that EPA's CPP goal data computation spreadsheet shows are able to displace less than 10 percent of their coal generation with existing NGCC generation, all but Missouri are located in or adjacent to booming shale gas basin: Marcellus shale: (Kentucky, Indiana, Ohio, Pennsylvania, Maryland, Tennessee) and Niobrara shale: (Wyoming, Nebraska). Moreover, these are the very states that received less stringent state emission targets because they had little underutilized existing NGCC capacity under building block 2.

To the extent that EPA continues to be concerned with upward pressure on natural gas

the cost of the conversion would be $62 million and "rates for electric customers will go down by [0.31]%, for a net savings of $10.2 million in 2016").

[137] *GHG Abatement Measures TSD*, at 6-4.

[138] *Id.* at 6-4, 6-5. In EPA's estimation, increased fuel costs were responsible for most of the cost of natural gas conversion. *Id.*

[139] *See* U.S. EPA, Power Sector Modeling Platform v.5.13 at Table 522 "Cost of Building Pipelines to Coal Plants" *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles; greater than the median distance because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.

[140] U.S. EIA, "Some Appalachian natural gas spot prices are well below the Henry Hub national benchmark" (Oct. 15, 2014) available at: http://www.eia.gov/todayinenergy/detail.cfm?id=18391. *See also*, William Pentland, "R.I.P. Henry Hub? Marcellus Shale Shifts Geography Of Natural Gas Markets," FORBES (Oct. 16, 2014) http://www.forbes.com/sites/williampentland/2014/10/16/r-i-p-henry-hub-marcellus-shale-shifts-geography-of-natural-gas-markets/.

prices that could potentially occur due to increased gas use through co-firing, EPA could limit the application of co-firing in the goal-setting process to these states that have little or no potential to displace coal generation with existing natural gas combined cycle units under building block 2.[141] Using gas co-firing potential in these states' goal calculation would also serve to mitigate equity concerns expressed by stakeholders that building block 2 has little or no effect on the states with large amounts of coal-fired generation and limited excess existing NGCC capacity.[142]

4. Including gas co-firing in the BSER determination and state goal calculation methodology would deliver enhanced non-air health and environmental impacts.

EPA impermissibly fails to consider the non-air quality health and environmental impacts of not including gas co-firing as BSER.[143] If EPA had properly considered this factor,[144] the Agency would have to have recognized that co-firing with natural gas at existing coal units, and especially conversion of coal units to combust 100 percent natural gas, would have far greater non-air health and environmental benefits than its proposed heat rate-only approach. Specifically, co-firing and/or conversion would reduce or eliminate the unit's production of coal combustion waste ("CCW"). CCW is an industrial waste that contains a range of toxic substances, including arsenic, selenium, and cadmium. Carcinogens and toxic chemicals from coal ash can leach into drinking water supplies and accumulate in the fish we eat.[145] EPA has proposed regulating the disposal of coal ash for the first time,[146] but even promulgation of a robust CCW rule cannot be completely effective in protecting communities from the dangers of coal ash. Conversion to natural gas firing also reduces on-site water quality impacts.[147]

---

[141] *See* discussion at 79 Fed. Reg. at 64,546, 49.

[142] *Id.*

[143] *Sierra Club*, 657 F.2d at 323 ("the agency must consider all of the relevant factors and demonstrate a reasonable connection between the facts on the record and the resulting policy choice").

[144] *Sierra Club*, 657 F.2d at 346, n.175.

[145] U.S. EPA, *Human and Ecological Risk Assessment of Coal Combustion Wastes* (draft) (Apr. 2010), *available at*: http://earthjustice.org/sites/default/files/library/reports/epa-coal-combustion-waste-risk-assessment.pdf. One of the study's conclusions was that managing coal ash in unlined or clay-lined waste management units results in up to 1 in 50 excess cancer risks.

[146] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities; Proposed Rule, 75 Fed. Reg. 35128 (June 21, 2010).

[147] As the Wisconsin Public Service Commission observed in approving the conversion of Valley Power Plant, "Converting the plant from coal to natural gas would eliminate some discharge sources and reduce wastewater treatment requirements. Conversion would eliminate coal pile runoff, yard runoff, ash transport water, and equipment wash wastewaters that convey coal or ash, thereby removing a potential source of mercury." Public Service Commission of Wisconsin, *Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility* at 19 (Mar. 17, 2014) , *available at*: http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=200566.

5. Gas co-firing can help coal generators manage system energy requirements so that potential adverse impacts on the power sector can be mitigated.

The SNL Energy analysis cited above demonstrates that gas co-firing is a cost-reasonable response to the energy, market, and regulatory environment faced by generators with coal units. The data shows that numerous natural gas repowering and co-firing projects are occurring today, most without regard to any direct requirement to reduce CO_2 emissions.[148] Dramatically lower natural gas prices and increased development of shale gas resources have made these projects even more economic.[149] The Babock and Wilcox and Black and Veatch engineering analyses demonstrate that co-firing can reduce maintenance requirements and increase operational flexibility by allowing the coal-fired plants to cycle (increase an decrease their output) more readily to respond to changes in load demand. These studies demonstrate that many companies are using natural gas conversion or co-firing as low cost mechanisms to reduce emissions of conventional and hazardous air pollutants to comply with the requirements of the Mercury and Air Toxics Rule, the Cross-State Air Pollution Rule, Regional Haze requirements, and other environmental requirements. Indeed, some of these projects have allowed companies to continue to rely on coal-fired facilities that would otherwise have retired.[150]

Some stakeholders have asserted that additional reliance on natural gas could create reliability concerns based on insufficient gas supply or gas delivery infrastructure. We address those concerns in our discussion of building block 2. However, the incremental effect of including additional gas demand via co-firing could be mitigated by applying co-firing in the state goal computation only in states with little or no potential to reduce emissions through redispatch of existing natural gas units. EPA should undertake an analysis of the natural gas supply and infrastructure to identify the potential for gas co-firing both at units that currently have natural gas supply and units in such states for which natural gas pipeline infrastructure could be constructed to supply the natural gas necessary for co-firing.

A careful weighing of the statutory criteria and other considerations EPA raised in the CPP proposal and NODA should lead EPA to the conclusion that gas co-firing should be included in the BSER analysis and state goal calculation formula as a unit specific measure under building block 1. Excluding this option on the sole basis that its cost per ton of CO_2 avoided is higher than for heat rate improvements is an impermissibly narrow basis for decision – and indeed cuts against the argument that a variety of measures (with varying costs) are available to states for use in compliance. In sum, EPA has ample basis to include increased natural gas co-firing and conversion measures to achieve CO_2 emissions reductions in its state target setting exercise. Inclusion of gas co-firing in building block 1 would direct greater

[148] Michael Niven and Neil Powell, "Coal unit retirements, conversions continue to sweep through power sector," SNL Data Dispatch (Oct. 14, 2014) (Ex. 3).

[149] *Id. See also* Babcock & Wilcox, *Natural Gas Conversions of Existing Coal-Fired Boilers* (2010); Black & Veatch, *A Case Study on Coal to Natural Gas Fuel Switch* (Dec 12, 2012), *available at*: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

[150] Michael Niven and Neil Powell *supra* note 148 (Ex. 3); *See also* text accompanying footnotes 10 to 19 *infra*.

reductions than unit heat rate improvements alone, and at reasonable cost. Moreover, inclusion of gas co-firing will have important non-air health and environmental benefits and reduce dangerous co-pollutant emissions.

iii. Affected source shutdowns/retirements as of the date of state plan submission should be included in target rates for each state.

Shut down or retirement of an existing EGU yields permanent "emissions limitations" or "emissions reductions"[151] at the existing unit – indeed it completely eliminates the unit's pollution emissions.[152] And the "best" system of emissions reduction surely must encompass actions that completely eliminate emissions. Shutdowns or retirements of existing EGUs therefore clearly should be considered a component of the BSER.

U.S. coal-fired power plants are shutting down or "retiring" at an accelerated rate due to a combination of lower natural gas prices, higher coal prices, low electricity demand, increased penetration of renewable energy sources and environmental regulations.[153] In 2012 alone, 10.2 GW of coal-fired capacity was retired.[154] In August 2014, the U.S. Government Accountability Office ("GAO") reviewed data from SNL Financial and determined that power companies retired or planned to retire about 13 percent of coal-fired net summer generating capacity (42,192 MW) at 238 units from 2012 to 2025.[155] Regional Transmission Organization officials reported to GAO that an additional 7,000 MW from 46 generating units also might be retired from 2012 to 2015.[156] About three quarters of these retirements are expected to occur before 2016.[157]

---

[151] 42 U.S.C. §7411(a)(1).

[152] EPA has recognized this in enforcement settings, including shut down as an "emissions reduction and control" requirement to comply with the Clean Air Act. *See, e.g.* Consent Decree, *United States v. Tampa Electric Co.,* Civ. No. 99-2524 (M.D. Fla. 2004) at 7-8 (prescribing permanent shut-down amongst "emissions reductions and controls"), http://www2.epa.gov/sites/production/files/documents/tecocd.pdf.

[153] *See* U.S. EIA, *Annual Energy Outlook 2014 with projections to 2040*, at IF-34 (Apr. 2014), *available at*: http://www.eia.gov/forecasts/aeo/.

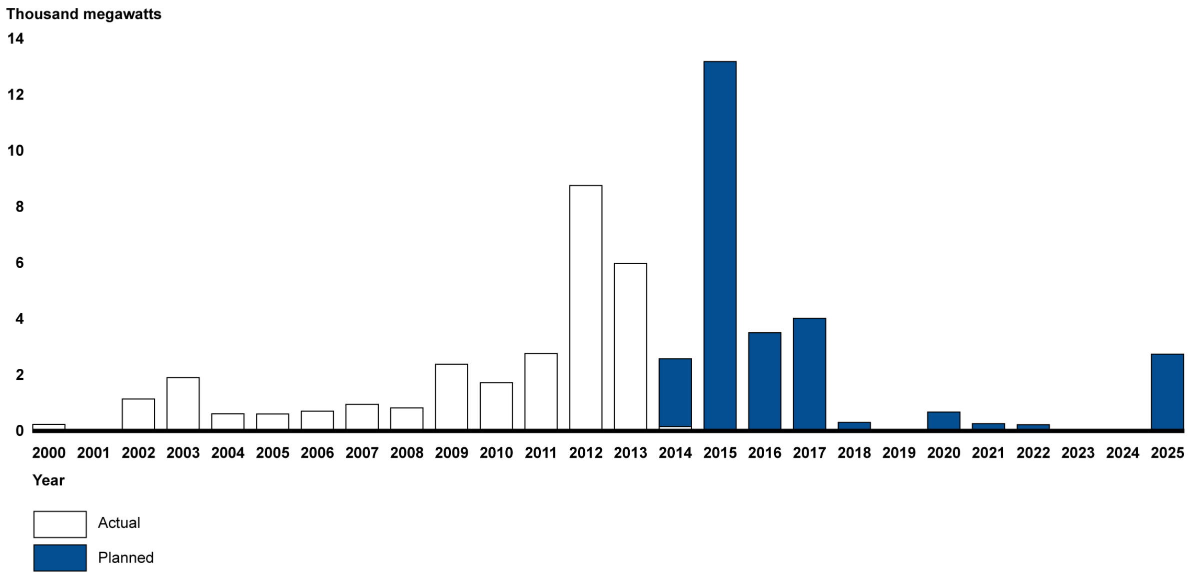
[154] U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503.

[155] U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 15 (Aug. 2014), *available at*: http://www.gao.gov/assets/670/665325.pdf. *See also* Michael Niven and Neil Powell, *Coal unit retirements, conversions continue to sweep through power sector*, SNL FINANCIAL, Oct. 14, 2014, *available at*: https://www.snl.com/interactivex/article.aspx?id=29431641&Printable=1&KPLT=6 (including tables of planned coal unit retirements).

[156] *Id.*

[157] U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 17 (Aug. 2014), available at: http://www.gao.gov/assets/670/665325.pdf.

Figure 1: Net Summer Generating Capacity of Actual and Planned Retirements of Coal-Fueled Electricity Generating Units, 2000-2025



Source: GAO analysis of SNL Financial data. | GAO-14-672

Figure 3: U.S. GAO, Report to the Ranking Member, Comm. on Energy and Natural Res., U.S. Senate, *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Units Retirements*, at 18 (Aug. 2014) (showing the summer net generating capacity of actual and planned retirements of coal-fired EGUs, 2000-2025).

The U.S. Energy Information Agency projects that 60 GW of capacity will retire by 2020, with about 40 GW occurring after 2012, and nearly all of that already reported on Form EIA-860.[158] Figure 4 below also shows that nearly all of those retirements are projected to occur by 2016, the deadline for state plan submittal under EPA's CPP rule.

However, EPA's proposed state targets do not reflect *any* of the approximately 60 GW of projected coal-fired power plant retirements projected to occur from 2012 through the 2016 deadline for state plan submittal—even those that *already* have occurred since 2012. EPA therefore has left significant CO_2 emissions reduction potential on the table in its proposed target setting process. For example, in the RGGI states, the regional carbon rate is reduced by over 56 lb./MWh if affected coal units that reach the average retirement age are actually shut down by 2020. [159]

---

[158] U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503.

[159] Comment submitted by Kelly Speakes-Backman, Chair, Regional Greenhouse Gas Initiative (RGGI), Doc ID: EPA-HQ-OAR-2013-0602-22395, at 15 (Nov. 5, 2014).

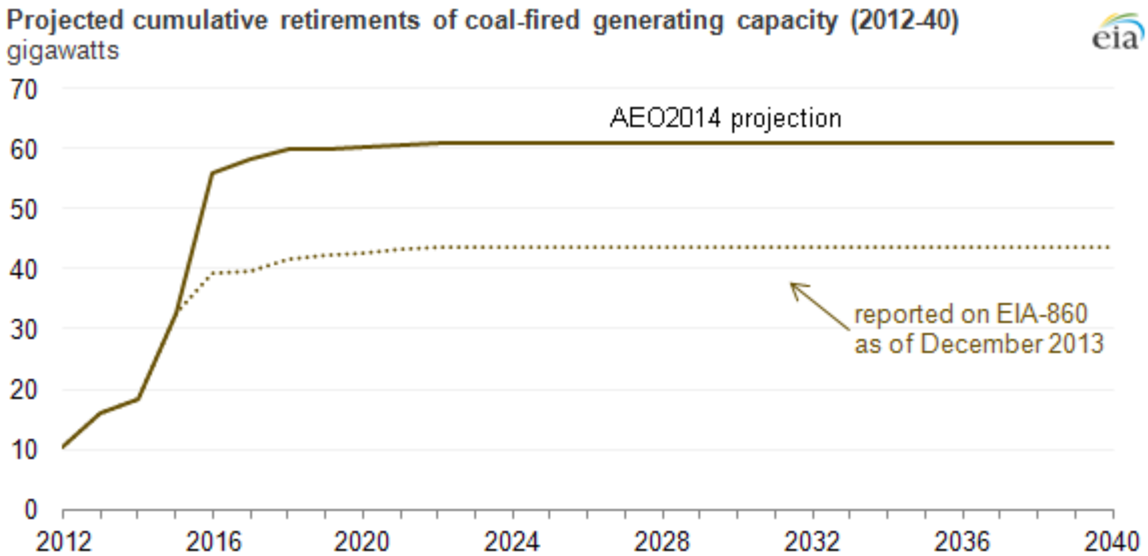


Figure 4: U.S. EIA, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled" (Feb. 14, 2014), *available at*: http://www.eia.gov/todayinenergy/detail.cfm?id=1503 (showing projected cumulative retirements of coal-fired generating capacity from 2012 to 2040).

EPA's BSER must accurately reflect expected control options,[160] which in this case clearly include affected source retirements since 2012, and retirements already planned to occur by the date of plan submittal. If the BSER were adjusted to include retirements that occur before the date a state submits its CPP compliance plan, that would not only more accurately reflect the CO_2 emissions reductions available from the affected sources, but also would provide states with an incentive to submit their CPP compliance plans as early as is practicable.

iv. Carbon capture and sequestration retrofits are available as unit specific measures under building block 1.

