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The Clean Power Plan and the "Future-Ready" Utility

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RESOURCES FOR THE FUTURE

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Abstract

This paper explores the synergies between two transformational forces—implementation of the Clean Power Plan and the advent of the "utility of the future"—that could lead to a lower-carbon electric grid with more options and new services for electricity customers. The paper reviews key issues that will shape the transition to new utility market and regulatory structures and finds that some of the same principles that will guide policymakers on the design of these structures can help shape decisions on compliance pathways for the Clean Power Plan. The paper recommends a "future-ready" approach for the Clean Power Plan that will adapt to different market and regulatory structures. This approach includes a mass-based emissions target that covers all sources in the power sector and transparent allowance distribution that accommodates state priorities and provides a level playing field for incumbent utilities and third-party market participants.

Key Words: Clean Power Plan, distributed energy resources, performance-based ratemaking, electric distribution system, allowance distribution, emissions trading

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1. Introduction

The Clean Power Plan will be implemented at a time when the United States power sector is undergoing dramatic changes. These changes are driven by flat or declining electricity demand caused by more efficient use of energy, low natural gas prices, and growing penetration of distributed energy resources (DERs). Changing market conditions will impact the financial health of utilities and will require innovative regulatory structures to accommodate new roles for utilities, third-party providers of energy resources and services, and electricity customers. Market changes will also lead to significant investment and profit opportunities, which will raise the question of how much of this new economic activity should occur in the regulated utility sphere and how much in deregulated markets. A few states are considering reforming regulatory approaches to address this evolving market environment, which is sometimes referred to as the "utility of the future." Meanwhile, most states are watching to see how cutting-edge regulatory experiments progress, while exploring more incremental modifications to existing regulations and market structures.

There has been significant analysis and discussion of the Clean Power Plan and the utility of the future as distinct topics, but much less focus on how the two forces will interact. This paper explores the synergies between these two transformational trends that, in combination, could lead to a lower-carbon electric grid with more options and new services for electricity customers. This paper recommends a "future-ready" approach for the Clean Power Plan that will accommodate different market and regulatory structures. The main findings of the paper are:

- Penetration of new technologies and changes in energy markets, which are happening regardless of the Clean Power Plan, will require reform of regulatory and market structures. State policymakers will need to address numerous thorny issues, such as how to align utility financial incentives with public policy objectives, how to value and allocate the costs and benefits to the electric system of new technologies and services,

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and how to provide a level playing field for third-party providers of energy resources and services.

- Some of the same principles that will guide policymakers on the design of new regulatory and market structures can be adapted to help shape decisions on compliance pathways for the Clean Power Plan and can make compliance easier and less costly. These guiding principles include:
    - **provide a transparent price signal** through a large and liquid multi-state market that doesn't require the verification of the tradable commodity on a case-by-case basis;
    - **minimize complexity** through proven market-based structures that avoid extra administrative steps;
    - **create a level playing field** among market participants by providing access to allowances for incumbents and new entrants and by avoiding market distortions caused by unequal treatment of existing and new electric generating units (EGUs);
    - **foster innovation** by allowing new technologies and combinations of technologies to be deployed for emissions reductions without the need for additional monitoring, reporting, and verification (MR&V) protocols and procedures under the Clean Power Plan;
    - **accommodate state and regional priorities** through complementary policies that achieve state energy policy goals, including achievement of low-carbon energy strategies and comprehensive transmission planning; and
    - **provide flexibility to adapt to a wide range of market and technology scenarios** through a compliance structure that accommodates uncertainty and change.
- When these principles are applied to Clean Power Plan design choices, the best option is a mass-based target that covers both new and existing sources, essentially the classic structure adopted for the successful SO_2 trading program 25 years ago. This option sets an explicit price on CO_2, minimizes complexity and market distortions, and facilitates a variety of potential technologies, market changes, and state policy priorities.
- In addition to this basic program architecture, state policymakers should consider transparent allowance-distribution approaches that support state policy objectives and

provide a level playing field for incumbent utilities and new entrants, which may include new players on the "distribution edge"[1] of the electric grid.

Section 2 of this paper looks at the market, technology, and regulatory forces leading to change in the utility sector and Section 3 summarizes proposals to address these changes. Section 4 addresses key issues that will shape the transition to new market and regulatory structures and could form the basis of new roles for utilities, third-party energy providers, and electricity customers. Section 5 describes high-level principles that could guide a path to the utility of the future. Sections 6 and 7 provide an overview of the Clean Power Plan and propose guidelines for how the Clean Power Plan might complement the broader regulatory changes that will be needed. Finally, Section 8 concludes with some thoughts on how to view the Clean Power Plan in the context of broader power sector changes.

2. The Changing Power Sector

Changes underway in the power sector will increasingly lead to new market and regulatory structures in which customers will have greater choice and play a more active role. Together with explicit policies to reduce emissions from the power sector at the state and federal levels, there are several significant market trends that are changing fuels, technologies, and energy services. First, implementation of a variety of energy efficiency standards and policies has led to slower growth in electricity sales (Satchwell et al. 2015). Growth in electricity consumption has dropped from 9.8 percent per year in the 1950s to 0.7 percent per year since 2000, and demand has begun to level off over the past decade. Power sales also have declined in six of the seven years between 2007 and 2014 (NACAA 2015). The US Energy Information Administration (EIA) projects an average growth rate of 0.8 percent per year to 2040 under its AEO 2015 reference case, which does not include the effects of the Clean Power Plan (US EIA 2015).

Second, increased penetration of DERs is reducing market share for utilities in some regions, as third parties or electricity customers implement smaller-scale energy resources that

[1] The term "distribution edge" is defined as "the interface between the electricity distribution system operated by utilities and the rapidly growing portfolios of energy assets, control systems, and end-use technologies at or near customers' premises." (RMI 2013.)

are not owned by utilities.[2] In the past few years, there has been a significant drop in the cost of distributed energy resources. A Lawrence Berkeley National Laboratory report of residential and non-residential solar PV systems found that, starting in 2009, installed prices for both residential and non-residential PV systems declined by an average of 13–18 percent per year across three customer segments (Barbose and Darghouth 2015). A Greentech Media study found that residential solar PV costs have dropped by almost 50 percent in the past five years and are projected to fall an additional 60 percent by 2030 (Kann 2015). The costs of energy storage are also declining, although a recent study found that behind-the-meter energy storage is not yet competitive with other energy supply alternatives (Lazard 2015). Total energy storage capacity (behind-the-meter and utility scale) is expected to double this year and could increase fourfold to 850 MW by 2019 (Lacey 2015).

