Duke
NICHOLAS INSTITUTE
FOR ENVIRONMENTAL POLICY SOLUTIONS

Policy Brief
NI PB 16-02
July 2016

www.nicholasinstitute.duke.edu

Cost Distribution Impacts of Clean Power Plan Compliance Pathways

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The U.S. Environmental Protection Agency (EPA) released the Clean Power Plan, the first national carbon dioxide (CO_2) limits under the Clean Air Act for existing power plants, in August 2015.[1] The Clean Power Plan (or "rule") establishes uniform emissions limits for two categories of existing power plants—fossil steam (mostly coal) and natural gas combined cycle (NGCC)—and directs states to develop plans to implement those limits.[2] States have broad flexibility to implement the Clean Power Plan, including the choice to apply the limits in one of two forms of emissions standards: rate (pounds of CO_2 per megawatt hour) or mass (total tons of CO_2).[3]

Although many factors are likely to influence state plan decisions, the choice between rate-based and mass-based emissions standards poses important policy questions regarding the distribution of costs among affected entities and electricity consumers (or "ratepayers") within a state. Affected entities (i.e., investor-owned utilities, rural electric cooperatives, municipal utilities, independent power producers, and so on) within a state may be in different situations with respect to compliance; some affected entities may be well positioned to comply given their existing generation mix, and others may face considerable compliance costs. For example, as a group, electric cooperatives tend to be more coal dependent than the industry as a whole.[4] This dynamic, whereby affected entities within one state face disparate compliance costs, can occur in states that are well positioned to comply overall as well as in states that face a high compliance burden. Therefore, there is likely to be a distribution of costs within states, and there is a potential for monetary transfers among power producers, between consumers and power producers, and among consumers served by different utilities.[5]

This policy brief explores distributional impacts of rate- and mass-based approaches to Clean Power Plan implementation.[6] It finds that although distributional impacts can occur under both rate- and mass-based approaches, allowance allocation is a powerful tool for mitigating them under a mass-based approach. That tool is not available under a rate-based approach. It further finds that the implications for consumers of disparate compliance costs across affected entities within a state depend in large part on the state's market and regulatory structure. In traditionally regulated states with utilities that largely meet customer demand with power from their own generators (i.e., the utilities "self supply"), consumers' electricity rate

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661 (Oct. 23, 2015) [hereinafter CPP Rule], https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for- existing- stationary-sources-electric-utility-generating. In February 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan—including state plan development deadlines—pending judicial review.
[2] An existing source under the Clean Power Plan is a fossil steam unit or natural gas combined cycle unit with capacity greater than 25 MW that commences operation before January 8, 2014. See, CPP Rule, 80 *Fed. Reg.* at 64,953 (codified at 40 C.F.R. pt. 60.5845).
[3] CPP Rule, 80 *Fed. Reg.* at 64,953 (codified at 40 C.F.R. pt. 60.5850).
[4] According to the National Rural Electric Cooperative Association, in 2012 coal was the source of 58% of electric cooperative sales versus 37% of total national electricity sales. See, NRECA, 2015. "U.S. Coops By the Numbers," http://www.nreca.coop/about-electric-cooperatives/co-op-facts-figures/u-s-co-ops-by-the-numbers/. Last modified September 2013.
[5] A transfer is a redistribution of money, income, or value from one party to another that is not necessarily driven by a change in the corresponding cost of production.
[6] Although the focus here is on the Clean Power Plan, this dynamic also applies to other mass- and rate-based environmental regulations, such as market-based standards for conventional pollutants (typically mass-based standards) and corporate average fuel economy standards for vehicles (rate-based standards).

increases or decreases will likely be based on the local utility's compliance burden.[7] In states where distribution utilities do not own generation resources, electricity rate impacts will largely depend on how costs are passed through the wholesale market. Finally, in states with traditionally regulated utilities that operate within an organized wholesale market—or within a robust power market absent a regional transmission organization or independent system operator (described below)—electricity rate impacts will depend on both the compliance burden of the local utility and the power market response.

First, this policy brief explores the cost distribution impacts for electricity producers of rate-based and mass-based compliance, respectively. It then considers how these producer impacts of rate- and mass-based compliance may be mediated by wholesale markets. Next, it turns to the implications for electricity consumers under various market and regulatory structures. Finally, it identifies opportunities to address distributional impacts if states wish to do so.

Cost Distribution Impacts for Electricity Producers in Rate-Based Plans

Under rate-based compliance with the Clean Power Plan, every affected fossil steam and NGCC unit must meet a target-adjusted emissions (pounds of CO_2 per megawatt hour-adjusted) rate on average in each compliance period. An affected unit can comply on the basis of its actual emissions rate—total CO_2 emissions divided by net generation during the compliance period—or by acquiring sufficient emission rate credits (ERCs) to bring the unit's adjusted emissions rate into compliance (see equation in Box 1).[8] Affected units that emit below their applicable rate earn ERCs, which they can sell or bank—that is, save to use in a later compliance period.[9] Post–2012 zero-emissions generation and avoided generation, including new or uprated nuclear, renewables, and end-use energy efficiency, are also eligible to generate ERCs that affected units can use for compliance.[10] In states utilizing subcategorized rates for existing fossil steam and NGCC, all existing NGCC generation creates gas-shift ERCs (GS-ERCs), which can be used by fossil steam units for compliance.[11]

Box 1. Adjusted rate calculation

Adjusted emissions rate: $$\frac{\text{Unit } CO_2}{\text{(Unit net MWhs +/- ERCs*)}} \leq \text{Regulated emissions rate}$$

Note: The adjusted rate must be below the regulated emissions rate for the affected unit. Affected units can submit ERCs to reduce their adjusted rate.
*ERCs that are submitted as needed (+) or that are earned (-) by operating below the regulated emissions rate.

Rate-based compliance creates value (i.e., a saleable credit) for ERC-generating resources and imposes cost (i.e., the cost of acquiring ERCs) on ERC-owing resources. On the basis of their existing and planned generation, some utilities or independent power producers may be net-sellers of ERCs and others may need to acquire ERCs or replace their higher emitting generation.[12] Thus some entities could profit from rate-based compliance (e.g., through the sale of ERCs), whereas others incur costs to comply.[13]

7 If a traditionally regulated utility buys a significant amount of the power needed to meet load, e.g., through bilateral contracts or wholesale markets, Clean Power Plan compliance costs for these purchases will depend on the change in purchase price due to the policy. Some areas of the country, such as the Southeast, do not have robust wholesale markets. Municipal utilities and electric cooperatives in areas without active wholesale markets likely fall in this category even if they do not self-supply a large portion of their load because they generally do not have a range of supply options and thus the costs they pass onto their consumers will largely depend on the compliance burden of their suppliers (e.g., generation and transmission cooperatives).