EPA identifies 17 states with enhanced oil recovery ("EOR") sequestration potential, in the assumptions it uses in the IPM modeling in support of the proposed rule.[161] Those states are - Alabama, Arkansas, California, Colorado, Florida, Illinois, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.[162] As more fully described below, modeling performed at CATF's direction by Charles River Associates, demonstrates that when more accurate and updated assumptions about CCS. CCS retrofit can result in near-zero CO_2 emissions from designated facilities and a detailed analysis of CCS retrofit technology is provided in Appendix B. CRA incorporated updated assumptions about CCS with EPA's other assumptions, affected sources in 9 of those states are projected to

[160] *Sierra Club v. Costle*, 657 F.2d 298, 332 (D.C. Cir. 1981) (standards should accurately reflect reality).

[161] U.S. EPA, *EPA's Power Sector Modeling Platform*, at Table 6-2, (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

[162] *Id.* These states have over 13 gigatons of EOR storage capacity.

apply CCS-EOR as a compliance pathway. That would yield reduced CO_2 emissions of nearly 85 million metric tons per year, or about 14 percent of the *total* annual reductions achieved nationwide in 2030 by the CPP, as compared to 2012 emissions.

EPA notes many advantages to CCS technologies that we agree are important:

- CCS can reduce CO_2 emissions 90 percent with full capture, and lower levels with partial capture. EPA found that partial CCS was adequately demonstrated and a BSER for new fossil fuel-fired steam EGUs and IGCC plants.[163]

- CCS retrofits are demonstrated at existing EGUs. Furthermore, carbon capture retrofits and EOR sequestration is already in use at Plant Barry, and at SaskPower's Boundary Dam facility, and is soon to be installed at NRG's W. A. Parish plant.[164]

Yet EPA also determines not to include any CCS or even partial capture (less than 90 percent capture) retrofits as an element of the BSER for existing power plants. EPA asserts that not all existing sources are located in close proximity to CO_2 storage or pipelines.[165] The Agency cites "technical challenges" with retrofit CCS, asserting the unremarkable proposition that integrating capture technology into an existing facility presents more challenges than building it into a new source, and that some sources may lack available land or space to host the capture equipment.[166] EPA also claims that cost and non-specific reliability concerns preclude the including of retrofit CCS in the target setting process.[167] These statements seemingly reflect the unrealistic assumption that including *some* CCS in the target setting equation in the rule would amount to a national mandate to apply CCS retrofits to *all* designating facilities, which of course is not the case for *any* of the BSER technologies EPA has included in the target setting metric.[168]

There are however, compelling reasons why available retrofit CCS technologies should be included in BSER, and in the goal-setting exercise for certain states. First, existing plants actually have a capital advantage over new plants with respect to CCS, because the investment to build an existing plant has already been made. So the investment for CCS retrofits at an existing plant is just for costs of the control equipment. In contrast, a new plant with CCS requires capital for both the plant and the CCS equipment.

---

[163] 79 Fed. Reg. at 34,856.

[164] *Id.* at 34,876.

[165] *GHG Abatement Measures TSD*, at 7-5 (contrasting the Boundary Dam, Parish, and Plant Barry projects with the norm for existing affected sources in that these projects are close to storage options, and relying again on the non-statutory concept that any element of the BSER must be "broadly available" for existing sources as a basis to reject including CCS).

[166] *Id.*; *see also* 79 Fed. Reg. at 34,876. The proposition that it is 'more challenging' to add pollution control to an existing source than to design it into a new source, is hardly novel – indeed it is nearly always true.

[167] *GHG Abatement Measures TSD*, at 7-5; 79 Fed. Reg. at 34,876.

[168] Taken to its logical conclusion. EPA's fabricated "broad applicability" criterion (with which we disagree) for existing source BSER reflects the assumption that selecting a technology for inclusion in BSER creates a national mandate to apply the technology, which is not consistent with the statutory frame.

Second, depending on the price the plant operator gets for selling the CO_2 to an EOR operator, the dispatch costs for the plant with a CO_2 capture retrofit can be less than the dispatch costs for the same existing plant prior to retrofit. That's because each hour of operation of the retrofit plant generates revenue from CO_2 sales. With lower dispatch costs, the retrofit plant may operate more frequently, increasing electricity sales and increasing the economic value of the power plant asset. This dispatch advantage is illustrated in the example below, which shows the electricity price needed in the market to dispatch a power-generating unit. In this example, a Texas coal plant receives $34 per short ton of CO_2 sold to an EOR operator in the Permian Basin. It is depicted in the bar on the far left of the chart. The other units operate without CCS with the exception of the unit represented by the bar on the far right, which must pay to dispose of its captured CO_2 into a deep saline formation (not EOR). The illustration shows that EOR revenues could vault existing coal with CCS to the front of the dispatch order, and allow such units to recoup the significant up-front retrofit capital costs in the energy market.

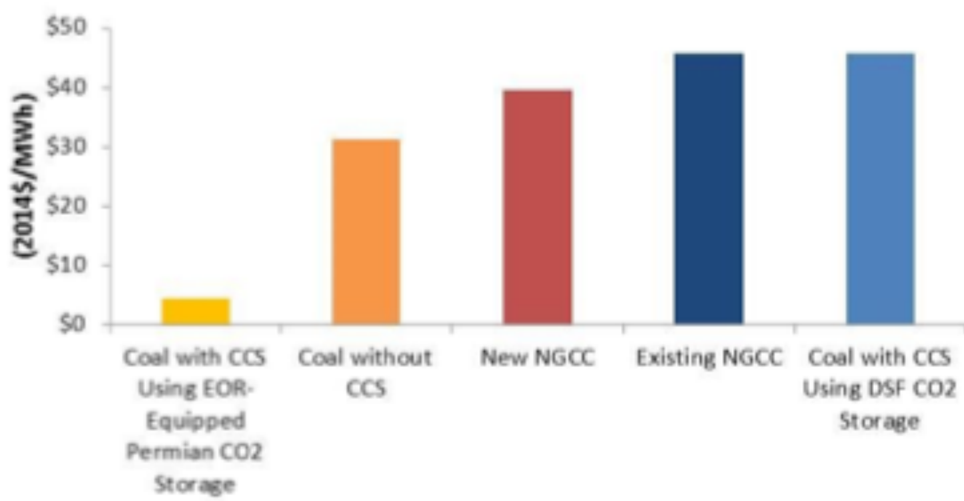


Figure 5: Illustrative dispatch cost advantage: Texas unit with CCS-EOR retrofit vs. other Texas Plants (Source: CATF).

Third, contrary to EPA's assertions, land requirements for CCS are not a major issue for all plants. A 2010 NETL study evaluated the feasibility of retrofitting capture technology at existing power plants, using aerial and satellite images of various power plant sites, and concluded that no sites were totally infeasible for retrofit.[169] And, for most plants, "there is the potential to have at least partial retrofit, which means retrofitting only some of the generating

[169] IEAGHG, *Retrofitting CO2 Capture to Existing Power Plants*, at 84, 86. (May 2011), *available at*: http://ieaghg.org/docs/General_Docs/Reports/2011-02.pdf.

units rather than the whole power plant."[170] Different capture technology options, especially oxyfuel, may require less space and increase partial CCS retrofit potential.[171]

Fourth, during the period between now and the 2030 target date it is not unrealistic to expect that pipelines can be built linking existing power plants to geologically favorable storage sites. So while it is certainly true that plants located closer to favorable geology are more likely to consider and install retrofit capture and sequester the captured CO_2, the need for pipeline construction is not a universal barrier to any retrofits between now and 2030. Indeed, the challenge presented by the need for more CO_2 pipelines to support the adoption of CCS retrofits is not conceptually very different from the challenge presented by the need to expand natural gas pipeline infrastructure to serve existing plants for repowering, or increase reliance on existing natural gas plants resulting from redispatch under building block 2.

Finally, adding CCS need not cut into the existing steam cycle of the power plant. As the plan for retrofitting the W. A. Parish plant in Texas demonstrates, the added power needed for CCS can be met by building a small gas plant adjacent to the existing facility. Indeed, this is not unlike the situation where small gas plants are needed for reliability purposes near some intermittent renewables.

For these reasons, CATF asserts that CCS retrofits are available over the period of this rule (to 2030) and should be included in building block 1 and used to evaluate state specific targets in the states identified as having EOR potential. Including some retrofit CCS not only better reflects projected reality under our modeling (described *infra*) but also has potential to yield significant contributions to state targets and overall national CO_2 reduction goals. The map below shows that the 17 states with EOR potential together account for about half of the total CO_2 reductions EPA projects will occur under the CPP from 2012 to 2030.

---

[170] Jia Li *et al.*, *An assessment of the potential for retrofitting existing coal-fired power plants in China*, 4 ENERGY PROCEDIA 1805, 1811 (2011) (Ex. 4).

[171] IEAGHG, *Retrofitting CO2 Capture to Existing Power Plants*, at 84, 86. (May 2011) *available at*: http://ieaghg.org/docs/General_Docs/Reports/2011-02.pdf.

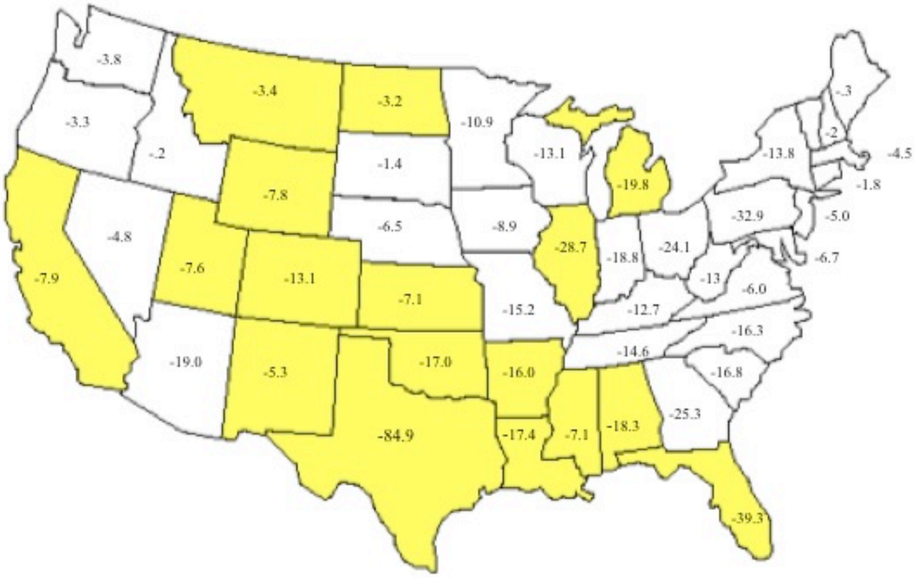


Figure 6: CO_2 Reductions by State from 2012 to 2030 Under the Clean Power Plan (Millions of Metric Tons). (Source: CATF).

And CCS can be grouped with other technologies that can reduce emissions directly at the designated facilities, under building block 1. Accepting for the sake of argument EPA's "broad applicability" criterion, as a whole this Unit Specific Measures approach to building block 1 would have broad applicability, just as building block 3 comprises a group of technologies not everywhere applicable[172] including nuclear generation.

Looking forward over the period 2014-2030, it is not unreasonable to assume that CO_2 pipelines could connect power plants in states without EOR potential to one of the states EPA currently identifies as having EOR sequestration potential. Providing a regulatory driver for CCS, by including some CCS retrofits in state target setting, would make an important contribution to the national CO_2 emission reduction goal.

The effect of including CCS retrofits in the state-specific target rates is illustrated by the example of Texas, which under the target rate developed by EPA is required to reduce its CO_2 emissions by nearly 85 million metric tons per year in 2030 relative to 2014 emissions. On a mass basis, Texas has the greatest emissions reduction target of any state in the proposed rule. However, Texas is also the state with the largest EOR operations in the U.S. In IPM model runs used to support the proposed rule, EPA has estimated that the annual quantity of CO_2 – EOR storage that is available to Texas power plants is 113 million short tons per year or 102 million metric tons.[173] So, CCS is "broadly applicable" to Texas because Texas sources have access to large EOR opportunities, and it has national significance because the state alone accounts for nearly 14 percent of the national CO_2 reductions that must occur between now and 2030 under the rule.

The choice of whether or not to retrofit a plant with CCS is an economic one. One factor in that choice, as EPA recognizes, is close proximity to EOR sites or pipelines. Other factors include the costs of capturing CO_2, transporting it by pipeline, and the revenue that a power plant owner receives for selling the CO_2 to the oil field. The "shadow price" of the CO_2 under the proposed regulation will also affect the choice whether or not to retrofit. We use the term "shadow price" to mean the marginal cost of abating the last metric ton of CO_2 in order to comply with the CPP's emission rate. In the CPP, different states have different emission targets and consequently, different shadow prices for CO_2. Generally, the deeper the emissions reductions in a state's target, the higher the shadow price of CO_2 in that state.

EPA's IPM modeling for the CPP predicted that no CCS would be built as a result of the rule. This was true even in states such as Texas where EOR is widely practiced, a retrofit project is already in construction, and the CO_2 shadow price under the rule would be expected to be large given the substantial CO_2 reductions represented by the state target. CCS is modeled in the CPP IPM runs using the assumptions found in EPA Base Case v5.13. This base case uses capture

[172] For example, off-shore wind is not "broadly applicable" – as EPA defines this concept – it is assuredly not capable of being developed everywhere in the nation, but only in coastal states. . However, by combining off-shore wind with other renewables, EPA creates the "renewables" portion building block 3.

[173] U.S. EPA, *EPA's Power Sector Modeling Platform*, at Table 6-2, (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

costs developed for new and retrofit plants, and combines them with storage and transportation costs developed with GeoCAT, a spreadsheet model developed by ICF to support EPA's Safe Drinking Water Act Underground Injection Control ("UIC") rulemaking in 2008.[174] GeoCAT develops commercial scale costs for storage in four of several possible settings: saline reservoirs, depleted gas fields, depleted oil fields, and EOR. These settings are characterized by "cost curves" that reflect total sequestration capacity and annual storage volumes in each region or state, at various costs.[175]

a. CATF commissioned modeling from Charles River Associates,[176] that corrected for outdated and incorrect EPA IPM assumptions.

CATF examined the CPP IPM runs and the assumptions that drove EPA's IPM results. We found significant problems that we observe lead to a dramatic understating of the amount of CCS projected to be built as a result of the CPP. A central problem is that GeoCAT has not been significantly updated since 2008. The GeoCAT "cost curves" for EOR price and supply thus are based on outdated assumptions, including:

- Oil prices are assumed to be $56 per barrel in GeoCAT. This low oil price significantly lowers the model's price paid for CO_2.
- CO_2 sent to EOR fields is assumed to meet Safe Drinking Water Act UIC program Class VI injection well standards, not UIC Class II with Clean Air Act subpart RR monitoring and reporting. As a result, EOR costs are overstated and the price field owners paid for CO_2 is understated in EPA's modeling.
- Since 2008, "next generation" EOR practices have been developed that greatly expand the EOR sequestration capacity in the United States. While GeoCAT assumes about 13 Gigatons of CO_2 EOR capacity, today's estimates are closer to twice that value.[177]
- Transportation costs included in GeoCAT are based on simplifying regional assumptions. But our observation is that at least for some states (Texas and Oklahoma, e.g.) these simplifications greatly overstate the costs of bringing CO_2 from power plants to EOR operations.

---

[174] U.S. EPA, *EPA's Power Sector Modeling Platform*, at ch. 6 (2013), *available at*: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

[175] *Id.* at 6-3.

[176] Charles River Associates is a leading global consulting firm that offers economic, financial, and strategic expertise to major law firms, corporations, accounting firms, and governments around the world. CRA's analytical and modeling tools are used to support expert testimony, assist clients in decision-making, provide input into valuation of assets, and provide insight into other complex matters in the electricity industry. CRA has developed proprietary analytic tools and models that have been used to: 1) value assets, 2) evaluate policy cost-effectiveness, 3) design market power-mitigation mechanisms, 4) evaluate contract portfolios, 5) optimize hydro dispatch, 6) test transmission constraints, 7) evaluate transmission investment economics and 8) evaluate market efficiency.

[177] *See CCS Assumptions Appendix A* for a detailed discussion of this capacity.

