Section of Environment, Energy, and Resources
AMERICAN BAR ASSOCIATION

Government and Private Sector Innovation Committee Newsletter

Joint newsletter of the Government and Private Sector Innovation Committee and the Energy Infrastructure, Siting, and Reliability Committee

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EDITOR INTRODUCTION

Douglas Canter

The Energy Infrastructure, Siting, and Reliability Committee (EISR) and Government and Private Sector Innovation Committee (GPSI) present this joint newsletter on topics of common interest to their respective members. EISR focuses on issues relating to modernizing and expanding the nation's energy infrastructure for both conventional energy resources, such as natural gas pipeline, and renewable energy resources, both utility scale and distributed generation (such as rooftop solar), and other issues related to infrastructure. GPSI addresses all aspects of government-private sector collaboration to facilitate innovation, new technology, and infrastructure that promote renewable energy, lower carbon impacts, or other interests consistent with sustainability. Both committees include a cross section of the bar with diverse experience in environmental and energy law, as well as financing. These practice areas come together at the intersection of innovation, infrastructure, technology, and sustainability.

The Section of Energy, Environment, and Resources (SEER) prides itself on its ability to foster meaningful cooperation between committees not just for the collegiality that it creates, but also for the practical recognition that legal issues frequently overlap topic subject matter borders. In recognition of that, both EISR and GPSI believe that all lawyers benefit from the capability of having a core understanding of the full range of consequences of unfolding events. Indeed, these committees are neither strictly energy nor environmental committees, but instead encompass a wide variety of issues both legal and policy driven.

In this joint newsletter, Ivan London, Tom Lee, and Jeremy Fancher, address the importance of carbon-trading programs to reach the carbon reduction requirements under the Clean Power Plan (CPP). Their article discusses the Clean Power Plan as it relates to carbon trading. They detail key components of two existing carbon-trading programs, the Regional Greenhouse Gas Initiative (RGGI) in the Northeast, and the California cap-and trade-program, as well as how the U.S. Environmental Protection Agency appears to endorse emissions trading more heavily in the final version of the CPP.

Devin T. Ryan explains how municipalities have structured public-private partnerships (P3s) agreements to address aging water and sewer infrastructure, and the benefits these P3s create for municipalities to pay down their ever-increasing debt obligations associated with this infrastructure. His article provides a summary of these P3 agreements and details recent use of these agreements in Pennsylvania.

Jessica A. Chiavara writes about municipal use of land banks to reclaim urban areas for uses consistent with sustainability. In the last 15 years, land banks have grown more than tenfold, with current active land banks totaling around 120

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Douglas Canter, Managing Editor
Will Yon and Shane Prate, Editors

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nationwide in the 10 states that have land bank-enabling statutes.

Jordan R. Sisson addresses recent developments of public-private partnerships in California water infrastructure. His discussion includes the December 2015 revision of the Water Infrastructure Finance and Innovation Act. That act makes low-cost federal loans available to finance up to 49 percent of eligible water projects that are privately owned and sponsored by a public agency.

Nawa Arsala discusses the Department of Energy's March 25, 2016, decision to participate in an electric transmission line that will move wind power from Texas and Oklahoma to Arkansas and Tennessee. The Department of Energy's participation in the Plains and Eastern Clean Line represents the first time the department has used Energy Policy Act section 1222 to design, develop, construct, operate, maintain, own, or participate with private entities in the design, development, construction, operation, maintenance, or ownership of electric transmission facilities.

Finally, Rebecca Smith details the Supreme Court decision in *FERC v. Electric Power Supply Assoc.*, 136 S. Ct. 760 (2016). That decision reversed the D.C. Court of Appeals and upheld the Federal Energy Regulatory Commission's (FERC) Order No. 745, a rule that set the price regional electric operators should charge for wholesale demand response. Ms. Smith discusses the significance of the Court's decision for future FERC-jurisdictional controversies under the Federal Power Act.

We hope you enjoy this joint newsletter and look forward to seeing your article contributions in future issues.

Douglas Canter *is the managing editor and* **Will Yon** *and* **Shane Prate** *are the editors of the Government and Private Sector Innovation Committee Newsletter.* **Christina Baker** *and* **Manisha Patel** *are the editors of the Energy Infrastructure, Siting, and Reliability Committee Newsletter.*

THE CLEAN POWER PLAN AND INTERSTATE TRADING PROGRAMS

Ivan London, Tom Lee, and
Jeremy Fancher

Introduction

In his 2015 State of the Union speech, President Obama argued for action to cut carbon pollution. He pressed action "because a changing climate is already harming western communities struggling with drought, and coastal cities dealing with floods." He then told the Environmental Protection Agency (EPA) "to work with states, utilities and others to set new standards on the amount of carbon pollution our power plants are allowed to dump into the air." By then, EPA had already moved to implement the mandate. On June 2, 2014, EPA had proposed regulations to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric-generating units (EGUs). Seventeen months later, EPA published the final regulations. This "Clean Power Plan" (CPP) established state-specific goals for carbon dioxide (CO_2) emissions, aimed at reducing those emissions from EGUs by 30 percent from 2005 levels by 2030.

By targeting the power sector, President Obama and EPA have focused on the largest sources of GHG emissions in the United States. However, as President Obama warned, the shift to cleaner energy will not happen overnight, "and it will require tough choices along the way." In the CPP, EPA would leave those tough choices to the states. In accordance with section 111(d) of the Clean Air Act, EPA would require the states to choose how to meet federally established state-specific, rate-based, or mass-based emissions goals through their own implementation plans. In this framework, the states can choose whether to use market-based options, including intrastate and interstate carbon-trading programs.

This article focuses on the CPP's endorsement of carbon-trading programs as a means to achieve required carbon reductions under the CPP. We will not weigh in on whether EPA's promulgation of the CPP was a lawful exercise of the agency's authority under the Clean Air Act. Nor will we speculate whether the CPP will withstand judicial scrutiny. To explore the provision for carbon-trading programs, we will assume—solely for the purposes of this article—that the CPP will withstand current legal challenges. However, we will describe briefly the status of the current legal challenges in this introduction for background.

So far, 27 states have asked the D.C. Circuit to strike down the rule. Many others have moved to intervene on behalf of EPA. On November 17, 2015, the Senate passed a joint resolution disapproving the CPP. Although that resolution has no binding effect on EPA, the Supreme Court of the United States stayed implementation of the rule on February 9, 2016, in the D.C. Circuit case. The stay prevents EPA from taking action to implement the CPP while the legal challenges against it are pending. The D.C. Circuit will hear oral arguments in the case this June. If the Supreme Court ultimately hears a case regarding the CPP, then it might not issue an opinion until 2017 or later.

In this article, we will briefly explain the structure of the CPP. We will then describe two carbon-trading programs: the Regional Greenhouse Gas Initiative (RGGI) and California's cap-and-trade program. Finally, we will describe EPA's plan to let the states include trading programs in their state implementation plans (SIPs), and some of the states' comments and concerns.

The Clean Power Plan

The ambitious and controversial CPP poses major challenges to the coal-fired power plant industry. It could spur growth of natural gas-fired electricity generation. It could also affect mining, natural gas production, manufacturing, and retail electricity consumption.

In promulgating the CPP under section 111(d) of the Clean Air Act, EPA first identified the "best system of emission reduction" (BSER) for CO_2 from

EGUs—and thereby determined the extent of the carbon reductions the states must design their plans to achieve. EPA considered three "building blocks" to identify BSER:

1. Coal-fired power plant efficiency improvements;
2. Natural gas combined-cycle unit generation displacement of generation from more carbon-intensive sources, particularly coal; and
3. Increased generation from new zero-emitting renewable energy generating capacity displacement of generation from fossil fuel-fired generating units.

EPA applied these "building blocks" to each state's existing EGU fleet to set state-specific CO_2 targets. In doing so, the CPP departed from EPA's typical approach to regulating air pollution by creating options for state compliance. Thus, the CPP affords states considerable flexibility in how they go about achieving the respective rate-based and mass-based total statewide CO_2 emissions targets specified in the rule.

1. Rate-Based Targets: States may use the "building blocks"—as well as other strategies they might come up with—to reduce statewide emissions rates. For example, if a zero-emission EGU, such as solar, were to begin operating, then that would reduce the statewide average emissions rate. Those reductions would be credited toward achieving the state target.
2. Mass-Based Targets: States may set hard caps on the mass of CO_2 emissions from EGUs, and set up carbon-trading programs based on those caps. The trading programs could be state-specific or include several states. The inclusion of several states in a program would promote the creation of a larger marketplace for emissions allowances.

EPA reacted to criticism of its proposed approach by also setting uniform, national CO_2 emission "performance rates" for two subcategories of EGUs—fossil fuel-fired electric steam generating units (coal, oil, or natural gas) and stationary combustion turbines (natural gas combined-cycle units). The uniform performance rates are the touchstone for EPA in establishing state-specific rate-based and mass-based targets, which take into account the specific mix of energy generation sources in each state.

The uniform baseline performance rates address two criticisms of EPA's original CPP proposal. First, EPA wants to ensure that the burden of CPP compliance falls most heavily on higher CO_2-emitting sources and more fossil-fuel dependent states. Second, and importantly for this article, EPA hopes that providing a national baseline will help states set up intrastate and interstate trading programs. As discussed later in this article, EPA's proposed approach presented concerns with respect to whether states could implement meaningful interstate carbon-emissions trading programs. EPA hopes that its creation of uniform baseline performance rates—even if the states do not adopt those standards—will provide the basis by which states can reach agreement regarding how to value emissions. If the states can agree on how to value emissions, then the states might be more likely to agree on how to trade emissions allowances. Moreover, EPA will have an easier job tracking allowances and emissions.

