RFF REPORT

Hedging an Uncertain Future: Internal Carbon Prices in the Electric Power Sector

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APRIL 2017

RESOURCES FOR THE FUTURE

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Summary

This report examines how internal carbon prices are used by companies and electricity regulators to manage regulatory risk, and identifies ways policymakers can offer guidance for companies to manage such risk in uncertain political climates.

Key Points

- Electric power companies have been at the forefront of using internal carbon prices to anticipate future policies, manage regulatory risks, prepare for new markets and services, and respond to customer interests.
- In particular, electric utilities have used carbon prices in integrated resource plans (IRPs) to evaluate future resource portfolios and to examine business decisions such as the retirement of fossil fuel units.
- A review of recent IRPs shows a diversity of carbon prices used based on a number of factors, including the potential for future constraints on carbon that go beyond current state and federal policies.
- In a new political environment less supportive of climate policy, the estimation of internal carbon prices for planning and hedging regulatory risk has become more difficult but no less important.
- State policymakers and electric power companies should consider renewed efforts to provide transparent assumptions about carbon prices in IRPs. In addition, there should be continued efforts to improve modeling and methodologies for carbon pricing.

Key Words: internal carbon pricing, US electric power sector, regulation, regulatory risk, integrated resource plans

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* Kruger is a visiting fellow at RFF. The author thanks Richard Morgenstern and Karen Palmer for their helpful comments.

Contents

1. Introduction

The cycle for electing (and ultimately, replacing) politicians in Washington is much shorter than the cycle for building and replacing generating assets.—Standard & Poor Global Ratings, December 2016

The election of a new president has created greater uncertainty about US policies to address climate change. The Trump administration has pledged to stop implementation of the Clean Power Plan (CPP) and may withdraw or scale back US participation in the Paris Agreement on reducing greenhouse gas emissions. Analysts have noted that the short-term effect of these potential changes may be limited because the electric power sector already appears to be headed to lower carbon dioxide (CO_2) emissions in many regions. Low natural gas prices, falling prices of renewable energy technologies, flat or declining electricity demand in many regions, and conventional air pollution regulations have made coal-fired power plants less economic and have reduced CO_2 emissions (BPC 2016; MJB&A 2016).

On the other hand, the electric power sector faces longer-term questions about whether to view decarbonization as inevitable in light of scientific consensus on the effects of climate change. Emissions reductions beyond those in the CPP could be mandated under a future administration or Congress, creating both challenges and opportunities for regulators, electricity consumers, companies, and investors. For example, if companies and policy makers ignore the potential for future carbon regulation, electricity costs could be higher for consumers in the longer term. This is particularly true if there are stranded assets—existing or new fossil fuel–fired power plants that have become uneconomic because of carbon regulation and whose costs ratepayers must absorb, whether in whole or in part. For electric power companies, a push toward lower-carbon electricity could be a potentially beneficial business strategy if, as many experts predict, decarbonization is coupled with a broader trend of electrification of the US economy (Weiss et al. 2017). For investors, both the potential benefits of new profit-making opportunities in the power sector and the downside of stranded assets create an uncertain investment environment. The chairman of the Arkansas Public Utilities Commission summed up the conflict between short-term politics and longer-term carbon risks for utilities and electricity regulators this way: “There are still scenarios with a cost of carbon presented. And to me, a utility commissioner isn’t doing their job, given that they make a long-term projection, if they’re not including resource diversity that includes non-carbon resources” (Holden 2017).

Fortunately, many electric power companies already have the tools and experience to manage regulatory risk, including significant experience using an internal carbon price for resource planning, scenario analysis, and other purposes. This process has been formalized for some utilities through integrated resource plans submitted to public utility commissions (PUCs). Merchant power companies, which are not regulated by state PUCs, also use carbon pricing for strategic planning or investment risk assessment. At the same time, SEC guidelines and voluntary efforts, such as the carbon disclosure system run by CDP (formerly the Carbon Disclosure Project), have pushed power companies to identify and disclose corporate risks of climate change to investors. Some companies have begun to disclose internal carbon prices as part of these more comprehensive assessments of the physical and financial risks posed by climate change.