The maximum price paid for CO_2 in EOR operations anywhere in the U.S. under GeoCAT's assumptions is $14.52 per short ton. But CO_2 prices in the Permian Basin in 2014 were typically around $35 per short ton, by contrast, and elsewhere in the U.S.; prices paid for CO_2 to be used in EOR began at $20 per short ton.[178] Furthermore, the transportation costs assumed by GeoCAT likely overstate the pipeline costs by several dollars per short ton, at least in regions with existing EOR. Therefore the net revenue received for sale of CO_2 to the EOR operator by the power plant owner will be underestimated by EPA, because both the assumed value of the CO_2 in EOR is too low, and the assumed transportation costs are too high.

EPA's CO_2 capture scenarios – that is, the "world" modeled in the CPP IPM runs - also are limited. For example, CCS can only be retrofit on a coal unit; IPM does not allow CCS on any new or retrofit existing natural gas units. And coal unit retrofits are limited to a single size (400 MW or greater) and to 90 percent CO_2 capture only. Partial capture (for example, capture on only one unit of a multi-unit plant, leading to, say 50 percent capture was not an available option in the model. New build CCS also is limited just to 90 percent capture, and applied only on IGCC plants: IPM does not include even the partial capture option as EPA proposed it in the Agency's new source performance standards for this industry under Clean Air Act section 111(b). Taken together, these limited scenarios are likely to make CO_2 capture retrofits appear both much less likely, and much more expensive in the IPM model runs used to support CPP than if more expansive CO_2 capture scenarios are considered. A wider set of scenarios properly should include consideration of partial and full capture, on both new and existing natural gas and coal units (both pulverized coal and IGCC), and sensitivities concerning how unit size, coal types and existing plant heat rates impact capture costs.

i. **CATF's modeling**.

To address these issues, CATF developed its own model runs of the CPP rule. We replicated the CPP policy case, and then made changes only to the CCS assumptions used by EPA, in order to examine the impacts on CCS retrofits and new builds. CATF retained Charles River Associates ("CRA") to evaluate the economic competitiveness of CCS as a CPP compliance option for "CCS-Ready" states where CO_2 captured at power plants can be used for EOR.

CRA evaluated CCS as a compliance option in three target states: Texas, Oklahoma, and Mississippi. These three states were chosen due to the kinds of EOR activities currently underway there, which are representative of EOR activity taking place elsewhere in the country. Also, these states are in close physical proximity to one another making modeling simpler, and by focusing on three states, CATF could look more closely at transportation issues and EOR CO_2 price effects.

CRA configured the fundamental power market model North American Electricity and Environmental Model ("NEEM")[179] to reflect, to the extent possible, the modeling assumptions

---

[178] *See CCS Assumptions Appendix A* for a detailed discussion of these costs.

[179] NEEM is one of the leading models used to assess the impacts of energy and environmental policy on electricity markets.

used by the EPA in its CPP modeling. The resulting "EPA Policy Case" scenario provided a benchmark against which the results of subsequent assumption changes can be measured. In preparing the EPA Policy Case, CRA configured the NEEM model as follows:

- Aligned demand growth rates and energy efficiency deployment in NEEM regions to EPA's CPP assumptions.
- Updated planned additions and retirements in NEEM to be consistent with data from Energy Velocity, as EPA did.
- Adopted EPA's assumptions for coal CCS retrofits.
- Updated NEEM CCS transport costs based on IPM to State Mappings.
- Adopted EPA unit and retrofit characterizations, and build availability by technology type.
- Updated FOM and VOM for all existing units to be in line with EPA assumptions.
- Created emission regions specific to the study states from NEEM regions and imposed EPA emissions constraints.
- Adopted EPA's Henry Hub forecast and regional gas price bases.

Next, CRA configured a "CATF case" based on the "EPA Policy Case," and that altered only key assumptions describing CCS. CATF opted for CCS related changes that are reasonable, consistent with the general approach outlined by EPA in setting building blocks for BSER. CATF's "World 1: Updated Retrofit and EOR Assumptions" uses the same assumptions as the "EPA Policy Case" described above except that in World 1, the CCS assumptions are adjusted compared with the EPA Base Case, as described in Appendix A. Generally, the EOR prices are higher for the Permian Basin and the rest of the U.S. in World 1 than in the EPA Base Case, and higher EOR storage volumes, and lower CO_2 transportation costs in Texas, Oklahoma, and Mississippi also characterize World 1. World 1 includes the most realistic set of EOR assumptions along with other assumptions reflecting the EPA Policy Case, and therefore provides the best look at likely outcomes under the CPP.

CRA also ran four additional sensitivity cases, summarized in Table 1 below, representing alternative scenarios, by changing the assumptions about key drivers (e.g. fuel prices, CO_2 value, technology availability and costs) that will, or might, affect the cost of electricity and the value of captured CO_2.

- The "World 2: EPA Retrofit Costs with Updated EOR" case utilizes World 1 EOR and transport assumptions but maintains EPA's technology cost and availability.
- The "World 3: $80 Oil" is identical to World 1, except that the EOR value of CO_2 is derived from an $80 per barrel assumption, as opposed to a $100 per barrel assumption.
- The "World 4: Greenfield CCS Compliance" case is identical to World 1, except that greenfield CCS projects are allowed to count towards CPP compliance.
- The "World 5: High Gas Price" is identical to World 1, except that the natural gas price trajectory uses data from the AEO 2014 Low Oil & Gas Supply scenario.[180]

---

[180] U.S. EIA, *Annual Energy Outlook*, at E-9 (2014), *available at*: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

Table 1: Summary of modeling assumptions used by EPA and CATF (Source: CATF).

	EPA IPM Runs Base Case v5.13 (3)	CATF NEEM World 1	CATF NEEM World 2	CATF NEEM World 3	CATF NEEM World 4	CATF NEEM World 5
Maximum Price Paid for CO_2 with EOR ($/short ton) (1)						
Permian Basin	14.52	34.32	World 1	27.46	World 1	World 1
New Mexico	14.52	34.32	World 1	27.46	World 1	World 1
Texas Outside Permian Basin	6.67	13.33	World 1	16	World 1	World 1
Oklahoma	14.52	20	World 1	16	World 1	World 1
Mississippi	14.52	20	World 1	16	World 1	World 1
Rest of Nation	14.52	20	World 1	16	World 1	World 1
EOR Capacity (Million Short tons) (2)						
Permian Basin	5,633	3,104	World 1	World 1	World 1	World 1
New Mexico	672	672	World 1	World 1	World 1	World 1
Texas Outside Permian Basin	724	3,896	World 1	World 1	World 1	World 1
Oklahoma	1,168	2,545	World 1	World 1	World 1	World 1
Mississippi	135	317	World 1	World 1	World 1	World 1
Rest of Nation	5,214	5214	World 1	World 1	World 1	World 1
National Total	13,546	15,748	World 1	World 1	World 1	World 1
Transportation (2)						
Texas	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Oklahoma	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Mississippi	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Rest of Nation	GeoCat Table 6-3	GeoCat Table 6-3	World 1	World 1	World 1	World 1
CO_2 Capture (2)						
Coal Retrofits	1 case- greater than 400 MW, 90%	15 cases based upn heat rate,50% or 90% capture level, and unit size	EPA Base Case v5.13	World 1	World 1	World 1
Gas Retrofits	No	Yes-90%	EPA Base Case v5.14	World 1	World 1	World 1
Coal New Builds	1 case- IGCC 90%	8 cases based on coal type, PC and IGCC, 90% and 50% capture	EPA Base Case v5.15	World 1	World 1	World 1
Gas New Builds	No	Yes-90%	EPA Base Case v5.16	World 1	World 1	World 1
Greenfield CCS Plants Count as Compliance Option for CPP?	No	No	No	No	Yes	No
Gas Prices (2)	EPA Base Case v5.13	EPA Base Case v5.14	EPA Base Case v5.15	EPA Base Case v5.16	EPA Base Case v5.17	AEO 2012 low O & G supply

Notes

1. $14.52 per short ton is the maximum price GeoCAT pays for EOR anywhere in the nation EPA Base Case v5.13. This corresponds to STEP 1 in Table 6-2 for the GeoCAT model. Other EOR prices ($/short ton) include STEP 2 is 9.68; STEP 3 is 4.84, and STEP 4 is $0. See Appendix A for CATF STEP prices and storage.
2. See Appendix A for detailed discussion of CATF storage capacities, transportation coststs, CO_2 capture costs, and gas prices.
3. EPA Analysis of the Clean Power Plan at http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html and EPA's Power Sector Modeling Platform v.5.1 at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

ii. CATF’s modeled EPA Policy Case and World 1 Results

The “EPA Policy Case” modeled by CRA successfully reproduced the results of the IPM policy case for 2030 developed by EPA to support the rule. It showed no CCS being built in response to the proposed rule, consistent with EPA’s IPM modeling results.

Our World 1 scenario, including more realistic (higher) CO_2 purchase prices, greater storage volumes, and lower CO_2 transportation costs, by contrast predicted that nearly 95 million short tons/year of CO_2 (85 million metric tons) would be stored as a result of the CPP. These results appear in nine states including Texas, Oklahoma, New Mexico, Illinois, North Dakota, Kansas, Wyoming, Michigan, and Nebraska. Over half the modeled World 1 reductions come from storage in the Permian Basin in Texas. Figure 7 below summarize the projected storage by year and location, under World 1 assumptions.

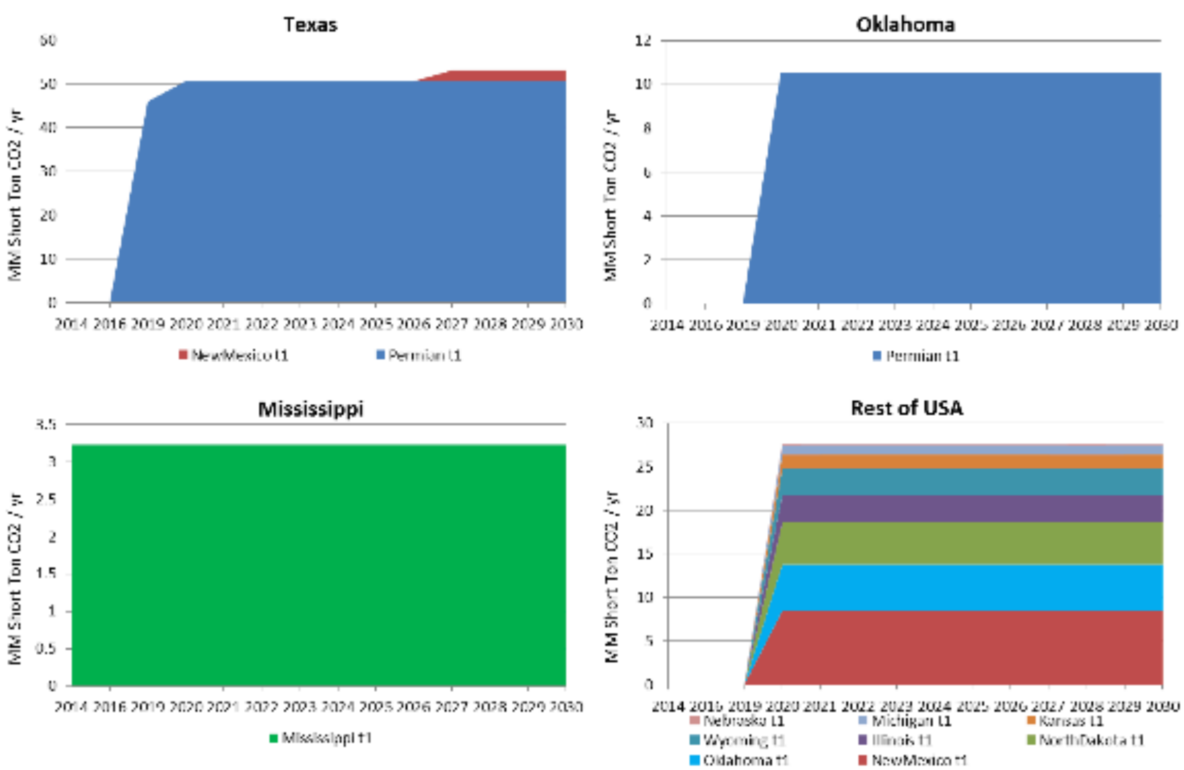


Figure 7: CO_2 sequestration in World 1 (summarizing the location of retrofits, new builds, and MW of capacity in World 1) (Source: CATF).

World 1: Updated Retrofit and EOR Assumptions				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,469	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,376	1	984

Table 2: (Source: CATF).

As Table 2 shows, 19 units nationwide and two new build CCS units occur in World 1. This represents over 10 GW of retrofits on existing coal units, well above the zero retrofits predicted by the EPA Policy Case.

iii. CATF sensitivities (Worlds 2 – 5) and results.

Figure 8 shows the amounts of CO_2 storage projected to occur under each of the other modeled CATF sensitivities – that is, Worlds 2 through 5 – graphed together with the EPA base case and World 1. As the figure shows, World 5 (high gas prices) drives the highest levels of CCS. Worlds 4 and 1 produce the next highest levels of CCS (about 95 million short tons stored). And, Figure 8 below summarizes the CCS retrofits and new builds predicted across all regions, under the EPA Policy Case and the CATF scenarios (Worlds 1-5).

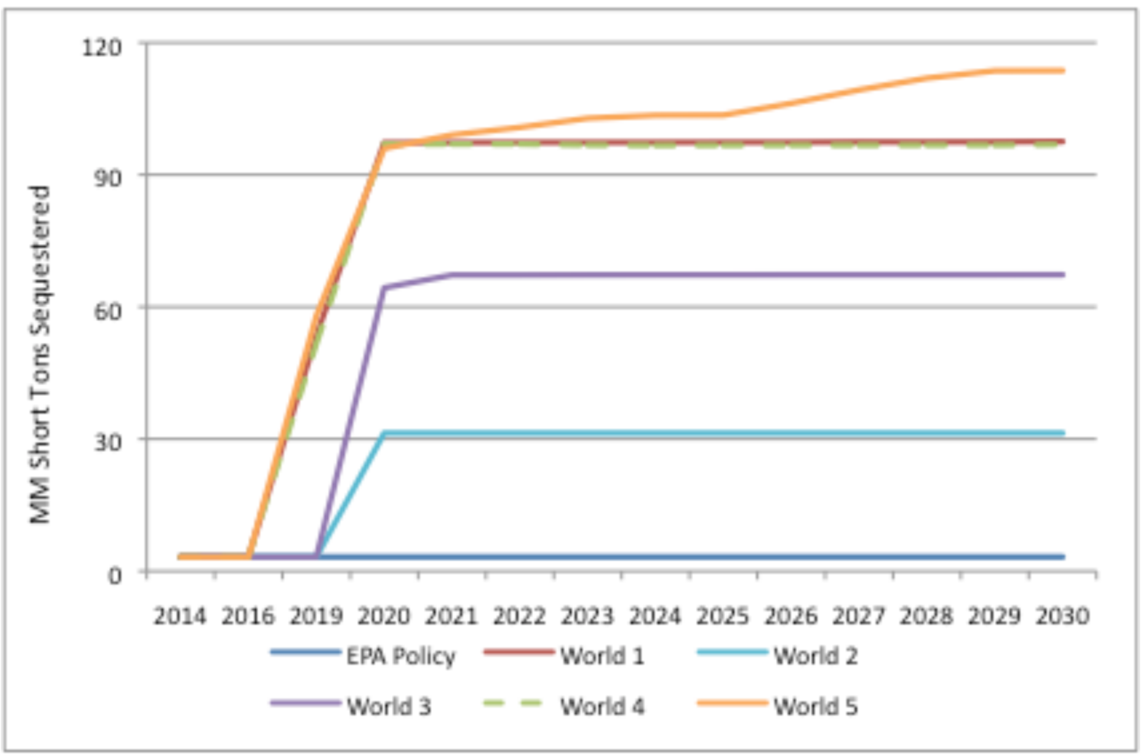


Figure 8: CO_2 storage under CATF's modeled scenarios (Source: CATF).