Within this framework of building blocks and preferences, a state has several compliance options. See generally, EPA, State Plans: More State Options, Lower Costs (rev. Aug. 5, 2015), https://www.epa.gov/sites/production/files/2015-08/documents/flow_chart_v6_aug5.pdf.

First, the state must decide whether to implement a rate-based or mass-based plan. Second, if the state chooses to implement a rate-based plan, then it can either:

1. Adopt EPA's uniform performance rates—or more stringent emission standards—and apply them directly to the two subcategories of affected EGUs; or

2. Establish a statewide rate-based emission standard applicable to affected EGUs that would ensure that the statewide fleet in aggregate meets the state-specific rate-based target; or
3. Establish unique emission standards separately applicable to individual affected EGUs or EGU categories on the condition that the state also provide a performance demonstration to EPA that the EGU-specific standards would in aggregate meet the uniform performance rates or the state's rate-based target.

Alternatively, if the state chooses to implement a mass-based plan, then it can either:

1. Establish federally enforceable, mass-based emission standards for affected—i.e., existing—EGUs in conjunction with state-enforceable mass-based emission standards for new fossil fuel-fired EGUs; or
2. Establish mass-based emission standards only for affected EGUs on the condition that the state also provide a performance demonstration to EPA that the mass-based standards would in aggregate meet the state's mass-based target; or
3. Establish a "state measures" plan wherein the state would have flexibility to establish and implement a range of state-enforceable pollution-reduction strategies—including rate- and mass-based emission standards, demand-side requirements, renewable portfolio standards, and measures involving sources other than affected EGUs—on the condition that the state (a) adopt EPA's uniform performance rates as a "backstop" and (b) provide a performance demonstration to EPA that the mass-based standards would in aggregate meet the state's mass-based target.

These compliance options have significant differences. However, EPA contends that, for all types of plans, states may adopt programs that allow emissions trading among affected EGUs. EPA repeatedly promotes trading as a preferred compliance option. Further, EPA appears to have included the "state measures" plan type specifically so that states can use existing trading programs, "such as the programs implemented by California and the RGGI participating states. . . ." EPA holds RGGI and the California cap-and-trade program out as models for other states to meet CPP-required carbon reductions. Accordingly, we will turn next to RGGI and California.

Existing Carbon Trading Programs

We do not know what the various state trading programs will look like under the CPP. However, the northeastern states' RGGI program and California's cap-and-trade program are likely models for multistate and state-specific trading programs. These programs represent the vanguard of emissions trading in the United States. They have not necessarily proven that trading programs will cause reductions in GHGs under the CPP. However, they show that the states can create functional programs. Those programs can allocate emissions allowances, and let market forces drive technological innovation and consequent emission reductions.

The Regional Greenhouse Gas Initiative

RGGI is a cooperative effort among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions from the power sector. These nine states will likely have an easier time achieving compliance with the CPP. Reports have opined that RGGI is "well positioned to serve as a compliance pathway" under the CPP. Acadia Center, The Regional Greenhouse Gas Initiative: A Model Program for the Power Sector 12 (July 2015), http://acadiacenter.org/wp-content/uploads/2015/07/RGGI-Emissions-Trends-Report_Final.pdf.

RGGI's market-based regulatory program sets a cap, which decreases over time, on the total allowable annual CO_2 emissions from all participating states. The program then allocates a percentage of emissions allowances to each state. Regulated sources must then purchase allowances equal to their three-year emissions. They can buy the allowances at state-run quarterly auctions. They can also buy the allowances from other entities in a secondary market.

RGGI's emissions requirements apply to fossil fuel-fired EGUs with a capacity of 25 megawatts or greater. At the end of the first three-year control period, which began in January 2009, these sources had to "true-up" by demonstrating that they held allowances equal to 100 percent of their CO2 emissions over that period. At the end of the period, they could adjust their allowance holdings to reflect changes in their emissions. For the most recent three-year control period, which commenced in January 2015, the sources must "hold allowances equal to 50% of their obligation over a two-year interim control period, before submitting 100% of the compliance obligation at the end of the three-year control period." Center for Climate and Energy Solutions, Regional Greenhouse Gas Initiative 4 (Dec. 2013), http://www.c2es.org/docUploads/rggi-brief-12-18-13-updated.pdf. In other words, there is a "carrot-and-stick" approach to regulation. During the first two years of the new period, the regulated sources will have less stringent emissions-allowance requirements than they originally faced. However, if they do not reduce their emissions in those two years, the regulated sources will face new pressure to reduce emissions to prevent their compliance costs from doubling—or worse if allowance prices increase—in the third year.

To monitor compliance, the regulated sources must install and certify CO_2 emissions monitoring systems and collect and report data on CO_2 emissions. The RGGI CO_2 Allowance Tracking System (RGGI COATS) measures compliance with the program. EPA's Clean Air Markets Division database and RGGI COATS keep the compliance data from the regulated sources' monitoring systems. RGGI updates the information on a quarterly basis and makes that information available to the public. RGGI COATS also tracks the sale of emissions allowances on the secondary market, as well as allowances produced by CO_2 offset projects.

The goal of RGGI was to stabilize emissions by 2015, and then reduce those emissions by 10 percent between 2015 and 2020. While the RGGI states have reduced their GHG emissions by roughly 44 percent through 2013, it has not been clear what portion of those reductions is attributable to the program. Recently, the Acadia Center report described RGGI as a "proven, cost-effective pathway to achieve emissions reduction targets." Acadia Center, supra, at 3. Emissions reductions in 2014 outpaced targets by over 5 percent. Furthermore, electricity prices across the region have decreased by 2 percent on average since RGGI took effect, although the extent to which that price reduction is due to RGGI is unclear. That said, in non-RGGI states, electricity prices increased 13 percent across the same time frame. Moreover, the amount of total allowances dropped from 165 million tons of CO_2 to 91 million tons. Other states—i.e., outside of RGGI—have experienced similar trends due to closures of inefficient and aging power plants, improvements in energy efficiency and increased renewable energy outputs. See, e.g., US Carbon Emissions Set to Fall to Lowest Level in Two Decades, The Guardian, Apr. 10, 2015, http://www.theguardian.com/environment/2015/apr/10/us-carbon-emissions-set-to-fall-to-lowest-level-in-two-decades.

Regardless whether the emissions and electricity-price successes can be reliably tied to any particular initiative, RGGI has created the framework for a working—not hypothetical—market-driven approach. It has also created an income stream for the RGGI states, which fund energy conservation and efficiency initiatives to reduce the demand on the power sector. According to www.rggi.org, RGGI auctions have generated substantial revenue—over $1.9 billion since 2008. New Jersey withdrew from RGGI in November 2011, but received $113,344,551.27 in revenue before doing so. See Regional Greenhouse Gas

Initiative, Inc., Regional Greenhouse Gas Initiative (RGGI), CO2 Budget Trading Program (n.d.), http://rggi.org/component/content/article/54-co2-auctions-tracking-a-offsets/Auction-Results/207-cumulative-allowances-a-proceeds-by-state. RGGI states have committed to invest 25 percent of the allowance-trading revenue to energy efficiency and strategic energy schemes. While the states have used some of the revenues to balance their budgets, the February 2014 Investment Report on www.rggi.org indicates that the states have directed the lion's share—over $700 million—to investments in energy efficiency and direct bill assistance for customers.

The California Program

In 2006, California passed Assembly Bill 32. The bill required California to return to 1990 levels of GHG emissions by 2020—a 15 percent reduction—by implementing a statewide cap-and-trade program. The program encompasses sources responsible for 85 percent of California's GHG emissions. California's cap-and-trade program (the California program) is functionally similar to RGGI. It sets mass-based emissions caps and requires regulated entities to purchase allowances. However, while RGGI only covers fossil fuel-fired EGUs with a capacity equal to or greater than 25 MW, the California program regulates all electricity-generating facilities. It also regulates electricity importers, industrial facilities that emit over 25,000 tons of CO_2 per year, fuel suppliers, CO_2 suppliers and waste-to-energy facilities. In total, it covers approximately 450 entities.

The California program created two different triggering thresholds for "covered entities." The first threshold arrived in 2013, and the second arrived in 2015. Regulated entities must report their GHG emissions. California uses the reporting requirement to determine whether a covered entity exceeds an applicability threshold, and the amount of emissions allowances that the entity must obtain. The allowance credits are sold at quarterly auctions and can be resold to other covered entities to allow market flexibility. However, unlike the RGGI auctions, the California allowances are sold out of two pools: one controlled by the utilities, and one controlled by California. There is a limit on the amount of total allowances that an entity or related entities can control annually. In other words, regulated entities cannot necessarily "buy" compliance if their emissions exceed certain levels.

Although the California program has only been running for three years, and has only recently expanded in size from 160 million tons of allowances to 395 million tons, the proceeds from the allowance auctions are staggering. The Center for Climate and Energy Solutions provides a useful summary of the California program at http://www.c2es.org/. According to a September 28, 2014, Wall Street Journal article, after the August 2014 auction, the auction process had sold $2.27 billion of allowances. The utility-controlled pool accounted for $1.4 billion of the total. These proceeds are particularly interesting given that the California program has a phase-in period. For the first few years after the regulations took effect, most covered entities received the majority of their allowances free. In some cases, regulated entities could get 90 percent of their required allowances without cost, meaning that they only had to buy 10 percent of their required allowances through the auction process. As California doles out fewer free allowances, the state and its utilities can expect the revenue stream to increase significantly.

