Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

October 12, 2018

To: EMP Committee, New Jersey Board of Public Utilities

Subject: New Jersey Energy Master Plan

The Institute for Policy Integrity at New York University School of Law[1] (Policy Integrity) respectfully submits comments on the New Jersey Energy Master Plan (EMP or the Plan). Policy Integrity is a nonpartisan think tank dedicated to improving the quality of government decisionmaking through encouraging a rational approach to environmental and regulatory policymaking that makes use of the best available economic tools. Policy Integrity advocates for sound cost-benefit analysis at every level of government and argues for an unbiased approach to measuring the costs and benefits of environmental, public health, and safety policy. Policy Integrity has previously filed public comments and written reports and articles on issues pertaining to economic analysis of grid modernization and resilience, and distributed energy resources (DER), including energy storage and DER valuation. Policy Integrity seeks to apply its economic, legal, and policy expertise to assist the Energy Master Plan Committee (the Committee), including the New Jersey Board of Public Utilities (the Board), as it drafts the 2019 Energy Master Plan.

These comments briefly respond to three of the five work group thematic areas for the EMP drafting process: Clean and Renewable Energy; Sustainable and Resilient Infrastructure; and Building a Modern Grid. When formulating the EMP, the Committee should:

1. Consider grid resilience in a holistic manner and apply cost-benefit analysis to resilience plans and investments;
2. Adopt a granular approach to rate design, rather than use to net metering, including for distributed energy resources, and;
3. Design an incentive structure for energy storage operators to ensure that the use of energy storage systems reduce greenhouse gas emissions.

We explain each of this points below and attach a number of our reports and issue briefs containing additional details, which may be of use to the Committee.

[1] These comments do not purport to represent the views of New York University School of Law, if any.

I. The Committee Should Take a Systematic View of Grid Resilience and Use Cost-Benefit Analysis When Making Resilience Plans and Investment Decisions

Resilience— the electric grid's ability to resist, absorb, and recover from high-impact, low-probability external shocks—is an important, yet broad and potentially amorphous concept. Many different actions can help the grid defend against, absorb, or recover from high-impact, low-probability shocks. Systematically and transparently evaluating the cost of a potential resilience-enhancing action and its expected impact on the probabilities and consequences of grid outages is critical to evaluating whether that action is worthwhile from an economic efficiency perspective or whether it is misguided. To ensure that resilience investments are efficient and cost-beneficial, decisionmakers must adopt a clear and usable definition of resilience, identify potential actions that improve resilience, and conduct an economic analysis of the social value of those actions. Only by engaging in this type of analysis can policymakers ensure that they do more than simply pick winners based on political preferences.

a. Resilience Can Be Measured as the Performance of the Grid and Its Components During and After a High-Impact Shock or the Attributes of the Grid and Its Components

Resilience can be measured based on the performance of the system or its components during and after a high-impact shock (e.g., number of customer outage hours, monetized value of lost economic productivity). It can also be based on the attributes of the system or its components (e.g., how hardened the distribution system is to high winds, the extent to which replacement transmission components are readily available, the extent to which a generator is vulnerable to fuel-supply disruption). Attribute-based measures are easier to develop but also are potentially more misleading. Because of interactions among different threats and components of the electric system, improving one attribute may or may not improve resilience as a whole. Moreover, many of the attributes that have been suggested in recent federal policy discussions—such as whether a plant has historically operated to serve baseload demand or whether a plant provided power during an extreme weather event—do not have a demonstrated connection to resilience. Performance-based metrics more directly measure resilience, are more reflective of the multi-faceted nature of resilience, and are more useful than system or resource attributes in quantitative analysis (such as cost-benefit analyses of potential resilience interventions). When thinking about electric system resilience, the Committee should focus on performance-based metrics.

b. Resilience Policies and Investments Should Be Assessed Using a Cost-Benefit Analysis Framework

Investments to improve the resilience of individual components of the electric system—generation resilience, transmission resilience, distribution resilience—should all be considered, but must be measured with respect to how they improve overall electric *system resilience.* Accordingly, the Committee should use a systematic, transparent framework for evaluating potential interventions, to ensure that the benefits of resilience-enhancing investments and policies justify the costs.

A framework developed by Sandia National Laboratories is analytically intensive but can provide critical insight when comparing potential resilience interventions.[2] This framework involves specifying threats, defining performance-based resilience metrics, using computer-modeling simulations to understand and monetize probabilistic baseline levels of resilience, and comparing those levels with monetized probabilistic estimates of resilience after potential interventions.

The benefits identified using this framework can be compared to the costs of the policy or investment, including the costs to the utility of making investments, costs to customers that result from market rules that change energy prices, costs associated with any countervailing resilience risks, and environmental costs that result from changes to the grid mix.

The Committee should consider adopting a policy of evaluating potential resilience improvements and utility investments using a cost-benefit framework.

Policy Integrity's report, Toward Resilience (attached as Exhibit A), explains each of these above points in greater detail.[3]

a. New Jersey can address resilience in three overarching ways

Because states have exclusive jurisdiction over distribution-level facilities, which are the source of the vast majority of customer outages from unexpected events,[4] they have focused on grid resilience for some time. States, particularly those that have faced highly disruptive events, have invested significant resources in analyzing opportunities for improving system resilience. There are two general ways in which states can intervene to improve electric system resilience:

1. Directing Distribution Utilities to Make Resilience Investments

The primary way that states can and do improve grid resilience is by directing public utilities under their regulatory authority to invest in key physical and operational systems, and to ensure that utilities can recover the costs of such investments.