Table 3 below summarizes the CCS retrofits and new builds across all modeled scenarios. With the exception of World 5, all of these units are coal-fired with 90 percent capture. Under the World 5 scenario, some of the greenfield units utilize partial (50 percent) capture.

Table 3: CCS Units and Capacity in Modeled Scenarios 2014 – 2030 (Source: CATF).

Texas	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	10	6,469	0	0
CATF World 2	6	3,370	0	0
CATF World 3	8	4,791	0	0
CATF World 4	10	6,472	0	0
CATF World 5	11	7,273	1	759

Oklahoma	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	3	1,241	0	0
CATF World 2	1	490	0	0
CATF World 3	2	571	0	0
CATF World 4	3	1,241	0	0
CATF World 5	3	1,526	0	0

Mississippi	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	1	840
CATF World 1	0	0	1	840
CATF World 2	0	0	1	840
CATF World 3	0	0	1	840
CATF World 4	0	0	1	840
CATF World 5	1	440	2	1,201

Rest of USA	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
EPA Policy Case	0	0	0	0
CATF World 1	6	2,376	1	984
CATF World 2	1	120	0	0
CATF World 3	4	1,795	1	1,084
CATF World 4	6	2,363	3	1,445
CATF World 5	7	4,605	2	2,678

World 1: Updated Retrofit and EOR Assumptions				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,469	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,376	1	984

World 2: EPA Retrofit Cost with Updated EOR				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	6	3,370	0	0
Oklahoma	1	490	0	0
Mississippi	0	0	1	840
Rest of USA	1	120	0	0

World 3: $80 Oil				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	8	4,791	0	0
Oklahoma	2	571	0	0
Mississippi	0	0	1	840
Rest of USA	4	1,795	1	1,084

World 4: Greenfield CCS Compliance				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	10	6,472	0	0
Oklahoma	3	1,241	0	0
Mississippi	0	0	1	840
Rest of USA	6	2,363	3	1,445

World 5: High Gas Price				
	Retrofit		New Builds	
	# of Units	MW	# of Units	MW
Texas	11	7,273	1	759
Oklahoma	3	1,526	0	0
Mississippi	1	440	2	1,201
Rest of USA	7	4,605	2	2,678

Projected CO_2 reductions under the modeled scenarios are significant. Figure 8 and Table 3 support a variety of findings:

- Table 3 shows that under our World 2 scenario, CATF's modeling projects 3370 MW of CCS-EOR retrofits in Texas, 490 MW of CCS-EOR retrofits in Oklahoma and 120 MW of CCS-EOR retrofits in the rest of the country, or about 4 GW of CCS-EOR retrofits total. World 2 adopts EPA's CO_2 capture cost assumptions but more realistic EOR prices, transport costs and storage capacity in key EOR states. This increase in CCS retrofits is significant, as compared with the EPA Policy Case.

- Higher natural gas prices under CATF's World 5 scenario drive significant increases in CCS retrofits and in the corresponding quantities of CO_2 stored/reduced from atmospheric release. Increasing the long-term natural gas price by approximately $2/MMbtu in the model, created incentives for greenfield 50 percent capture units in Mississippi and Texas not seen in other scenarios. Our World 5 predicts nearly 14 GW of retrofit capacity nationwide. This underscores the importance of CCS on coal as a hedge against higher natural gas prices.

- World 3 ($80 oil with CATF retrofit costs) predicts more CO_2 storage than World 2 ($100 oil and EPA retrofit costs). Both scenarios predict less CO_2 will be stored than is predicted under the World 1 scenario. These comparisons show that CATF's updated CCS retrofit cost/penalty assumptions are more influential than the $80 vs. $100 oil prices, in driving CCS and lowering marginal CPP compliance costs.

- In all scenarios modeled, CCS retrofits are preferred to CCS-equipped new builds even in a case where new CCS-equipped plants can count towards CPP compliance.

The three states examined in detail in CATF's modeling also showed differing levels of CCS penetration in the predicted 2016, 2020, 2025 and 2030 generation mix. These results are summarized in Figure 9. Figure 9 shows the percentage of TWH from each category of generation and equivalent demand side energy efficiency in 2016, 2020, 2025 and 2030. Both Texas and Oklahoma show significant CCS penetration. In 2030, CCS on coal units represents 4 - 9 percent of the generation mix in Texas depending upon the scenario, and about 4 percent of the generating mix in Oklahoma. In Mississippi, the only CCS plant is Kemper, which is under construction and expected to begin CCS operations in 2015. In our modeling, Kemper absorbs most of the EOR-enabled CO_2 storage in Mississippi, curtailing incremental CCS.

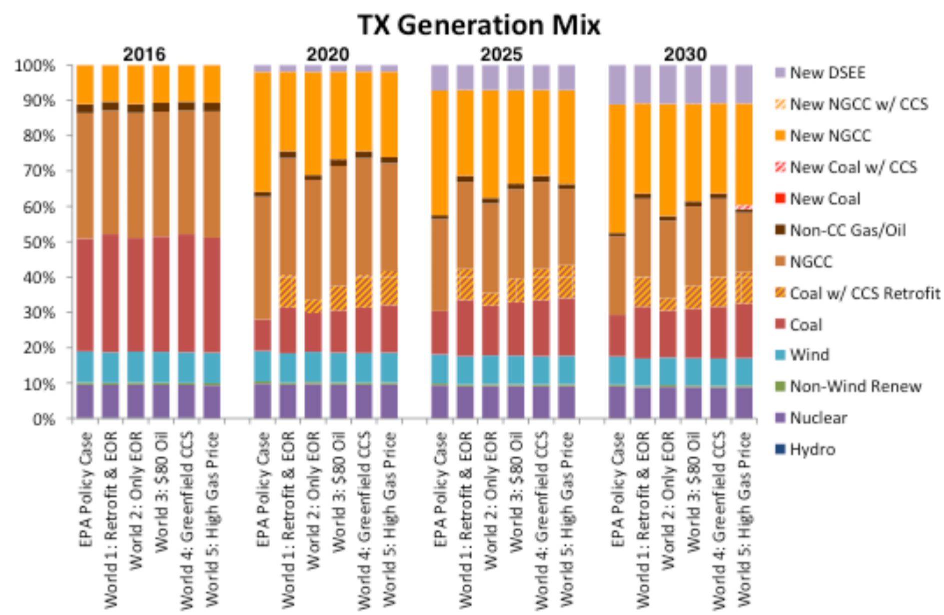
In both Texas and Oklahoma, modeled increased coal CCS retrofits come at the expense of new NGCC plants. CCS retrofitted on existing coal plants prevents some retirements of coal units and postpones when new NGCC plants are built. In Texas, the new NGCC falls from about 171 TWH in the EPA Policy Case in 2030, to 124 TWH to 152 TWH in the CATF World 1 through 5 scenarios. In Oklahoma, New NGCC in the EPA Policy Case is predicted to reach 28.5 TWH in 2030. CATF's modeling predicts CCS at Oklahoma coal plants but reduces the amount of new NGCC electricity production to a range of 14.5 -24 TWH depending upon the scenario. The amount of hydroelectric, nuclear, non-wind renewables, wind and demand side energy efficiency are unchanged compared to the EPA Policy Case.

The CATF modeling also predicts that CCS retrofits in Texas, Oklahoma and Mississippi can allow more non-CCS coal to operate. This is because CCS retrofits can allow "border line" non-CCS coal units to remain online and/or generate more without violating CPP rate limits. But as Table 4 below shows, these increases above the EPA Policy Case, where they exist, are modest.

Percentage Change in CO_2 Emissions in World 1 from the EPA Policy Case

	2020	2030
Texas	1.7%	2.1%
Oklahoma	0.2%	-2.0%
Mississippi	1.6%	1.8%

Table 4: (Source: CATF).



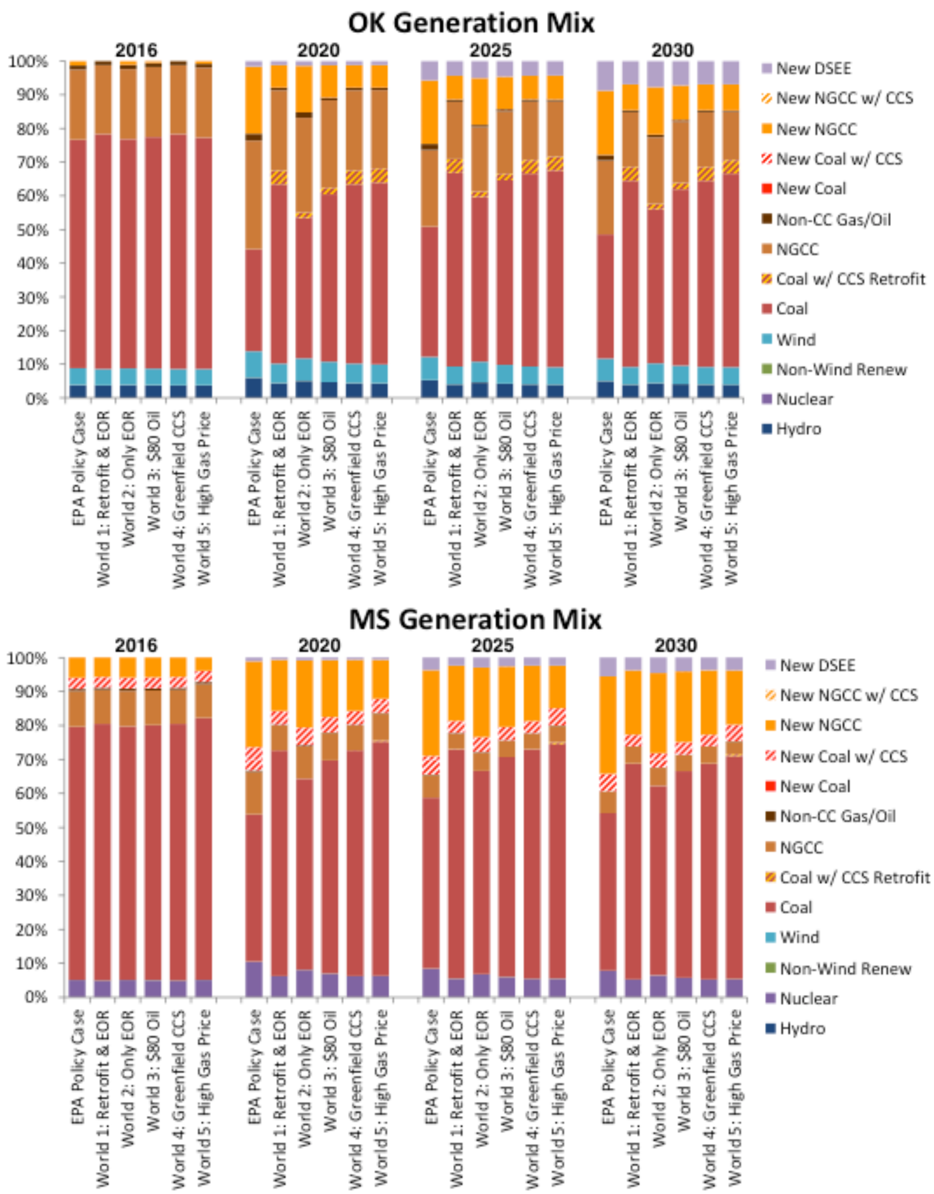


Figure 9: Generation mix in Texas, Oklahoma and Mississippi: 2016, 2020, 2025 & 2030, under modeled scenarios (Source: CATF).

With respect to costs of CCS retrofits, our modeling showed small but meaningful decreases in total system costs in the areas we studied. The shadow price for CO_2 (again, the marginal cost of abating the last metric ton of CO_2 in order to comply with the rule) varied in the modeled EPA Policy Case, depending upon year. For Texas, the shadow price in 2020 was $30 per short ton and dropped through 2029 to around $15 per short ton. For World 1, the shadow price of CO_2 was generally about $10 per short ton less than the EPA Policy Case, across all years. Other modeled scenarios showed lower shadow prices than the EPA Policy Case with the exception of the World 5 scenario, the high natural gas price scenario. In World 5, higher natural gas prices drive abatement costs up, although CCS retrofits on coal units do help mitigate to some degree these higher gas price effects.

CATF's model runs also show that there are small but meaningful decreases in total system costs in the regional transmission organization ("RTOs") encompassing Texas and Oklahoma, where CCS is retrofit. More favorable CCS economics allow more existing coal to survive and in turn forestall new NGCC builds. The total system costs reductions are depicted in Figure 10 below.

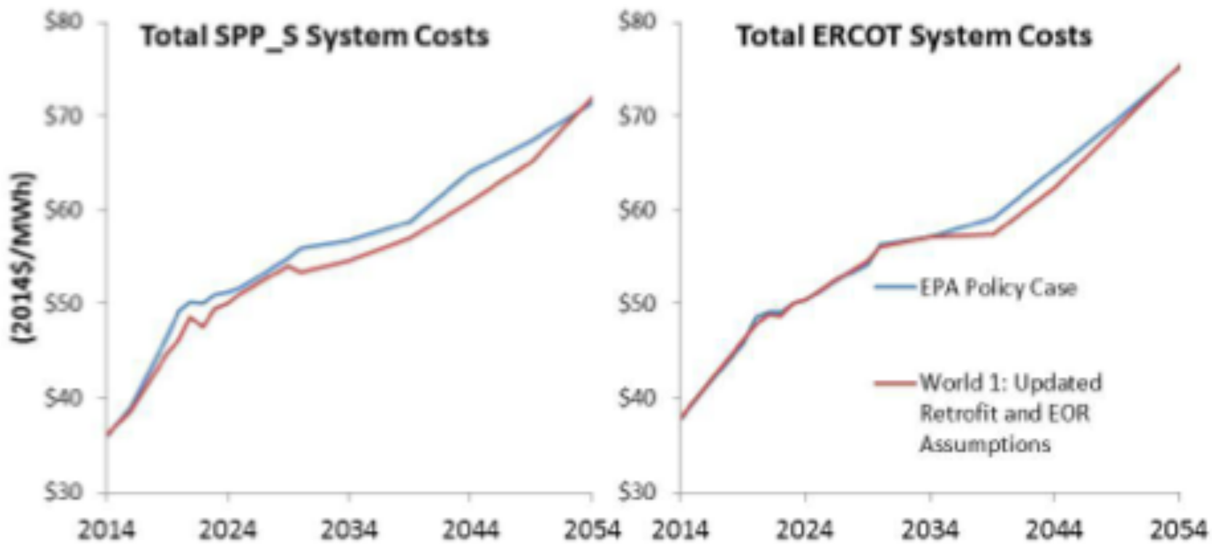


Figure 10: System costs in the Oklahoma and Texas RTOs: World 1 vs. EPA Policy Case (Source: CATF).

Figure 10 shows, in present value (2014-2054) terms, that the total system costs in the Oklahoma RTO ("SPP_S") decrease by $5.1 billion under CATF World 1 assumptions, or by 2.4 percent as compared with the EPA Policy Case. Similar results are observed in the Texas RTO ("ERCOT"). In ERCOT, total system costs decrease by $2.4 billion, or 0.5 percent as compared with the EPA Policy Case. This demonstrates that World 1 can achieve lower electricity prices in the modeled regions than will the EPA Policy Case.

2. Conclusions and recommendations.

a. CCS is a significant compliance pathway in two of the three EOR states studied in detail by CATF.

As Table 5 below shows, CATF's modeling predicts significant CO_2 tonnage reductions will be achieved using CCS-EOR retrofits on affected units in Texas, and this accounts for 25 - 65 percent of the total CO_2 reductions that must be achieved in 2030 as a result of the CPP Texas CO_2 emission targets. For Oklahoma, CATF's modeling predicts CO_2 reductions using CCS-EOR retrofits of between 21and 92 percent of the 2030 CPP targets, depending on the scenario modeled. In Mississippi, the only CCS shown in the CATF modeling is Kemper, which is considered an existing source under the rule.

Table 5: Texas and Oklahoma modeled CO_2 storage as a percentage of the 2030 CPP state goals.