The California program is notable for another reason. In January 2014, the California program "linked" with Quebec's cap-and-trade system, so that entities in either jurisdiction could purchase and use emissions allowances available in either market. Quebec's program shares structural similarities with the California program. The linkage gives entities in both jurisdictions access to a larger pool of allowances. In addition, the partnership raises the limit on the number of allowances that a single entity can hold.

The California program is still in its proving period. So far, the auctions have run smoothly, and the market has borne the cost of allowances and the constriction caused by the annual reductions. California is a member of the Western Climate Initiative. The state has indicated interest in helping others develop their own trading programs. Moreover, additional linkages—like the Quebec partnership—could form with similarly situated markets.

Reports coming out ahead of the final federal rule this year suggested California's compliance with the CPP would be a "breeze." Tony Barboza, California Is Ahead of the Game as Obama Releases Clean Power Plan, L.A. Times, Aug. 4, 2015, http://www.latimes.com/science/la-me-climate-change-20150804-story.html. The CPP may actually be less stringent than the California program. A study by the California Air Resources Board suggested the state may be able to meet CPP targets 10 years early simply by following its existing climate change programs. See id. California's renewable energy industry may also benefit substantially from the CPP as it accelerates the adoption of alternative energy sources. Moreover, EPA appears to expect California to continue implementing the California program. However, as with the other states, California's implementation will be telling.

Fitting Existing Programs into the Plan

The CPP lets the states include cap-and-trade or emissions credits programs in their implementation plans. More particularly, EPA appears to promote emissions trading more heavily in the final rule than EPA did when it proposed the CPP. It may be fair to say that EPA expects the states to use emission trading to comply with the CPP. The final rule promotes interstate collaboration as a tool for compliance. The states may jointly submit their plans. EPA also encourages the states to join existing cap-and-trade programs. The RGGI states and California submitted extensive comments on the proposed rule. It is possible that the experienced emissions-trading states and EPA will be able to provide the necessary, meaningful guidance to other states to ensure that their plans will work. Moreover, the RGGI states and California have indicated that they intend to maintain their current programs. EPA thinks that additional states will ask to join RGGI. EPA proposes mass-based trading in its "model rule" to implement the CPP. Moreover, a federal implementation plan proposal published alongside the final rule suggests that EPA would push into a trading program states that do not submit a SIP or fail to submit an approvable SIP. See John Upton, Could the Clean Power Plan Create a Massive Cap-and-Trade System?, GreenBiz, Aug. 7, 2015, http://www.greenbiz.com/article/could-clean-power-plan-create-massive-cap-and-trade-system. However, states that are not part of RGGI or the California program may face impediments to implementing their own trading programs.

Rate-Based Standards for Mass-Based Programs

There have been—and to some extent still are—substantial questions regarding how states could implement trading programs. EPA spends much of the preamble to the final CPP regulations explaining how it has addressed those questions. Nevertheless, it is worth examining them.

As EPA originally proposed the CPP, there was a conceptual challenge to implementing RGGI and the California program and similar trading programs. RGGI and the California program express compliance based on whether a regulated entity's total emissions fall under a set mass-based emissions "cap"; hence, the expression "cap-and-trade." However, EPA has traditionally set federal new source performance standards (NSPS) under section 111 that are rate based, not mass based. For example, in 40 C.F.R. section 60.44Da, EPA has set a nitrogen oxide emission limit for new or reconstructed coal-fired EGUs expressed as 0.50 lb/MMBtu.

Recognizing that its goal of maximizing state flexibility in achieving CPP-required GHG reductions does not fit a traditional section 111 implementation, EPA has come up with a novel approach to regulating GHG emissions under section 111. Under the CPP, EPA will allow the states to measure compliance using mass-based standards. Consistent with its proposed version of the CPP, EPA has set state-specific rate-based CO_2 goals. EPA has now also set uniform EGU emission performance rates. However, to facilitate trading programs that follow the well-known cap-and-trade format, EPA has also established mass-based emissions goals for the individual states. In other words, EPA will allow states to adopt a mass-based carbon cap as an alternative to imposing traditional rate-based emission standards on individual EGUs.

EPA's decision to set state-specific, mass-based carbon caps potentially resolved a major "translation" issue in EPA's original proposal. The proposal presented a possibly intractable problem concerning how states could translate the cap-and-trade approach to the rate-based approach required by the NSPS. However, while fixing one problem, EPA may have created another. As described above, section 111 of the Clean Air Act requires EPA to regulate by establishing standards of performance for sources. For example, section 111 does not explicitly authorize EPA to regulate individual sources by setting a statewide emission cap. Perhaps to survive a legal challenge, EPA has simultaneously set alternative nationwide "backstop" performance rates and let states adopt those performance rates or promulgate state-specific emission-rate standards that would let the states meet state-specific targets. EPA expresses optimism that states would consider rate-based emission standards and even create rate-based trading programs.

Thus, under the CPP, a state may attempt to implement a rate-based trading program rather than the more familiar cap-and-trade program. To allow for this, EPA has devised a way to create "emission rate credits" (ERCs) that would be analogous to the allowances used in the cap-and-trade context. For example, a facility could create ERCs by operating below a rate-based emission limit, and then sell the resulting ERCs to facilities that exceed their limits. Moreover, if a state adopts a "state measures" approach, then the state must meet an overall mass-based target. However, it may use ERCs to comply on a source-specific basis. While the ERCs may solve the "translation" issue, there are still problems with such a system.

First, for existing cap-and-trade programs like those used by the RGGI states and California, that approach would require an entirely new regulatory framework. Extensive state-agency time and expense would be necessary to design such a program, respond to comments and refine it.

Second, the entire credit market would rely on potentially fluctuating emissions rates. For example, a facility may operate below the emissions limit one month but not the next; so, verifying the basis for each credit would require significant monitoring and oversight. EPA has attempted to address this issue in two ways. On the one hand, EPA has created uniform performance rates that the states can adopt. However, the states do not have to adopt them. On the other hand, EPA would limit the potential trading markets for rate-based trading states. In other words, a state that wanted to implement a rate-based trading program could only trade with another state that chose the same emission-rate standards—whether the uniform standards or some other state-specific standards. However, such limitations highlight—rather than resolve—the complexity of rate-based trading and would tend to undermine EPA's desire to promote multistate trading programs.

Third, a rate-based program like the one described above might not necessarily generate revenue for the states. The RGGI states and California would not be happy about the prospect of foregoing billions of dollars of revenue. In sum, there is a lot riding on whether EPA's attempt to troubleshoot the "translation" problem from the original CPP will really work. Moreover, the mass-based emissions goals for the states may provide a simpler means to implement a trading program. However, it is unclear—and we do not speculate—whether such a program would survive judicial review even in the context of EPA's attempt to rescue the idea by proposing an alternative trading system that more directly fits within the traditional methodology under section 111.

Multistate Flexibility

In furtherance of an approach that maximizes states' flexibility by embracing multistate trading programs like RGGI, EPA also expressly promotes multistate compliance strategies. In their comments on the final regulations, the RGGI states praised EPA's recognition that well-designed multistate, market-based programs like RGGI can deliver cost-effective emissions reductions. The RGGI states presented several recommendations to EPA, including that EPA should facilitate the formation of larger carbon trading markets by adopting a mass-based federal plan; EPA should encourage the auctioning of allowances and reinvestment of auction proceeds; and EPA should adopt a trading program that is flexible and customizable to encourage broader trading markets. Letter from RGGI States to EPA (Jan. 21, 2016), http://www.rggi.org/docs/PressReleases/RGGI_Joint_Comments_CPP_FP_MR.pdf.

The issues of whether the CPP and its promotion of multistate plans would require the states to undertake legislative action, and whether states can join or leave multistate plans with impunity are thorny. In this article, we do not address the viability and challenges of pushing the CPP down on states if those states are not currently able to comply based on their current or future laws. It suffices to say that some states may have to enact new laws that permit multistate and multistate agency participation and agreement. The negotiation of multistate plans will take time, and it does not seem clear what will happen if a state seeks to negotiate a multistate plan, only for its legislature to void any such plan at the "eleventh hour." Regardless, the state level administrative and legislative tensions that will necessarily arise to engage in multistate plans under the CPP will require the regulated community to spend significant money and efforts to "read the tea leaves," influence the process, and ultimately comply.

Moreover, there may be a legal incentive for states to enact new state laws formalizing their approaches to the CPP, especially for those states that seek to enter a mass-based trading program like RGGI. Under the CPP, EPA has promulgated the "state measures" approach in part to make sure that states have latitude to continue using and even expand emissions-trading programs that do not line up perfectly with the restraints that Congress imposed on EPA under section 111. For example, the California program applies to emissions sources that are outside the scope of the CPP. If EPA did not provide the "state measures" approach, then California would have to amend its cap-and-trade program if it hoped to incorporate the program into its CPP plan. However, all states—not just California—have access to the state measures approach. Under the state measures approach, a state could impose state-enforceable measures on entities other than the EGUs and, potentially but not necessarily, emission standards for EGUs. While the state must also adopt a federally enforceable "backstop" ensuring compliance with the Clean Air Act, the reliance on state-enforceable measures may give the states latitude in shielding sources from Clean Air Act citizen suits and penalties. For fuller treatment of this issue, please see Raymond L. Gifford et al., The Clean Power Plan: Carbon Trading, State Legislation and the Political Economy Issue (Oct. 2015), http://www.wbklaw.com/uploads/White%20Paper%20%20Carbon%20Trading%20State%20Legislation%20and%20the%20Political%20Economy%20Issue%20Oct15.pdf. EPA appears to acknowledge that if states adopt their "state measures" through state legislation, then those measures "would not be federally enforceable. . . ." Accordingly, if the CPP survives judicial review, then the states may rush to shield operators from federal enforcement by taking the sort of legislative actions that could produce the troublesome and uncertain issues described above.