Third, a variety of new grid technologies will facilitate changes in how the grid operates, how consumers use energy, and how utilities and their customers interact (Fox-Penner 2014). The electric grid is changing from a system of centralized power plants where power flows in one direction through transmission and distribution lines to consumers, to a more complex system where information and electricity flow back and forth from the grid to consumers, guided by "smart" technologies, powerful "big data" analytical tools, and device-to-device communications (sometimes known as "the internet of things.") Ultimately, increased penetration of electric vehicles could provide an additional use for smart grid technologies, as vehicles become both a new source of demand for electricity and a potential form of energy storage for the grid.

The dramatic changes described above will create significant growth and profit opportunities for the energy industry. However, they are also potentially at odds with the financial incentives built into traditional regulatory and market structures (Kind 2013; Fox-Penner 2014; Satchwell et al. 2015). Under the traditional paradigm, utilities earn a return, based on their capital investment in power plants or grid infrastructure, to cover their costs of serving customers and to earn a rate of return for their shareholders. If customers or third parties provide assets for the grid, the utility and its shareholders lose the opportunity to earn a return on those assets (NACAA 2015). In addition, most of the utility's revenue collection is based on electricity

[2] DERs are here defined broadly to include a variety of resources, such as residential and commercial solar PV, energy storage, microgrids, fuel cells, combined heat and power (CHP), and demand-response technologies and programs.

sales, which aligns its financial interests with maximizing sales of electricity.[3] Thus, in simple terms, and absent other policies, it has historically been in the interest of most utilities to build new assets and sell more electricity.

The recent trends described above create a dilemma for utilities because flat or declining growth in sales, coupled with the need for fewer centralized generation resources, affects their profitability. Meanwhile, if customers decide to generate their own electricity (or contract with third parties for energy generation) the fixed costs of utilities will be spread among fewer and fewer customers, thereby driving a need to increase electricity rates to recover these costs. In theory, these higher rates could create a continuing cycle of further defections from the grid followed by additional rate increases (Kind 2013).

Of course, this scenario assumes that utilities and their regulators do not adapt to these changes. As discussed in the next section, state regulators, utilities, third-party energy providers, and other stakeholders are engaging in analysis, regulatory proceedings, and stakeholder processes to address these changing market conditions.

3. New Market and Regulatory Structures

While increased energy efficiency and distributed technologies are eroding the traditional pillars of utilities' financial health, these same forces are creating the technological basis for new structures to provide electricity and customer services. This dual impact—erosion of sales and less need for large centralized generation on the one hand and greater capability and customer demand for "distribution edge" technologies on the other—has led to the exploration of new market and regulatory structures. It has also led many utilities to adapt their business models to address their customers' interest with a wide array of energy services.

A 2015 GTM Research paper notes that the push for new market structures can come from three (sometimes overlapping) sources: customers, regulators, or energy providers. Electricity customers may drive change in areas with "high residential electricity rates, substantial demand charges for commercial and industrial customers, an abundance of renewable

[3] While this has been a traditional model for many utilities, it is important to note that 15 states have "decoupling" mechanisms for electric utilities that break the direct link between revenues and sales, and additional states have lost-revenue adjustment mechanisms or performance incentives for energy efficiency (Gileo et al. 2015). Brennan (2010) notes that decoupling and related policies have the political benefit of neutralizing utility opposition to energy efficiency policies.

resources, and a more progressive, tech-savvy customer base." Regulators may be the motivating force where they have identified problems with the status quo and factors such as "an aging, strained infrastructure or heightened resilience requirements [that] may drive consideration of new approaches." Finally, in some markets, the utilities themselves may be at the forefront of offering new products and approaches to facilitate DERs and other distribution-system products (GTM 2015).

Not surprisingly, stakeholders have different visions of what the distribution grid will look like, how it will be run, and by whom. Various analysts have suggested a spectrum of approaches (Fox-Penner 2013; Lehr 2015; RMI 2013; Corneli and Kihm 2015). These range from incremental tweaks to the current regulatory model to more fundamental changes. For example, on one end of the spectrum, former Federal Energy Regulatory Commission (FERC) Chairman John Wellinghoff has suggested an entirely new entity—the independent Distribution System Operator—to run the distribution grid (Trabish 2014). Others have suggested that the utilities could take the lead role in running the platform for DERs (Kind 2015). As will be discussed in the next section, there is also debate on who should own and operate DERs, including the management systems that allow DERs to be integrated with the larger utility distribution system (Corneli and Kihm 2015).

In response to changing market conditions and the demand of electricity customers for DERs and other energy services, some states are exploring how distributed energy resources can be incorporated into the grid and what regulatory changes might be needed to facilitate this:

- New York has established an effort called Reforming the Energy Vision (REV) that is developing new approaches to utility regulation. In a July white paper, the state public service commission (PSC) proposed that New York's utilities would run a distribution system platform that would allow customer-side technologies to be incorporated into the overall grid. The Commission also proposed new approaches for aligning utility financial incentives with New York's reform objectives (NYPSC 2015).
- California has ordered its distribution utilities to develop plans that "begin the process of moving the IOUs toward a fuller integration of DERs into their distribution system planning, operations, and investment" (CPUC 2014). More specifically, the commission asked its utilities to identify approaches for valuation of distributed resources, including identifying how the location of DERs on their systems affects that value. Utilities were also asked to propose demonstration projects that would support their approaches for valuing DERs (Trabish 2015). Finally, California has mandated that its three investor-

owned utilities add 1.3 GW of energy storage by 2020, with the goal of transforming the energy storage market (CPUC 2013).

- Minnesota utilities and other stakeholders have launched a collaborative effort called the e21 Initiative that is looking at how new ratemaking, planning, and other regulatory structures could facilitate a new utility model in the state. The initiative, led by the Great Plains Institute, has issued a Phase I report with high-level principles that would guide changes, as well as some specific consensus recommendations about ratemaking, planning, and process reforms (GPI 2014).

4. Key Issues for the Utility of the Future

While the details of state approaches will differ as they address new market developments, there are some fundamental issues that will need to be considered. These include:

- Who should own and operate distributed technologies and related services?
- How should emerging technologies and services be valued and who will bear the costs and risks of different investments?
- How should utilities be regulated in their new roles?

While a full exploration of these questions is beyond the scope of this paper, the following sections provide a short summary of the relevant issues.