	Texas	
	MM Metric Tons Stored Through EOR in 2030	**% of 2030 Texas Target (84.87 MM Metric Tons)**
World 1	48.20	57%
World 2	20.82	25%
World 3	36.22	43%
World 4	48.21	57%
World 5	55.42	65%
	Oklahoma	
	MM Metric Tons Stored Through EORin 2030	**% of 2030 Oklahoma Target (16.98 MM Metric Tons)**
World 1	14.37	85%
World 2	3.54	21%
World 3	9.40	55%
World 4	15.99	94%
World 5	15.55	92%

The emissions reductions that our modeling shows can be achieved by CCS-EOR retrofits are significant when compared with the sum of the CPP's state emissions reductions targets. In the continental United States, the CPP is expected to reduce emissions from existing affected sources by over 607 million metric tons per year in 2030 relative to 2012 levels.[181] As shown in Table 6 below, our modeling predicts that CCS-EOR retrofits can account for between 4 and 16 percent (depending on the scenario modeled) of the U.S. total CO_2 reductions under the CPP.

[181] U.S. EPA, *Technical Support Document: Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents*, Docket ID No. EPA-HQ-OAR-2013-0602 (Nov. 2014) [hereinafter *Rate-Based to Mass-Based Translation TSD*].

Table 6: CO_2 Storage in U.S. modeled scenarios (Source: CATF).

	World 1	World 2	World 3	World 4	World 5
Million Metric Tons Stored by CCS-EOR in 2030	85.57	25.50	58.12	84.94	100.17
% of Continental US 2030 reduction target compared to 2012 emissions achieved by CCS-EOR	14%	4%	10%	14%	16%

Another way to evaluate the significance of the CCS-EOR reductions modeled by CATF is to compare them to the reductions EPA estimated in assessing the CO_2 reduction potentials of its various building blocks. For example, EPA developed a simplified cost estimate for its building block 1 (HRI), which it modeled would achieve 97 million metric tons of CO_2 reductions by 2030[182] By comparison, the total CO_2 reductions modeled to be achieved by 2030 using CCS-EOR in the scenarios modeled by CATF range between 25 and 100 million metric tons. The World 1 scenario incorporates what CATF believes are the best estimates for both EOR price, supply and CO_2 transportation and best estimates of retrofit costs. Therefore the most likely result is 85 million metric tons sequestered under the World 1 scenario – an amount comparable with the CO_2 reductions EPA projects will be achieved by heat rate improvements.[183]

The modeled CCS-EOR CO_2 emissions reductions moreover are economically reasonable. As described earlier in the analysis and results section, the reductions in World 1 are achieved at less cost than in the EPA Base Case. The CATF World I run showed that there are small but meaningful decreases in total system costs in the RTOs encompassing Texas and Oklahoma, where CCS is retrofit. In present value (2014-2054) terms, total system costs in

[182] *GHG Abatement Measures TSD*, at 2-39.

[183] EPA's IPM model predicts 10 GW of incremental non-hydroelectric renewable generating capacity to be in place between 2020 and 2030 under the CPP. *See* U.S. EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, at 3-34, Table 3-12, Docket No. ID: EPA-HQ-OAR-2013-0602-0391 (June 2014) [hereinafter *RIA*] (showing predicted non-hydro renewables in 2030 in the "Option 1 State" at 115 GW, and in 2020 at 105 GW, a difference of 10 GW). Over the same period, CATF's modeling shows 10 GW of retrofitted CCS capacity resulting from our modeled World 1 scenario.

SPP_S decrease by $5.1 billion, or 2.4 percent, and in the ERCOT, system costs decrease by $2.4 billion, or 0.5 percent.

3. EPA should adjust relevant state-specific building blocks to include CCS-EOR, especially if the Agency opts to finalize a rule based solely on building blocks 1 and 2.

In summary, the result of adding CCS-EOR retrofits to the BSER building block 1 would be a target rate that reflects an incremental amount of CO_2 reductions on the order of 85 million metric tons per year in 2030. This is a significant quantity of CO_2. In comparison, building blocks 3 and 4 together reduce CO_2 by 262 million metric tons per year relative to the 2020 base case.[184] The contribution by CCS could therefore be about 32 percent of the total contribution of building blocks 3 and together.

If EPA finalizes its block 1 and 2 only approach to target setting, including CCS as part of building block 1 (referred to as Unit Specific Measures in these comments) helps maintain the stringency of the rule at a reasonable cost.

b. Building block 2 is reasonable if not conservative.

EPA has requested comment on all aspects of its findings related to building block 2, which assesses the potential for CO_2 reductions based on the displacement of existing high-emitting coal generation with natural gas, through a redispatch mechanism to be directed by states and RTOs.[185] EPA assumes a 64 percent average existing natural gas unit utilization factor as well as imposing a "ceiling" of 70 percent, and specifically requests comment on whether it should consider a higher utilization rate (up to 75 percent).[186] CATF's Power Switch report[187] and underlying economic analysis commissioned by CATF from The NorthBridge Group ("NorthBridge")[188] supports the conclusion that EPA's proposed emission rate targets are

---

[184] The total amount of CO_2 reductions from building blocks 3 and 4 is 262 MM tonnes in 2030 relative to the 2020 base case. This is calculated from the total amount of reductions in the rule of 555 MM tonnes (*RIA* at Table ES-2) minus the amount of reductions from building blocks 1 and 2, which is 293 MM tonnes (U.S. EPA, *Memo: Emissions Reductions, Costs, Benefits and Economic Impacts Associated with Building Blocks 1 and 2*, at 3 (June 2014)).

[185] 79 Fed. Reg. at 34,862-34,866.

[186] *Id.* at 34,865.

[187] CATF, "*Power Switch*: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants" (Feb. 2014), *available at:* http://www.catf.us/resources/publications/files/Power_Switch.pdf.

[188] The NorthBridge Group is an economic and strategic consulting firm serving the electric and natural gas industries, including both regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge's practice is national in scope, and they have long-standing consulting relationships with a number of electric utility clients across the country. NorthBridge applies market insights, rigorous quantitative skills and regulatory expertise to solving complex business and policy challenges.

reasonable and, specifically, that EPA's proposed building block 2 is reasonable, if not conservative: EPA's proposed 70 percent utilization "ceiling" for natural gas utilization could be raised to at least 75 percent.

i. CATF's Power Switch used state-of-the-art modeling and realistic assumptions to show the CO_2 reductions achievable using a common sense gas-redispatch scenario.

During the stakeholder process leading up to EPA's proposal, CATF suggested a common sense approach to existing fossil fueled power plant CO_2 emissions reductions based on performance standards designed to result in displacement of power generation from the highest-emitting coal-fired power plants by generation from under-utilized, efficient natural gas plants. Building block 2 of the CPP proposal reflects this concept of natural gas for coal "redispatch."

In *Power Switch*, CATF suggested that if EPA set separate emission rate target standards for fossil-fueled utility boilers at 1,450 lbs. CO_2/MWh, and for natural gas combustion turbines at 1,100 lbs. CO_2/MWh,[189] and facilitated least-cost implementation for states by issuing a model interstate trading rule with the opportunity to use the free allocation of allowances to protect electric retail ratepayers of all classes, significant CO_2 reductions would be achieved through coal to gas redispatch. The NorthBridge analysis used two main models. The first, *FastForward*,[190] is a commercially available fundamental dispatch and wholesale market price forecasting tool developed by NorthBridge for EPRI. For the purpose of this effort, *FastForward* was run on a deterministic basis to produce hourly pricing results for the power grid reliability regions here:

[189] 1,100 lbs CO_2/MWh is a rate consistent with the performance of the vast majority of existing natural gas-fired affected units today. Edward Rubin, Carnegie Mellon University *A Performance Standards Approach to Reducing COEmissions from Electric Power Plants*, at 8 (June 2009) *available at*: http://www.c2es.org/docUploads/Coal-Initiative-Series-Rubin.pdf. *See also* 79 Fed. Reg. 1,447.

[190] *FastForward* is a PC-based VisualBasic model designed to rapidly generate forward market prices for electricity on a probabilistic basis. At its core, it is a multi-region dispatch model that quickly estimates hourly electric market-clearing prices under an array of load, resource and commodity scenarios. The model relies on a Scenario Generation module to identify statistically meaningful scenarios based on volatility and correlation parameters for each input variable. The market price outputs derived for each scenario describe a sample distribution from which a variety of statistics are calculated. In addition to the expected market price trajectory, the Statistical Estimation module can calculate the probability distribution associated with market prices and correlations with other variables. *FastForward* is used by major investor-owned utilities, competitive generating companies, load-serving entities and consulting firms in the United States to forecast market prices, assess generating asset market values and develop risk management plans.

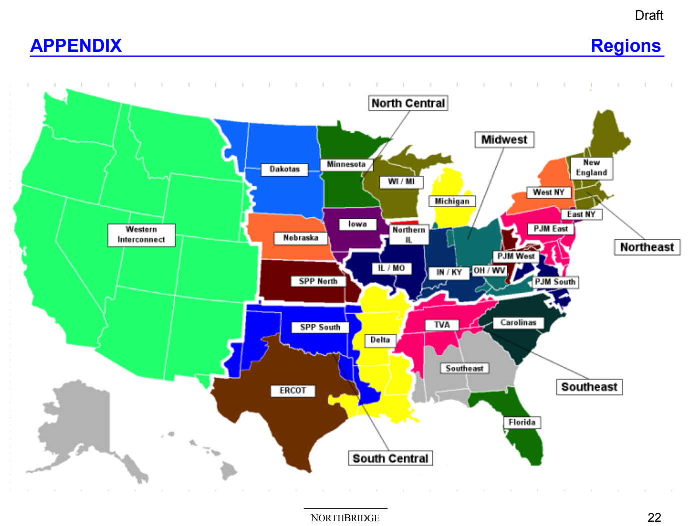


Figure 11: Power grid reliability regions used in FastForward (Source: NorthBridge).

The second part of the NorthBridge analysis used a proprietary emissions compliance-planning model,[191] which takes as its inputs the unit-specific generating data and regional hourly market price results from FastForward, along with NorthBridge-developed cost and performance assumptions for carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury emission control technologies from. It then estimates unit retirement and emission control retrofit decisions annually. And sensitivities also can be run achieving results under alternate commodity assumptions and regulatory scenarios.

The compliance model is easily adapted to evaluate the impact of potential new conventional pollutant policies, with or without carbon pricing policies. The NorthBridge model also uses unit retirement decision assumptions that are based on economic criteria tailored to the regulated and merchant ownership status of individual units rather than engineering or physical unit criteria (such as age, etc.), in order to more accurately reflect the manner in which unit owners make unit retirement decisions.

[191] The advantages of using the NorthBridge modeling platform and mode of analysis over other dispatch models include that: (1) it provides unit-specific results (unlike ICF Consulting's Integrated Planning Model/IPM model which analyzes only "model" units and then "parses" the run results to specific real-world units;) (2) investor owned utility companies, competitor generators, load-serving entities, and other consulting firms all rely on the NorthBridge model and analysis in making business decisions including asset valuation for the purchase or sale of units, regulatory compliance decisions and planning, etc.; and (3) it allows the analysis of the "phase-in" of policies over time (unlike the IPM model) which avoid electricity and gas price spikes that are artifacts of the model and not representative of real world conditions.

ii. The gas prices and gas price response assumptions in EPA's IPM modeling analysis are too high, needlessly constraining the potential cost-effective role of additional use of natural gas in the redispatch of existing and new NGCC units as well as through gas co-firing in coal units.

Several proposed findings in the CPP are sensitive to EPA's assumptions regarding gas price and gas price response (i.e., gas price elasticity) including: the 70 percent "ceiling" for existing gas unit utilization in building block 2 and the decision not to include new NGCCs or gas co-firing in the BSER determination and state goal calculation methodology.

The gas price forecast in the June 2014 IPM base case (adjusted to nominal dollars using a 1.5 percent annual inflation rate) starts at $5.70/MMBtu in 2020 and rises to $7.00/MMBtu by 2025.[192] In contrast, recent NYMEX prices (in nominal dollars) start at just $4.43/MMBtu and only rise to $4.84/MMBtu during the same period.[193] This means the June 2014 base case IPM prices are roughly $1.25/MMBtu to $2.00/MMBtu higher than current NYMEX prices. This is equivalent to a 30 percent to 45 percent premium. *See* Figure 12 below. Note that since current NYMEX prices are well within the range of NYMEX prices over the last year, this conclusion is not the result of a temporary or unusual pattern of NYMEX prices, but a more basic shift.

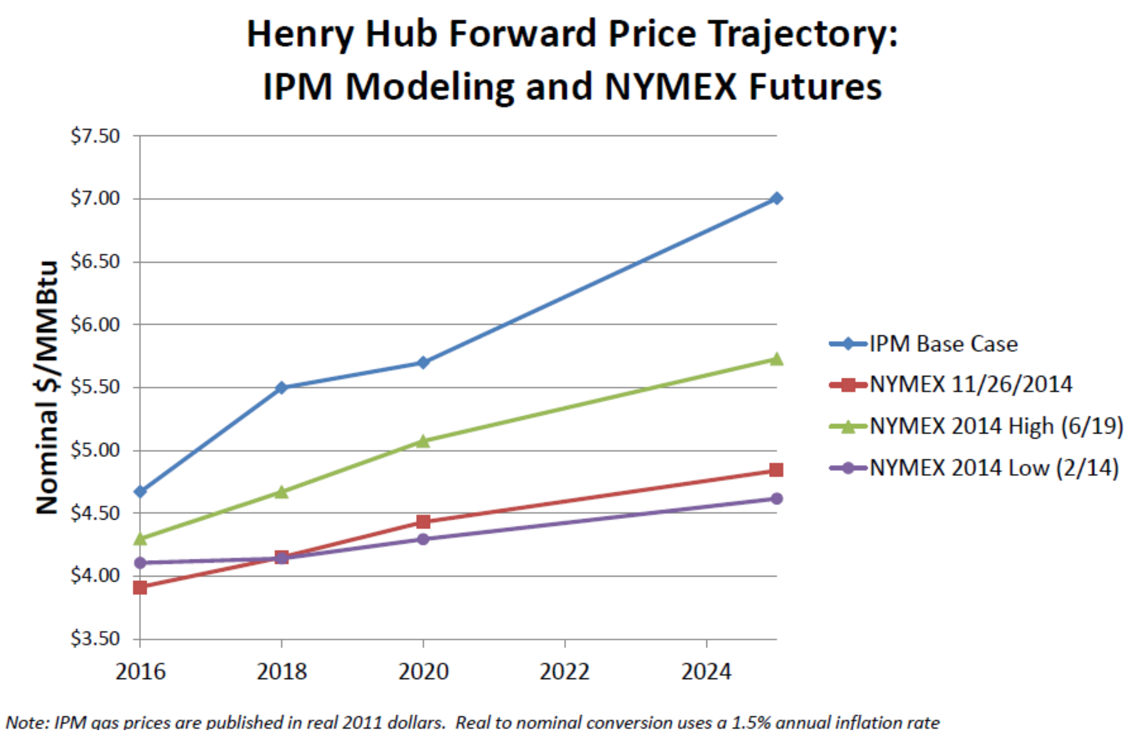


Figure 12: Ventyx, "NYMEX Henry Hub Natural Gas Futures" *available at*: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite.

---

[192] Ventyx, "NYMEX Henry Hub Natural Gas Futures" *available at*: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite

[193] *Id.*

The fact that the June 2014 base case IPM gas price assumptions are 30 to 45 percent higher than current market expectations suggests the gas resource assumptions (that is, the cost of production and quantity of gas resources) underlying the IPM estimates are overly conservative compared to current market expectations. The market forwards suggest that there may well be a larger quantity of gas reserves and lower cost of production than is reflected in the June 2014 IPM base case.

Since the base case prices appear high, the increase in gas prices forecasted in the policy cases may well also be overstated. If there is more natural gas available at relatively low prices, then increased demand for natural gas may cause prices to rise by a smaller amount than forecasted in the IPM policy cases. This overstatement of gas prices raises the estimated cost of the CPP rule and can cause the role of gas in the compliance mix to be understated.

iii. EPA should update the gas price and gas price response assumptions that it uses in its IPM compliance modeling.