The RGGI states and California clearly intend to incorporate their current programs into their implementation plans or multistate plans, and their paths to compliance look promising. Six of the nine states in RGGI are likely on track to meet the CPP's mass-based goals for 2030 by 2020, and every RGGI state but Maine will likely meet the two-year targets for 2022–24 under the current RGGI schedule for emissions reductions. Gerald B. Silverman, Most States in Northeast Trading Program on Track to Meet Clean Power Plan Targets, Bloomberg BNA, Daily Environmental Report, Aug. 14, 2015, http://web.law.columbia.edu/sites/default/files/microsites/climate-change/most_states_in_northeast_trading_program_plan_to_meet_cpp_targets.pdf. They appear to have a competitive advantage over other states if they can truly "flip" their current programs into the CPP simply because they might experience fewer tensions and headaches resulting from interstate, intrastate, and public-private fighting than those states who seek, for the first time, to enter such trading programs once the CPP becomes effective.

Conclusion

The CPP presents an opportunity for the country's existing trading programs to grow into a national compliance scheme, while preserving their state- or region-specific benefits. It appears that the RGGI participants and California are actively seeking to integrate their existing CO_2 emissions trading plans into their CPP state implementation plans, and these trading programs may provide a model for other states.

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LIFE PRESERVER: HOW PUBLIC-PRIVATE PARTNERSHIPS ARE SAVING MUNICIPAL WATER AND SEWER SYSTEMS

Devin T. Ryan

Public-private partnership (P3) agreements are rapidly becoming more commonplace in the United States and offer intriguing opportunities for cash-strapped municipalities that own and operate public water and sewer facilities in dire need of capital improvements. This article explains how municipalities have structured P3 agreements to address their aging water and sewer infrastructure and to pay down their ever-increasing debt obligations.

What Is a P3 Agreement?

In general, a P3 agreement is a contract between a private entity and a public partner under which the private entity provides a public service. Both the private entity and public partner share resources, as well as the risks and rewards of delivering that public service.

Although the exact structure and terms of P3s can differ greatly depending on the specific needs of the private entity and the municipality, there are common aspects among P3 agreements concerning existing water and sewer systems. First, the municipality generally retains ownership over the assets and maintains overriding control over the management of the assets. Water P'ship Council, Establishing Public-Private Partnerships for Water and Wastewater Systems 12 (2003), *available at* http://www.nawc.org/uploads/documents-and-publications/documents/document_567764ad-b69f-4715-bc5d-eaa32c304fdd.pdf. Second, the agreements contain a formula for establishing user rates and rate increases over the life of the contracts. The rate formulae generally provide for increases to recognize known cost increases (e.g., labor, supplies) and recovery of capital investments undertaken by the private party. Third, the private entity provides the specified services under the P3, such as operating and maintaining the water or sewer system, performing meter reading and billing services, providing customer service, and replacing and upgrading the system's infrastructure. *Id.* at 12–13. Fourth, legal, regulatory, and financial risks are allocated between the parties. *Id.* at 71–75.

Despite these common underpinnings, the structures of P3s can vary. Often, the interrelated trade-offs of a P3 agreement are embodied in several interrelated contracts. Further, "[t]he key distinctions of P3s are the duration of the partnership, the nature of the financing and the sources of revenue." Eric Orts & Joanne Spigonardo, The Wharton Sch., Univ. of Pa., Investing in America's Public Water Systems—Making Public-private Partnerships Work 5 (2015), *available at* http://d1c25a6gwz7q5e.cloudfront.net/reports/2015-06-10-Investing-in-Americas-Public-Water-Systems.pdf. Some basic models of P3s include (1) concession or concession/lease, where the private entity makes an up-front payment to the public partner in exchange for collecting revenues directly from the customers who use the existing system; (2) design-build, where the private entity is contracted to design and construct the project (assuming the risks during this phase) and then the public partner takes over the responsibility of operating and maintaining the system upon completion; (3) operate and maintain, where the private entity is only contracted to operate and maintain the system for a period of years; and (4) design-build-finance-operate and maintain, where the private entity is responsible for every phase of the project—finance, design, construction, operation, and maintenance of the new facilities. *Id.*; *see* Water P'ship Council, *supra*, at 53; Chasity H. O'Steen & John R. Jenkins, *We Built It, and They Came! Now What?*, 41 Stetson L. Rev. 249, 271–78 (2012) (listing and describing types of public-private partnership agreements). This list is not exclusive, and parties may choose to modify aspects of each type to suit their goals.

Why Are P3 agreements Attractive for Municipal Water and Sewer Systems?

P3 agreements, particularly concession agreements, have recently become very attractive to municipalities that own their own water and sewer facilities for two key reasons: (1) there is an urgent need to replace and upgrade their infrastructure; and (2) municipalities are burdened by outstanding debt and pension liabilities and, therefore, lack funds to make those improvements.

The need to replace the country's aging water and sewer infrastructure is widely acknowledged and pressing. The American Society of Civil Engineers gave a rating of D-minus to the country's drinking water system in 2009, and leaking pipes lose an estimated seven billion gallons of water per day. Alison Kosik, *Experts: U.S. Water Infrastructure in Trouble*, CNN (Jan. 21, 2011), http://edition.cnn.com/2011/US/01/20/water.main.infrastructure/. This problem is particularly relevant for Pennsylvania, whose two largest cities (Philadelphia and Pittsburgh) had the third and fourth worst water leakage rates in the United States between 2000 and 2010. *See* Orts & Spigonardo, *supra*, at 1. Even more recently, a 2012 audit found that 38.4 percent of the water that enters Philadelphia's distribution system is lost and unaccounted for. Rob Curran, *Flint's Water Crisis Should Raise Alarms for America's Aging Cities*, Fortune, Jan. 25, 2016, http://fortune.com/2016/01/25/flint-water-crisis-america-aging-cities-lead-pipes/. Fixing these problems is no cheap task. The American Water Works Association (AWWA) estimates that water utilities will need to invest more than $1.7 trillion over the next 40 years to address their aging water infrastructure, with about 54 percent of those funds for replacing existing facilities and 46 percent for installing new facilities. American Water Works Association, Buried No Longer: Confronting America's Water Infrastructure Challenge 10 (2012).

But today, local governments are often dealing with burdensome debts and pensions that inhibit their ability to address their water and sewage systems. Indeed, "[w]ith more than $1.7 trillion in long-term debt already on the books, and pension liabilities surging, cities are hard pressed to finance badly needed capital improvements for water systems." Orts & Spigonardo, *supra*, at 4; *see also* Congressional Budget Office, The Underfunding of State and Local Pension Plans (2011), *available at* https://www.cbo.gov/sites/default/files/cbofiles/ftpdocs/120xx/doc12084/05-04-pensions.pdf; Steven Maguire, Cong. Research Serv., State and Local Government Debt: An Analysis (2011), *available at* https://www.fas.org/sgp/crs/misc/R41735.pdf. Further, several communities throughout the country are doubling and tripling their water rates or implementing "massive bond initiatives" to pay for these improvements. David Schaper, *As Infrastructure Crumbles, Trillions of Gallons of Water Lost*, NPR, Oct. 29, 2014, http://www.npr.org/2014/10/29/359875321/as-infrastructure-crumbles-trillions-of-gallons-of-water-lost.

By entering into P3s that are concession agreements, municipalities can address their large amount of debt and pension liabilities while securing much needed investment to replace their aging water infrastructure. For example, in Pennsylvania, the Middletown Borough Authority (Middletown) entered into a concession agreement with United Water, Inc. (United Water) and KKR & Co. L.P. (KKR), an investment firm, to address its existing debt, pension liability, and water infrastructure issues. *United Water and KKR to Bring Water and Sewer Investments to Borough of Middletown, PA*, United Water (Dec. 15, 2014), http://blog.unitedwater.com/2014/12/15/united-water-and-kkr-to-bring-water-and-sewer-investments-to-borough-of-middletown-pa/. Under this agreement, Middletown would receive an initial payment of $43 million to eliminate its existing debt and pension liability. *Id.* According to one of the borough's councilmen, this cash infusion would eliminate all of the borough's debt. Julianne Mattera, *Middletown Approves 50-Year Water, Sewer Lease with United Water*, PennLive, Sept. 29, 2014, http://www.pennlive.com/midstate/index.ssf/2014/09/middletown_approves_50-year_wa.html. Additionally, United Water committed to making $83 million worth of infrastructure improvements over the 50-year term of the contract. *United Water and KKR to Bring Water and Sewer Investments to Borough of Middletown, PA*, United Water (Dec. 15, 2014), http://blog.unitedwater.com/2014/12/15/united-water-and-kkr-to-bring-water-and-sewer-investments-to-borough-of-middletown-pa/. However, Middletown would still retain ownership over the water and wastewater system and control customers' rates, which are set using a formula in the concession agreement. *Id.* In exchange, United Water and KKR obtain a relatively predictable revenue stream for providing water service to these customers under the rates established by the agreement.