2. Rules to Encourage Resilience-Enhancing Distributed Energy Resources

States can also use their distinct role in regulating distributed energy resources (DERs) to enhance grid resilience. DERs, including rooftop solar, electric batteries, backup generators, microturbines, and demand response, can enhance resilience in several ways.[5] Because DERs are generally located close to end users, they reduce customers' reliance on vulnerable distribution infrastructure. This is

---

[2] Jean-Paul Watson et al. Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States. Sandia National Laboratories (Sept. 2014).
[3] Burcin Unel & Avi Zevin, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System. Institute for Policy Integrity Report (Aug. 1 2018), available at: https://policyintegrity.org/publications/detail/toward-resilience
[4] FERC & NERC, REGIONAL ENTITY JOINT REVIEW OF RESTORATION AND RECOVERY PLANS 1 (2016)
[5] SHERRY STOUT & ELIZA HOTCHKISS, NAT'L RENEWABLE ENERGY LAB., DISTRIBUTED ENERGY GENERATION FOR CLIMATE RESILIENCE (2017), https://www.nrel.gov/docs/fy17osti/68296.pdf. EPRI, ENHANCING DISTRIBUTION RESILIENCY: OPPORTUNITIES FOR APPLYING INNOVATIVE TECHNOLOGIES 11 (2013), HTTPS://WWW.EPRI.COM/#/PAGES/PRODUCT/000000000001026889/.

particularly true when DERs can operate as islanded microgrids, allowing them to supply limited power to critical loads during large grid outages of long duration.[6] DERs are nonetheless generally interconnected with the distribution system and so can provide redundant generation supplies in the case of a generation, transmission, or distribution disruption that limits traditional sources' ability to supply energy. Because they are typically much smaller and more geographically dispersed than traditional power plants, DERs can reduce the risk that a single point of generation or transmission system failure will have a significant impact on customers.

II. The Committee Should Implement a Granular Compensation Scheme for Distributed Energy Resources

a. The Committee Should Use a Value Stack Approach for Compensating Resources

DERs should be compensated for the full value they contribute to the grid. This objective requires unbundled price signals that could value generation and transmission, distribution, and ancillary services, as well as environmental benefits, separately, and that are granular with respect to time and location.[7] Achieving this objective fully, however, requires new technological as well as methodological capabilities, such as advanced metering infrastructure.

New Jersey should follow New York's lead and replace the current net metering approach to compensating DERs with a value stack approach. In particular, the Committee can enhance economic efficiency by:

- Using a design that aligns the price signals customers receive with the underlying costs of generating, transmitting, and distributing electricity, including environmental externalities;
- Acknowledging the need for a similar treatment between the compensation that DER consumers receive for their electricity injections into the grid and the rates they pay for the electricity they withdraw from the grid;

Policy Integrity submitted comments to the New York Public Service Commission in April 2017 that outlined steps for improving New York's imprecise and crude valuation methodologies and provide better incentives for more efficient DER deployment by recognizing the time-variant energy value, the locational distribution system value, the capacity value, and the environmental value that DERs

---

[66] NAT'L ACAD. OF SCI., ENG'G & MED., ENHANCING THE RESILIENCE OF THE NATION'S ELECTRICITY SYSTEM vii (2017), https://www.nap.edu/catalog/24836 [hereinafter NAS] at 106-107.

[7] Case 15-E-0751, Proceeding in the Matter of the Value of Distributed Energy Resources, Joint Comments of Environmental Defense Fund and the Institute for Policy Integrity at New York University School of Law in Response to the Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (April 18, 2016) [hereinafter "Joint NY comments"]; Case 17-01276 (In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack), Case 17-01277 (In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design), Comments of the Institute for Policy Integrity at New York University School of on Rate Design Successor to Net Energy Metering for Mass Market Customers (May 29, 2018).

provide.[8] We suggested a more refined construct, "LMP+D+E", where "LMP", "D", and "E" stand for locational marginal price of energy, distribution system value, and environmental value, respectively. This approach serves a foundation for more accurate and precise DER valuation as our methods improve.[9] Providing incentives for economically efficient DER integration requires unbundled price signals that are based on cost causation and are granular with respect to both time and location.[10]

b. The Committee Should Include Environmental Attributes When Valuing DERs

As New Jersey has specific environmental goals in mind for the Energy Master Plan, it is also important for the Committee to understand the elements of the environmental, climate, and public health value of DER generation (the "E" value). Because DER use often displaces the use of traditional, fossil-fuel-fired generators, the substitution reduces emissions of many air pollutants, including greenhouse gases and local pollutants such as particulate matter, SO_2 and NOx. Furthermore, DERs can be particularly valuable if they avoid local air pollution imposed on populations that are especially vulnerable to this pollution, such as low-income communities and communities of color.

The E value of DER injections depends on two main factors: the emissions rate of the generation being avoided (i.e., what resources does the DER replace?) and the monetary value of the damages avoided. The perceived complexity of this analysis is the basis for a common criticism of including an E value in DER compensation analysis, in part because the E value is contingent on a number of variable factors, like time and location of emissions, as well as weather patterns. However, a number of simplifying assumptions and preexisting modeling tools are available that make determining and compensating DERs for a granular estimate of their E value a feasible policy approach.

Details on how to calculate the "E" value are included in Policy Integrity's report, "Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources"[11] (attached as Exhibit B) and corresponding issue brief, "How States Can Value Pollution Reductions from Distributed Energy Resources" (attached as Exhibit C).[12]

III. As Energy Storage Operation Can Increase Emissions, the Committee Must Include Mechanisms that Incentivize Greenhouse Gas Emissions Reductions Along With Any Energy Storage Deployment Policy

a. Energy Storage Can Increase Greenhouse Gas Emissions

Policy Integrity has extensively analyzed the relationship between greenhouse gas emissions and energy storage operations. In an academic article published by Policy Integrity's Director and Energy Policy Director, "Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas

[8] *See generally* Joint NY comments.
[9] *Id*. at 4.
[10] *Id*. at 19, 25.
[11] Jeffrey Shrader, Burcin Unel & Avi Zevin. Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources. Institute for Policy Integrity Report (Mar. 23, 2018), available at: https://policyintegrity.org/publications/detail/valuing-pollution-reductions.
[12] Institute for Policy Integrity. How States Can Value Pollution Reductions from Distributed Energy Resources. Issue Brief (Jul. 20, 2018), available at: https://policyintegrity.org/publications/detail/how-states-can-value-pollution-reductions-from-distributed-energy-resources.

Emissions" [13] (attached as Exhibit D) and in our April 2018 report, *Managing the Future of Energy Storage*,[14] (attached as Exhibit E) we explain that contrary to the prevailing wisdom, energy storage is not guaranteed to reduce emissions, and may, in fact, increase emissions if policies are not designed carefully. Energy storage can cause an increase in net emissions for two main reasons:

- If energy storage charges from the grid when marginal emission rates are high, and discharges to the grid when marginal emission rates are low, it will increase emissions.[15]
- Energy storage demands more total energy generation to compensate for energy lost during charging and discharging, which may lead to greater emissions.