The gas price response (i.e., gas price elasticity assumptions) built into EPA's IPM model appear to be materially higher than those reflected in the NorthBridge analysis of the CATF Power Switch approach and the recent Rhodium Group analysis of the CPP using the NEMS modeling platform.[194]

Figure 13 below shows the percent change in U.S. electricity consumption predicted by EPA's IPM modeling in the RIA, Rhodium Group's analysis for CSIS (using the NEMS model), and the NorthBridge analysis of CATF's Power Switch proposal (using FastForward and the proprietary NorthBridge unit dispatch model).

[194] The Rhodium Group for the Center for Strategic and International Studies, *Remaking American Power*, (July 24, 2014) (updated Oct. 2, 2014) *available at*: http://csis.org/files/attachments/140724_RemakingAmericanPower.pdf; Clean Air Task Force, *Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants*, (Feb. 2014), *available at*: http://www.catf.us/resources/publications/files/Power_Switch.pdf; *See also* The NorthBridge Group, *Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions*, (Feb. 2014) *available at*: http://www.catf.us/resources/publications/files/NorthBridge_111d_Options.pdf.

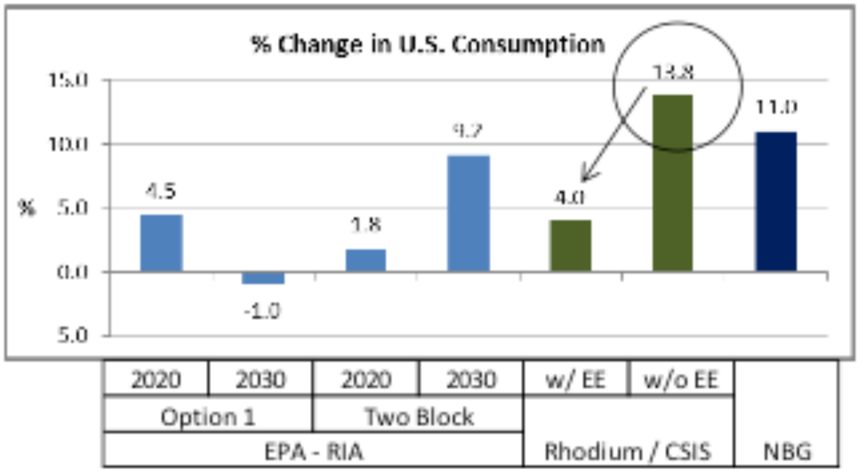


Figure 13: (Source: NorthBridge).

Figure 14 below shows the percent change in electricity price per percent change in U.S. consumption. Comparing the results demonstrates that the gas price response in EPA's IPM modeling is more sensitive to gas demand than either NEMS or the NorthBridge modeling platform by at least factor of 2 to 6.

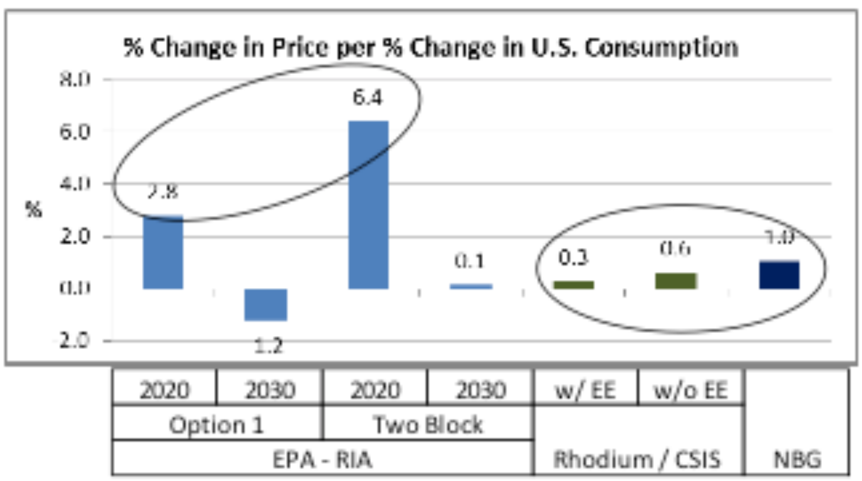


Figure 14: (Source: NorthBridge).

This indicates that the gas price elasticities in EPA's IPM modeling may reflect an overly sensitive gas price response that does not fully account for the potentially large quantity of shale gas reserves. As a result, EPA's modeling could overstate the natural gas price impact of the CPP policy and needlessly constrain the potentially cost-effective role of additional use of natural gas in redispatch of existing and new NGCC units as well as through gas co-firing in coal units.

iv. Power Switch modeling results show that EPA's proposed 70 percent utilization factor for natural gas fired units is reasonable.

We compared the Power Switch results to the EPA CPP modeling, and found that the amount of coal generation (and, therefore CO_2 emissions) displaced by higher utilization of natural gas in the policy modeled in Power Switch is close to the redispatch effect modeled by EPA in building block 2.[195] Because the Power Switch approach and EPA's building block 2 include comparable assumptions, the NorthBridge economic analysis demonstrating the feasibility of the Power Switch approach also lends support for the reasonableness of EPA's proposed building block 2, and therefore to EPA's proposed target emission rates in general.

The result of implementing the Power Switch approach, NorthBridge found, would be that operators would shift reliance from the highest- emitting coal units to existing under-utilized natural gas units, thereby reducing CO_2 emissions by about 27 percent, as compared with 2005 levels, or by 636 million metric tons.[196] The analysis demonstrated that these results could be achieved at a marginal cost of only $34/metric ton CO_2 ($2013) while ensuring electric and gas system reliability. Both the marginal cost and the average cost of the Power Switch concept ($32/metric ton CO_2 ($2013)), are less than the Social Cost of Carbon ("SCC") put forward by the U.S. government.[197]

By definition, the NorthBridge economic modeling analysis selects the least-cost compliance pathway to achieve emissions performance. NorthBridge's analysis of the Power Switch approach found that by 2020, almost 70 percent of the compliance would be achieved through redispatch of natural gas generation to replace coal generation.[198] The remainder of the CO_2 reductions would result from a combination of heat rate improvements, some coal unit retirements, and a small amount of demand reduction due to electric price response. The result: a remarkable decrease in CO_2 emissions from the power sector simply by optimizing the existing fossil electric system to use the most efficient power plants first.

---

[195] *Compare* EPA IPM result found at *RIA* Table ES-2 (371 MMT CO_2 reduction from base case in 2020) *with* Power Switch at 6 (308 MMT CO2 reduction from base case in 2020).

[196] The Power Switch approach also predicted additional public health benefits including 2,000 avoided premature deaths and 15,000 avoided asthma attacks annually as a result of the annual reductions of over 400,000 tons in sulfur dioxide (SO2) emissions and nitrogen oxides (NOx) emissions in 2020 associated with the reduced utilization of covered coal plants. Those health benefits represent $34 billion in benefits, or over three times the cost of compliance. And the Power Switch approach was predicted to increase average nationwide retail electric rates by only 2 percent in 2020 which, based on Energy Information Administration forecasts, should result in no net increase in monthly electric bills.

[197] *See* U.S. EPA, "The Social Cost of Carbon" http://www.epa.gov/climatechange/EPAactivities/economics/scc.html; *and* Interagency Working Group on Social Cost of Carbon, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*, (May 2013) *available at*: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

[198] *Power Switch* at 7, 22 Fig.12.

Summary of Results by 2020	
Reduction in fossil CO2 (%) from 2005 levels	-27%
Reduction in CO2 (metric tons) from 2005 levels	636
Reduction in CO2 (metric tons) from forecast 2020 levels	308
CO2 price ($ 2013/metric ton)	$20
Reduction in coal TWh (%)	-27%
Coal retirements (GW)	42
Increase in gas consumption (TCF)	3.0
Increase in Henry Hub gas price ($/MMBtu)	11.4%
Increase in US wholesale electric price (%)	6.9%
Increase in US retail electric price – without allowance offset (%)	6.2%
Increase in US retail electric price – with allowance offset (%)	2.3%
Marginal cost ($ 2013/metric ton)	34
Average cost ($ 2013/metric ton)	32
Total program costs ($ 2013 billion)	9.4
Total program benefits ($ 2013 billion)	34

Table 7: (Source Northbridge).

The following chart illustrates the amount of coal-to-gas redispatch predicted nationwide by the NorthBridge analysis of the Power Switch approach in 2020, relative to a 2020 "business-as-usual" base case.

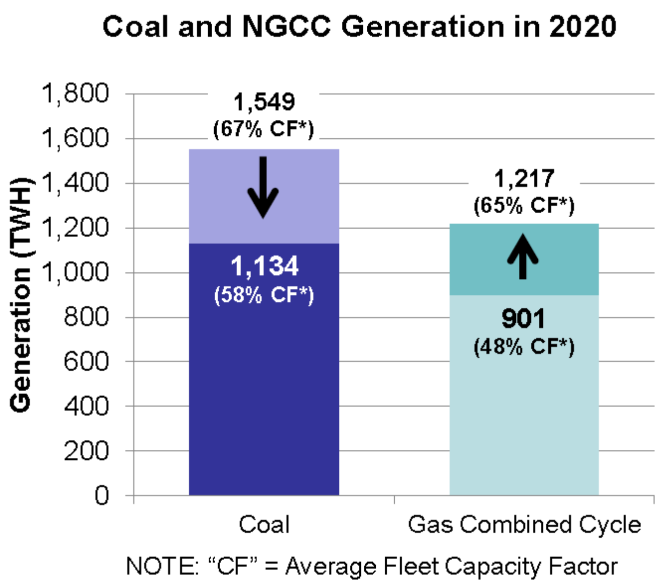


Figure 15: (Source: NorthBridge).

Figure 15 shows the average national utilization factor (or capacity factor or ("CF")) for coal units would fall from 67 percent to 58 percent. The utilization factor for natural gas combined cycle units would increase from 48 percent to 65 percent. This increase in gas unit utilization factor is almost identical to the 64 percent national average natural gas utilization factor EPA derived in building block 2 in the CPP proposal.[199] Additionally, the NorthBridge modeling predicts that in several states, natural gas combined cycle units would exceed the 70 percent utilization factor level, some by a substantial amount (up to 85 percent). Thus, the NorthBridge analysis provides evidence that EPA's proposed 70 percent utilization ceiling is reasonable, if not conservative, and provides support for EPA raising the natural gas unit utilization ceiling to at least 75 percent.

The Power Switch approach would protect system reliability and grid stability by relying on proven, existing fossil electric units that are in operation today. Moreover, the Power Switch modeling results, which find that through an interstate trading system commensurate carbon dioxide reductions can be achieved affordably and reliably show that concerns about the cost impacts and system reliability associated with higher levels of gas redispatch and unit utilization than EPA has proposed in the CPP can be mitigated by EPA facilitating an interstate trading program by the states. A streamlined, easily implemented interstate trading program (perhaps through multistate or "linked state plans") would mitigate cost impacts under any approach to

[199] The EPA's Goal Data Computation spreadsheet shows that the average capacity factor for the existing U.S. natural gas combined cycle fleet was 44 percent in 2012, rising to 64 percent after redispatch. These numbers can be readily calculated from the NGCC generation and capacity rating data in the EPA's GDC spreadsheet. The EPA's capacity factor estimate after redispatch is quite similar to the 65 percent average capacity factor for NGCC facilities estimated to result from CATF's Power Switch approach. While normalizing the two estimates to reflect summer capacity ratings (as opposed to the nameplate rating used by the EPA) would raise the EPA's estimate to some extent, the Power Switch approach was not intended to maximize redispatch from either a technical or economic perspective. Increasing the stringency of the Power Switch approach would also result higher NGCC capacity factors.

target-setting, by allowing affected states and facility owners to comply using the least cost emission avoidance strategies available on the electric system. A trading program also would help mitigate any localized system reliability concerns, as the owners of facilities in constrained areas would be able to purchase of emission allowances from affected facilities in states with greater opportunities for natural gas redispatch.

v. The seasonal pattern of demand for natural gas transportation services, current efforts to address peak day infrastructure constraints and the flexibility of compliance provisions under the proposed rule all support the stringency of building block 2.

Commenters have suggested that EPA's building block 2 assumptions are unrealistic due to existing constraints in natural gas supply, which would result in an inability to meet the level of gas redispatch the Agency predicts.[200] We disagree. While gas transport constraints exist during some peak demand days in some regions of the country, transport capacity is still available for redispatch in unconstrained regions and off peak times of the year.[201] Natural gas consumption in the U.S. peaks during the winter home heating season and inter-state gas pipeline capacity is often fully utilized during at least some of that season.[202] In other times of the year when gas consumption is lower, unless it is used to fill market-area storage or for other purposes, pipeline capacity is often available.[203] This capacity could allow existing NGCC units to increase generating output without infrastructure expansion.

The availability of transport capacity is illustrated by four sets of mapped results from the draft Eastern Interconnection Planning Collaborative ("EIPC")[204] Target 2 Report. The Target 2

[200] Comments submitted by Anda Ray, Vice President, Environment and Chief Sustainability Officer, Electrical Power Research Institute, EPA-HQ-OAR-2013-0602-21697
(Oct. 20, 2014)**;** Steve Corneli, Senior Vice President, Policy & Strategy, NRG Energy "Glide Paths Instead of Cliffs: Greater Emission Reductions at Lower Cost" Doc. ID: EPA-HQ-OAR-2013-0602-17281.

[201] U.S. EIA, "Natural Gas Pipeline Capacity & Utilization," *available at* http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/usage.html.

[202] U.S. EIA "Trends in Natural Gas Storage Capacity Utilization Vary by Region," *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=12811.

[203] U.S. EIA, "Natural Gas Pipeline Network: Changing and Growing," *available at* http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_trends/pdf/chapter5.pdf

[204] According to the Target 1 Report: The Eastern Interconnection Planning Collaborative (EIPC) was formed in 2009 by 25 of the major eastern electric utilities, in order to complete work awarded to the PJM Interconnection, LLC (PJM) on "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009. The work was divided into two phases. Phase 1 focused on the formation of a diverse stakeholder group (the Stakeholder Steering Committee) and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the stakeholder group. The final undertaking in Phase 1 was for the stakeholder group to choose three futures scenarios to pass onto Phase 2 of the project. Phase 2 of this project focused on conducting the transmission studies and production cost analyses on the three scenarios chosen by the stakeholders at the end of Phase 1. This work included developing transmission options, performing a number of studies regarding grid reliability and production costs resulting from the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

report of the EIPC's DOE project, "*Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems"* evaluates the ability of the natural gas systems in the study region to meet the demand of end use and gas-fired electric generation customers over 5-year and 10-year planning horizons. The primary goals of the Target 2 research are to develop a chronological dispatch model of the electric system; incorporate forecasts of generator gas demand with forecasts of end use gas demand and represent seasonal peak days at the five-year and ten-year horizons across the Study Region; identify gas system infrastructure constraint points and evaluate infrastructure adequacy to meet generation gas demand on seasonal peak days; and determine potential mitigation measures to address gas system infrastructure constraints.

The EIPC maps labeled Winter 2023 – Reference Gas Demand Scenario and Winter 2023 High Gas Demand Scenario show pipeline capacity conditions during a peak winter day, one under a reference gas demand scenario and the second under a high gas demand scenario in modeled year 2023.[205] Fully utilized pipeline segments are shown in red), and the total extent of red pipelines is not dramatically different as between the two Winter 2023 scenarios. Furthermore, there are natural gas pipeline systems not fully utilized under either set of Winter peak day conditions, shown by the green and yellow pipelines.

EIPC, Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces ") at xiv, *available at*: http://www.eipconline.com/uploads/Target_1_Report_Final_Draft_4Apr14.pdf.

[205]The reference gas demand scenario represents a forecast that is in accord with the economic, market, and regulatory assumptions characterizing the resource planning process of each of the power producing areas over the five- and ten-year study horizons. The high gas demand scenario represents a plausible maximum level and profile of gas requirements across the Study Region, driven primarily by increased deactivation or retirement of coal plants, lower delivered natural gas prices, and higher electric loads.

.