P3s are not without their detractors, as some parties are wary of their local government turning over the operation of the water or sewer system to a for-profit enterprise. *See* Orts & Spigonardo, *supra*, at 6. However, by entering into P3 concession agreements, municipalities are able to retain ownership of the water or sewer system while receiving large up-front payments that can exceed the current book value of those assets. If the municipality were simply seeking to sell its water or sewer system to a regulated utility, the municipality may not receive payments from the sale comparable to those received under a P3 concession agreement due to valuation differences. This is because the regulated utility's ability to earn a return and set rates generally is limited by traditional rate base/rate of return regulation. Therefore, a regulated utility's plant valuation may differ from a private entity's future revenue stream valuation. Moreover, the parties may be less able to develop innovative rate formulas under utility rate regulation than through a negotiated P3 agreement. Thus, in certain circumstances, P3s can be more attractive for a municipality seeking to solve its infrastructure and debt issues than selling its water or sewer system to a utility.

Nonetheless, municipalities and regulated utilities entering into P3 concession agreements need to take great care in clearly defining the risks they will assume over the life of the contracts. They also should pay close attention to the formulae for revising water and sewer rates. These rates will have long-term impacts on the affected customers, and utilities will need to garner enough revenue at those rates to fund capital improvements and provide service to customers. There are many unknowns in a contract that may last 50 years. If the parties are not careful when drafting the concession agreement, disputes may arise if unanticipated circumstances alter the parties' assessment of risk and reward.

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BOTTOM-UP BROWNFIELDS THROUGH MUNICIPAL GREEN LAND BANKING

Jessica Chiavara

Land banks are state-created institutions allowed to reclaim condemned, abandoned, and tax delinquent properties when such properties are deemed to contribute to blight in a given community. The land bank then has (at least) a tax lien ownership over the property and can repurpose these properties via any number of avenues—whether public auctions for interested first-time homeowners, razing the property for remediation and a new zoning use such as a public green space, or rehabilitating the property in its current form so that a new tenant can move in and return it to productive use. Land banking is proving to be an innovative and malleable accelerator for community revitalization, because though it is created through a top-down state legislative enabling statute, the land banks themselves are created by municipalities.

In the last 15 years, land banks have grown more than tenfold, with current active land banks totaling around 120 nationwide in the 10 states that have land bank enabling statutes. *See* Frank Alexander, *Land Banks and Land Banking*, http://www.communityprogress.net/filebin/LandBanksLandBankingVer2DigitalFinal.pdf, at 103 (Dec. 21, 2015). One example is New York's enabling statute. *See* NewYork Not-for-Profit Corporation Law, art. 16 (2011). This permits up to a certain number of cities, counties, or city/county teams to apply for program funding under land banking liens. Under the law, a state legislature grants permission to the applicants, and the land bank is formed out of the municipal government but is established as a fully independent, type C not-for-profit organization. *Id.* § 1602.

Under the New York system, the municipalities control the set of revitalization goals for the property with substantial input from the communities covered by the relevant land bank's jurisdiction. This local, tailored approach allows for communities to decide what the priority issues are for rebuilding robust neighborhoods. *See* Alexander, *supra*, at 68–72. For example, where high, double-digit vacancy in a residential neighborhood is the biggest problem, acquiring those properties and auctioning them off at well below market prices will encourage residents who want to become homeowners to take advantage of an otherwise out-of-reach opportunity. This, in turn, immediately increases short- and long-term revenue by increasing the tax base for the area by repopulating neighborhoods.

Where vacant properties are predominantly commercial, however, the chief concern is likely persistent under- and unemployment. The land bank would therefore craft a different approach: one that tailors itself to attracting businesses back to the area through tax breaks, below-market rent or leases, incentives for hiring local residents, and the like. This has a dual policy attainment of increasing the property tax base, while at the same time increasing the average wealth of the neighborhood by putting people back to work. Finally, a common issue for land-banked properties is where hazardous conditions created by abandoned and condemned properties—whether as a fire hazard, vermin and pest attraction, or contamination of the land—jeopardize the health and welfare of residents in the land bank's jurisdiction. In these instances, municipalities can remediate these risks by spreading the cost burden, then recouping its expenses when it returns the property to private use. *Id.*

But more and more, as land banking evolves and as a more holistic approach to community health and safety is taken, environmental health and sustainability goals will be prioritized quite highly in future projects. That is why current land banks have "green" programs formally built into operations. *See Green Lots Leases and Green Lots Grant Program*, http://syracuselandbank.org/programs/ (Dec. 21, 2015). But even among those that do not formally include an environmental program, like the Ohio program, the enabling statutes for land banking authorities will still make it clear that green space, garden space, and other environmentally beneficial uses are beneficial to overall community revitalization. Cleveland City Planning Commission, *Eight Ideas for Vacant Land Re-use in Cleveland*, http://planning.city.cleveland.oh.us/ftp/8IdeasForVacantLandReuseCleveland.pdf (Dec. 21, 2015).

For a current geographical map of active land banks with a corresponding list of contact information and links to websites, visit http://www.communityprogress.net/land-bank-map-pages-447.php. Land banking is sure to continue to be a growing trend as an innovative revitalization catalyst, and a successful intersection of state and local governments working hand-in-hand with the private sector.

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PUBLIC-PRIVATE PARTNERSHIPS IN CALIFORNIA WATER INFRASTRUCTURE

Jordan R. Sisson

Every four years, the American Society of Civil Engineers (ASCE) grades U.S. infrastructure. In 2013, ASCE gave U.S. water infrastructure a "D" grade, noting much of the infrastructure was nearing the end of its useful life. *See* ASCE, *Executive Summary*, *America's Infrastructure 2013 Report Card*, http://www.infrastructurereportcard.org/a/#p/overview/executive-summary (last visited Apr. 17, 2016). With an estimated 240,000 water main breaks per year, it would require at least $1 trillion to replace every existing pipe in the United States. *Id*. California alone will need $266 billion in infrastructure improvements over the next 10 years to satisfy just its water demands—all while facing its fourth year of drought. *See* League of California Cities, *Innovative Water and Wastewater Infrastructure Financing* at 1, https://www.cacities.org/Resources-Documents/Policy-Advocacy-Section/Federal-Issues/2014-Federal-Letters/Innovative-Water-Infrastructure-Financing.aspx (2014). To meet this challenge, the state recognizes the need for increased collaboration between federal, state, and local partnerships. *See* California Natural Resources Agency, *California Water Action Plan 2016 Update* at 4, http://resources.ca.gov/docs/california_water_action_plan/Final_California_Water_Action_Plan.pdf (2016).

Public-private-partnerships (P3) offer an opportunity to leverage government resources with private sector innovation. Over the past six months the P3 model has been advanced by the U.S. Congress, California legislature, and local water agencies.

Congress Revises WIFIA

In December 2015, President Obama signed the $305 billion, 1300-page transportation bill known as the Fixing America's Surface Transportation (FAST) Act. *See* Pub. L. No. 114-94, 129 Stat. 1312. In addition to funding highway, transit, and rail projects over the next five years, the FAST Act repeals restrictions on using tax-exempt bonds to fund water projects under the Water Infrastructure Finance and Innovation Act (WIFIA) program. *Id*. § 1445 (codified as amended, 33 U.S.C.A. § 3907). Passed in 2014, WIFIA is a five-year, $350 million pilot program administered by the Environmental Protection Agency (EPA). The program makes low-cost federal loans available to finance up to 49 percent of eligible water projects that are privately owned but sponsored by a public agency. *See generally*, EPA, *WIFIA: Introduction and Development*, https://www.epa.gov/sites/production/files/2015-09/documents/wifia-04-01-15-webcast-2.pdf (Apr. 1, 2015). The revisions to WIFIA now allow the remaining 51 percent to be funded through tax-exempt bonds; the most common financing mechanism used by public water systems. *See* American Water Works Association (AWWA), *WIFIA's Bond Prohibition Shuts Off Water Project Finance Tool*, http://www.awwa.org/Portals/0/files/legreg/documents/FlyInWIFIACorrection.pdf (last visited Apr. 17, 2016). According to chief executive officer of the AWWA, David LaFrance, "Congress has freed WIFIA to do its important work in addressing America's enormous water infrastructure challenge." *See* Lynn Hume, *Allowing Tax-Exempt Use with WIFIA Loans Will Lower Borrowing Costs*, The Bond Buyer, http://www.bondbuyer.com/news/washington-infrastructure/allowing-tax-exempt-use-with-wifia-loans-will-lower-borrowing-costs-1091520-1.html (Dec. 10, 2015).

California Allocates Proposition 1 Funds

As of April 2016, the California Natural Resources Agency (CNRA) has committed over $5.9 billion in its first round of funding from the Water Quality, Supply, and Infrastructure Improvement Act of 2014 (Proposition 1). *See* CNRA, *Proposition 1 Overview*, http://bondaccountability.resources.ca.gov/p1.aspx (last visited Apr. 17, 2016). Proposition 1 authorized $7.5 billion in general obligation bonds for water storage, water quality, flood protection, watershed protection, and restoration projects. *See* 2014 Cal. Legis. Serv. ch. 188 (West) (codified at Cal. Water Code § 79700). Among the 47 programs funded, $100 million has been earmarked for the Water Desalination Program administered by the Department of Water Resources (DWR). *See* CNRA, *supra*, *Proposition 1 Allocation Balance Report*, at 45 (Apr. 14, 2016). The program grants funding for water recycling and advanced treatment projects including groundwater and seawater desalination facilities. According to the latest program schedule, DWR should be accepting applications by September and announcing awards by November. *Id.*, *supra*, *Draft Proposition 1 Development Schedule* (Mar. 29, 2016). Other programs funded by Proposition 1, including grant application guidelines, are available on the CNRA website. *Id.*, *supra*, *Proposition 1 Programs* (last visited Apr. 17, 2015).