The use of internal carbon pricing as a proxy for future constraints on carbon could have multiple effects, including accelerating more stringent reductions in emissions through the anticipation of future carbon prices and avoiding overinvestment in fossil fuel infrastructure that may be uneconomic in a future of higher carbon prices and lower renewable energy prices. This report addresses the following questions: In an increasingly uncertain regulatory and legal environment, how should utilities revise and adjust internal carbon prices? How could policymakers provide better guidance for managing the risk of future emissions constraints and carbon prices?

2. The Benefits of Internal Carbon Pricing

The basic premise of internal carbon pricing is that companies use a price of carbon in their strategic plans and models to explore future scenarios and to observe changes in the relative economics of potential investments or deployment of resources. This price, sometimes known as a "shadow price," can drive decisionmaking and is a way to manage the risk associated with future carbon regulation and changing energy and technology markets.

Companies and analysts cite several benefits of using internal carbon prices (WBCSD 2015):

- anticipating future policies that may put a mandatory price on carbon or that require deployment of low- or zero-carbon technologies;
- managing regulatory risk associated with stranded assets or inefficiently allocated capital associated with fossil fuel facilities that could be costly to ratepayers and shareholders (CERES 2010; Morris 2015);
- preparing for new markets and customer services that will evolve as the electricity sector decarbonizes; and
- responding to customers' or investors' interests in reducing emissions (UN Global Compact 2015).

More specifically, electric power companies use an internal carbon price for a variety of planning and strategic purposes specific to the sector. For example, Entergy Corporation reported in 2015 that it "used a forecasted price of CO_2 to evaluate the impacts on long lived asset investments, to inform decision-making on the optimal mix of future resources, and to evaluate business decisions such as whether or not to conduct power uprates, acquisitions, deactivations, power purchases and divestitures" (CDP 2015, 41). Essentially, a carbon price can be used in electric utility models as a proxy for a wide variety of future carbon policies that would affect a company's resource mix, operations, and business decisions, including building new, zero-carbon resources and retiring existing fossil-fuel generating units.

Regarding future carbon regulations, internal pricing may prompt faster and more stringent reductions in emissions through the anticipation of future carbon prices. Two recent analyses have looked at this feature of carbon pricing under the modeling assumption that the electric power sector would have "perfect foresight" about future regulations. A June 2016 analysis of the CPP by the Bipartisan Policy Center modeled a scenario in which more stringent emissions standards would apply to both new and existing power plant units starting in 2030 and would escalate to a 65 percent reduction in CO_2 from 2005 levels by 2040. The analysis found that expectations about these future emissions constraints affected emissions and capacity mix in the near-term period from 2022 to 2027 (BPC 2016). In other words, anticipation of a carbon price more than a decade in the future changed near-term investment decisions about the least-cost path for the power sector. The analysis found that under an expectation of more stringent emissions reductions, there were 31 gigawatts (GW) of additional wind capacity, 76 GW of additional solar capacity, and 36 GW of additional coal retirements, on average, from 2022 to 2027. In addition, 5

GW of nuclear power plant retirements were delayed. An Energy Information Administration (EIA 2016) analysis of the CPP that assumed a 45 percent reduction in CO_2 emissions from 2005 levels by 2040 similarly found that from 2015 to 2030, anticipation of future more stringent emissions targets resulted in changes to the generation capacity mix, retiring an additional 12 GW of fossil fuel capacity and adding 20 GW of solar capacity beyond what occurs in the CPP without a more stringent post-2030 target.

Of course, in the real world, electric power companies and their regulators must operate under considerable uncertainty about the future and don't have the luxury of perfect foresight. Nevertheless, as discussed in the next section, many companies do model future carbon price scenarios that inform business decisions and resource planning.