4.1 Who Should Own and Operate DERs?

As new technologies and services are developed that could be owned and operated by utilities, third-party energy providers, or electricity customers, state regulators are considering who should own and operate DERs. In the traditional market structure, utilities have a monopoly over electricity distribution and a duty to serve customers at just and reasonable rates. However, some analysts have expressed concerns about whether utilities can provide the most innovative and lowest-cost approaches to deploying new technologies. Moreover, some observers argue that incumbent utilities have an incentive to use their regulated status to discriminate against rivals by favoring their own DER affiliates. For example, a utility might provide better access to backup power for customers who connect to its DER subsidiary (Brennan 2014). As one proponent of this view has noted, there is a conflict of interest in allowing utilities to control the distribution platform that is analogous to “an air traffic controller that also owns an airline” (Trabish 2014).

Others analysts contend that, with appropriate oversight by regulators, utilities can equitably provide an open platform that facilitates DERs provided by a variety of participants. Kind (2015) argues that utilities should continue to “be at the center of integrating resources and stakeholder collaboration through accountability and incentives.” O’Boyle (2015) discusses three models of owning and operating DERs—utility-centric, third-party-centric, and customer-centric—and finds that all three can work if utility regulators ensure that financial incentives are aligned with the public interest. Under a utility-centric model, utilities would pay for and own DERs and would recover costs and assume risks through ratemaking. Under the third-party-centric model, DERs could either be operated in conjunction with utilities through utility-funded programs to provide services. Alternatively, DERs’ services could be aggregated and sold to utilities or into wholesale markets. The customer-centric model would focus on customer-owned and software-operated systems, which would respond to electricity rates and manage electricity use. The author notes that these three models are not mutually exclusive; each can work in conjunction with the others.

Finally, Corneli and Kihm (2015) raise the issue of whether utilities or “competitive DER providers and optimizers” should run distributed energy resources management systems (DERMS), essentially information systems to maximize the value of DERs to customers and utilities. They debate which of these two types of entity would be better suited to integrate DERs into the distribution system and maximize the value of DERs for customers.

4.2 How Should New Distribution Edge Services be Valued?

A critical component of evolving regulatory approaches is how to value the new electric system services provided by emerging technologies so that they can be incorporated appropriately into utility planning and ratemaking. This debate has been particularly prominent for rooftop solar, where there has been controversy over the rate paid to customers who sell excess electricity back to their utilities under net energy metering (NEM) programs. In the context of solar rooftop resources, critics of NEM programs have argued that, while consumers with solar panels can sell back electricity to the grid at the full retail rate, they should also be responsible for sharing in the costs of maintaining the electric grid, either through paying a fixed charge or through receiving less than the retail rate. Otherwise, critics say, the costs of these programs are shifted to other ratepayers who are not participants in the solar programs (Craver 2013).

On the other hand, there is a variety of benefits to the electric system provided by distributed energy that may not be determined in markets or reflected in the current utility regulatory structure. These benefits could include avoided energy costs, avoided capacity costs for generation, reduced costs for ancillary services, lower line losses on the transmission and distribution system, and reduced investments in transmission and distribution facilities (Beach and McGuire 2013). Linville et al. (2013) argue that DERs should be compensated to reflect all relevant costs and benefits and they note that state regulators should develop policies that recognize the specific circumstances of their states and utilities. [4]

While much of the attention to valuing DERs has focused on rooftop solar, the issue also applies to other grid edge technologies, including demand response and energy storage, as well as combinations of technologies (e.g., distributed solar plus storage). In the case of storage, a Rocky Mountain Institute (RMI) study found 13 different uses for battery energy storage. The study recommends changes to ratemaking structures to reflect the value of the full range of energy storage uses and benefits to make "utilities indifferent to the distinction between distributed and centralized resources" (RMI 2015). More generally, in response to the growing integration of DERs, Perez-Arriaga and Bharatkumar (2014) propose a framework to identify key drivers of distribution system costs, and allocate costs according to profiles that capture the contribution to total system costs of each grid user.

Finally, some commentators have argued that the difficulty of valuing DERs reflects a broader disconnect between traditional ratemaking practices and new and evolving technologies that are valued in different ways by different consumers. Hu et al. (2015) contend that "the real problem is that pricing mechanisms are too blunt and rigid; prevailing regulation cannot dynamically balance the benefits of distributed resources to the grid and grid users." Kind (2015) calls for a broad reform of utility regulation that "shifts regulatory oversight from being administered primarily through periodic rate cases to a forward looking focus on planning, accountability, and financial incentives for results achieved." These types of new regulatory approaches are discussed in the following section.

4.3 What Types of Regulatory Innovations will be Necessary?

If traditional cost-of-service regulation is no longer aligned with emerging utility market structures, what types of new approaches are necessary? Some analysts believe that performance-based rate-making (PBR)—an approach that ties utility profits to achievement of

[4] For a comprehensive framework for valuing costs and benefits of distributed energy generation, see Woolf et al., 2014.

specific targets or benchmarks—will fill the void.[5] Aggarwal and Burgess (2014) note that PBR "starts with the objectives that matter most to customers, utilities, regulators, and other power sector industry participants," such as cost minimization, reliability, environmental performance, and customer service. While creating incentives for specific objectives, PBR can also decouple revenues from sales, a feature that can address utility concerns about revenue erosion due to increased energy efficiency or deployment of DERs.[6] Aggarwal et al. (2015) note that new financial mechanisms should be developed to ensure that utilities attract capital and achieve adequate returns on investment as they provide additional value to customers and society.

In the past, regulators have experimented with PBR on a number of utility issues, including nuclear unit performance and energy efficiency programs. Other possible incentives related to modernizing the grid could include a share of the value of services uninterrupted by outages or a share of savings from optimizing voltage on the distribution system (Malkin and Centolella 2014). New York's PSC staff has proposed a series of incentive mechanisms that would be measured and monetized as part of the NY REV process. These mechanisms include peak reduction, energy efficiency, customer engagement and information access, affordability, and interconnection (NYPSC 2015).

While some US states have experimented with PBR and the NY REV process includes elements of performance-based regulation, the United Kingdom's Office of Gas and Electric Markets (Ofgem) has adopted a comprehensive PBR framework for regulating utilities. The approach, known as RIIO ("Revenue set to deliver strong Incentives, Innovation and Outputs,") is essentially a "performance-based revenue cap with decoupling" (Fox-Penner et al. 2013). Under RIIO, each of the UK's utilities must submit a business plan with a set of performance metrics and incentives that reward over-performance and penalize under-performance.