Local Water Agencies Go Live with Desalination

In December 2015, the controversial seawater desalination plant in Carlsbad officially completed its 30-day test period showing it could deliver 55 million gallons of potable water per day. The nearly $1 billion, ultra-modern facility is the largest in the Western hemisphere and product of a massive collaboration between the San Diego County Water Authority and Boston-based Poseidon Water. Following 10 years of negotiations, the Water Authority entered into a 30-year performance-based purchase agreement with Poseidon, which bore the entire cost of construction through private bonds. Poseidon CEO Carlos Riva explained, "[O]ur model is to say: [w]e will take on the risk of development, financing, building and operation, and in exchange [the water agency] takes the market risk of buying our water." *See* Allysia Finley, *Slaking California's Thirst—If Politics Allows*, Wall St. J., May 15, 2015, http://www.wsj.com/articles/slaking-californias-thirstif-politics-allows-1431729692.

Undeterred by its experience in Carlsbad—which included 14 environmental lawsuits and 17 years of planning, permitting, and construction—Poseidon is now employing a similar P3 strategy up the California coast in the city of Huntington Beach.

There, a $1 billion, 50-million-gallon-per-day facility is being proposed next to the AES power plant. Again, Poseidon is taking on the development risk. Plans for the facility received city approval in 2006 and are currently under review by the California Coastal Commission. Poseidon hopes to secure the necessary permits and start construction later this year and for the site to be operational by 2020. Meanwhile, Poseidon continues conversations with the Orange County Water District, which may take on the market risk by purchasing the water for a 50-year period. Under a draft term sheet, not yet approved, the Water District would be responsible for finding cities to buy the water, deciding whether to use the water to replenish the county's groundwater basin, and building and maintaining the distribution system. *See* Anthony Carpio, *O.C. Water District Narrows Distribution Options for Desalinated Water from Proposed H.B. Plant*, Huntington Beach Independent, Mar.4, 2016, http://www.latimes.com/socal/hb-independent/news/tn-hbi-me-0310-ocwd-20160304-story.html.

Conclusion

Not without their critics, desalination facilities reflect the realities of combating climate change over the long term. As California tackles its water security issues and sustainable development into the future, P3s offer a path forward from an unworkable status quo. As expressed by Scott Maloni, vice president at Poseidon Water, the question is "what happens ten years . . . and twenty years from now . . . [c]an you really count on the Colorado River or Northern California to continue to supply the vast majority of the state's population with water?" Daniel Potter, *Why Isn't Desalination the Answer to All California's Water Problems?*, KQED Science, http://ww2.kqed.org/science/2015/12/18/why-isnt-desalination-the-answer-to-all-californias-water-problems/ (Dec. 18, 2015).

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CLEAN LINE TRANSMISSION PROJECT: SIGNS OF A NEW BEGINNING OR EVIDENCE OF A TROUBLED PAST IN GRID MODERNIZATION

Nawa Arsala

On March 25, 2016, the U.S. Department of Energy announced that it will participate in the development of the Plains and Eastern Clean Line (Clean Line) project. This is the first time the department will use its authority granted in section 1222(b) of the Energy Policy Act of 2005 to support an electric transmission project. Pursuant to Energy Policy Act section 1222, the Department of Energy, through its secretary, has authority to "design, develop, construct, operate, maintain, or own, or participate with other entities in designing, developing, constructing, operating, maintaining or owning, an electric power transmission facility and related facilities."

If it obtains market support and is built, Clean Line will have the capacity to deliver approximately 4000 megawatts (MW) from renewable energy generation facilities, primarily wind power, located in the Oklahoma Panhandle and potentially Texas Panhandle regions, to the electrical grid in Arkansas and Tennessee. The facilities covered by the department's participation consist of 705 miles of +600 kilovolt (kV) overhead, high-voltage direct current (HVDC) electric transmission facilities, and related facilities from western Oklahoma to the eastern state line of Arkansas near the Mississippi River. Record of Decision in re Application of Clean Line Energy Partners LLC at 1. As per the participation agreement between the department and the private entities developing the project owner, the department will not participate in the building of additional facilities to connect the project in Texas and Tennessee. *Id.* at 2. Clean Line will be 100 percent privately invested.

Clean Line Energy Partners, the company proposing to build the transmission line, and its investors believe Energy Policy Act section 1222 was intended to help overcome regulatory barriers to siting interstate electricity infrastructure projects while allowing for third-party financing. Clean Line Energy Partners, Our Investors, *available at* http://www.cleanlineenergy.com/about/investors. Through its record of decision and participation agreement, the Department of Energy has evidenced a similar view. Under the participation agreement, the Department of Energy assumes the role of acquiring land for the project, with the cost borne by the project sponsors, in certain circumstances where the project sponsors have been unable to acquire the land themselves after using all commercially reasonable efforts. The department's role in the $2.5 billion project is facing strong opposition from many state legislators.

As evidenced by statements in the Energy Policy Act and Department of Energy grant programs, U.S. energy policy includes a goal of modernizing the electric transmission grid. As evidenced by the record of decision, the department believes its participation in the Clean Line project is consistent with this grid modernization goal, a "modern and resilient grid that could accommodate increasing demands for power with newly available resource." *Energy Department Announces Participation in Clean Line's Large-Scale Energy Transmission Project* (Mar. 25, 2016), *available at* http://energy.gov/articles/energy-department-announces-participation-clean-line-s-large-scale-energy-transmission-. The department's participation in the Clean Line project also furthers the U.S. interests in expanding use of renewable energy sources. The department's 2015 Quadrennial Energy Review found that new long-distance transmission capacity, like Clean Line, has the "potential to enable lower-carbon electricity, enhance system reliability and operate at a reasonable cost to consumers." *Id.* But the federal government's role in promoting, operating, and siting an interstate transmission line is not settled.

In order for the Energy Policy Act section 1222 (42 U.S.C. 16421) to apply, three criteria must be met. The Secretary of the Department of Energy must find a geographic area that (1) is experiencing electric energy transmission capacity constraints or congestion, (2) adversely affects consumers as a national interest electric transmission corridor, and (3) is within the Western Area Power Administration or Southwestern Power Administration. Final Environmental Impact Statement; Clean Line Transmission Line, EIS-0496 (Mar. 23, 2016), *available at* http://energy.gov/nepa/downloads/eis-0496-epa-notice-availability-final-environmental-impact-statement. Pursuant to section 1222 (42.U.S.C. § 16421), the Secretary of Energy can act through the Southwestern Power Administration or the Western Area Power Administration to design, develop, construct, operate, own, or participate with other entities in designing, developing, constructing, operating, maintaining, or owning two types of electric transmission projects. DOE website at http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/section-1222. The department's authority to promote electric transmission targets transmission and related facilities needed to upgrade existing transmission facilities owned by the Southwestern Power Administration or the Western Area Power Administration. 42 U.S.C. 16421(a). The department's authority to promote electric transmission also covers new electric power transmission and related facilities located within any state in which the Southwestern Power Administration or the Western Area Power Administration operates. 42 U.S.C. 16421(b).

Section 1222 also allows the department to exercise eminent domain authority as a last resort, pursuant to the Condemnation Act. For the Condemnation Act to apply, the project must be considered "public use." Projects submit their applications to the Department of Energy. The department evaluates applications to ensure their compliance with section 1222 as a national interest corridor under the Energy Policy Act and to fulfill its requirements pursuant to the National Environmental Policy Act. For the Clean Line Transmission Project, the department held 15 public hearings in several states through which the line would run, and received approximately 950 comments, which led to the final environmental impact statement (EIS) issued on March 23, 2015. Final Environmental Impact Statement; Clean Line Transmission Line, EIS-0496 (Mar. 23, 2016), *available at* http://energy.gov/nepa/downloads/eis-

0496-epa-notice-availability-final-environmental-impact-statement.

The Department of Energy was the lead federal agency in preparing the EIS, with support from the Bureau of Indian Affairs, Natural Resources Conservation Service, Tennessee Valley Authority, U.S. Army Corps of Engineers, U.S. Environmental Protection Agency, and U.S. Fish and Wildlife Service. Record of Decision in re Application of Clean Line Energy Partners LLC at 7 (Mar. 25, 2016). Once approved, the Department of Energy and the project owners execute a participation agreement that memorializes the department's approval and any conditions attached to that approval.