3. Integrated Resource Planning and Carbon Pricing

Integrated resource plans (IRPs) are used by many electric utilities and their state regulators to meet future energy and peak-capacity demand through a mixture of supply- and demand-side resources. (Merchant power companies, which operate in regions with wholesale power markets, are not subject to this type of planning requirement.) The content of IRPs is often dictated by state legislation or regulations, with varying requirements on the issues that must be addressed, frequency of updates, planning horizons, treatment of environmental costs or regulatory risk, and other issues (Wilson and Biewald 2013). In many cases, IRPs assess numerous potential future resource portfolios and perform sensitivity analyses based on important parameters, such as fuel prices, growth in electricity demand, and the potential future costs of climate change regulatory programs. A recent study by Synapse Economics found that the percentage of IRPs including a carbon price has grown steadily in recent years, from none of the IRPs reviewed from 2003 to 2007, to more than half of the IRPs reviewed between 2012 and 2014, to almost all of the IRPs reviewed from 2014 to 2015 (Luckow et al. 2016). This most recent period coincides with the development of the Clean Power Plan.

4. Internal Carbon Prices in IRPs

US companies in the electric power sector employ a wide variety of carbon prices in IRPs.[1] Table 1 displays carbon price information from a sample of recent integrated resource plans (IRPs) from US investor-owned electric utilities.[2] These IRPs are all dated after the announcement of the final Clean Power Plan regulations in August 2015 but before the November 8, 2016 presidential election.

Several differences in the carbon pricing used by electric power companies are worth noting. First, companies differ on whether they include a carbon price in their base case assumptions, in sensitivity analyses, or in both. Barbose et al. (2009, 16) argue for including in the base case an estimated carbon price that reflects "the most likely carbon regulations over the planning period." In addition, some IRPs present a range of carbon prices that reflect different future natural gas price assumptions, rather than alternative stringencies for future carbon policies.

[1] This diversity in carbon prices is reflected in other countries and sectors. An international survey of companies across all economic sectors found that carbon prices ranged from less than $8/metric ton of CO_2 to more than $800/metric ton (CDP 2016).

[2] Some public power utilities, including federal power authorities, municipally owned utilities, and rural electric co-ops, also use carbon prices in their IRPs.

TABLE 1. INTERNAL CARBON PRICES (2016$/METRIC TON CO_2)

Company, date	**Carbon price(s)**
Ameren Spring 2016	Low case: $26/ton in 2025; **$33/ton in 2034** Base case: $39/ton in 2025; **$49/ton in 2034** High case: $60/ton in 2025; **$90/ton in 2034**
Appalachian Power (VA) April 2016	No carbon case Low case: **$7/ton in 2025; $14/ton in 2030** Mid case: **$12/ton in 2025; $25/ton in 2030** High case: **$15/ton in 2025; $30/ton in 2030**
Arizona Public Service October 2016	Low case: $0/ton Base case: (California market prices) **$16/ton in 2025; $20/ton in 2032** High case: TBD
Dominion Power (VA & NC) April 29, 2016	No CO_2 cost forecast (assumes no CO_2 standard) **CPP commodity forecast[3]: $10/ton in 2022; $19/ton in 2035** ICF reference case: $5/ton in 2022; $27/ton in 2035
Duke Energy Indiana November 1, 2015	Carbon tax scenario: $17/ton in 2020, increasing to $39/ton by 2035; Higher-tax sensitivity: $78/ton by 2035
Duke Energy Progress (SC)	CPP scenarios using a 3rd-party CO2 price forecast (not specified): Scenarios with varying levels of an intrastate tax System mass cap scenario starting in 2022 and declining until 2030 with emissions held flat afterwards
Duke Energy Carolinas (NC & SC)	CPP scenarios using a 3rd-party CO2 price forecast (not specified): Scenarios with varying levels of an intrastate tax System mass cap scenario starting in 2022 and declining until 2030 with emissions held flat afterwards
Georgia Power January 2016	Scenarios: $0, $10, $20/ton, starting in 2020 (price would increase at undisclosed annual interest rate)
Indiana Michigan Power November 2, 2015	No carbon case Base case: $13 in 2022; $13 in 2035 High scenario: $22/ton starting in 2022; $22 in 2035
Indianapolis Power & Light November 1, 2016	Base case: Mass-based carbon tax assumptions from consultant ABB (not specified) Enhanced environmental case with higher carbon tax assumptions from ICF, Inc. (not specified)
NIPSCO (IN) November 1, 2016	Base delayed carbon scenario: $4/ton in 2025; $27/ton in 2035 Base and challenged economy scenarios: $6/ton in 2023; $28/ton in 2035. Booming economy scenario: $13/ton in 2023; $29/ton in 2035 Aggressive environmental regulation scenario: $9/ton in 2023; $52/ton in 2035
Portland General Electric November 2016	Base case: $22/ton in 2022; $29/ton in 2030; $90/ton in 2050 High case: $28/ton in 2022; $47/ton; $122/ton in 2050