8 The Clean Power Plan defines net generation as gross generation as measured at the generator terminals less the electricity used to operate the plant. See, CPP Rule, 80 Fed. Reg. at 64,960 (codified at 40 C.F.R. pt. 60.5880).

9 This option assumes the state plan allows for ERC purchases and sales.

10 For a discussion of resources eligible to earn ERCs, see, DeMeester, J. and S. Adair, "The EPA's Clean Power Plan: Understanding and Evaluating the Proposed Federal Plan and Model Rules," NI PB 15-05 (2015), https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_pb_15-05_0.pdf.

11 GS-ERCs are earned on the basis of a proposed equation in the rate-based model rule that credits the portion of NGCC generation that substitutes for fossil steam generation. States can propose their own GS-ERC calculation mechanisms on the basis of existing NGCC generation, subject to EPA approval.

12 This likelihood assumes that the state plan allows for a market for ERC exchange.

13 Utilities and other entities can also profit from rate-based compliance if power market prices, e.g. wholesale power markets, change to their advantage. For example, a plant owner may need to purchase some ERCs to comply with the Clean Power Plan, but an increase in wholesale prices due to the Clean Power Plan raises the plant's profits on net.

Consider the following illustrative example, which compares the positions of two actual utilities in the same state with respect to compliance based on their respective 2012 operations data.[14] The first—Utility A—owns one coal steam plant and one NGCC plant. The second—Utility B—has a large fleet of NGCC units as well as steam gas units but does not own any coal generation. Tables 1 and 2 summarize each utility's affected generation and emissions in 2012, the baseline year that the EPA used to calculate the Clean Power Plan emission limits.[15] Table 3 shows the emissions rate limits for affected NGCC and fossil steam units in each of the interim and final compliance periods. Comparing the emissions rates of each utility's affected units with the rate-based limits reveals that—based on 2012 operations—Utility A's units are above the standard on average in all compliance periods, whereas Utility B's NGCC and fossil steam units earn ERCs for operating below the standard on average in the first interim compliance period.

Tables 4 and 5 further calculate the GS-ERC and ERC balances for Utility A and Utility B in each of the interim and final compliance periods, considering only GS-ERCs earned and ERCs earned or owed by affected units on the basis of 2012 operations.[16] In this illustrative scenario, Utility A is a net purchaser (negative net ERCs) in all compliance periods, whereas Utility B is a net seller through 2027.[17]

Table 1. Utility A's 2012 affected generation, emissions, and emissions rates

	2012 affected generation TWh	2012 affected CO_2 emissions million short tons	Emissions rate lbs/MWh
NGCC	2.49	1.13	904
Coal steam	7.59	7.53	1,984
All	10.09	8.66	1,717
% state 2012 affected EGUs total	5.3%	7.3%	

Source: Clean Power Plan Final Rule Technical Documents Data File: Goal Computation Appendix 1-5.xlsx.

Table 2. Utility B's 2012 affected generation, emissions, and emissions rates

	2012 affected generation TWh	2012 affected CO_2 emissions million short tons	Emissions rate lbs/MWh
NGCC	73.80	31.73	860
O&G steam	5.93	4.61	1,557
All	79.73	36.34	912
% state 2012 affected EGUs total	42.0%	30.7%	

Source: Clean Power Plan Final Rule Technical Documents Data File: Goal Computation Appendix 1-5.xlsx.

Table 3. Clean Power Plan subcategorized rate-based standards for fossil steam and NGCC units

	2022–2024	2025–2027	2028–2029	Final
NGCC	877	817	784	771
Fossil steam	1,671	1,500	1,380	1,305

[14] The example utilities are located in the same traditionally regulated state.

[15] U.S. EPA, Goal Computation Appendix 1-5 (xlsx) Data File Technical Support Document for CPP Final Rule 21 (Aug. 2015), https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

[16] GS-ERC balances assume the primary form of the GS-ERC formula in the EPA's proposed rate-based model rule. See, "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed On or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations," Fed. Reg. 80(205): 64966–65116, [Hereinafter "Proposed Federal Plan & Model Rules"], http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/html/2015-22848.htm at 65,093 (to be codified at 40 CFR 62.16434). Although future operations will differ from 2012 operations, this example illustrates the utilities' potential rate-based compliance trajectories. Utility A has no public plans to retire its coal plant and will likely continue to be coal dependent. Utility B's generation portfolio makes it likely to continue to generate a significant portion of its electricity supply using NGCC units.

[17] Alternatively, Utility B could save ("bank") ERCs earned in the first two interim compliance periods for use in subsequent periods.

Table 4. Utility A ERC balance based on 2012 affected EGUs operation (million ERCs)

	2022–2024	2025–2027	2028–2029	Final
GS-ERC	0.25	0.32	0.24	0.20
ERC	-1.50	-2.71	-3.70	-4.17
Net ERCs	-1.25	-2.39	-3.46	-3.97
Cumulative interim period GS-ERCs		2.2		
Cumulative interim period ERCs		-20.0		

Table 5. Utility B ERC balance based on 2012 affected EGUs operation (million ERCs)

	2022–2024	2025–2027	2028–2029	Final
GS-ERC	7.88	10.08	7.79	6.54
ERC	1.82	-4.07	-7.88	-9.64
Net ERCs	9.70	6.01	-0.09	-3.10
Cumulative interim period GS-ERCs		69.50		
Cumulative interim period ERCs		-22.50		

As the above example illustrates, under rate-based compliance, the existing and planned capacity of a utility (or other electricity producer) and its projected dispatch—along with any end use energy efficiency programs it can use to generate ERCs—will largely determine whether the utility will be a net seller or purchaser of ERCs.