5. Principles for the Utility of the Future

Several analysts have put forward high-level principles that could guide the development of new market and regulatory constructs. For example, Hu et al. (2015) provide a conceptual framework that they call "grid neutrality" for addressing the transition. The concept, which is analogous to "net neutrality" for the Internet, views the electric grid as a fair and open platform

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[5] Whited et al. (2015) provide a thorough examination of performance incentive mechanisms.

[6] For a look at the economics of decoupling, see Brennan (2010) and RAP (2011).

that can facilitate new and innovative technologies and services. More specifically, the authors argue that the evolving electric grid should be designed with the following five principles in mind:

- empowering the consumer while maintaining universal access to safe, reliable electricity at reasonable cost;
- demarcating and protecting the commons;
- aligning risks and rewards across the industry;
- creating a transparent, level playing field; and
- fostering open access to the grid.

The authors note that, rather than supporting any specific design, these principles would help "future-proof the grid with the flexibility, resilience, and scalability to meet future needs."

With a similar goal of guiding future market and regulatory structures, RMI (2013) provides attributes for the "ideal" distribution edge platform. The authors note that different market and regulatory structures will require tradeoffs on some of these attributes but that, in general, a future structure should:

- ensure network efficiency, resilience, and reliability;
- create a level playing field for all resources;
- foster innovation;
- provide transparent incentives where necessary to promote technologies that result in social benefits;
- minimize complexity;
- enable a workable transition from traditional business models to new structures; and
- support the harmonization of business models of regulated and non-regulated service providers.

As will be discussed in Section 7 of this paper, some of these principles are directly applicable to thinking through how different designs for the Clean Power Plan can accommodate emerging utility regulatory structures.

6. The Clean Power Plan and the Electric Grid

While a few states are experimenting with new market and regulatory structures, virtually all states are faced with the more immediate set of decisions on how to implement the Clean Power Plan. This raises an important question for state policymakers and utilities: If new regulatory and market structures are imminent, how should that affect decisions about the compliance pathways for the Clean Power Plan? Section 7 of this paper will address that question directly, but first it is useful to describe briefly the main provisions of the regulations, and to review how EPA views the Clean Power Plan in the larger context of the electric power grid.

The basic provisions of the Clean Power Plan are as follows:

- The Clean Power Plan sets nationally uniform, technology-specific standards for electric generating units (EGUs), with sub-categories for coal and gas. These coal- and gas-specific standards are applied at the state level, based on the generation mix in the state, and each state has a statewide standard.
- The standards are based on three "building blocks" that are, essentially, types of technologies or approaches that could reduce emissions. They include: heat rate improvement at coal plants, shifting to natural gas generation from coal generation through increased use of existing natural gas combined cycle (NGCC) plants, and increased generation from new renewable energy.
- While the targets are based on the three building blocks, EPA has stressed that the approaches to the plan available to each state are diverse and include a wide range of options on both sides of the electric meter. One study by the National Association of Clean Air Agencies described 29 different options that could be used in state plans (NACAA 2015).
- EPA provides states with two options for the standard: a rate-based standard in pounds of CO_2/MWh, and a mass emissions standard, denominated in annual tons of CO_2.
- Each state must develop a plan for meeting the standard and may allow plant owners to determine the specific measures for compliance. States can use any measures they want to improve emissions performance, including energy efficiency and renewable energy. They can also band together with other states that have chosen the same type of target (i.e., rate- or mass-based) in trading markets.

- For states with mass-based targets, the trading commodity (allowances) is denominated in tons of CO_2. For states with rate-based targets, the trading market is denominated in emission-rate credits (ERCs), which represent MWh of energy efficiency savings and zero carbon electricity from new renewable energy and nuclear power generation. Utilities may also create ERCs from existing natural gas/combined cycle by operating at a lower emission rate than its assigned rate or by increasing generation about its 2012 levels to displace higher emitting generation. [7] For compliance, utility emissions are divided by MWh to yield an emissions rate (tons/MWh) and electric generating units must have sufficient ERCs to achieve their standard.
- The regulations require states with mass-based targets to address the potential emissions leakage that could arise from new NGCC units not covered under the target. States can address this issue through: (a) voluntarily including these new units under an expanded mass-based target; (b) an allocation-distribution approach that subsidizes existing natural gas units and new renewable energy generation; or (c) a state-specific proposal to address leakage accompanied by analysis showing that leakage is unlikely.
- There is a series of deadlines. States have to submit an initial plan in 2016, but all states can get an extension until 2018 for the final plan. Interim targets start in 2022; there are several other interim milestones between 2022 and 2030.
- If states refuse to submit a plan, or submit one that EPA deems inadequate, EPA will step in and impose a federal plan. EPA has proposed model rules for both mass-based and rate-based plans.
- To spur earlier reductions, EPA includes a Clean Energy Incentive Program, under which qualified energy resources can earn carbon allowances or credits for projects that are undertaken after their final state plans are in place and will reduce emissions in 2020 and 2021.
- EPA requires states to include a public participation process as part of the development of their state plans. The agency is also requiring states to demonstrate how they are actively engaging with communities, including low-income, minority, and tribal communities, as part of this public engagement process.

[7] For a detailed discussion of ERCs, see Peskoe (2015).

Under EPA's framework for the Clean Power Plan, the electric grid is a "complex machine," which allows states and utilities to adopt system-wide approaches rather than just plant-specific technologies (US EPA 2015a, 64769). In particular, EPA gears this approach toward compatibility with the operation of bulk power markets, and includes a number of provisions that are intended to accommodate electric system issues. These include building blocks for targets that rely on "outside the fence" measures such as renewable energy and shifting dispatch to natural gas, compliance flexibility that allows crediting of clean generation and energy efficiency, reliability provisions that encourage policymakers to take a regional approach, and different options for multi-state collaboration and emissions trading.

EPA's treatment of the electric grid is focused less explicitly on new distribution-edge technologies or the changing market conditions in the power sector. For example, the final rules do not include energy efficiency or distribution-system technologies when they set the stringency of the EGU emissions standards. However, the agency does acknowledge the importance of energy efficiency and distributed technologies for compliance. For example, EPA cites analysis from DOE and NREL that "cost-effective opportunities for distributed generation alone could satisfy one-third to over one-half of the stringency associated with [the renewable generation] building block. . . ." (US EPA 2015a, 64810).