[3] Dominion also forecast the cost of emission rate credits (ERCs) for scenarios in which it would adopt a rate-based target under the Clean Power Plan. The company forecasts an ERC price of $0/MWh under those scenarios.

Company, date	Carbon price(s)
Puget Sound Energy November 30, 2015	Low case: \$0/ton federal price but CA price to power plants in CA Mid-case: \$18/ton in 2020; \$37 in 2035 (uses estimated CA price and applies as federal price to all plants) High case: \$35 in 2020; \$83 in 2035
Sierra Pacific Power July 2016	**CPP scenario: \$0/ton in 2022; \$26/ton in 2035** **Low case: \$5 in 2022; \$9 in 2035** **Mid-price scenario: \$10/ton in 2022, \$19/ton in 2035** **High-price scenario \$20/ton in 2022; \$35/ton in 2035**
SCANA February 26, 2016	No discussion of carbon pricing
Tucson Electric Power April 2016	No discussion of carbon pricing

Note: All prices are in 2016\$/metric ton. CO2 prices have been converted from \$/short tons to \$/metric tons where relevant. When the unit was not specified in the IRP, it was assumed to be \$/short tons and was converted to \$/metric tons. Where the year\$ was not specified in the IRP, it was assumed to be the year of the IRP. Nominal \$ were discounted using the inflation rate specified in the IRP. If the inflation rate was not specified in the IRP, a rate of 2% was assumed. In some cases, specific carbon prices were not noted in the IRP but were depicted in a graphic. In such cases, prices were estimated and shown in boldface.

Second, companies differ in how explicit they are in public documents about their carbon pricing scenarios. For example, although most IRPs describe the prices they use in analysis, others state only that they have used various carbon prices, without providing any numbers. (This level of transparency may differ across operating companies in different states owned by the same utility holding company.) Finally, some IRPs do not have <u>any</u> discussion of carbon prices.

Third, the basis for setting a carbon price varies considerably, and the rationales change over time. A 2009 review of practices in western states found that several companies used modeling of potential legislative proposals, including the Waxman Markey economy-wide cap-and-trade bill, to set internal carbon prices (Barbose et al. 2009). In some cases, states have mandated specific prices or approaches to develop prices. Oregon, for example, sets carbon pricing guidelines that require at least one scenario that would trigger the selection of a portfolio of resources substantially different from the portfolio preferred by the company (Oregon 2008, C-2). Many of the IRPs reviewed for this report include scenarios that project a carbon cost associated with CPP compliance.[4] Several companies have flagged the difficulty of projecting carbon prices because of the program's decentralized structure and legal uncertainties. As one company noted recently, "The potential for carbon regulation has been part of the integrated resource planning process and is continuously evolving as more definitive requirements emerge from Congress and federal regulators" (Indiana Michigan Power 2015, 4).