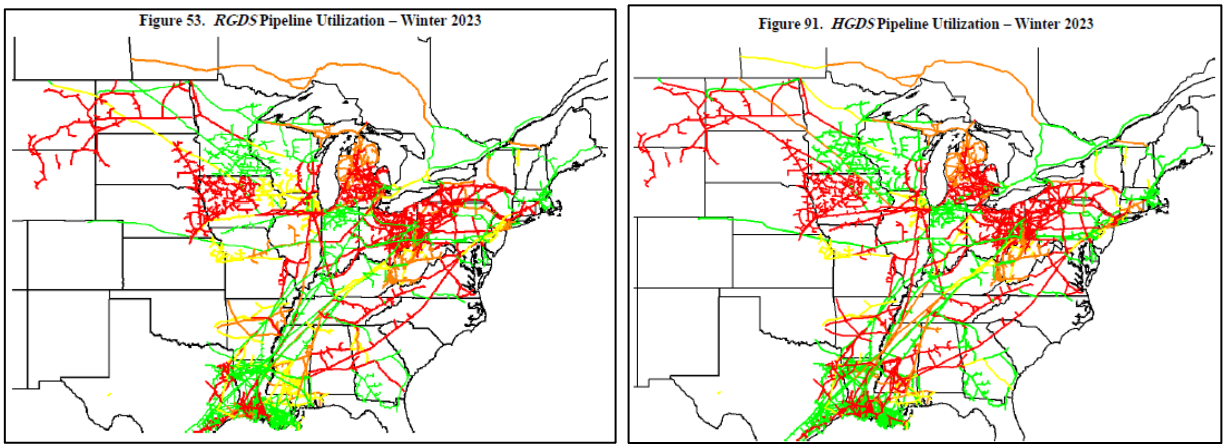


Figure 16: Winter 2023 – Reference Gas Demand Scenario Winter 2023 – High Gas Demand Scenario (Source: EIPC, *Target 2 Draft Report*, at 73 *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

The second set of maps shows EIPC's modeled peak summer day pipeline conditions. When compared with the winter peak conditions under both the Reference Gas Demand Scenario and the High Gas Demand Scenario, it is clear that there are predicted to be many fewer fully utilized pipeline systems in the summer months, under either scenario.

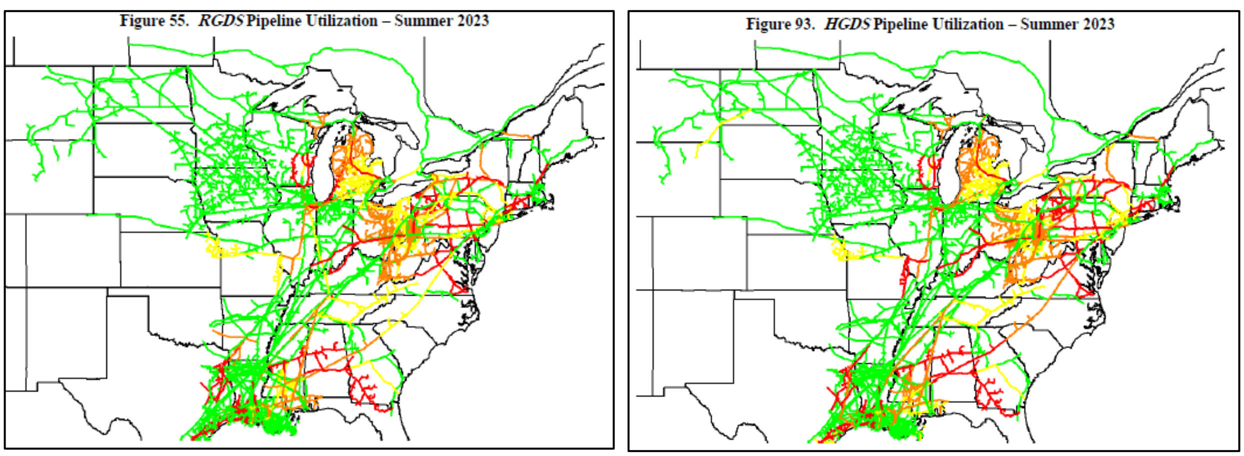


Figure 17: Summer 2023 – Reference Gas Demand Scenario Summer 2023 – High Gas Demand Scenario (Source: EIPC, *Target 2 Draft Report*, at 103, 1095 *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

Concerns regarding gas deliverability and electric supply in New England are not representative of electric-gas conditions across the country. EIPC's Target 1 Report, titled "*Baseline Existing Natural Gas-Electric System Interfaces"* includes the figure below. The report notes that: "Green represents favorable gas-electric interface conditions relative to the other power producing areas (PPAs), that is, the absence of pressing concerns regarding the gas-electric interface capability operational available to generation companies. Yellow represents neutral conditions, that is, conditions not clearly favorable or unfavorable to generation companies. Red represents comparatively unfavorable conditions."[206]

Table 3. Qualitative Assessment of Gas – Electric Interface Attributes

	Criterion	PJM	MISO	NYISO	ISO-NE	TVA	IESO
Natural Gas Supply	Gas Supply Portfolio Diversity	Green	Green	Green	Red	Yellow	Green
	Pipeline Connectivity Level	Green	Green	Green	Red	Yellow	Yellow
	Conventional Storage Deliverability	Green	Green	Yellow	Red	Yellow	Green
	LNG Storage Capability	Yellow	Yellow	Yellow	Green	Yellow	Yellow
Electric-Gas Interface	Firm Transportation Entitlements	Yellow	Yellow	Yellow	Red	Yellow	Green
	Direct Pipeline Connectivity	Green	Green	Yellow	Green	Green	Green
Electric/Gas Tariff	Pipeline or LDC Penalties	Red	Red	Red	Red	Red	Green
	LDC Provision of Flexible Service	Green	Yellow	Green	Yellow	Yellow	Green
	Active Secondary Market	Green	Green	Green	Green	Yellow	Red

Table 7: Qualitative Assessments of Gas-Electric Interface Attributes (Source: EIPC, Target 1 Report, *available at*: http://www.eipconline.com/Gas-Electric_Documents.html).

The gas and electric industries, along with federal and state regulators, are engaged in multiple efforts to assess and, where needed, bolster the adequacy of fuel transport and storage systems.[207] For this reason alone, it is likely that any critical infrastructure constraints can be addressed.

Moreover, the proposed rule provides flexibility for states to comply by allowing them to average the CO_2 emissions rate associated with affected units across a state, within a year, for each year during the 2020 to 2029 period. EPA's rule can be implemented through a mass-based allowance system, under which emissions allowances can be traded on an interstate basis with other states, as we recommend, and discuss more fully *infra* at Sec. III. All of this suggests that the existence of a current infrastructure constraint need not preclude CO_2 reduction through redispatch.

vi. Both historical data and forecast analyses suggest the 64 percent average NGCC utilization factor and 70 percent maximum NGCC utilization factor relied on by EPA in goal setting are reasonable.

[206] Target 1 Report at ES-19 – ES-22 http://www.eipconline.com/Gas-Electric_Documents.html.

[207] *See generally* FERC, "Major Pipeline Projects Pending" (June 15, 2014), *available at*: http://www.ferc.gov/industries/gas/indus-act/pipelines/horizon-pipe.pdf; New York Independent System Operator (NYISO), "Proposed Gas Electric Study Scope (Mar. 2012): Study of the Adequacy and Security of the Interaction of the Gas and Electric Systems in the Northeastern US, Midwest US, and Ontario, Canada," *available at* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_egcwg/meeting_materials/2012-03-27/Multi-Regional_Electric_Gas_SOW_030812_Final_Draft__2_.pdf; *See also* Tim Maverick, *Changing Gas Sources Present Rare Opportunity*, WALL ST. DAILY (Oct. 15, 2014), available at: http://www.wallstreetdaily.com/2014/10/15/natural-gas-pipeline/.

EPA's building block 2 estimates the CO_2 reductions achievable based on the redispatch of generation from higher to lower emitting affected units – that is, from coal to NGCC plants in each state. If it is assumed that only designated facilities are redispatched, the amount of CO_2 reduction is directly related to the amount of coal generation in 2012, and the incremental generation available to be generated by NGCC plants existing and under construction as of 2012 when operated at a 70 percent annual utilization factor,[208] rather than the 44 percent utilization factor experienced in 2012. Since the additional NGCC generation available in some states is greater than 2012 coal generation, this methodology results in an average utilization factor for existing and under construction NGCC capacity of 64 percent and total redispatched generation of 438 TWh. And because even older existing NGCC units emit only half as much CO_2 as would generating the same amount of electricity by burning coal, ramping up NGCC generation and backing down coal generation this amount yields significant CO_2 emission reductions from existing sources.

Historical capacity and generation data from the Ventyx Velocity Suite shows the NGCC fleet historically has achieved utilization factors equal or close to the 64 percent average utilization factor and 70 percent maximum utilization factor assumed in EPA's building block 2. The U.S. NGCC fleet has operated at a 60 percent utilization factor on a week-long basis, just four percentage points shy of the average utilization factor in EPA's methodology.[209] Similarly, it has operated at 58 percent utilization on a month-long basis,[210] just six percentage points lower than the 64 percent utilization factor EPA assumes. Figure 18 below illustrates this. All six regions of the country have achieved weekly utilization factors of 62 percent to 66 percent, close to or above the 64 percent average utilization factor. The six regions have also achieved monthly utilization factors between 55 and 64 percent.

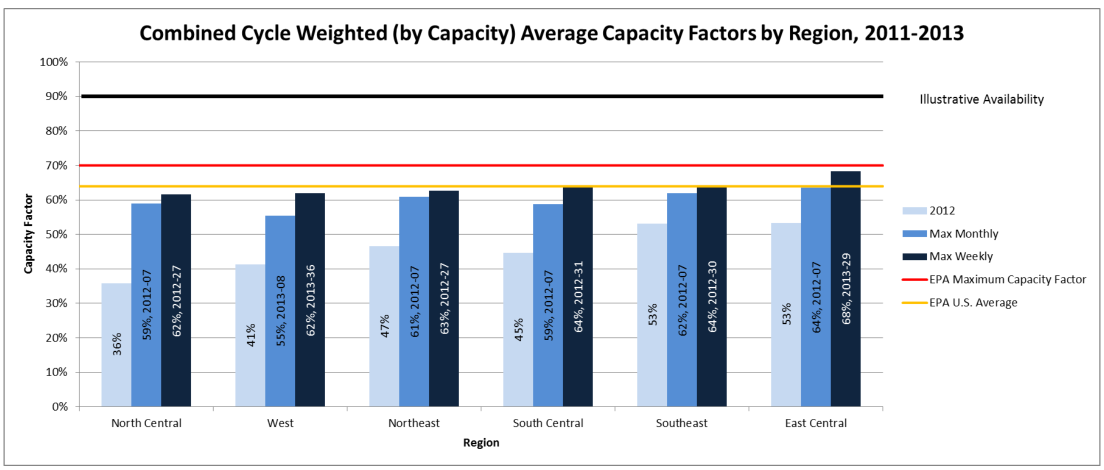


Figure 18: (Source: NorthBridge Group analysis based on data from the Ventyx Velocity Suite).

---

[208] 79 Fed. Reg. at 34,857. The 70 percent maximum utilization factor is based on the observation that, in 2012, 10 percent of NGCC plants operated at an annual utilization factor of 70 percent or higher.

[209] *Id.* at 34,857.

[210] *Id.* at 34,865.

In addition, Figure 19 shows that The NGCC fleets in 25 of 41 states with NGCC capacity have operated at a weekly utilization factor of 64 percent or higher. Similarly, 16 states have operated at a monthly utilization factor of at least 64 percent.

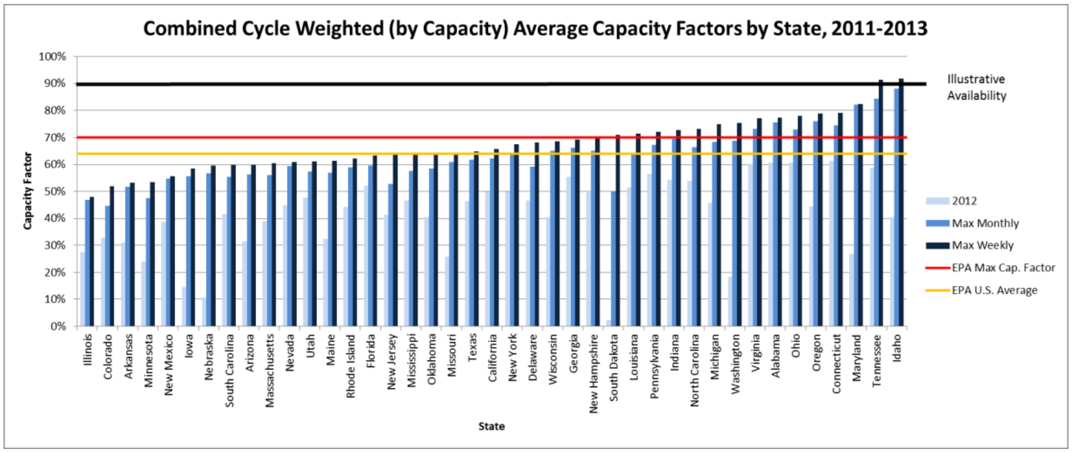


Figure 19: (Source: NorthBridge Group analysis based on data from the Ventyx Velocity Suite).

Forecasts show the potential to redispatch coal to NGCC generation within the existing fossil fleet and energy system infrastructure. The MIT Future of Gas study in 2011 reported the results of modeling case estimating the availability of redispatch and associated CO_2 emissions reduction between the existing goal and gas fleet in the country. That study found approximately 420 million metric tons of CO_2 could be reduced, by displacing 700 TWh of coal generation, through redispatch of NGCC. The study found an 87 percent capacity factor for these natural gas units.[211]

A recent "bottom-up" analysis of the potential carbon mitigation from redispatching the fleet of coal generating units to NGCCs by researchers at the National Renewable Energy Laboratory ("NREL") found that this strategy holds the technical potential to mitigate over 500 million metric tons of CO_2, or about 25 percent of the power sector's total emissions in 2012.[212] The study found that over 300 million metric tons of CO_2 could be avoided at EPA's proposed 70 percent NGCC utilization "ceiling."[213]

vii. NGCC Air Emission Permit Limitations Should not Limit the Availability of Re-dispatch.

CATF explored our hypothesis that the amount of existing NGCC redispatch contemplated by the state goal calculation methodology in building block 2 and in EPA's compliance modeling analysis is not limited by constraints in air permits limiting the number of

---

[211] MIT, The Future of Natural Gas (2011) *available at*: https://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

[212] Rachel Gelman, *et al.*, *Carbon Mitigation from Fuel-Switching in the U.S. Power Sector: State, Regional, and National Potentials*, 27 Elec. J. 63-72 *available at*: http://www.researchgate.net/publication/265337856_Carbon_Mitigation_from_Fuel-Switching_in_the_U.S._Power_Sector_State_Regional_and_National_Potentials.

[213] *Id.*

hours per year that existing NGCC units can run. Specifically, we investigated whether NGCC units located in ozone nonattainment areas may have taken run restrictions or tonnage limitations in order to limit their emissions of nitrogen oxides ("NO_x") and/or to achieve "synthetic minor" status in order to avoid major source permitting requirements and Title V fees.[214]

CATF examined a sampling of NGCC operating permits in ozone nonattainment areas. (*See* Attached at Ex. 12). Of the permits evaluated, sixteen appear to have no NOx emissions standards or fuel use restrictions that would limit their annual operations. One facility in Arkansas (170 MW) has an annual NOx limit that appears to limit the facility's annual operations. If the facility were retrofit with advanced NOx controls, it may be capable of additional annual operations. Its permit indicates that it only has low NOx burners installed for NOx control. A second facility in Colorado also appears to have an annual NOx limit that would constrain its annual operations. This facility has a relatively high NOx emission rate, according to EPA's Clean Air Markets database. It appears that the units could run more if their NOx emission rates were lower or the facility limited its supplemental duct firing. To select our sample, CATF applied four "screening" criteria: the unit had to be in (1) an ozone nonattainment area; (2) a state in which government officials have expressed opposition to the CPP; (3) a state with significant NGCC capacity; and (4) a state for which air permits are available online. CATF identified the following ozone nonattainment areas based on both the 1997 and 2008 ozone standards (see nonattainment maps and table below):[215]

[214] A synthetic minor source is an air pollution source that has the potential to emit air pollutants in quantities at or above the major source threshold levels but has accepted federally enforceable limitations to keep the emissions below such levels. 40 C.F.R. § 49.158.