7. A "Future-Ready" Clean Power Plan

Given the inherent uncertainty of future electric grid development, how might state policymakers think about an approach to the Clean Power Plan that would be compatible with evolving regulatory and market structures? Stated another way, what would be a "future-ready" approach for state policymakers that could address a variety of scenarios? The remainder of the paper argues that a future-ready approach starts with a mass-based target that covers both new and existing power plants, essentially the classic structure used in the successful SO_2 trading program. In addition, states should consider allowance distribution approaches that support state policy objectives and provide a level playing field for incumbents and new entrants. More specifically, and based on some of the principles discussed in section 5, the following are six high-level recommendations that could enable state plans under the Clean Power Plan to complement the broader regulatory changes that will be needed.

1. **Provide a transparent price signal** through a large and liquid multi-state emissions market that doesn't require the verification of the tradable commodity on a case-by-case basis.

2. **Minimize complexity** through proven market-based structures that avoid extra administrative steps.
3. **Create a level playing field** among market participants by providing access to allowances for incumbents and new entrants and by avoiding market distortions caused by unequal treatment of existing and new EGUs.
4. **Foster innovation** by allowing new technologies and combinations of technologies to be deployed for emissions reduction without the need for additional Clean Power Plan MR&V protocols and procedures.
5. **Facilitate state and regional priorities** through complementary policies that achieve state energy policy goals, including comprehensive transmission planning and achievement of low-carbon energy strategies.
6. **Provide flexibility to adapt to a wide range of market and technology scenarios** through a mass-based structure that accommodates uncertainty and change.

The following subsection elaborates on these guidelines and provides an assessment of how each one might guide the choice of Clean Power Plan design elements.

7.1 Provide Transparent Price Signals and Incentives

A mass-based target with allowance trading will set an explicit price on CO_2 and provide clear signals for utility planning, regardless of the new market or regulatory structures that evolve. Under the rate-based options, tradable ERCs will have a price signal denominated in MWh, including MWh of energy efficiency. However, unlike allowances under a mass-based system where the total quantity will be known from the beginning of the program, the quantity of ERCs is unpredictable because they must first be generated and verified. As will be discussed below, this is particularly challenging for ERCs from energy efficiency projects and programs, because EPA will require monitoring and verification protocols and third-party verification of MWh saved.

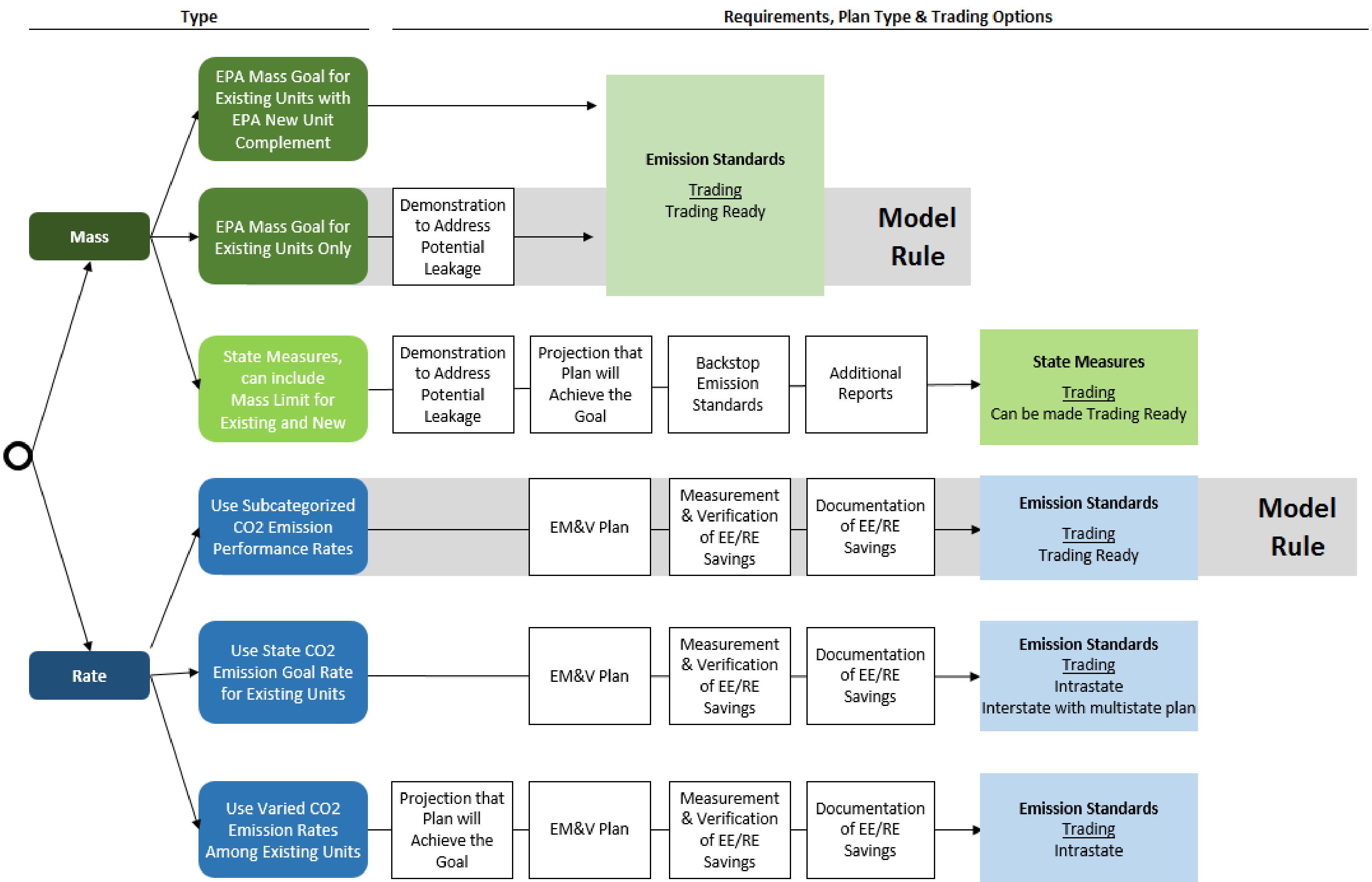
Past trading programs have shown that eliminating the need to approve or certify a trading commodity on a case-by-case basis reduces administrative and transaction costs and leads to more active markets (Rico 1995; Schmalensee and Stavins 2015). In addition, under- or over-estimates of ERCs as a result of inconsistent emissions monitoring and verification (EM&V) from state to state could lead to unequal incentives and distort ERC markets. Finally, market liquidity will also depend on the number of states that adopt mass- versus rate-based targets. If most states decide to use mass-based targets, and there are some early indications that this might be the case, the states that adopt rate-based targets may not have an adequate supply of ERCs (Inside EPA 2015). Similarly, states with utilities that generate excess ERCs may not find a large market if most states have mass-based targets.