Fourth, some companies have used carbon prices that go beyond existing regulatory

[4] Note that the Clean Power Plan does not <u>require</u> states to use a mass-based emissions target with tradable allowances, although the program does offer this option. Instead, states may use an emission rate standard denominated in CO_2/MWh.

requirements such as the Clean Power Plan and consider the possibility of longer-term constraints on emissions, either in their base case scenarios or in sensitivity cases. For example:

- Portland General Electric and Ameren Missouri include scenarios with a methodology developed by a consulting firm, Synapse Energy Economics, Inc., based on a variety of data and analytic inputs. Portland General Electric's 2016 IRP notes that this approach "would allow for CPP compliance from 2022–2030 and science-based climate goals to be achieved by 2050."
- Sierra Pacific Power models scenarios developed by NERA to project a hypothetical future carbon tax, cap-and-trade, or regulatory program. The low-, mid-, and high-CO_2 price scenarios assume that prices begin in 2022 at $5, $10, and $20 ton CO_2, respectively, and increase over time at a 5 percent real rate.
- The Tennessee Valley Authority (not included in Table 1) presents a "De-Carbonized Future Scenario" that "models a regulatory environment in which there are significant carbon taxes that impact the relative efficiency of alternative strategies" (2015, 194).
- Dominion uses an "Alternative Commodity Price Scenario" based on a reference case developed by ICF, Inc., that weights the probability of three possible outcomes: a $0/ton CO_2 price; a mass-based program on existing and new sources based on the requirements of the CPP; and a more stringent version of the CPP mass-based trading program or a comparable legislative requirement post-2030. Dominion states in its 2016 IRP that "the Company considers it likely that there will be future regulation requiring it to address carbon and carbon emissions in some form beyond what is required today, even with the exact future of the CPP, at present, undetermined" (Dominion 2016, 1).

Finally, IRPs may present policies or resource scenarios that include assumptions about lower-carbon resources in addition to, or instead of, more stringent future carbon constraints. For example, Duke Energy Indiana analyzes an "Increased Customer Choice Scenario" that assumes that in addition to more stringent carbon constraints, roof-top solar serves an additional 1 percent of load per year beginning 2020, customers adopt higher levels of energy efficiency, and new utility-scale generation is provided by merchant generators (Duke Energy Indiana 2015).

5. Pricing Carbon: Compliance Costs or Social Costs?

The previous discussion has focused on the most common approach for internal carbon pricing used in IRPs--estimating the projected compliance cost of meeting future regulations. However, an alternative approach to pricing carbon—the social cost of carbon (SCC)--estimates the future damages from climate change and the marginal benefit from avoiding these damages. In economic terms, this is the "right question," since society would want to mitigate carbon emissions to the level that the marginal cost of reducing a ton of emissions equals the marginal benefit of reducing that ton. However, the answer to this question depends on complex scientific, economic and methodological issues. US government analysts have developed a methodology for the SCC to estimate the "monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change"

(IWG 2016, 3). The SCC provides a range of cost estimates based on discount rates and other assumptions, and the Obama administration used a price in the middle of the range—$36/ton CO_2 in 2015 (2007$)—to represent the benefits of carbon reduction in cost-benefit analysis for regulations (Table 2). Estimates for the SCC rise over time "because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to gross GDP" (IWG 2016, 16). (A recent presidential executive order, however, disbanded the federal interagency working group responsible for developing estimates of the social cost of carbon and withdrew several documents underpinning the group's methodology and analyses, stating that they "are no longer representative of government policy.")