Cost Distribution Impacts for Electricity Producers in Mass-Based Plans

Under a market-based approach to mass-based compliance with the Clean Power Plan, a state would mint a number of allowances in each compliance period equal to the state's mass-based budget set out by the rule. Each allowance would represent permission to emit one short ton of CO_2. The state plan would determine how to distribute the allowances—for example, by allocating allowances for free to affected units or by selling them at auction—and would allow for allowance trading. At the end of each compliance period, the state would require each affected unit to surrender a number of allowances equal to the unit's total CO_2 emissions in that period.

Under mass-based compliance, cost distribution is highly dependent on how allowances are allocated, which is a state choice.[18] Consider two alternative methods of allocating allowances to the same two utilities examined above—methods based on historic emissions and historic generation (grandfathering).[19] Tables 6 and 7 summarize the allowance balances of Utility A and Utility B, respectively, assuming allocation based on each company's percentage share of affected generation or emissions in 2012.[20] Allocation based on historic generation leads Utility A to become a net purchaser of allowances and Utility B to become a net seller, relative to their 2012 emissions—outcomes reflecting differences in the carbon intensity of their generation. In contrast, grandfathering based on historic emissions leads each company to face a proportionate shortfall of allowances relative to its 2012 emissions.

[18] The size of potential monetary transfers is also dependent on electricity markets and how they affect the value of allowances. For example, if fossil generation is low due to weather, broad economic trends, end use efficiency, or increased renewable generation, the value of an allowance would likely decrease, reducing potential monetary transfers across plant owners and ratepayers. Market forces that increase the value of allowances would increase potential transfers.

[19] In allowance allocation, grandfathering refers to allocation methods that distribute allowances at no cost to emitters on the basis of historical operations—for example, historical emissions or generation in some year or years—determined at the beginning of the mass-based policy. The distribution does not adjust over time due to changing market conditions. Under some versions of grandfathering, plants can lose their allocation if they close. The decision to use grandfathering (as opposed to other allocation methods) and the method of grandfathering are state choices under the Clean Power Plan.

[20] The calculation assumes all allowances for existing sources are allocated through grandfathering. Mass-based plans that cover only existing sources must include measures to address the risk of leakage. The EPA has proposed allowance set-asides to address leakage that would reduce the amount of allowances available for grandfathering. Proposed Federal Plan & Model Rules, 80 *Fed. Reg.* at 65,063-65,067 (to be codified at 40 CFR 62.16235).

Table 6. Utility A allowance balance and percent of 2012 emissions covered assuming grandfathering

	Based on 2012 generation		Based on 2012 emissions	
	Million short tons	% 2012 emissions	Million short tons	% 2012 emissions
Avg. annual allocation interim periods	6.00	69	8.26	95
Annual allocation final period	5.58	64	7.69	89

Notes: This example assumes grandfathering based on 2012 affected EGUs operation and compares it to 2012 operation. Utility A affected unit emissions were 8.66 million short tons in 2012.

Table 7. Utility B allowance balance and percent of 2012 emissions covered assuming grandfathering

	Based on 2012 generation		Based on 2012 emissions	
	Million short tons	% 2012 emissions	Million short tons	% 2012 emissions
Avg. annual allocation interim periods	47.45	131	34.68	95
Annual allocation final period	44.13	121	32.26	89

Notes: This example assumes grandfathering based on 2012 affected EGUs operation and compares it to 2012 operation. Utility B affected unit emissions were 36.34 million short tons in 2012.

As the example above demonstrates, whether a utility (or other power producer) is a net seller or net purchaser of allowances depends on the allocation method. Notably, there are many additional options for allowance allocation under the Clean Power Plan, and a state's choice of allocation method may depend on a host of state-specific factors or goals.[21] The intent of the above example is not to advocate for a specific allocation method; rather, the intent is to illustrate that (1) the choice of allocation method directly affects distributional outcomes, and (2) allowance allocation is a tool states have in mass-based compliance to adjust distributional outcomes, if they desire to do so.

Cost Distribution Impacts for Electricity Producers in Areas with Organized Wholesale Markets

In states with organized wholesale markets, distributional impacts will also depend in part on how those markets respond to the rule. Two-thirds of U.S. electricity demand is served by independent system operators (ISOs) and regional transmission organizations (RTOs) (Figure 1).[22] ISOs and RTOs operate the transmission system and facilitate competition among generators through organized wholesale markets for electricity. In these regions, the ISO/RTO dispatches generation in merit order (lowest-cost resources first) to meet overall demand.[23] All generators that are dispatched receive the same—market-clearing—price.[24] Under the Clean Power Plan, market-clearing prices may rise or fall under rate- or mass-based compliance.