In other words, the net effect of storage on emissions depends on the difference between the emission rates of marginal plants that supply electricity for charging and the emission rates of marginal plants that are displaced when systems discharge.[16] The emissions of the marginal unit can vary widely, depending on the time of day, location, fuel type, efficiency, and other grid constraints affecting the marginal unit. For example, marginal emissions can be zero when renewables are the marginal generator, but skyrocket if an oil-peaker plant is on the margin. Furthermore, marginal emission rates vary by location based on grid operation and transmission constraints. And, ample academic work using hourly and sub-hourly marginal emission rates demonstrates the possibility of emissions increases.[17]

b. Real-Time Greenhouse Gas Emissions Rates Give Energy Storage Operators the Necessary Information to Make Decisions About Deployment

Using average emission rates, or focusing only on emissions avoided during discharging periods, would lead to inaccurate results. For example, if storage is charged when the marginal emissions rate is .4 kgCO2/kWh and discharged when the rate is .6 kgCO2/kWh, the average emissions rate would be .5 kgCO2/kWh over the entire period. This averaging fails to capture the increase in emissions between charging and discharging. Therefore, hourly, sub-hourly, or other more real-time marginal

---

[13] Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas Emi*ssions, 42 HARV. ENVTL. L. REV. 139, 143 (2018).

[14] Madison Condon, Richard Revesz & Burcin Unel, *Managing the Future of Energy Storage*, Institute for Policy Integrity (2018) [hereinafter "Future of Energy Storage Report"], *available at* http://policyintegrity.org/publications/detail/managing-the-future-of-energy-storage.

[15] Revesz & Unel, *supra* note 13.

[16] *See* Revesz & Unel, *supra* note 13; Future of Energy Storage Report, *supra* note 14.

[17] Eric S. Hittinger & Ines M. L. Azevedo, *Bulk Energy Storage Increases United States Electricity System Emissions*, 49 Envtl. Sci. & Tech. 3202 (2015); Joshua Graff Zivin, Matthew J. Kotchen & Erin T. Mansur, Spatial and Temporal Heterogeneity of Marginal Emissions: Implications for Electric Cars and Other Electricity-Shifting Policies 1 (2013); Duncan S. Callaway, Meredith Fowlie, & Gavin McCormick, *Location, Location, Location: The Variable Value of Renewable Energy and Demand-Side Efficiency Resources*, 5 J. Ass'n Envtl. & Resource Economists 39 (2017); Eric S. Hittinger & Ines M. L. Azevedo, *Estimating the Quantity of Wind and Solar Required To Displace Storage-Induced Emissions*, 51 Envtl. Sci.& Tech. 12988 (2017); Laura M. Arciniegas & Eric Hittinger, *Tradeoffs Between Revenue and Emissions in Energy Storage Operation*, 143 Energy 1 (2018); *Storing Solar Power Increases Energy Consumption and Emissions, Study Finds*, UTNews (Jan. 30, 2017), https://news.utexas.edu/2017/01/30/storing-solar-power-increases-energy-use-and-emissions.

emissions rates provide a much more accurate picture of whether energy storage deployment causes a change in emissions.

In addition, there are energy losses associated with charging, discharging, and maintaining charge.[18] These "round-trip efficiency" losses vary depending on the technology, and can be quite high.[19] As a result, even if there is no difference in the marginal emission rates between charging and discharging periods, energy storage can increase emissions by simply increasing the amount of energy generation needed to serve the same amount of load.[20] Therefore, the net emissions impact of energy storage varies depending on where, when, and how it operates, and would require a thorough analysis using marginal operational emission rates.

As explained above, using average emission rates, or focusing only on emissions avoided during discharging periods, would lead to inaccurate results. Therefore, energy storage systems should be evaluated by analyzing their *net* emissions with high temporal granularity, using the difference between the marginal emission rates during the discharging period and the marginal emission rates during the charging period. The granular approach using real-time greenhouse gas emissions rates, gives much more accurate information to energy storage operators.

c. Incentives Are Necessary in Order to Ensure Emissions Reductions

Greenhouse gases contribute to climate change and therefore cause external damages. Because these damages accrue to third parties and are not priced within the market, greenhouse gas emissions must be addressed by public policy.[21] The first-best solution to a negative externality such as greenhouse gas emissions is to place an economy-wide tax on greenhouse gases.[22] In the absence of an economy-wide greenhouse gas tax, policymakers should, where possible, put a price on greenhouse gas emissions based on the amount of external damage caused by those emissions.[23] Such pricing is crucial to fully internalizing the climate change externality and improving the efficiency of market outcomes. In the electricity sector, this would materialize as a wholesale market carbon charge. With

---

[18] Revesz & Unel, *supra* note 13, at 166.
[19] *Id.*
[20] *Id.*
[21] M. Greenstone, E. Kopits & A. Wolverton, Developing a Social Cost of Carbon for US Regulatory Analysis: A Methodology and Interpretation, 7 REV. ENVIRON. ECON. POLICY 23–46 (2013).
[22] M.L. Weitzman, Prices vs. Quantities, 41 REV. ECON. STUD. 477–491 (1974) (providing the theoretical motivation for preferring taxes over emission quantity restrictions in the case of climate change). For direct support of a carbon tax, see, e.g. Reuven S. Avi-Yonah & David M. Uhlmann, Combating Global Climate Change: Why a Carbon Tax is a Better Response to Global Warming than Cap and Trade, 28 STANFORD ENVIRON. LAW J. 50 (2009).
[23] Iliana Paul, Peter Howard & Jason Schwartz. The Social Cost of Greenhouse Gases and State Policy. October 2017 at 1. ("The best estimates of the SCC for states to draw from are currently the 2016 estimates from the federal government's Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), despite the fact that this group was recently disbanded. The 2016 IWG estimates are based on the most up-to-date science and economics and were arrived at through an academically rigorous, transparent, and peer-reviewed process. The National Academies of Science, Engineering and Medicine (NAS) conducted a thorough review of the IWG estimates in 2016, and a group of scholars at the nongovernmental organization Resources for the Future has begun a project to update the SCC based on the NAS recommendations.") (Attached as Exhibit F).

that policy lever in place, other signals or incentives are less necessary to reduce greenhouse gas emissions.