7.2 Minimize Complexities

Given the numerous regulatory issues that will need to be addressed as state regulators decide how to update their regulatory structures for the utility of the future, it is important to build a system that minimizes complexity. In Figure 1, EPA illustrates several pathways for compliance. The top pathway shows a mass-based target that includes new units (the “new source complement”) and a “trading-ready” design in which tradable mass emissions obligations are assigned to EGUs. States and EGUs would be required to utilize an EPA-approved or EPA-administered tracking system for allowances. Although states have significant autonomy on allowance distribution under this approach, in other respects this model is virtually identical to the structure of the acid rain SO_2 trading program.

As shown in the figure, there is a more complicated process under the rate-based pathways. First, the ERC provider must submit an application to the state in which it describes the project, projects the MWh generation or energy saved, and includes an EM&V plan. Second, after the project is implemented, and in order to receive the ERC credits, the ERC provider must submit an EM&V report documenting the results of project implementation, and ensure both that the results are verified by an independent verifier and that the verification report is submitted—by the verifier—to the state. When these steps are completed, the state will issue the provider’s ERCs into a tracking system. There is no ex ante or presumptive guarantee of ERCs, and final issuance of ERCs comes only at the completion of this process.

Figure 1. States Plan Decision Tree



Source: US EPA 2015.

In contrast, EPA notes that energy efficiency "automatically counts toward compliance under a mass-based approach since it displaces fossil generation and emissions under the cap, freeing up allowances for emitting sources to trade. There is no limit on the use of energy efficiency programs and projects, and energy efficiency activities do not need to be approved as part of a state plan—therefore, Evaluation, Measurement and Verification (EM&V) is generally not required for mass-based approaches under the Clean Power Plan" (US EPA 2015b).[8]

Finally, it is important to acknowledge that many states already have EM&V procedures for energy efficiency that are used to evaluate programs for cost recovery, incentive payments, or other purposes. What is not clear, however, is whether these existing protocols and procedures will meet EPA's timing, planning, and procedural requirements. EPA has set rigorous requirements because ERCs offset generation from sources that emit CO_2. Thus, if they are not verified properly, ERCs can dilute the emissions reduction results from the Clean Power Plan (Palmer 2016). Moreover, ERCs from energy efficiency programs in some states, or from some utilities, could be subject to legal challenges under the Clean Air Act if NGOs or market participants, for example, suspect that the credits were poorly verified.

7.3 Create a Level Playing Field among Participants

As market and regulatory structures evolve, it will be important to encourage fair competition between incumbent utilities and third-party providers of DERs, energy efficiency, and other energy services. As discussed below, several aspects of the design of the Clean Power Plan could tip the balance in one direction or another, including allowance distribution approaches and leakage provisions.

Distribution of Allowances

States should consider whether allowance-distribution approaches provide a level playing field between incumbent utilities and new entrants, either third-party generators or entities on the grid edge. Fortunately, there is an extensive body of research on the distributional implications of various allowance approaches that can inform this question

[8] There would, however, be requirements for EM&V in states with mass-based targets for allowance set-aside programs that include energy efficiency, including the Clean Energy Incentive Program (CEIP) or set-asides to address leakage.

(Palmer and Paul 2015; Schmalensee and Stavins 2015; Burtraw et al. 2012). Although a full discussion of allowance distribution issues is beyond the scope of this paper, it is worth noting a few points on how the value of allowances can favor different groups:

- First, allowance value can be allocated to electricity producers, electricity consumers, and government. These options include the ability of states to create incentives for specific technologies and programs, raise revenues through auctions, use auction revenues to provide compensation directly to households through per capita payments, reduce consumer electricity costs through rebates, and offset costs for electricity producers. Allowances can be allocated directly or they can be auctioned, with the value distributed in a variety of ways (Palmer and Paul 2015). For example, states can also use revenues from auctions to fund energy efficiency and other clean energy programs. This approach has been used in the RGGI program to distribute nearly $2 billion to participating states since 2009 (Hibbard et al. 2015).[9]
- Second, allowances may be allocated based on historic generation or they may be updated periodically based on generation output (i.e., an updating, output-based allocation). To the extent that an allocation is updating, it will change future behavior by creating an incentive to produce more electricity in order to receive more allowances. This applies, for example, to the updating output-based allocation mechanism for preventing leakage from existing natural gas-fired units to new natural gas units (discussed below). It is also relevant to set-asides for incremental additions of clean energy or other specific technologies. If these types of set-asides are used, policymakers should open them both to utilities and third-party providers of clean energy and energy services to ensure a level playing field.
- Third, in the case of fossil fuel generators, direct, free distribution can be used to cushion the compliance costs of the Clean Power Plan, and some states may decide that it is desirable to use the value of allowances to ease the transition of incumbent utilities to new market structures. However, research shows that only a relatively small portion of allowance value is generally needed for this purpose, and that over-allocation to incumbents can needlessly take away allowance value

[9] While the focus here is on clean energy incentives under mass-based programs, it is important to note that, under the rate-based target compliance pathway, EPA allows third parties, such as distributed solar companies and energy service companies, to earn ERCs directly.

that could be used for other valuable social purposes (Burtraw and Palmer 2008). Moreover, it is worth noting that "grandfathering" can have a greater impact on electricity prices in regions with market-based pricing than in regions with cost-of-service pricing. This is because where there is market-based pricing, the value of the allowance will be passed along in electricity rates even if it is distributed without cost to a utility. In contrast, in cost-of-service regions, regulators may not allow the "opportunity cost" of the allowance to be passed to consumers.[10]

- Fourth, allocation value can be directed to electricity consumers through their local distribution companies (LDCs), with the condition that they rebate that value to consumers (Palmer and Paul 2015). One variation on this approach is the use of a consignment auction, such as the California cap and trade program auction, which requires LDCs to auction off a portion of their direct allocation and use the revenues for ratepayers (CARB 2015; Burtraw et al. 2012). A small consignment auction was also part of the sulfur dioxide trading program under Title IV of the Clean Air Act (Ellerman et al. 2000). This approach has the added advantage of providing a source of allowances for new entrants. A consignment auction also helps with price discovery, which can supplement price information provided by secondary markets.