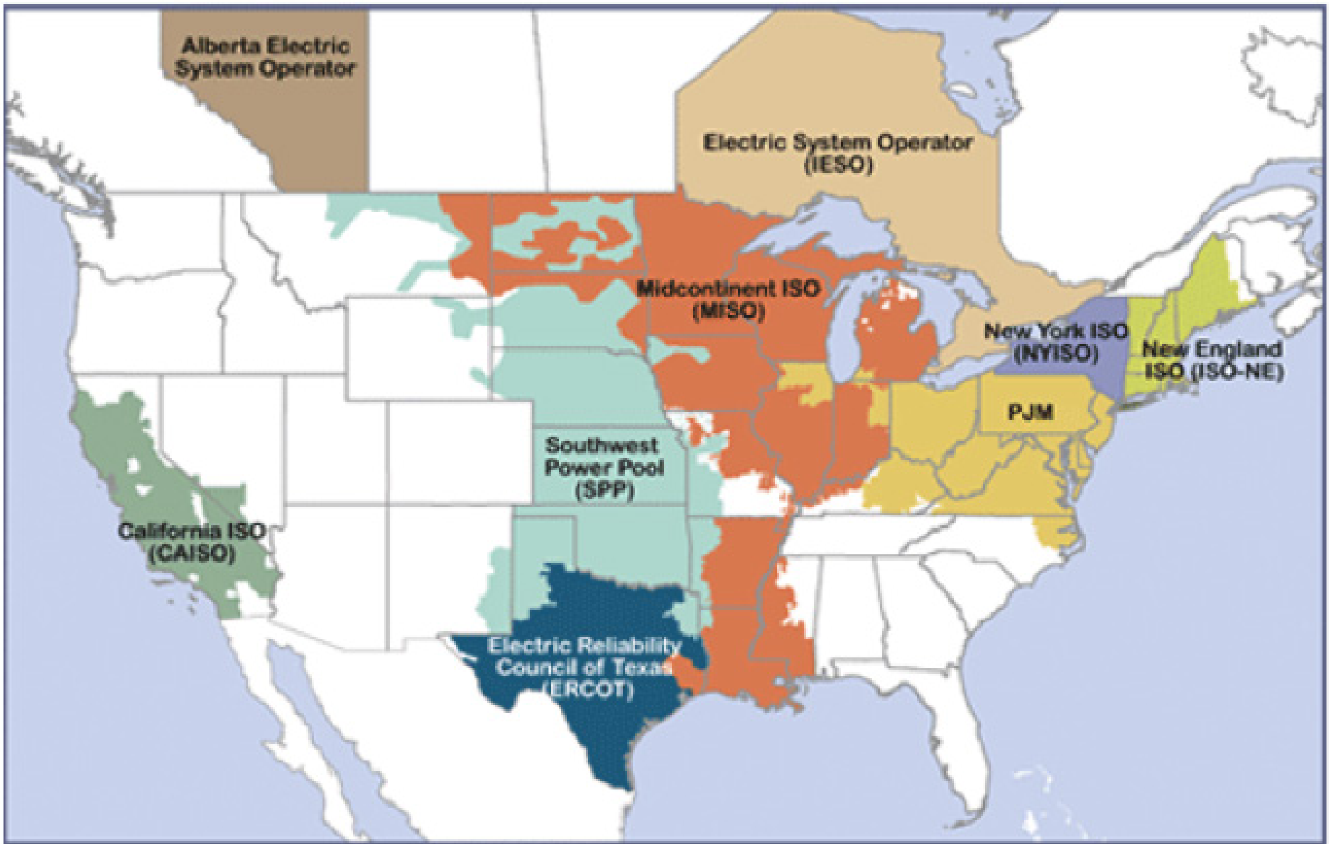
[21] Other options for allocating allowances include "updating" methods and auctions with different market and electricity rate impacts. States can also use multiple methods, for example, auctioning a portion of allowances and grandfathering the remainder. For an in-depth discussion of allowance allocation options under the Clean Power Plan and how these options relate to state goals under the Clean Power Plan, see F. Litz and B. Murray, "Mass-Based Trading under the Clean Power Plan: Options for Allowance Allocation," NI WP 16-04 (Durham, NC: Duke University, 2016), http://nicholasinstitute.duke.edu/publications.

[22] FERC, 2016. "Electric Power Markets: National Overview," http://www.ferc.gov/market-oversight/mkt-electric/overview.asp. Last modified February 2016.

[23] RTOs and ISO dispatch some units on a grid reliability basis and other units on a must-run basis.

[24] There are some minor exceptions but conceptually this is correct. For example, imagine three generators that bid into the market at $20/MWh, $30/MWh, and $40MWh. The first two generators are needed to meet demand, meaning that the market-clearing price—and the price received by both generator 1 and generator 2—is $30/MWh.

Figure 1. Service territories of regional transmission organizations and independent system operators



Source: Federal Energy Regulatory Commission.

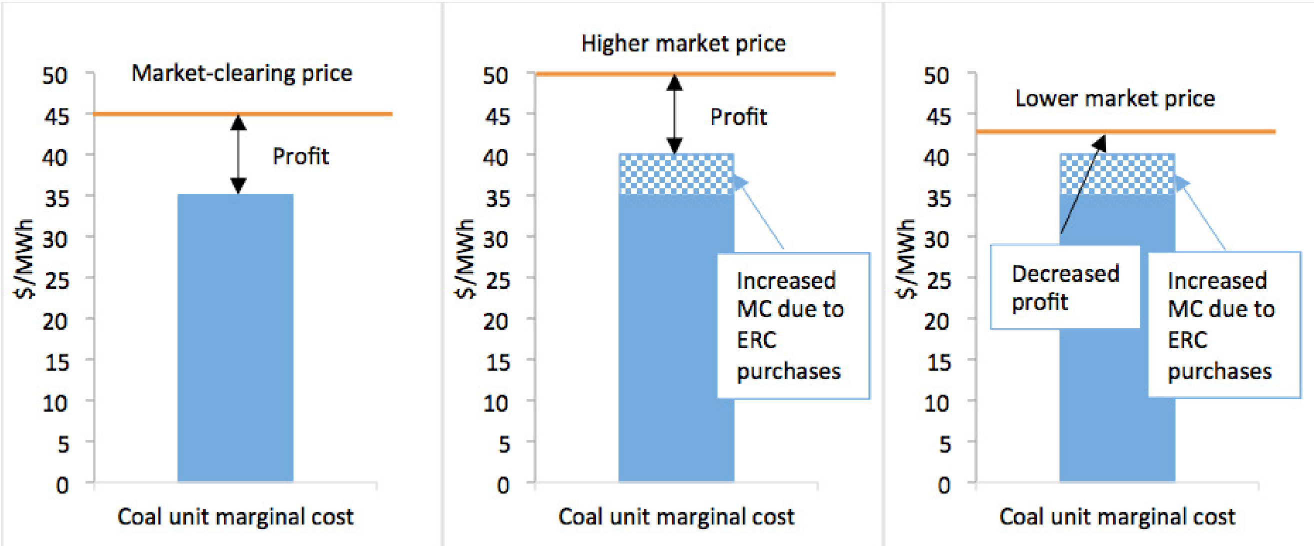
Under rate-based compliance, whether wholesale prices rise or fall depends on whether the marginal unit—which sets the market-clearing price—is an ERC-owing or ERC-earning resource. If an ERC-owing resource sets the marginal price, the cost of the ERC increases the marginal cost of generation and the market price rises. In contrast, wholesale prices could fall if the marginal unit is ERC-earning because generation creates ERCs that the unit can sell, effectively subsidizing the generation. The value of the earned ERCs lowers the net cost of generation for these units and reduces their bid price.