However, absent PJM adopting a wholesale carbon charge, similar to what NYISO is venturing to undertake, the Committee can embed greenhouse gas performance incentives into the 2019 EMP. This can be particularly useful for energy storage systems. Tying payments to emissions reductions provides the right incentives for operators to deploy and operate energy storage systems only when reductions can be achieved. A real-time greenhouse gas signal would encourage the same behavior, but absent a wholesale carbon charge, is not necessarily enough to prompt emissions reductions.

By accurately compensating energy storage operation, the Committee can take a step toward maximizing the net benefits of energy storage while solving the potential problem of energy storage increasing greenhouse gas emissions. If energy storage operators have the ability to understand the greenhouse gas consequences of their operations on a granular level, and if the Committee integrates that value into the payments that storage operators receive, the incentives of operators will be more aligned with the greenhouse gas reduction goals of the State.

In conclusion, Policy Integrity makes three recommendations for the Committee as it drafts the 2019 EMP:

1. Consider grid resilience in a holistic manner and apply cost-benefit analysis to resilience plans and investments;
2. Adopt a granular approach to DER compensation, rather than defer to net metering, including for distributed energy resources; and,
3. Design an incentive structure for energy storage operators to ensure that the use of energy storage systems reduce greenhouse gas emissions;

Policy Integrity looks forward to a draft version of the Plan and intends to continue to engage with the Committee in the next round of public comments.

Respectfully submitted,

Iliana Paul, Policy Associate
Institute for Policy Integrity
Iliana.paul@nyu.edu
212-998-6596

Exhibit A

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

ELECTRICITY POLICY INSIGHTS

(c) U.S. Air Force photo/Senior Airman Luke Hill

Toward Resilience

Defining, Measuring, and Monetizing Resilience in the Electricity System

August 2018
Burcin Unel, Ph.D.
Avi Zevin

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Burcin Unel is the Energy Policy Director at the Institute for Policy Integrity. Avi Zevin is an Attorney at the Institute for Policy Integrity.

Executive Summary

Resilience—the electric grid's ability to resist, absorb, and recover from high-impact, low-probability external shocks—is an important, yet wide-ranging and potentially amorphous concept. Many different actions can help the grid defend against, absorb, or recover from high-impact, low-probability shocks. However, some potential actions will do little to address specific threats and have been suggested for what appears to be political reasons. Moreover, many actions that can significantly enhance electric system resilience come at substantial cost. Systematically and transparently evaluating the cost of a potential resilience-enhancing action and its expected impact on the probabilities and consequences of grid outages is critical to evaluating whether that action is worthwhile from an economic efficiency perspective or whether it is misguided. To ensure that we make only efficient and cost-beneficial investments, decisionmakers must adopt a clear and useable definition of resilience, identify potential actions that improve resilience, and conduct an economic analysis of the social value of those actions. Only by engaging in this type of analysis can policymakers ensure that they do more than simply pick winners based on political preferences.

This report aims to assist policymakers in understanding grid resilience and evaluating potential interventions aimed at improving it. The following key insights can help policymakers improve the resilience of the electric system by acknowledging and responding to real threats in a systematic, transparent, and accountable way.

Defining and measuring resilience are necessary first steps.

- Grid resilience is a broad concept that can be simplified into a four-part framework. A resilient electric system is one that has the ability to (1) avoid or resist shocks, (2) manage disruption, (3) quickly respond to a shock that occurs, and (4) fully recover and adapt to mitigate the effects of future shocks.

- Resilience can be measured based on the performance of the system or its components (e.g., number of customer outage hours, monetized value of lost economic productivity). It can also be based on the attributes of the system or its components (e.g., how hardened the distribution system is to high winds, the extent to which replacement transmission components are readily available, the extent to which a generator is vulnerable to fuel-supply disruption). Attribute-based measures are easier to develop but also are potentially more misleading. Because of interactions among different threats and components of the electric system, improving one attribute may or may not improve resilience as a whole. Moreover, many of the attributes that have been suggested in recent federal policy discussions—such as whether a plant has historically operated to serve baseload demand or whether a plant was utilized during an extreme weather event—do not have a demonstrated connection to resilience. Performance-based metrics more directly measure resilience, are more reflective of the multi-faceted nature of resilience, and are more useful than system or resource attributes in quantitative analysis (such as cost-benefit analyses of potential resilience interventions).

- Investments to improve the resilience of individual components of the electric system—generation resilience, transmission resilience, distribution resilience—should all be considered, but must be measured with respect to how they improve overall *electric system resilience*.

Resilience policies and investments should be evaluated using a cost-benefit analysis framework.

- Policymakers should use a systematic, transparent framework for evaluating potential interventions, to ensure that the benefits of resilience-enhancing investments and policies justify the costs.
- A framework developed by Sandia National Labs is analytically intensive but can provide critical insight when comparing potential resilience interventions. This framework involves specifying threats, defining performance-based resilience metrics, using computer-modeling simulations to understand and monetize probabilistic baseline levels of resilience, and comparing those levels with monetized probabilistic estimates of resilience after potential interventions.
- The benefits identified using this framework can be compared to the costs of the policy or investment, including the costs to the utility of making investments, costs to customers that result from market rules that change energy prices, costs associated with any countervailing resilience risks, and environmental costs that result from changes to the grid mix.

In general, sufficient legal authorities exist at the state and federal levels to implement cost-beneficial resilience improvements.

- Because most customer outages are the result of disruptions to the distribution system, substantial focus on resilience should be on states, who have the authority to regulate distribution system investments and policies. States have numerous authorities to require resilience improvements.
- The federal role in enhancing resilience is restricted but important. The Federal Energy Regulatory Commission can use its authority over transmission investments, reliability standards, planning and coordination, and electric market rules to implement any identified cost-beneficial improvements to the bulk power system.
- The Department of Energy is vested with authority to respond to grid emergencies in the unlikely circumstance that existing market rules and reliability standards prove insufficient to respond to a high-impact, low-probability event. That authority must be exercised within the confines provided by Congress and subject to judicial review.

The Trump Administration's proposals to provide cost-based financial support to coal and nuclear plants do not reflect the best-practices for policy intended to support electric system resilience outlined in this report.