A handful of states require some sort of assessment of the environmental damages of CO_2 emissions in their IRPs. Most prominently, Minnesota law requires the use of an externality value for CO_2.[5] In April 2016, a state judge made a nonbinding recommendation that the Minnesota PUC adopt the federal SCC to update the state's externality price, currently $0.44 to $4.53 ton/$CO_2$. The Minnesota PUC has not yet adopted this recommendation, and the state's utilities have criticized the SCC on several methodological issues (Cusick 2016).

Nevada regulations require utility resource planners to assess environmental externality costs, defined as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[6] In other words, these are costs of damages beyond the costs incurred by a carbon regulatory program. In its 2016 resource plan, Sierra Pacific includes a report that provides "illustrative estimates" of these costs based on the SCC but notes the many uncertainties associated with the estimates (NERA 2016).

[5] The state also has a 2007 law (updated in 2009) that sets a likely range of CO_2 prices from future climate regulations. In July 2016, the commission ruled that utilities in the state are not required to apply these costs until 2022, the first year of Clean Power Plan compliance.

[6] Nevada Administrative Code at 704.9359.

TABLE 2. SOCIAL COSTS OF CO_2, 2010–2050 (IN 2007$/METRIC TON CO_2)

	Discount rate and statistic			
Year	*5%*	*3%*	*2.5%*	*High impact (95th percentile at 3%)*
2015	$11	$36	$56	$105
2020	$12	$42	$62	$123
2025	$14	$46	$68	$138
2030	$16	$50	$73	$152
2035	$18	$55	$78	$162
2040	$21	$60	$84	$183

Note: The values in the first three columns are based on the average social cost of carbon from three integrated assessment models at discount rates of 5, 3, and 2.5 percent. The last column represents the costs of lower-probability but higher-impact outcomes from climate change, corresponding to the 95th percentile of the frequency distribution of estimates based on a 3 percent discount rate.
Source: US EPA.

6. Additional Drivers for Internal Carbon Pricing

6.1. Valuing Distributed Energy Resources for the Utility of the Future

Pricing of environmental attributes has also been proposed to help value a wide array of distributed resources and services that will be provided by customers and third parties under emerging regulatory and market structures sometimes known as “the utility of the future” (Tierney 2016; EPRI 2014; Bradford et al. 2013). A study by the Rocky Mountain Institute’s eLab found that cost-benefit studies of distributed solar PV resources had different assumptions about the value of carbon reductions and the prices used (RMI 2013). Minnesota’s PUC has used the SCC as a component of a value of solar methodology for ratemaking that may be adopted voluntarily by its utilities (Minnesota Department of Commerce 2014). The commission ruled in July 2016 that the methodology should be used to set rates for a community solar program (Jossi 2016). New York’s Department of Public Service (DPS) ordered utilities in the state use the SCC to help value distributed energy resources and services provided by customers and third parties. In the case of New York, a kilowatt hour of distributed energy generation will be valued at the higher of the SCC and the price of renewable energy certificates in New York’s market (New York DPS 2017).

6.2. Climate Disclosure and Carbon Pricing

The increased interest in internal carbon pricing is related to a broader movement to disclose more information about the potential corporate financial risks of climate change. This movement, often referred to as “climate disclosure,” is premised on the idea that investors are entitled to transparent information on the legal, regulatory, and physical risks of climate change to a company’s assets from such effects as increasingly severe weather or rising sea levels.

In 2010, the US Securities and Exchange Commission (SEC 2010) released guidance on disclosure related to climate change. In response to criticism that companies were not disclosing adequate information, the SEC asked for comments in April 2016 on how to improve disclosure requirements to give investors better information on climate risks (SEC 2016).

Meanwhile, a task force established by the Financial Stability Board—an international group that monitors and makes recommendations about the international financial system—released a report at the end of 2016 with recommendations on governance issues related to climate disclosures, corporate strategy around climate risks and opportunities, risk management surrounding assessment and management of climate risks, and metrics and targets used to manage climate risks. The task force recommended that companies disclose how they use scenario analysis to better understand potential financial implications of climate change and that companies disclose their internal carbon prices "where relevant" (FSB 2016).