Consider a coal unit with a marginal cost of $35/MWh absent the Clean Power Plan (Figure 2). If the unit bids into the market at $35/MWh and the market-clearing price is $45/MWh, the unit is dispatched with a profit margin of $10/MWh. To comply with the final fossil steam rate (1,305 lbs/MWh) under the Clean Power Plan, a coal unit with an emissions rate of 2,000 lbs/MWh would need to buy approximately 0.5 ERCs for each MWh of output. If this purchase increases operating costs $5/MWh (ERC price ~$10/MWh), the unit would bid into the market at $40/MWh ($35/MWh + $5/MWh).[25] If the marginal unit in the wholesale market is an ERC-owing resource like the coal unit just described, the market-clearing price is likely to rise. In this stylized example, the market-clearing price rises to $50/MWh because the price-setting unit's cost (bid) also rises by $5/MWh (just like the cost of the example unit). In that case, the example coal unit's profit margin remains $10/MWh. Alternatively, if the market-clearing price is set by an ERC-earning resource, such as an NGCC unit generating ERCs on net, the market-clearing price would decline (e.g., a decrease from $45/MWh to $43/MWh) as the coal unit's marginal cost increases, leading to a decrease in profit.[26]

[25] A coal unit with an emissions rate of 2,000 lbs/MWh would need to purchase approximately 0.5 ERCs for each MWh of output to meet the final emissions rate of 1,305 lbs/MWh for fossil steam units. If ERC prices are $10/MWh, the operating cost of a 2,000 lbs/MWh coal unit would increase approximately $5/MWh.

[26] An NGCC unit generating ERCs on net under a subcategory rate would create more GS-ERCs than the ERCs it would need to purchase, if any, to comply with the emissions rate limits for NGCC units under the Clean Power Plan. An NGCC unit operating below its regulated rate would produce ERCs and GS-ERCs. At the final emissions rate limit for NGCC units under subcategory rate-based compliance, any NGCC unit operating below 842 lbs/MWh would produce ERCs, including GS-ERCs, on net. Units that earn ERCs on net through their operations should reduce their bid price to reflect the gains from creating ERCs. Post–2012 renewable and nuclear capacity generators will produce ERCs through their operations and should reflect this in their bids. However, renewable and nuclear capacity generators are typically not the marginal generators in wholesale markets.

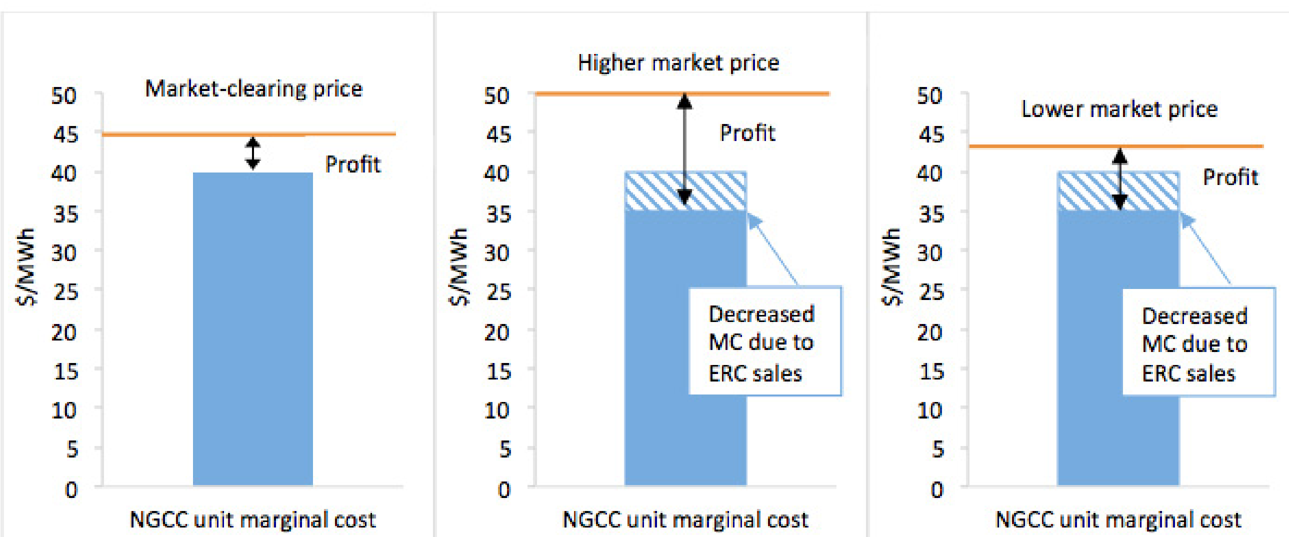
Figure 2. Coal unit (ERC-owing resource) profit without Clean Power Plan and with rate-based Clean Power Plan compliance



Note: This example assumes an ERC-owing resource on the margin (middle) and an ERC-generating resource on the margin (far right).

An NGCC unit generating ERCs on net would similarly change its bid into wholesale markets but with a different outcome. If an NGCC unit bids into the market at $40/MWh absent the Clean Power Plan and the market-clearing price is $45/MWh, it would earn a marginal profit of $5/MWh. Under rate-based compliance, it would reduce its bid to reflect the value of ERCs generated on net. If each MWh of generation created $5/MWh of ERC value, the unit would reduce its bid price to $35/MWh. If the market-clearing price increased, the NGCC unit would realize a larger profit margin from both the change in wholesale price and its reduced net marginal operating cost (inclusive of the ERC "subsidy"), and if the market-clearing price decreased, the unit's lower bid price would help protect the unit's profit margin (Figure 3).

Figure 3. NGCC unit (ERC-earning resource) profit without Clean Power Plan and with rate-based Clean Power Plan compliance