Table of Contents

Executive Summary i

Introduction 1

Understanding Resilience 4

The Basics: Defining and Measuring Electric System Resilience 4

Defining Electric System Resilience 4

Measuring Resilience 5

Putting it Together: The Phases of Electric System Resilience 7

Deepening Understanding: Grid Resilience Insights 8

Resilience Should Be Evaluated with Respect to the Full Electric System 9

Resilience Should Be Defined and Measured with Respect to Specific Threats 10

Resilience and Reliability are Distinct Concepts with Different Metrics 11

Evaluating Resilience Interventions 13

Incremental Benefits of Resilience Interventions 15

Step 1: Characterize Threats 16

Step 2: Define Resilience Metrics 16

Step 3: Quantify Baseline Resilience 17

Step 4: Characterize Potential Resilience Interventions 18

Step 5: Evaluate Resilience Improvements from Interventions 19

Limitations 19

Incremental Costs of Resilience Interventions 20

Relevant Examples from States 20

Addressing Resilience within the Federal System 22

A Brief Overview of the Electric System Jurisdictional Divide 22

States' Role in Improving Electric System Resilience 24

Directing Distribution Utilities to Make Resilience Investments 24

Rules to Encourage Resilience-Enhancing Distributed Energy Resources 26

Local Resilience Rules 28

The Federal Role in Improving Electric-System Resilience 28

FERC Can Establish Transmission-Compensation Rules that Enhance Resilience 30

FERC Can Approve Reliability Standards that Have Resilience Co-benefits 31

Federal Agencies Can Mandate or Facilitate Planning and Coordination Among Regional Entities 33

FERC Can Approve Market Rules that Create Incentives for Generation-System Resilience 34

DOE Can Issue Emergency Orders to Address Rare and Unforeseen Events If They Occur 37

Key Takeaways for Proposals to Subsidize Coal and Nuclear Plants Based on Grid Resilience 39

Conclusion 43

Introduction

Grid resilience—the electric grid's ability to resist, absorb, and recover from high-impact, low-probability external shocks—has concerned electric utilities and grid planners for decades. However, a recent series of extreme weather events and cybersecurity incidents, and political efforts by the Trump Administration to prop up certain favored generation sources, have brought a renewed focus to this critical electric sector issue.

In the United States, Superstorm Sandy in 2012 and the Polar Vortex in 2014 kicked off the recent focus on grid resilience as a critical infrastructure priority, resulting in congressionally mandated studies,[1] federally directed policy changes,[2] new state energy policies,[3] and private-sector investment and innovation.[4] A series of high-impact, low-probability events during the summer and fall of 2017 brought grid resilience back into the news, prompting discussion of policy changes to prepare for events such as hurricanes,[5] wildfires,[6] cybersecurity incidents,[7] and high-profile power failures.[8]

The Trump administration's attempts to promulgate policies that support coal and nuclear power plants under the pretense of enhancing resilience have also drawn attention to the issue. In September 2017, the United States Department of Energy (DOE) issued a controversial and high-profile directive to the Federal Energy Regulatory Commission (FERC) to consider and act on a proposal to provide economic support to power plants that maintain 90-days' worth of on-site fuel (primarily coal and nuclear plants).[9] DOE justified the need for this support by claiming these plants provide essential grid resilience benefits that wholesale electric markets fail to sufficiently value. FERC ultimately rejected DOE's proposal but initiated a proceeding to request additional information from grid operators on how to think about and enhance resilience.[10] More recently, President Trump ordered DOE to develop policies to forestall retirement of coal and

---

1 Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System vii (2017), https://www.nap.edu/catalog/24836 [hereinafter NAS] (describing the report's origin in a 2014 Congressional mandate that the Department of Energy conduct a "national-level comprehensive study on the future resilience and reliability of the nation's electric power transmission and distribution system").

2 *Order on Technical Conferences*, 149 FERC ¶ 61,145 (Nov. 20, 2014).

3 2015 New York State Energy Plan at 34-35, https://energyplan.ny.gov/-/media/nysenergyplan/2015-overview.pdf (discussing extreme weather events that contributed to the development of New York's "Reforming Energy Vision" energy policy).

4 Magdalena Klemun, *5 Market Trends That Will Drive Microgrids Into the Mainstream*, Green Tech Media (Apr. 9, 2014), https://www.greentechmedia.com/articles/read/5-market-trends-that-will-drive-microgrids-into-the-mainstream (showing microgrid investment was driven by recent extreme weather events).

5 This includes a series of hurricanes in the Gulf of Mexico that caused significant power outages, resulting in damage and lost economic opportunity in Texas and Florida. *See* Karma Allen & Maia Davis, *Hurricanes Harvey and Irma May Have Caused Up to $200 Billion in Damage, Comparable to Katrina*, ABC News (Sep. 11, 2017, 8:09 PM), http://abcnews.go.com/US/hurricanes-harvey-irma-cost-us-economy-290-billion/story?id=49761970; Arelis R. Hernandez et al., *SinLuz Life Without Power*, Washington Post (Dec. 14, 2017), https://www.washingtonpost.com/graphics/2017/national/puerto-rico-life-without-power/.

6 Ivan Penn, *Power Lines and Electrical Equipment are a Leading Cause of California Wildfires*, Los Angeles Times (Oct. 17, 2017, 2:05 PM), http://beta.latimes.com/business/la-fi-utility-wildfires-20171017-story.html