In 2010, Clean Line filed an application for approval for a certificate of public convenience and necessity to operate as a public utility in Arkansas, which was ultimately denied. The state commission held that Clean Line did not meet the statutory definition of a "public utility." "Public utility" is defined by the state of Arkansas as a utility "owning or operating in this state equipment or facilities for . . . transmitting . . . power to or for the public for compensation." Ark. Code. Ann. 23-1-101(9)(A). Further, the line must also be "to or for the public for compensation." Clean Line had no contracts for public utility service with any utility, including Arkansas utilities. With no assets or customers, the commission rejected Clean Line's application. Michael Skelly, Clean Line's co-founder and chief executive, said the company decided to seek approval under section 1222, rather than dispute the definition of a public utility in Arkansas because "changing laws is quite a Herculean task." Jeffrey Tomich & Kristi E. Swartz, *DOE Agrees to Involvement in Clean Line Transmission Project*, EnergyWire (Mar. 20, 2016), *available at* http://www.eenews.net/stories/1060034661. Skelly and other wind industry supporters believe that the Department of Energy's support will lead to thousands of construction jobs and millions of dollars in tax benefits for all the states involved. *Id.* A delegation of Republican congressmen from Arkansas released a statement following the Department of Energy's record of decision approving Clean Line, describing it as "unprecedented executive overreach." As section 1222 grants siting authority to the Department of Energy, the congressmen believe the approval of the line "forgo[es] the will of the Natural State and hand[s] over the historic ability of state-level transmission control" to the Department of Energy. Arkansas Delegation Denounces DOE Clean Line Approval, Press Release (Mar. 25, 2016), *available at* https://westerman.house.gov/media-center/press-releases/arkansas-delegation-denounces-doe-clean-line-approval. Energy Policy Act section 1222 recognizes that states retain primary authority over transmission citing. However, the act also provides siting authority to the Federal Energy Regulatory Commission (FERC) if, along with other conditions, the state "withholds approval for more than a year." Section 1221 of EPAct 2005, 42 U.S.C. 16421. The delegation from Arkansas has planned to investigate and review the passage of the decision, and refute it by "any avenue necessary."

The delegation also references the Assuring Private Property Rights over Vast Access to Land Act they introduced last year. APPROVAL Act, H.R. 3062, 114th Congress (2015–2016), *available at* https://www.gpo.gov/fdsys/pkg/BILLS-114s485is/pdf/BILLS-114s485is.pdf. The act, introduced by Senators John Boozman (R-AR) and Tom Cotton (R-AR), directs DOE to obtain approval from a governor and state public service commission prior to any use of section 1222 and subsequent use of eminent domain. Supporters believe it "provides flexibility and empowers our states by ensuring they have the final say on eminent domain." Arkansas Delegation Introduces APPROVAL Act in House, Press Release (July 15, 2015), *available at* http://womack.house.gov/news/documentsingle.aspx?DocumentID=398564.

If the Secretary of the Department of Energy deems a geographic area a "national interested corridor," Energy Policy Act section 1221 (Federal Power Act section 216) confers upon the Federal Energy Regulatory Commission (FERC) "backstop" federal authority to permit the siting and construction of new or modified interstate electric transmission lines. Peter Behr, *Industry*

Hears Details of New FERC Energy Strategy, N.Y. Times, Sept. 7, 2011, *available at* http://www.nytimes.com/cwire/2011/09/07/07climatewire-industry-hears-details-of-new-ferc-energy-st-69363.html?pagewanted=all. In *Piedmont Environmental Council v. FERC*, 558 F.3d 304, 325 (4th Cir. 2009), this authority was challenged. The case addressed FERC's proposed regulations implementing this authority and viewed its scope more narrowly than FERC had proposed. The court addressed one condition of FERC's backstop authority pursuant to Federal Power Act section 216, specifically, when a state has "withheld approval for more than 1 year after the filing of an application." Energy Policy Act (2005) § 1221 (C)(i) (42 U.S.C. 16421). The Fourth Circuit held that FERC's backstop siting authority only applied when the state took no action at all during the prescribed one-year period; it rejected FERC's argument that FERC's authority included situations where the state had rejected a project, as Arkansas had done in the Clean Line case. However, the court also held that if a state commission had "project-killing" conditions on its permit, then FERC would have authority. Arkansas' State Commission rejected Clean Line's application because it did not meet their statutory definition of a public utility, which Clean Line considered a project-killing condition.

The Clean Line Transmission Project, although the first of its kind and celebrated by many, will face inevitable legal challenges. Critically important is the federal government's ability to use condemnation to acquire land for the project if the project sponsors are unable to acquire the needed land voluntarily. Congressmen in several of the states affected have vowed to refute the federal government's authority and work to protect what they believe is an inalienable state right. The future of such projects remains uncertain, although the addition of the controversial section received bipartisan support.

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SUPREME COURT AFFIRMANCE OF FERC'S DEMAND RESPONSE RULE MAY STRENGTHEN FERC'S POWER TO REGULATE WHOLESALE UTILITIES

Rebecca E. Smith

On January 25, 2016, the Supreme Court, reversing a D.C. Circuit Court's May 23, 2014, decision, upheld the Federal Energy Regulatory Commission's "demand response" rule. *FERC v. Electric Power Supply Assoc.*, 136 S. Ct. 760 (2016), *rev'g*, 753 F.3d 216 (D.C. Cir. 2014) (*EPSA* case). FERC's rule requires wholesale electric market operators to compensate large wholesale electricity consumers (called "demand response providers") that reduce their energy use during high-energy demand periods. *See Demand Response Competition in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16658 (codified at 18 C.F.R. § 35.28(g)(1)(v)). FERC's rule requires that demand response providers be paid the same price as is paid to generators for producing more energy.

The *EPSA* case is viewed as a win for the Obama administration and clean energy advocates. Environmentalists benefit because demand response programs decrease air pollution, reduce the need for power plants, and allow for increased clean energy resources. Consumers will pay lower electricity rates and receive more reliable service during periods of high demand. On the other hand, the Court's ruling is interpreted negatively for power generators, as demand response programs lead to decreased profits. The Court's decision provides clarity to all affected parties by affirming that demand response is here to stay, introducing a new chapter in the ever significant story of federalism and FERC's power to regulate wholesale utilities.

Background: The FPA and Demand Response

FERC promulgated the demand response rule under the Federal Power Act (FPA). The FPA authorizes FERC to regulate, among other things, the interstate wholesale sales of electric energy, including wholesale electricity rates and rules or practices "affecting" such rates. The FPA leaves for the states the regulation of retail sales and intrastate wholesale sales. It does so by expressly removing from FERC's jurisdiction all sales of electricity other than wholesale sales in interstate commerce. Against this statutory framework, the *EPSA* case presented a FERC rule that regulates the wholesale price for a commodity—demand response—that reflects retail customer decisions not to purchase electricity. Given that the wholesale and retail markets in electricity are inextricably linked, the Court had to decide the extent of FERC's power to regulate rates, rules, or practices affecting jurisdictional rates.

Demand response programs are not new. Wholesale market operators (nonprofit entities FERC created to manage wholesale markets) started using them 15 years ago due to peak energy demand creating extremely high prices and threatening service problems from grid overload. During some peak times, wholesale market operators can provide electricity more cheaply and reliably by paying users to decrease their consumption instead of paying power plants to increase production. When Congress encouraged demand response practices in the 2005 Energy Policy Act, FERC began issuing rules regulating demand response in organized wholesale markets.

The rule at issue here, order no. 745, requires market operators to pay the same price to demand response providers for conserving energy as to generators for producing it, as long as it passes a "net benefits test" to ensure that accepted bids save consumers money. The Electric Power Supply Association (EPSA) and four other energy industry associations challenged the rule on two issues: whether the FPA permits FERC to regulate demand response, and whether FERC failed to adequately explain why demand response providers and electricity producers should be paid the same amount.

The Court of Appeals for the District of Columbia Circuit vacated the rule in a 2-1 decision. The D.C. Circuit held that FERC exceeded its FPA authority by directly regulating the retail market by "luring . . . retail customers" into the wholesale market, and causing them to decrease "levels of retail electricity consumption." It also held that the rule's compensation scheme is arbitrary and capricious under the Administrative Procedure Act because FERC failed to adequately explain its decision to pay the same rate to consumers and generators.

The Supreme Court's *EPSA* Decision

The Supreme Court upheld FERC's wholesale demand response rule, reversing the D.C. Circuit in a 6-2 vote. The Court held that FERC did not exceed its FPA authority in promulgating the rule and that the compensation scheme was not arbitrary and capricious. Justice Kagan wrote the majority opinion, joined by Chief Justice Roberts and Justices Kennedy, Ginsburg, Breyer, and Sotomayor. Justice Thomas joined Justice Scalia's dissent, and Justice Alito recused himself.

The majority held FERC acted within its authority under the FPA in promulgating the demand response rule for three reasons. The rule (1) directly affects wholesale rates, (2) does not regulate retail sales, and (3) aligns with the goals of the FPA in protecting against excessive prices.

First, the Court held that the demand response practices that the rule regulates directly affect wholesale electricity rates, adopting the D.C. Circuit's limiting principle that a practice must "directly affect the wholesale rate" under the FPA's "affecting" language. The FPA provides that "[a] ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate transmission or wholesale sales—as well as "all rules and regulations *affecting* or pertaining to such rates or charges"—must be "just and reasonable." 16 U.S.C.S. § 824d(a) (emphasis added). Moreover, if "any rate [or] charge," or "*any rule, regulation, practice, or contract affecting such rate* [or] charge[,]" fails to meet that standard, the

Commission shall determine what is “just and reasonable” and “fix the same by order.” 16 U.S.C.S. § 824e(a) (emphasis added). The Court ruled that the statutory standard was met here because the formula for compensating demand response lowers wholesale electricity prices. As the Court explained, “[w]holesale demand response . . . pays consumers for commitments to curtail their use of power, so as to curb wholesale rates and prevent grid breakdowns.” 136 S. Ct. 760, 769.