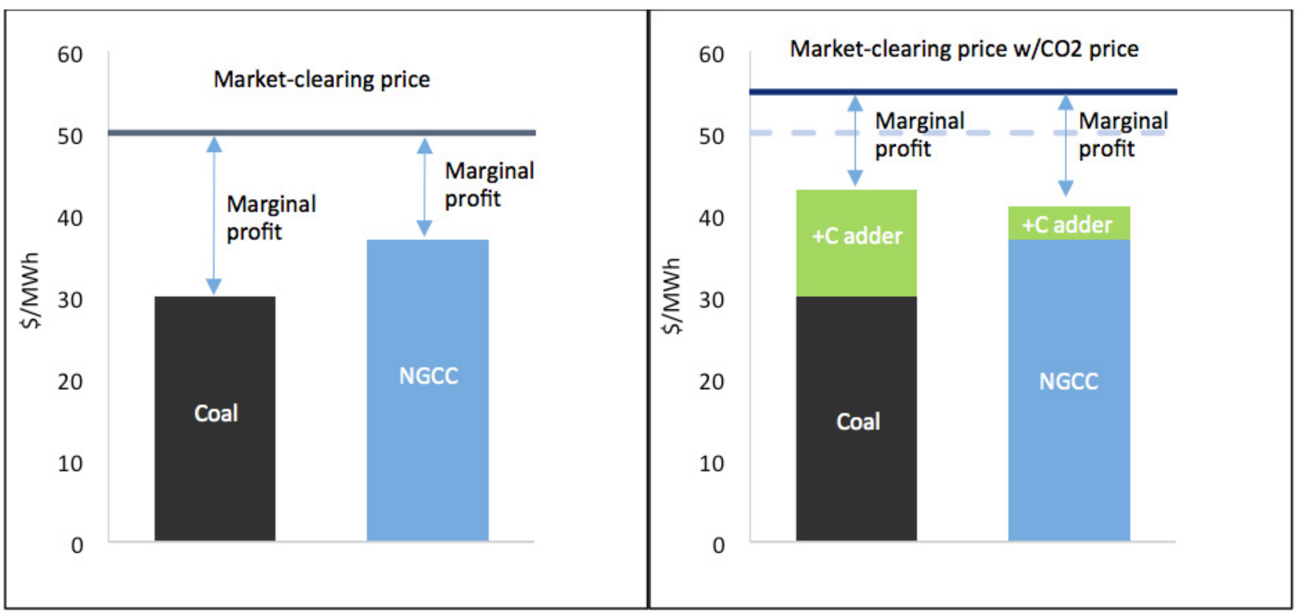
Notes: This example assumes both an ERC-owing resource (middle) and an ERC-generating resource (far right) on the margin. It also assumes that the illustrative NGCC unit has a low emissions rate such that it is on net earning ERCs. In practice, some NGCC units may on net owe ERCs.

In practice, the marginal unit—and thus the effect of rate-based trading on generators' profits—is likely to vary over time. In the PJM market, for example, coal units were on the margin 52% of the time in 2015, and natural gas units were on the margin 36% of the time.[27]

In contrast, under mass-based compliance, wholesale market prices can be expected to rise to reflect allowance prices under most allocation methodologies; generators will normally include the allowance price in their bid, even if allowances are freely allocated, to reflect the opportunity cost of selling the allowance.[28] This cost arises because all covered fossil units face a cost for their emissions, regardless of their emissions rate, and they will include it in their bids into wholesale power markets. Thus highly efficient NGCC units will face higher operating costs—including the opportunity cost of submitted allowances—under mass-based compliance. By contrast, under rate-based compliance, these units might receive a subsidy and reduce their bids. One notable exception is updating output-based allocation. In this allocation method, units earn allowances through operation. If an affected unit's earned allowances exceed the unit's emissions, the unit receives an incentive to operate and will reduce its bid, much like an ERC-earning unit under rate-based compliance.[29]

The profit margin of individual fossil units will depend on how much their operating costs (including the opportunity cost of allowance use) increase due to the mass-based policy versus any increase in the market-clearing price from the policy. If mass-based compliance increases wholesale prices less than the increase in cost of a covered unit, the unit's profit margin will decrease (see coal unit in Figure 4). If wholesale prices increase more than the unit's increase in operating cost due to the rule, its profit margin will increase (see NGCC unit in Figure 4). Allowance allocation does not affect a unit's marginal operating cost and therefore its marginal profit, unless a state adopts updating output-based allocation, but that allocation does significantly affect the cost distribution of the policy across affected units and can create benefits for individual units, including windfall profits.[30] The allocation flexibility allowed in a mass-based plan under the Clean Power Plan allows states to use allocation to compensate utilities and unit owners facing decreases in marginal profit and incurring other compliance costs such as capacity changes, if desired. States can also use allocation to control cost distribution impacts for ratepayers, as explained below.

Figure 4. Wholesale price impact of mass-based Clean Power Plan compliance



[27] Monitoring Analytics, 2016. *PJM State of the Market – 2015, Volume 1,* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml. Last modified March 10, 2016.

[28] To understand why wholesale prices can be expected to rise even if allowances are freely allocated, consider how the inheritor of a house would behave. He or she is unlikely to sell the house for free just because it was obtained at no cost. Instead, the inheritor is likely to sell the house for the market price. For an in-depth discussion of allocation options under mass-based Clean Power Plan compliance see, Litz and Murray, 2016, *supra* note 22.

[29] All other allocation methods tend to raise prices because marginal units are generally affected units that must surrender allowances to operate and the opportunity cost of the surrendered allowances is included in their bid.

[30] Marginal profit is the difference between the marginal revenue and the marginal cost of producing an additional unit of output. Windfall profits can arise from unexpected gains and supply shortages. If a state allocated a power plant more allowances than it needed to cover its emissions, that plant could sell the excess allowances for a profit that is not related to its performance. The act of giving the power plant allowances unneeded for operation would be an unexpected gain and would result in the power plant receiving a windfall profit.

Implications for Electricity Consumers

The illustrative examples above demonstrate how rate-based and mass-based approaches to Clean Power Plan implementation can give rise to disparate compliance costs among affected entities, including investor-owned utilities, rural electric cooperatives, municipal utilities, or independent power producers. The implications of these differences in compliance costs for electricity consumers depend on how the state's electricity sector is regulated.

Because parts or all of the electricity supply chain (i.e., electricity generation, transmission, and distribution) is provided by monopoly suppliers—depending on the state—state regulators play an integral role in determining how electricity costs, including the cost of compliance with environmental regulations, are passed on to consumers.[31] State utility commissions set electricity rates for customers of monopoly investor-owned utilities on the basis of what they judge to be the "cost of service" as well as their determinations of how those costs should be distributed across customer classes. Utility commissions have legislative mandates to protect consumers, to set rules governing rates of return (profit) for regulated utilities, and to determine whether costs to supply consumers are prudent and necessary.