7. Conclusions and Future Research

In a new political environment less supportive of climate policy, the estimation of internal carbon prices for planning has become more difficult but no less important. With the Trump administration opposed to using the CPP to reduce CO_2 emissions, it is unclear whether the next round of IRPs will reflect this policy in their use of internal carbon prices. On the other hand, states and utilities with a longer-term view of climate science and policies may want to continue hedging regulatory risks and may decide to assume carbon prices based on factors that go beyond the costs of CPP implementation. Under this view of the future, and given the length of the planning horizon for the electric power sector, the *anticipation* of future carbon policies and prices could drive near-term action to deploy clean energy technology and reduce emissions.

Following are recommendations for how policymakers, companies, and investors can navigate the uncertainties about future greenhouse gas policies.

First, if they do not already, state PUCs should require utilities under their jurisdiction to explain their assumptions about future carbon prices and to use a carbon price or range of prices in IRPs. These plans continue to be a natural vehicle to explore regulatory scenarios because the risk of future carbon regulation is directly related to cost, fuel diversity, reliability, and other objectives that have long been at the heart of electricity regulators' core mission. Moreover, as more state regulators and companies explore the implications of distributed energy resources for market and regulatory structures, a carbon price should be used to help value these resources.

Second, with more stringent mandatory carbon disclosure guidelines from the SEC now less likely under the Trump administration, electric power companies, including merchant power companies not subject to IRP requirements, should consider adopting voluntary carbon disclosure guidelines that include scenarios with a range of potential future carbon prices. The electric power sector is well positioned to take the lead on this type of disclosure because many electric power companies utilities already produce this this information in some form, either for a mandated IRP process or for their own internal strategic planning or investment screening.

Third, although it is impossible to know exactly how carbon policy will unfold in the next decade, better methodologies to estimate potential future compliance costs will be critical. This need for continued improvement of methodologies applies to prices estimated for electric utility planning as well as for voluntary disclosure of corporate carbon prices. Modeling of different climate policy scenarios, including modeling potential scenarios for a likely second commitment period under the Paris Agreement should be a priority. These scenarios could include both sectoral and economy-wide policies, representing a variety of potential program designs for mass emissions-based trading or carbon taxes.

Although only a few states and companies have used the SCC for planning purposes or to value distributed energy resources, interest could increase as the imperative to act on climate change grows stronger. In any event, despite opposition to the SCC approach by the new administration, development and refinement of SCC methodologies should continue for use in cost-benefit analysis of actions that reduce carbon emissions. A committee established by the National Academy of Sciences recently released a report that could serve as a guide for improving understanding of the scientific and economic aspects of climate change over time. It recommends near- and long-term actions to "improve the scientific basis, characterization of uncertainty, and transparency of the SC-CO_2 framework" and suggests updating the SCC approximately every five years (2017, 3).

Ideally, the federal government could play an important role in projecting the cost of future compliance with climate mandates and using SCC approaches to estimating the price of carbon emissions (Morris 2015). However, this appears to be unlikely in the near term, with the new political climate. Thus, it would be beneficial for states or groups of states to cooperate on this type of modeling and research. Alternatively, or in addition, a consortium of researchers and analysts could help develop this information for the public benefit.

Finally, the use of internal carbon prices to hedge risk raises research and policy questions related to how companies use these prices and to the evolution of a lower-carbon electricity system:

- What carbon prices should be used for the most cost-effective trajectory to meet prospective emissions targets? What are the costs of underestimating (or overestimating) the level of carbon price needed?
- How will changes in electricity technologies, fuel prices (particularly natural gas), and market structures affect the level of carbon pricing necessary to meet emissions targets?
- How will other types of policies, including renewable energy mandates and energy efficiency standards, affect internal carbon pricing?

Answers to those and related questions will help identify more cost-effective pathways to a lower-carbon electricity system during a period of great political uncertainty.

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