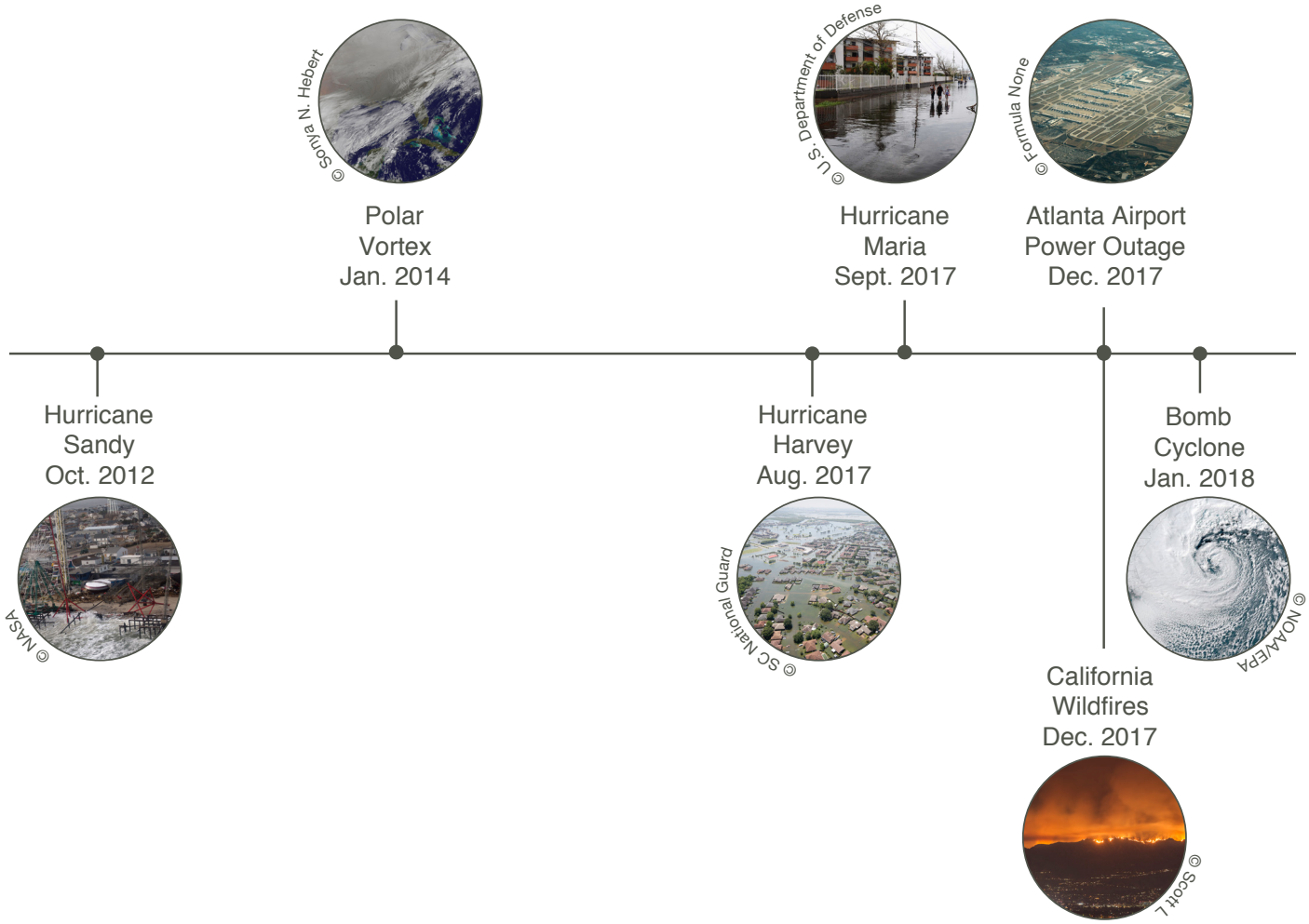
7 Michael Riley et al., *Russians Are Suspects in Nuclear Site Hackings, Sources Say,* Bloomberg (last updated July 7, 2017, 2:55 AM), https://www.bloomberg.com/news/articles/2017-07-07/russians-are-said-to-be-suspects-in-hacks-involving-nuclear-site.

8 Taylor Barnes & Jacey Fortin, *Power Failure at Atlanta Airport Snarls Air Traffic Nationwide,* NY Times (Dec. 17, 2017), https://www.nytimes.com/2017/12/17/us/atlanta-airport-power-out.html?hp&action=click&pgtype=Homepage&clickSource=story-heading&module=first-column-region&region=top-news&WT.nav=top-news.

9 *Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017) [hereinafter "DOE NOPR"].

10 *Grid Reliability and Resilience Pricing, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, 162 FERC ¶ 61,012 (Jan. 8, 2018) [hereinafter "FERC Resilience Order"].

Timeline of recent resilience threats



nuclear plants, asserting that planned retirements present national security concerns by "impacting the resilience of our power grid," which is used by military installations and defense-critical infrastructure.[11]

Recent events—particularly the devastation brought by long-term blackouts in Puerto Rico caused by Hurricane Maria in September 2017—have shown how damaging sustained power outages can be for U.S. citizens. And, while the DOE resilience proposal and the presidential order to DOE to keep coal and nuclear plants operational have been the subject of widespread criticism,[12] good-faith efforts to understand and improve the resilience of the electric grid at the local, state, regional, and federal levels are critical to the United States' continued prosperity.

If DOE, FERC, state and local governments, utilities, and grid operators are interested in truly improving resilience, they have many potential options. The process will require a systematic and considered focus; economic investment by ratepayers, utilities, and governments; and sustained and deliberate coordination and planning between utilities, grid operators, and regulators.

---

[11] Brad Plumer, *Trump Orders a Lifeline for Struggling Coal and Nuclear Plants*, NY Times (June 1, 2018), https://www.nytimes.com/2018/06/01/climate/trump-coal-nuclear-power.html.

[12] Jeff St. John, *Behind the Backlash to Energy Secretary Rick Perry's Demand for Coal-Nuclear Market Intervention*, Greentech Media (Oct. 5, 2017), https://www.greentechmedia.com/articles/read/behind-the-backlash-to-energy-secretary-rick-perrys-demand-for-coal-nuclear; Gavin Bade, *How Trump's 'Soviet-style' Coal Directive Would Upend Power Markets*, Utility Dive (June 4, 2018), https://www.utilitydive.com/news/how-trumps-soviet-style-coal-directive-would-upend-power-markets/524906/.

Resilience is a wide-ranging and potentially amorphous concept. A variety of actions can help the grid defend against, absorb, or recover from high-impact, low-probability shocks; however, many potential actions that do so come at substantial cost. For example, it is expensive to harden existing systems (that is, make the system more resistant to potential physical disruption) or build infrastructure that is needed only if existing infrastructure fails or is destroyed. In some cases, those costs may exceed the benefits of avoiding or quickly recovering from grid outages, and making such investments would not be beneficial to society. Therefore, the cost of resilience-enhancing actions, and their expected impact on the probabilities and consequences of grid outages are critical to evaluating whether an action is worthwhile from an economic efficiency perspective. Ensuring that we make only efficient and cost-beneficial investments will require a clear and useable definition of resilience, categorization of attributes that improve resilience, and economic analysis of the social value of those attributes. Only by engaging in this type of analysis can policymakers ensure that they do more than simply pick winners based on political preferences.