In traditionally regulated states with utilities that largely self-supply and operate without an organized wholesale market—states that are primarily located in the Southeast and in the West (Figure 1)—ratepayer impacts are likely to mirror the compliance cost differentials among utilities. Investor-owned utilities in these areas are typically regulated monopolies that own and operate the generation, transmission, and distribution infrastructure required to meet customer demand within an exclusive service territory. Electricity rates are set by state regulators on the basis of the cost of service plus a reasonable return on capital investments. Clean Power Plan compliance will tend to increase electricity rates for customers of utilities that face a net compliance burden requiring them to buy allowances or ERCs. It will tend to decrease electricity rates for customers of utilities that are net sellers of ERCs or allowances because operating cost changes—including any gains from operation, for example, creation of ERCs for sale or dispatch to reduce emissions below a utility's allowance allocation—are passed on to customers.[32]

As demonstrated by the above comparison of the compliance positions of two actual utilities, under rate-based compliance and under mass-based compliance with select allowance allocation schemes (e.g., grandfathering based on historical generation), individual utilities in a state may be significant buyers of ERCs or allowances whereas other utilities in the same state may be significant sellers.[33] Because the costs and gains from ERC and allowance transactions are typically passed on to ratepayers in traditionally regulated states, differences in compliance burdens across utilities within a state can effectively create monetary transfers among different utilities' ratepayers within the state. Those transfers will track the exchange value of compliance instruments from utilities that buy ERCs or allowances to those that sell them.[34] Ratepayers may also send or receive monetary transfers across state borders with interstate trade of ERCs and allowances. States can largely avoid transfers among ratepayers within a state under mass-based compliance by allocating more allowances to utilities with higher compliance burdens, and by extension to their ratepayers, thereby reducing those utilities' need to purchase allowances from other utilities and minimizing discrepancies in compliance costs. Under rate-based compliance, states lack this direct control mechanism because they do not have initial ownership of the supply of ERCs, which are created through operations.[35] If a state chooses to auction allowances, it can use the auction proceeds to proportionally assist ratepayers on the basis of the compliance burden of each utility.[36]

The implications of compliance burden disparity for electricity consumers in areas with active wholesale markets are likely to depend both on the wholesale market response and on their state's system of electricity regulation. Retail customers in

[31] Cooperative and municipal utilities self-regulate to protect consumers and are governed by their members and city governments, respectively.

[32] In traditionally regulated states, utilities earn a return on their approved capital investments and pass on all prudent operating costs to ratepayers. If a regulated utility earns money from its operations, for example, through power exports or the sale of tradable environmental compliance instruments, it typically passes that money onto ratepayers to offset other costs. Municipal utilities and cooperatives, which self-regulate, have cost structures similar to those of investor-owned utilities in traditionally regulated states, and they pass through all operations and capital costs, including gains from operations, to ratepayers.

[33] Example utilities A and B are located in a traditionally regulated state without an organized wholesale market.

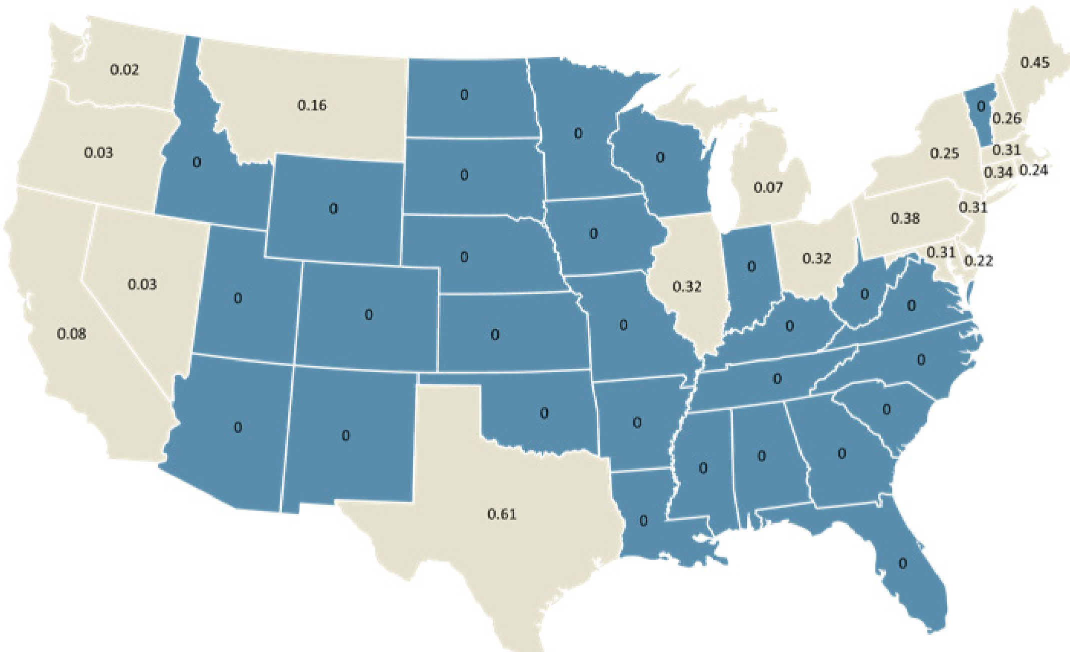
[34] There may also be transfers among ratepayers if one regulated utility sells power to another as a result of the rule. However, many vertically integrated utilities generally meet the majority of their load with their own resources, making transfers among ratepayers more likely as a result of ERC or allowances sales and purchases in traditionally regulated states not part of an ISO or RTO.

[35] Rate-based states can, however, take actions to reduce ERC prices, potentially reducing transfers, as discussed in more detail in the conclusion.

[36] States may have reasons to reward utilities and ratepayers that have a low compliance hurdle. The Nicholas Institute is not endorsing the use of allowance allocation to reduce transfers among ratepayers or utilities. If a state adopts output-based allocation, the potential for monetary transfers among ratepayers is similar to rate-based compliance.

ISO or RTO service territories not served by cooperatives or municipal utilities are served either by vertically integrated utilities that bid their generation into the wholesale markets or by distribution utilities—also called "load-serving entities"—that do not own generation and that purchase electricity at wholesale to meet retail demand (Figure 5).

Figure 5. Share of retail shares from retail power marketers



Source: S. Borenstein and J. Bushnell. 2015. "The U.S. Electricity Industry 20 Years after Restructuring." EI @ Hass WP 252R. Berkeley, CA. https://ei.haas.berkeley.edu/research/papers/WP252.pdf.