[215] U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/.

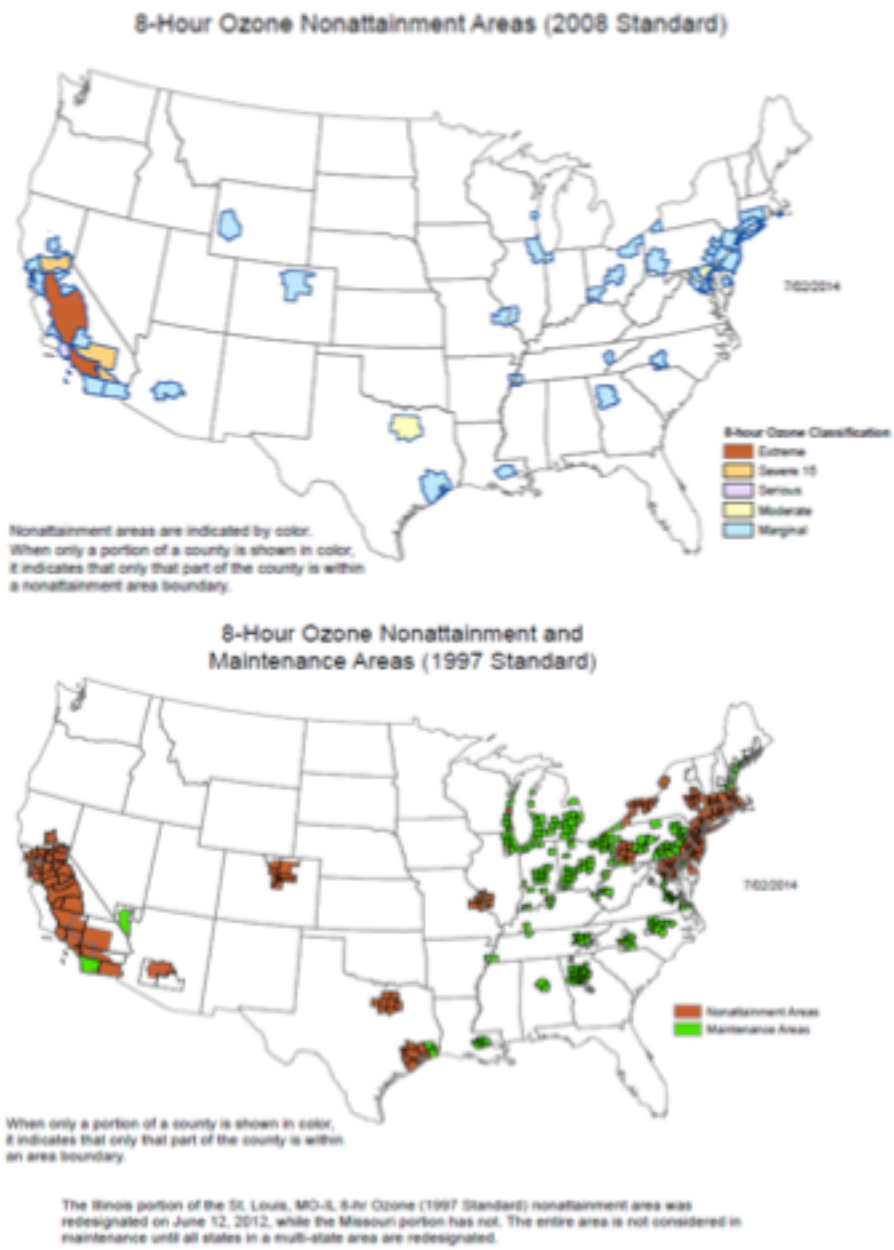


Figure 20: (Source: U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/)

Table 8: Ozone Nonattainment by State (Source: CATF table using U.S. EPA, "The Greenbook Nonattainment Areas for Criteria Pollutants," http://www.epa.gov/airquality/greenbook/).

States	8-hour Ozone Nonattainment (2008)	8-hour Ozone Nonattainment (1997)
Arizona	X	X
Arkansas	X	
California	X	X
Colorado	X	X
Connecticut	X	X
Delaware	X	X
District of Columbia	X	X
Georgia	X	
Illinois	X	
Indiana	X	
Kentucky	X	
Louisiana	X	
Maryland	X	X
Massachusetts	X	X
Mississippi	X	
Missouri	X	X
New Jersey	X	X
New York	X	X
North Carolina	X	
Ohio	X	
Pennsylvania	X	X
Rhode Island		X
South Carolina	X	
Tennessee	X	
Texas	X	X
Virginia	X	X
Wisconsin	X	X
Wyoming	X	

CATF then identified the states whose political leadership has expressed opposition to the proposed CPP based on whether: (1) the state Attorney General signed the white paper: "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act"[216]; (2) the state legislature passed legislation or resolution for state standards or opposing the proposal; or (3) public statements in opposition by lead state environmental officials. The results are expressed in the table below.

[216] Letter from Jon Bruning, Attorney General of Nebraska to Regina McCarthy, Administrator of the U.S. Environmental Protection Agency (Sept. 11, 2013) attaching "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act" *available at*: http://www.nationaljournal.com/free/document/4554.

Table 9: (Source: CATF)

States with Expressions of Opposition	AG Signed White Paper: "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act"	Passed Legislation or Resolution for State Standards or Opposing Proposal	Public Statements of Lead Environmental Officials
Alabama	X		
Alaska	X		
Arizona	X		
Arkansas		X (I.R. 2013-007)	
Florida	X		
Georgia	X		
Illinois		X (HR 0782)	
Indiana	X	X (HR 11- within the fence)	
Kansas	X		
Kentucky	X		
Louisiana	X		
Michigan	X		
Missouri			
Montana	X		
Nebraska	X		
North Dakota	X		
Ohio	X	X (H.B. No. 506- within the fence)	
Oklahoma	X		
South Carolina	X		
South Dakota	X		
Texas			X
West Virginia	X		
Wisconsin	X		
Wyoming	X		

We then ranked the states that met criteria 1 and 2 by existing NGCC capacity:

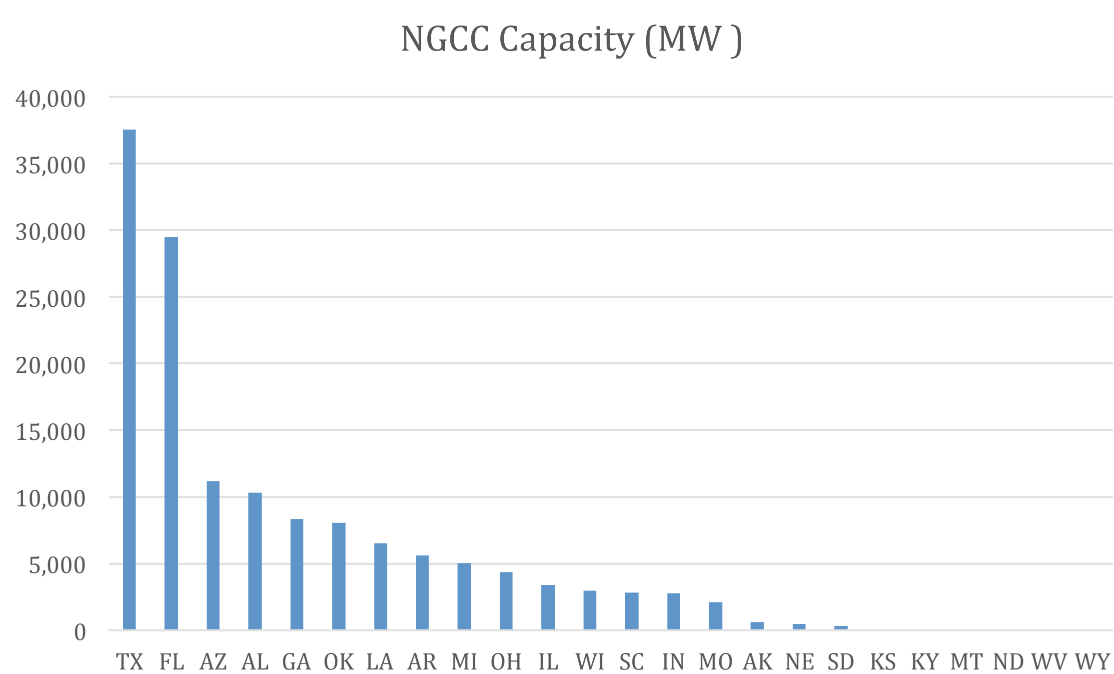


Figure 21: (Source: CATF).

Lastly, after determining the states that met criteria 1-3, we determined which states had online permit access. The results are displayed in the table below:

Table 10: (Source: CATF).

States	Total MW of NGCC	8-hour Ozone Non-attainment (2008)	8-hour Ozone Non-attainment (1997)	Meets criteria 1-3	Permits Available Online
Arizona	11,202	X	X	Yes	Partial
Arkansas	5,588	X		Yes	Yes
Colorado[1]	3,315	X	X	Yes	Yes[2]
Georgia	8,355	X		Yes	Yes
Illinois	3,396	X		Yes	Yes[2]
Indiana	2,768	X			
Louisiana	6,508	X		Yes	Not Identified
Missouri	2,079	X	X		
New Jersey[1]	5,832	X	X		No
Ohio	4,343	X		Yes	Yes
Pennsylvania[1]	9,582	X	X		No
South Carolina	2,839	X			
Texas	37,548	X	X	Yes	Partial
Wisconsin	2,977	X	X		

From this list, we chose those states that met the first two criteria, had the highest NGCC capacity, and had available (online) access to air permits. Those states are: Arizona, Arkansas, Colorado, Georgia, Ohio, and Texas. We obtained the 18 permits that were available for NGCC units located in nonattainment areas in these states. Our examination found that of those 18 permits, only two contained permit restrictions that might constrain its availability to run for re-dispatch at below an 70 percent annual utilization factor and installation of NOx controls would allow both of them to run at utilization factor greater than 70 percent.[217]

In sum, our examination of available permit "headroom" in underutilized NGCC units strongly indicates that these units' air permits do not contain restrictions that would create a barrier to the level of natural gas redispatch EPA has assumed in building block 2 or in its compliance modeling.

viii. If EPA finalizes target rates based on redispatch phased in over a number of years, the starting point for EPA's revised analysis of the CO_2 effects of redispatch in 2020 should be no lower than the historical maximum capacity factor for NGCC.

In the NODA, EPA highlighted a proposal made by commenters concerned that states will not be able to redispatch coal to gas quickly enough to meet the interim state goals.[218] Commenters propose that EPA phase in building block 2 over time as they do with building

[217] The JM Shafer Generating Station, a combined heat and power facility in Colorado, is subject to an annual plant wide NOx emission limit of 589 tons/year. Our examination of the permit found that the plant could be limited to 55 percent annual utilization if the units with the larger rated duct burners are used exclusively.

[218] 79 Fed. Reg. 64,543, 64,545 (Oct. 30, 2014).

blocks 3 and 4 based on growth rates accounting for infrastructure construction and the book life of existing coal-fired power plans.[219] EPA requested comment on other "specific potential rationales for phasing in dispatch changes under building block 2."[220]

If the EPA finalizes targets based on the phase in of building block 2 redispatch over a number of years, the Agency will need to determine the amount of utilization shift (or put differently, the NGCC capacity factor achievable) by 2020. We recommend that EPA select a maximum utilization/capacity factor that is no lower than the level that each state or region has achieved historically. Specifically, the Agency should use the average of the highest monthly utilization/capacity factors achieved during the winter and summer seasons during the years 2011 through 2013 in calculating the portion of the CO_2 emissions reductions targets achievable through building block 2 redispatch. That would reflect the times of greatest NGCC production during the multi-year period about which the Agency has real information, and would also take into account the differing availability of pipeline capacity during the winter and summer seasons.

ix. Modifying building block 2 to account for interstate redispatch opportunities would deepen the emissions reductions available from this rule.

EPA's proposed methodology calculates redispatched generation assuming each state is an island – that is, each state must have the existing NGCC capacity to increase output in the amount needed to reduce emissions from existing coal units in the same state. This metric unfortunately ignores the reality of interstate power flows (which EPA elsewhere recognizes). It therefore misses an opportunity for NGCC generation in one state to displace coal generation in a neighboring state. Calculating redispatch on a regional basis instead of state-by-state would increase the amount of redispatched generation by 104 TWh (or 24 percent).

As noted *supra* Sec. II.a.v, EPA's section 111(d) rules permit the Agency to recommend the contours of an allowance system that could be adopted by multiple states. Many states have asked for such guidance, and we discuss our perspective on the appropriate contours for such a system, *infra* at Sec. III. That approach would allow EPA to better reflect the interstate nature of the industry it is regulating, and would demand an approach to building block 2 that reflects the availability of NGCC capacity for redispatch not only in the same state with the coal units at which utilization is reduced, but also in the states in the same region with the state in question.

x. Building block 2 assumes future increased reliance on natural gas, making even more imperative the need to regulate methane emissions from natural gas production activities.

While EPA's proposal would achieve critical reductions of CO_2 from the largest contributor to that pollutant (fossil fueled power plants), the proposal would also highlight the need to reduce methane emissions from the oil and natural gas sector, the nation's largest industrial source of methane. Any increased usage of natural gas for electricity generation projected to occur under EPA's proposal suggests a strong likelihood that there will be increased methane emissions – including leaks – associated with oil and gas production, processing,

[219] *Id.* at 64,548.

[220] *Id.*

transmission, storage, and distribution. The current Federal regulations addressing these sources do not directly address the methane problem, focusing only on controlling volatile organic compound emissions from some – but not all – new sources; existing sources are free to operate unabated. As a result, the industry can continue wasteful practices in many segments of the industry.

Fortunately, as EPA is aware, opportunities exist *today* to mitigate emissions from this sector in manners that not only represent a very reasonable cost for industry but that also reduce other harmful pollutants like ozone, benzene and toluene. The Agency is currently evaluating responses to White Papers from five of the highest methane emitting sources.[221] The White Papers show that measures are available now to reduce these emissions. Indeed, we estimate that EPA can eliminate up to half of the methane pollution from the oil and gas industry in just a few years.[222] Because natural gas is primarily composed of methane, capturing it actually ensures that more natural gas reaches market (as opposed to wasted to the atmosphere). Thus, many of the methane control measures pay for themselves in a relatively short time period.

Any increased dependence on natural gas as an electricity generation fuel must be accompanied by regulations directly addressing and reducing methane emissions from the oil and natural gas sector. Without such regulations, the sector's methane emissions threaten to erode the projected climate benefits of EPA's current proposal.

c. Building block 3 is overly conservative. The assumptions are incorrect, and EPA inaccurately assumes that biomass is zero carbon-emitting. New natural gas units should also be included.

i. EPA's nuclear assumptions are overly conservative: A more appropriate assumption assumes continued U.S. reliance on nuclear Energy or other non-emitting generation at levels more closely approximating current levels.

Existing nuclear power plants currently provide more than 19 percent of US electricity and more than 63 percent of US emission-free electricity generation.[223]

Existing nuclear power plants will eventually need to be replaced as they retire, and it is critical to reducing U.S. CO_2 emissions that they are replaced with equally non-emitting energy technologies, whether they are nuclear, renewable, hydroelectric, or fossil with CCS.

EPA has recognized the importance of maintaining the existing level of renewable zero-emitting generation by including 100 percent of existing renewable energy in the 2012 baseline

[221] *See* U.S. EPA, Oil and Natural Gas Air Pollution Standards: White Papers on Methane and VOC Emissions a*vailable at* http://www.epa.gov/airquality/oilandgas/whitepapers.html.

[222] *See* Clean Air Task Force *et al*., Report Summary, *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry* (Nov. 2014), *available at*: http://catf.us/resources/publications/files/WasteNot_Summary.pdf.

[223] EIA, *Electric Power Annual*, (Dec. 12, 2013), *available at*: http://www.eia.gov/electricity/annual/pdf/epa.pdf. In discussing "emission-free generation," we include wind, solar PV, solar thermal, geothermal, and hydroelectric.