Second, the Court rejected the claim that the rule regulates retail sales in violation of the FPA. 16 U.S.C.S. § 824(b). FERC has sales jurisdiction over wholesale sales (i.e., sales for resale) in interstate commerce. But, with exceptions not applicable here, the statute also excludes from FERC’s sales jurisdiction “any other sale of electric energy. . . .” *Id.* But the Court held that FERC’s rule did not constitute regulation of retail sales, which the FPA leaves to states. “[A] FERC regulation does not run afoul of [the FPA] just because it affects—even substantially—the quantity or terms of retail sales.” The Court emphasized that every aspect of the rule “happens exclusively on the wholesale market and governs exclusively that market’s rules.” Additionally, FERC’s reasons for regulating demand response are only about improving the wholesale market through reduced prices and enhanced reliability.

Third, the Court reasoned that holding FERC’s rule outside its authority would undermine the FPA’s purposes of protecting against excessive prices and ensuring effective transmission of electric power. The Electric Power Supply Association (EPSA), an industry trade group that advocates on behalf of power suppliers, took the position that neither FERC nor the states have authority to regulate wholesale demand response. But that, the Court said, would leave wholesale demand response programs with no jurisdiction to regulate them, which the FPA requires. So adopting EPSA’s position would abolish wholesale demand response programs. “We will not read the FPA, against its clear terms, to halt a practice that so evidently enables [FERC] to fulfill its statutory duties of holding down prices and enhancing reliability in the wholesale energy market.”

After upholding FERC’s authority, the Court held that the compensation formula—paying demand response providers at the same rate as generators—was not arbitrary and capricious. The Court said it must uphold a rule if the agency has “examined the relevant considerations and articulated a satisfactory explanation for its action, including a rational connection between the facts found and the choice made.” The Court added that “nowhere is that more true than in a technical area like electricity rate design.” The Court concluded that FERC engaged in reasoned decision making by providing reasons supporting its position and responding to the proposed alternative.

In dissent, Justice Scalia (joined by Justice Thomas) argued that the FPA prohibits FERC from regulating the demand response of retail purchasers of power. He said the rule regulates retail sales because the demand response participants are retail customers in that they purchase electric energy only for their own consumption. He claimed they are thus excluded from the FPA’s definition of wholesale as “a sale of electric energy to any person for resale.”

Implications for the Future

The Court’s holding removes the uncertainty over wholesale demand response that the D.C. Circuit Court’s decision created. As the Court pointed out, demand response programs are consistent with national energy policy. 136 S. Ct. 760, 770. It is generally accepted that demand response provides utilities with a valuable tool to balance variable electric generation, such as wind and solar, with customer energy demands. Pursuant to FERC’s rule, regional market operators must pay demand response providers the same amount to conserve electricity as they would pay generators to produce it. *Id.* The clarity provided by the *EPSA* decision will allow wholesale demand response programs to continue to expand.

EPSA influenced the Court's April 19, 2016, decision in *Hughes et al. v. PPL EnergyPlus LLC et al.* (Case Nos. 14-614 and 14-623) involving Maryland's authority to incentivize local electric generation through retail utility power purchase contracts. Lower courts had found the contracts set a retail price under a mechanism that affected wholesale rates, and therefore infringed upon FERC's power to regulate wholesale sales. In affirming the Fourth Circuit, the Court, in part, cited *EPSA*, "The FPA leaves no room either for direct state regulation of the prices of interstate wholesales or for regulation that would indirectly achieve the same result." Slip op. at 12. As a result, *EPSA* may strengthen FERC's power over states to regulate contracts and practices that do not constitute retail sales and which directly affect wholesale electricity rates.

From a jurisprudential perspective, the *EPSA* case further defines and expands FERC's authority to regulate the electric grid. The Court made clear that FERC may issue rules and regulations regarding the operation of the wholesale market even if they substantially impact retail markets. FERC's authority thus includes setting wholesale rates, changing wholesale market rules, allocating electricity between wholesale purchasers, and taking "virtually any action respecting wholesale transactions." Yet, further clarification is needed to elucidate the roles to be played by the federal government and the states in this evolving energy marketplace.

Rebecca E. Smith *is a third-year law student at the University of Chicago Law School.*

ENERGY INFRASTRUCTURE, SITING, AND RELIABILITY CHAIR MESSAGE

Roger Feldman and Jason D. Gellman

EISR has been working hard to put together programs of interest to its respective members. EISR recently held a Quick Teleconference Program, *Innovative Responses for Clean Power Plan (CPP) SIP Implementation*, on February 4, 2016. EISR also joined forces with the Environmental Law Institute to present *The Circular Economy: Regulatory and Commercial Law Implications* in Washington, D.C., on February 23, 2016. Special thanks to Kim Johnson and Roger Feldman for putting those programs together.

EISR Committee members Manish Patel and Yvonne Castillo are also working to put together a program later this year on federal net-zero energy projects. Stay tuned for more information on this program, as EISR continues to work toward greater visibility and providing more content to its members. Along those lines, we changed the name of this committee in 2015 in order to broaden its scope and explore more topics that affect issues of interest to our members. EISR addresses legal issues that relate both to dealing with the changing profile of the electric power industry's facility requirements and the similar types of issues that affect the siting, reliability, and resilience of facilities financed or operated on a public or a public-private basis. We have teamed with GPSI to present a total of six articles for this joint newsletter addressing diverse topics of current relevance within the broad range of interests to members of each committee. One of the objectives of EISR is to begin to translate to text the valuable substantive presentations that are made at virtually all of our committee meetings into our broadly circulated publications as well. This newsletter represents an important first step in this ongoing process. We seek additional input and participation from our members, especially as we look toward the 2016–17 ABA year.

Special thanks to EISR Committee Vice Chairs, Newsletters, Manisha D. Patel and Christina Baker, GPSI Co-Chairs Douglas Canter and Jessica Chiavara, and GPSI Vice Chairs, Will Yon and Shane Prate, for all of their hard work and diligence to put this newsletter together. Cheers!

Roger Feldman *and* **Jason D. Gellman** *are co-chairs of the Energy Infrastructure, Siting, and Reliability Committee. Roger may be reached at rogerfeldman@andrewskurth.com and Jason at jgellman@swlaw.com. Please visit the committee website at http://apps.americanbar.org/dch/committee.cfm?com=nr252000.*

GOVERNMENT AND PRIVATE SECTOR INNOVATION CHAIR MESSAGE

Doug Canter and Jessica Chiavara

Government-private sector collaboration has fostered innovation and new technologies in renewable energy, energy efficiency, carbon reducing infrastructure, and other actions consistent with sustainability. Government-private sector collaboration can occur through formal joint public-private partnerships, such as the municipal P3s discussed by Devin Ryan's article in this issue. Government-private sector collaboration also can occur through government regulation or other decisions, often in combination with actions to foster private markets. The articles in this issue about the relationship of carbon trading and the Clean Power Plan, the Department of Energy's involvement in the Plains and Eastern Clean Line project, and the impact of the Supreme Court's decision in *FERC v. Electric Power Supply Association* touch on loose forms of joint government and private sector partnerships.

Against the backdrop of the broad area of collaborative government and private sector actions to promote sustainability, GPSI has sponsored a variety of programs over the past two years. The committee has addressed state green banks, water infrastructure financing, solar power securitization, crowd funding as an alternative approach to financing wind and solar projects, public power partnerships to expand energy efficiency, and the Clean Power Plan.

With rapid advances in smart growth and renewable energy technologies, governments at all levels have increasingly looked to partner and rely upon the private sector. We encourage you to participate in our programs, submit to our publications, and explore our existing resources. Please share your stories about government and private sector initiatives that promote energy efficiency, renewable energy, green building, storm water management, and other sustainability projects. We hope you enjoy this joint newsletter and look forward to your future participation on GPSI programs and publications.

Doug Canter *and* **Jessica Chiavara** *are co-chairs of the Government and Private Sector Innovation Committee. Doug may be reached at dcanter@postschell.com and Jessica at jesschiavara@gmail.com. Visit the committee website at http://apps.americanbar.org/dch/committee.cfm?com=NR350550.*

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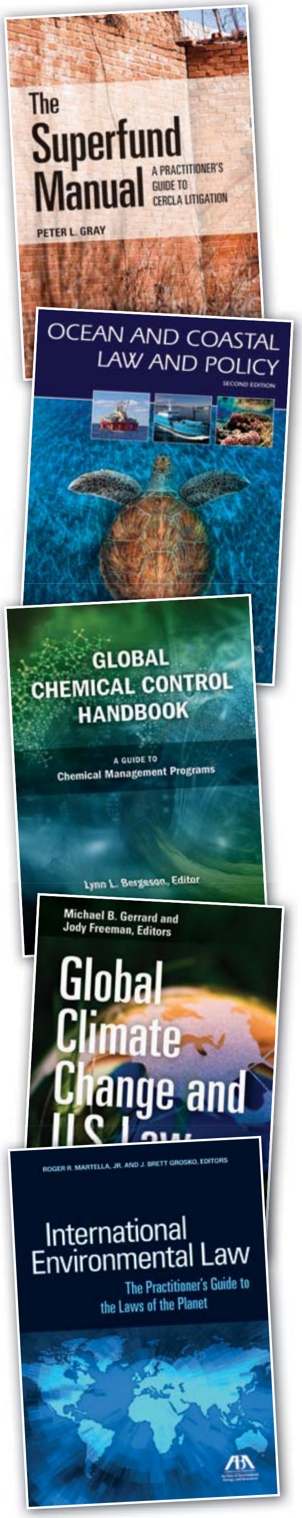

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