This report aims to assist policymakers in understanding grid resilience and evaluating potential interventions aimed at improving it. The report first provides a definition of resilience grounded in academic literature. It then outlines a framework to identify socially optimal resilience investments. Next it outlines the authorities that states and federal agencies have for improving grid resilience, consistent with the jurisdictional divides established by the Federal Power Act. Finally, it applies the insights developed throughout the report to recent proposals from the Trump Administration to provide financial support to coal and nuclear generators based on asserted resilience attributes.

Key Institutions with a Role in Grid Resilience

State Public Utility Commissions - State regulators, commonly called "public utility commissions" or "public service commissions," are responsible for regulating local distribution utilities, setting retail electricity rates, and deciding on other state-level policies, such as distributed energy compensation, renewable portfolio standards, and energy efficiency programs.

Federal Energy Regulatory Commission (FERC) - FERC is a federal regulatory agency responsible for ensuring just and reasonable rates for wholesale electricity and interstate transmission. It maintains the authority to regulate the market rules implemented by operators of wholesale electricity markets. FERC is also responsible for ensuring reliable operation of the bulk power system—the system of large electric generators and high-voltage transmission lines.

Department of Energy (DOE) - DOE plays a limited role in resilience. Its primary electric-system responsibilities consist of analysis, funding new technologies, issuing regulatory proposals for FERC's consideration, and ordering specific actions in the case of electric-system emergencies.

National Electric Reliability Corporation (NERC) - NERC is a non-profit corporation designated by FERC to ensure reliable operation of the bulk power system. NERC collects information on power system outages, conducts reliability analyses, and develops and enforces reliability standards.

Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) - ISOs/RTOs operate the wholesale electric system in two-thirds of the country, including operating competitive electricity markets. ISOs/RTOs ensure that supply and demand of the bulk power system are balanced using complex economic and engineering algorithms that take into account the location of both generators and demand, the costs of generation, and congestion in the transmission system. ISO/RTO-operated markets are also responsible for regional analysis, planning, and coordination of transmission and reliability.

Understanding Resilience

In order to improve electric system resilience, it is necessary to first have a common understanding of resilience, including what resilience is and how to measure it. This section starts with the basics, including the definition of resilience and how to measure it, and puts those concepts together into a useful conceptual model. It then draws implications of these concepts to give more nuance and provide a deeper understanding of grid resilience.

The Basics: Defining and Measuring Electric System Resilience

Defining Electric System Resilience

The concept of "system resilience" originates in the academic literature on ecological systems. Here, resilience was first defined as "a measure of systems and of their abilities to absorb change and disturbance and still maintain the same relationships between populations or state variables."[13] Since then, this concept has been applied to a variety of contexts and so has been incorporated into system planning across many disciplines. While the specific definition in each discipline varies, all definitions consider **the ability of a system to resist, absorb and adapt, and recover after an external high-impact, low-probability shock.**[14]

Over the last decade, a number of government entities have developed definitions of resilience for U.S. infrastructure in general, and for the electric system in particular.[15] These definitions have been broadly consistent with the academic literature and with each other. In its order rejecting DOE's resilience proposal and initiating a new proceeding to consider resilience in ISO/RTO markets, FERC synthesized these different efforts to arrive at a useable definition of resilience as

---

[13] C. S. Holling, *Resilience and Stability of Ecological Systems*, 4 Ann. Rev. Ecol. Syst. 1, 14 (1979).

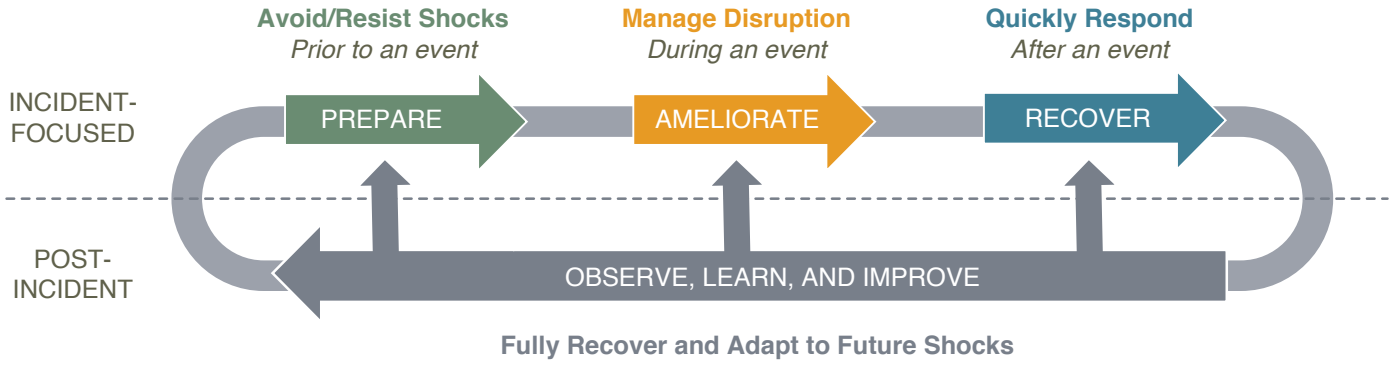
[14] Mathaios Panteli & Pierluigi Mancarella, *The Grid: Stronger, Bigger, Smarter?*, IEEE Power Energy Mag., May–June 2015, at 58, http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7091066; Min Ouyang & Leonardo Dueñas-Osorio, *Multi-dimensional Hurricane Resilience Assessment of Electric Power Systems*, 48 Struct. Saf. 15, 15–24 (2014), http://dx.doi.org/10.1016/j.strusafe.2014.01.001; Eric Vugrin et al., Sandia Nat'l Labs., Resilience Metrics for the Electric Power System: A Performance-Based Approach (2017), http://prod.sandia.gov/techlib/access-control.cgi/2017/171493.pdf; Dep't of Energy, Transforming the Nation's Electricity System: the Second Installment of the Quadrennial Energy Review 4–3 (2017), https://energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf [hereinafter "DOE QER"]; Henry H. Willis & Kathleen Loa, RAND Corp., Measuring the Resilience of Energy Distribution Systems, 1–25 (2015); Cen Nan & Giovanni Sansavini, *A Quantitative Method for Assessing Resilience of Interdependent Infrastructures*, 157 Reliabity Engineering & Sys. Safety 35 (2017), http://dx.doi.org/10.1016/j.ress.2016.08.013; Dep't of Energy, Staff Report on Electricity Markets and Reliability 63 (2017), https://energy.gov/sites/prod/files/2017/08/f36/Staff Report on Electricity Markets and Reliability_0.pdf [hereinafter "DOE Staff Report"].