Leakage Provisions

To maintain a level playing field among sources with emissions, states should avoid incentives or distortions that would shift generation to sources that are not subject to a cost of emissions. This issue arises in the Clean Power Plan because there are different requirements for new versus existing sources. New natural gas-fired units are not subject to a mass-based target under section 111(d) unless a state chooses to include them, while existing units must surrender an allowance for every ton of emissions. From a market perspective, differential treatment of new and existing sources can create distortions by giving new units a cost advantage over existing units, which can cause generation and emissions to shift ("leak") from existing to new units.

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[10] An additional implication of grandfathering concerns the treatment of allowance distributions to EGUs that shut down. If allocation is dependent on continued generation, it effectively gives incumbent generators an incentive to continue generating. See Ahman et al. (2007).

Past experience with trading programs has shown that intra-sector leakage can be minimized if all significant sources of emissions in that sector are included under the same cap (Schmalensee and Stavins 2015). EPA addresses potential leakage in the Clean Power Plan by allowing states to bring new sources under the cap voluntarily, thus creating one integrated mass-target.[11] To facilitate this approach, EPA provides a higher mass-based target for each state that includes its new units in a mass-based target. These additional tons are called the "new source complement."

If states choose not to include their new units under the mass-based target, they have the option to adopt one of two other approaches provided by EPA. First, states can address leakage through an allowance allocation approach that evens out incentives between new and existing units. Under this option, states could address leakage by creating a set-aside of allowances for an updating output-based allocation for existing natural gas units. This approach essentially subsidizes output from existing units to negate the emissions costs advantage at new units not subject to the mass-based target and a cost per ton of CO_2. An approvable allocation approach under this option would also have to include a renewable energy set-aside.[12] EPA notes that this set-aside "is expected to address concerns regarding leakage by lowering the marginal cost of production of the incented clean energy technologies" and will "make RE [renewable energy] more competitive against new sources, reducing the potential for leakage to new sources."[13]

Alternatively, states could propose their own leakage mechanism, together with a demonstration that leakage is unlikely to occur because of unique factors in their states. EPA notes that such a demonstration should be "supported by credible analysis" and could include evidence of the "presence of existing state policies addressing emission leakage [and] unique characteristics of the state and its power sector."

While it may be possible to reduce leakage through allowance-distribution approaches, this type of mechanism has some shortcomings. First, it will be difficult to predict exactly what size of allowance incentive is needed to diminish the leakage and

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[11] Because new units are not regulated under section 111(d), limits on new units would not be federally enforceable and would have to be enforceable under state law.

[12] EPA has asked for comment on whether to include demand-side energy efficiency, CHP, and other technologies in this set-aside.

[13] Proposed Federal Plan and Model Rule, Clean Power Plan at 65022.

whether the incentive provided will be too big or too small.[14] In the preamble to the proposed federal plan, EPA notes this uncertainty by requesting comment on a number of possible parameters, including the size of output-based set-asides, the rate at which allowances are allocated, and the capacity factor at which allowances should be allocated. In addition, affected EGUs will face uncertainty until the end of each compliance period regarding how many allowances they will receive for the next period, and whether the set-aside will be oversubscribed. Moreover, as proposed in the federal implementation plan and model rule, utilities would not know their output-based allocations for NGCC units until 2025 because EPA would need data from the first three years of implementation (2022–2025) to calculate the allocations. Second, the renewable energy set-aside (which may ultimately include energy efficiency and other technologies, depending on EPA decisions on the final model rule) will require the same projection, third-party verification, and ex post evaluation procedures, as described for ERCs below.

Some stakeholders have expressed the concern that adopting the new source complement could constrain growth because the additional increment of emissions allowed by EPA to cover new sources may not be big enough to cover all new emissions (Holden 2015). Adair and Hoppock (2015) note that the effect of adopting the new source complement provision depends on assumptions about future load growth and the mix of resources chosen to meet this growth. They note that adopting the new source complement provision could actually increase the number of allowances in some states. This could come about for a variety of reasons: for example, if demand growth is less that projected by EPA, if the number of coal plant retirements is greater than projected, or if growth is met by non-emitting sources such as new renewable energy or nuclear power plants. Moreover, even if utilities in some states are short on allowances, the ability to participate in a large and liquid multi-state allowances markets could limit the risk of having more emissions than allowances. This has been the lesson of previous mass-based programs such as the acid rain program.

There are also liabilities and uncertainties associated with not adopting the new source complement. Adair and Hoppock (2015) note that these include possible electricity market distortions, reduced flexibility on allowance allocation because some portion of allowances will be needed for the leakage provisions, and reduced

[14] In fact, analyses of the EPA proposal on leakage have found that the allowance incentive proposed by EPA to reduce leakage is inadequate (Burtraw et al. 2016, MJB&A, 2016).

effectiveness of actions taken to address impacts of leakage on environmental integrity. Burtraw, et al. (2016) note that the Clean Air Act calls for EPA to re-evaluate the New Source Performance Standards (NSPS) every eight years, although the agency may choose to do so at any time. Under such a scenario, new units today could be existing units in the future. The authors call for EPA to affirm a schedule for re-evaluation of the NSPS to clarify that new units would not be excluded from the existing cap indefinitely. This would create a clearer expectation of the potential long-term costs of building new electric generating units.

Finally, although EPA does not require provisions to address other types of leakage, such as leakage between states with different compliance pathways, the agency says it will monitor these issues once implementation of the Clean Power Plan begins. Based on that evaluation, "EPA will determine whether there are potential concerns and what course of action may be appropriate to remedy such concerns."[15]

7.4 Foster Innovation

The convergence of the Clean Power Plan with new utility business models could be a significant driver of innovation as companies look for new sources of revenue that don't depend on selling more electricity. As the CEO of Opower has written:

> That's the real power of the Clean Power Plan. Yes, it will lower carbon emissions, but it will also push energy companies to innovate. They'll need to keep investing in new technologies. They'll need to retool their business models for a century where the old way of doing things no longer makes sense. The long-term benefits will be bigger and better than any one rule could accomplish (Laskey 2015).

While both mass- and rate-based targets can foster innovative ways to comply, mass-based targets will be able to adapt more rapidly to innovative technologies or combinations of technologies. This is because there will be no need to create new verification protocols to calculate ERCs every time a new grid technology is deployed, nor will it be necessary to have those methods approved by EPA in plan amendments. Moreover, combinations of technologies, such as energy storage and rooftop solar panels, will automatically create emissions reduction benefits through the measured emissions reductions from power plant stacks. Combinations of hardware and software innovations

[15] Clean Power Plan rule at 64890.

will create infinite variations that would need to be verified separately under a rate-based plan. As big data analytics increasingly become a component of new energy efficiency, demand-response, and renewable energy strategies, it will be impossible to predict exactly what types of innovations will have the greatest potential for emissions reduction. Thus, it is unrealistic to assume that regulators will be able to keep up with emerging approaches and it will be important to create barriers based on the lack of approved ERC verification protocols. Similarly, incentives should not be distorted such that the most easily verified measures are adopted at the expense of less verifiable but more cost-effective or innovative measures.