In states with rate-regulated vertically integrated utilities that dispatch electricity as part of an ISO/RTO, the cost of Clean Power Plan compliance or of any benefit from sales of ERCs or allowances should be reflected in electricity rates set by state regulators. For example, if a vertically integrated utility is a net purchaser of ERCs or allowances and the utility's total generation and the wholesale price it receives for that generation do not change, the utility's costs would likely rise because of the ERC or allowance purchases and that increase would be reflected in its electricity rates. Conversely, if a utility is a net seller of ERCs or allowances and its total generation and wholesale prices do not change, the utility's costs would fall and that decrease would also be reflected in its electricity rates. In practice, wholesale prices could change under both rate- and mass-based compliance and a net-ERC/allowance purchaser could decrease its generation, increasing its reliance on wholesale power purchases to meet demand and reducing its ERC/allowance purchases. Thus, ratepayer impacts would again depend in part on how wholesale market prices respond to this shifting of generation across generating units, which will affect the bid structure of the wholesale markets and allowance allocation for mass-based compliance.[37]

In states with restructured electricity markets, in which distribution utilities do not own generation, energy prices paid by different distribution utilities within a state should be similar in most cases because the utilities are buying from the same wholesale market.[38]As a result, ratepayers of different distribution utilities across a restructured state are likely to be in a similar position and to face similar price impacts from the rule. As explained above, electricity rate impacts will depend on how wholesale prices respond, and in the case of a mass-based plan, how allowances are allocated. Allocating allowances for free to affected entities in restructured states can lead to transfers from ratepayers to affected entities because state regulators lack a mechanism to prevent affected generators from passing the opportunity cost of an allowance on to

[37] There is still the potential for monetary transfers across ratepayers in a traditionally regulated state in an ISO or RTO, but access to a robust wholesale market provides a potential pathway—depending on changes in wholesale prices relative to the utility's generating costs under the policy—to avoid ERC/allowance purchases. At the same time, increasing reliance on the wholesale market could also increase potential monetary transfers between ratepayers and wholesale market suppliers.

[38] Exceptions include areas with transmission constraints and higher locational pricing as well as long-term purchase contracts. If a state is part of more than one organized market, energy costs should be similar for distribution utilities within the same market but not across markets.

consumers. Restructured states can also directly allocate allowances to distribution utilities, which should use the proceeds from the sale of allowances to benefit ratepayers and thereby offset part or all of the price increases caused by the rule.[39]

Conclusion

The distribution of compliance costs across utilities and ratepayers is one factor states may wish to consider as they weigh alternative approaches to implementation of the Clean Power Plan. For example, a state may wish to lessen costs borne by ratepayers of utilities with a relatively high compliance burden. Alternatively, a state may prefer to reward utilities that took early action to reduce emissions and that are therefore well positioned to comply.

Under rate- and mass-based compliance, states have options to minimize ERC and allowance prices, which can lower compliance costs for net purchasers of ERCs or allowances without changing the distribution of those costs. For example, states can adopt complementary policies such as renewable portfolio standards, energy efficiency resource standards or programs, tax incentives for renewables or energy efficiency, or updated building codes. Any policy that decreases demand for ERCs or allowances by reducing CO_2 emissions or that increases the supply of ERCs by encouraging the deployment of ERC-generating resources would lower ERC or allowance prices. If a mass-based state auctions all or a portion of its allowance budget, it could likewise use the proceeds to reduce demand for allowances. However, complementary policies may increase the overall cost of compliance to the extent that they encourage more expensive ways of reducing emissions, and they could create additional transfers (e.g., from taxpayers to renewable energy developers).

Expanding or limiting the scope of ERC and allowance trade is another potential option to minimize ERC and allowance prices. In general, extending trading reduces compliance costs by incenting the lowest-cost emissions reductions irrespective of state boundaries. However, for states with a relatively large supply of ERC-generating resources or mass-based allowances (low ERC or allowance price states), interstate trading may raise ERC/allowance prices relative to intrastate trading only. This outcome would potentially increase transfers from ERC and allowance-buying entities and would increase transfers to selling entities. These transfers would potentially decrease if expanded ERC and allowance trading reduced ERC and allowance prices in a state. However, adjusting the scope of ERC and allowance trading also affects interstate electricity trade, further affecting transfers among utilities, ratepayers, and others.[40]

States that want to account for the potential distribution of compliance costs across utilities and ratepayers within their borders will want to understand how their existing utility market and regulatory structure affect cost distribution as well as understand differences in the market impacts of rate- and mass-based compliance. As noted above, under rate- and mass-based compliance, states have options to minimize ERC and allowance prices, but these options may create additional transfers and shifts in compliance costs. Allowance allocation, however, provides a substantial policy lever under mass-based plans that is not available under rate-based plans.

[39] Distribution utilities are regulated by the state, earning a return on capital investments and passing on prudent operating costs. Thus gains from allowance allocation should be passed onto ratepayers as an adjustment in operating costs. California uses this approach for allowances allocated to utilities under its cap-and-trade program. Allowances allocated to investor-owned EGUs must consign all allowances to auction and direct proceeds to benefit ratepayers, consistent with the goals of AB 32. See, California Air Resources Board, "Allowance Allocation," (2016), http://www.arb.ca.gov/cc/capandtrade/allowanceallocation/allowanceallocation.htm. Last modified February 29, 2016. For an in-depth discussion of consignment auctions, see D. Burtraw and K. McCormack, "Consignment Auctions of Free Emissions Allowances under EPA's Clean Power Plan," DP 16-20, Washington D.C.: Resources for the Future, 2016), http://www.rff.org/research/publications/consignment-auctions-free-emissions-allowances-under-epa-s-clean-power-plan.

[40] Expanded trading decreases total system costs and forgoing expanded trading can eliminate a number of benefits for low-compliance-cost states with low ERC and allowance prices. The forgone benefits of trading include potential ERC or allowance export opportunities for sellers and increased market liquidity for parties inside and outside the state. But the effects on power exports/imports are ambiguous. Some allowance sales could come at the expense of reducing in-state generation. On the other hand, ERC sales may be enabled by increased in-state generation at units operating below the emissions standard.

Acknowledgments
The authors gratefully acknowledge feedback from Brian Murray, Franz Litz, Jim Gardner, and Talina Matthews.

Citation
Hoppock, D., and S.K. Adair. 2016. "Cost Distribution Impacts of Clean Power Plan Compliance Pathways." NI PB 16-02. Durham, NC: Duke University. http://nicholasinstitute.duke.edu/publications.

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