7.5 Accommodate State and Regional Policies, Planning, and Priorities

A mass-based emissions target could be complemented by a variety of policies and approaches, including ramped-up state energy efficiency resource standards; utility programs for industrial, commercial, and residential energy efficiency; state building code improvements; and innovative financing policies for efficiency measures.

Moreover, under a mass-based target, states could use changes to utility regulatory structures to drive emissions reductions and lower the costs of compliance. For example, NACAA (2015) provides several examples of electricity regulatory initiatives that could constitute components of an effective emissions reduction strategy. These include electricity pricing and rate-design policies and improved utility resource planning practices. In the case of rate design, Lazar and Colburn (2015) find that states could reduce emissions through time of use (TOU) and other types of electricity rates. As discussed above, under a mass-based target, there would be no need for additional MR&V protocols or procedures to account for emissions reductions that result from these types of electricity rates and initiatives.

Finally, a mass-based target, with its clear price signal, well-defined tradable commodity, inter-state flexibility, and streamlined emissions accounting rules will best accommodate the transmission planning processes that will be critical for the evolving industry structure. States, utilities, transmission owners, and system operators already collaborate extensively on the adequacy, rules, reliability, and operations of the bulk power system. Changes underway in the electric system will require a new look at these standard practices and will be an opportunity to accommodate Clean Power Plan compliance approaches (Analysis Group 2015).

7.6 Accommodate Market and Regulatory Developments

Past experience of mass-based emissions targets with trading shows that they are particularly good at accommodating market and technological developments. To the extent that these regulations piggyback on other market trends, they could have a larger than expected impact at lower than expected cost. For example, the onset of the acid rain program in the 1990s coincided with deregulation of the railroads, which facilitated the transportation of western low-sulfur coal to power generators and was a contributing factor to a dramatic drop in sulfur dioxide emissions in 1995. As the authors of an assessment of the SO_2 trading program wrote:

> One can expect a tradable allowance program both to produce surprises and to adapt reasonably efficiently to them. The more flexible a regulatory program, the more unexpected behavior it will produce as regulated firms exercise ingenuity in adapting to the new requirement and to unexpected events in related markets that affect efficient control strategies and optimal emission levels (Ellerman et al. 2000).

Similarly, the RGGI program benefited from unexpectedly low natural gas prices driven by technological innovations that led to the shale gas boom in the United States. Murray and Maniloff (2015) find that lower natural gas prices contributed to a significant portion of the emissions reductions that occurred under the initial years of the RGGI program. This ability of a mass-based target to seamlessly incorporate market trends will be critical as utilities incorporate new "grid edge" technologies and market structures in the coming years.[16]

Finally, the Clean Power Plan architecture may also have to adapt to future climate initiatives. The 2015 Paris climate agreement encourages countries to review their emissions pledges and to potentially submit stronger pledges for emissions reductions every five years, starting in 2020. This creates uncertainty for states and utilities and suggests that the Clean Power Plan is unlikely to be the last word on de-carbonization in the electric power sector. Whether the United States would continue to use the Clean Air Act or some new authority to achieve emissions reduction is also uncertain. As noted earlier, based on continued expectations of technological change in the electric power sector, it is possible that revised versions of the new source

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[16] To the extent that policymakers wish to maintain a minimum allowance price that will provide allowance price predictability during unexpected market changes, they can also use a price floor mechanism (Burtraw et al. 2010).

performance standard and existing source guidelines could be a component of future US efforts to reduce emissions. This suggests additional potential benefits for the trading-ready, mass-based target architecture recommended in this paper. Such an approach could provide for the banking of allowances, which could create an incentive for early reductions and a smother path to a future standard.[17]

8. Conclusions

The Clean Power Plan provides an opportunity for states to think through longer-term issues and structures concerning the utility sector with the participation of relevant government agencies, Regional Transmission Operators/Independent System Operators (RTOs/ISOs), utilities, and other stakeholders. The public participation requirement in the Clean Power Plan could be one of the drivers to help facilitate this discussion with state agencies. Public processes will provide an opportunity for each state to take a comprehensive look at how technology, infrastructure, markets, and consumer preferences are changing and how state energy policy and utility regulatory structures should respond. Kind (2015) notes that the timing of the Clean Power Plan process provides an excellent opportunity for states to consider their utility models. To that end, grid-related regulatory initiatives could be important complementary policies for the Clean Power Plan. Finally, processes that include broad participation of government agencies would likely be the best paths to a comprehensive approach.

As discussed in this paper, there are several critical issues regarding market and regulatory structures that will require additional analysis and stakeholder participation. These include:

- How should new “grid edge” technologies be valued and how should the costs and benefits be allocated?
- How can regulators provide a level playing field for all utilities and third-party providers of energy resources and services?
- How can performance-based ratemaking or other approaches align utility financial goals with public policy objectives?

[17] See Schmalensee and Stavins (2015) for a discussion of the benefits of banking in emissions trading programs.

Addressing these and other issues will take an enormous effort by regulators, utilities, third-party companies, electricity customers, and other stakeholders. Regulatory structures and business models will have to evolve to meet new market conditions. New technologies and services have the potential to create enormous benefits for electricity customers and the environment, but only if the regulatory and market structures can be developed to facilitate these benefits.

In comparison, the path forward for Clean Power Plan implementation seems relatively straightforward. With the approach of the 25th anniversary of the landmark acid rain program, we are now in our third decade of experience with an approach that used a mass-based target with trading to reduce emissions. The acid rain program and subsequent programs with mass-based targets and trading have been analyzed and reviewed extensively, and there is a significant body of experience regarding which design features work well and which features should be avoided (Schmalensee and Stavins 2015). Given the difficulty of predicting exactly what mix of technologies and institutions will develop in the coming years, the mass-based approach that covers the entire electric generation sector is the most flexible and “future-ready” pathway for Clean Power Plan compliance. The synergies between the Clean Power Plan and the utility of the future are clear. States that embrace the utility of the future will be well positioned to comply with the Clean Power Plan at lower cost, and states and utilities that are implementing the Clean Power Plan will benefit from exploring how emerging market and regulatory structures can provide new choices and services for consumers.

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