[15] In 2013, President Obama signed Presidential Policy Directive/PPD 21: Critical Infrastructure Security and Resilience, which establishes national policy on critical infrastructure security and resilience. PPD 21 defines resilience of critical infrastructure (including the electric system) as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions." Presidential Policy Directive/PPD-21, *Critical Infrastructure Security and Resilience*, The White House (Feb. 12, 2013), https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil [hereinafeter "PPD-21"]. This definition was echoed by DOE in the Second Installment of the Quadrennial Energy Review, a comprehensive analysis of trends and set of recommendations for modernizing the nation's electricity system to lower costs, reduce environmental effects, ensure reliable access to electricity. DOE QER at 4-4 (defining residence as "the ability to prepare for and adapt to changing conditions, as well as the ability to withstand and recover rapidly from disruptions, whether deliberate, accidental, or naturally occurring.")
The National Academy of Sciences defines resilience as encompassing a process for "lessen[ing] the likelihood that [electricity] outages will occur" and "coping with outage events as they occur to lessen their impacts, regrouping quickly and efficiently once an event ends, and learning to better deal with other events in the future." NAS at 10.

it relates to the electric system: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recovery from such an event."[16]

The characteristics highlighted in the FERC definition can be divided into a four-part framework developed by the National Infrastructure Advisory Council. A resilient electric system is able to: (1) avoid or resist shocks, (2) manage disruption, (3) quickly respond to a shock that occurs, and (4) fully recover and adapt to future shocks. In its 2017 report *Enhancing the Resilience of the Nation's Electricity System*, the National Academy of Sciences adopted this framework and developed a useful graphic for visualizing it, presented in Figure 1.

Figure 1: Four-part framework for conceptualizing resilience



Adapted from: Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System 11 (2017), https://www.nap.edu/catalog/24836 .

Measuring Resilience

Resilience must be measured in order for policymakers and utilities to understand the electric system's current level of resilience, and evaluate potential interventions aimed at improving it. This requires a set of consistent resilience "metrics."[17]

The most useful type of resilience metrics are "performance-based." Performance-based metrics use quantitative data on either electric-system performance or the consequences of non-performance in the event of a high-impact, low-probability disruptive event.[18] These metrics can be based on the direct or indirect consequences resulting from such an event, depending on the goals and concerns of policymakers and grid operators. For example, a metric may focus on the direct consequences of a disruption to the generation, transmission, or distribution of electricity, such as the amount of energy services delivered to customers or the percentage of critical-customer energy demand served.[19] Alternatively, a performance-based metric may focus on indirect consequences or broader social perspectives, such as the availability of critical services that are at risk in the event of electric system outages (such as a potable water supply) or the general level of economic activity.[20]

---

[16] FERC Resilience Order, 162 FERC ¶ 61,012 at P 23.
[17] Panteli & Mancarella at 59; Nan & Sansavini at 38.
[18] Vugrin at 13.
[19] *Id.* at 19-20.
[20] *See* Watson.

A Less Useful Alternative Approach: Attribute-Based Resilience Metrics

Attribute-based resilience metrics are an alternative to performance-based metrics.[21] Attribute-based metrics identify properties of systems generally thought to be resilient and categorize the extent to which an evaluated system possesses those properties, using expert surveys. The political discussion surrounding grid resilience has focused on system attributes—e.g., number of generators with on-site fuel, whether a system is an islanded micro-grid—rather than performance measurements.

Argonne National Laboratory has developed an attribute-based methodology for grading the resilience of critical infrastructure, which can be applied to the electric grid.[22] Table 1 provides examples of electric-system attributes that can contribute to resilience for each resilience characteristic discussed in the four-part framework.

Table 1: Example Attributes of Resilient Systems, by Characteristic[23]

Avoid/Resist	Manage	Respond	Recover/Adapt
Deployment of Advance Warning Technologies	Fuel Security including Fuel-less Resources, Fuel Storage, Availability of Fuel Delivery Infrastructure	Ability to Reroute Around Damaged Resources	Ease of Coordination
Hardened/Weatherized	Ability to Separate/Island	Available Substitute Resources	Investment
Regular Maintenance/ Vegetation Management	Ability to Load Shed or Ration	Stockpiled Replacement Resources	Process for Learning from Past Failures
Quantity of Resources Available	Redundant Resources		Number of / Magnitude of Mutual Aid Agreements

For each attribute, a system or component is assigned a numeric score. For example, a distribution system with underground wires may be assigned a high "hardened" score, and each identified attribute can be similarly categorized. This data is then aggregated into a numerical resilience score using subjective weighting and simple arithmetic.

Attribute-based metrics may be appealing because they require less data collection than performance-based metrics, and they may be more easily understandable for casual observers. However, these metrics are more subjective, creating risks that improvements to the attribute will not translate into measurable or predictable improvements in resilience. For example, recent political discussion has focused on "fuel security" as a critical resilience attribute, but a recent analysis of the 2018 cold weather event known as the "bomb cyclone" concluded that coal units had higher forced outage rates than natural gas units, despite the fact that coal units are generally thought to have higher "fuel security" attributes than gas units.[24] In addition, attribute-based metrics, particularly when evaluated one-by-one, are less useful than performance-based metrics for accurately measuring changes in system resilience. For example, a system that is incredibly hardened but lacks redundancy, warning systems, and regular maintenance would be fragile. While a system with a moderate amount of each might be quite resilient.

---

[21] Vurgin at 12-13.

[22] F.D. Petit, et al., Argonne Nat'l Lab., Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience (2013), http://www.ipd.anl.gov/anlpubs/2013/07/76797.pdf.

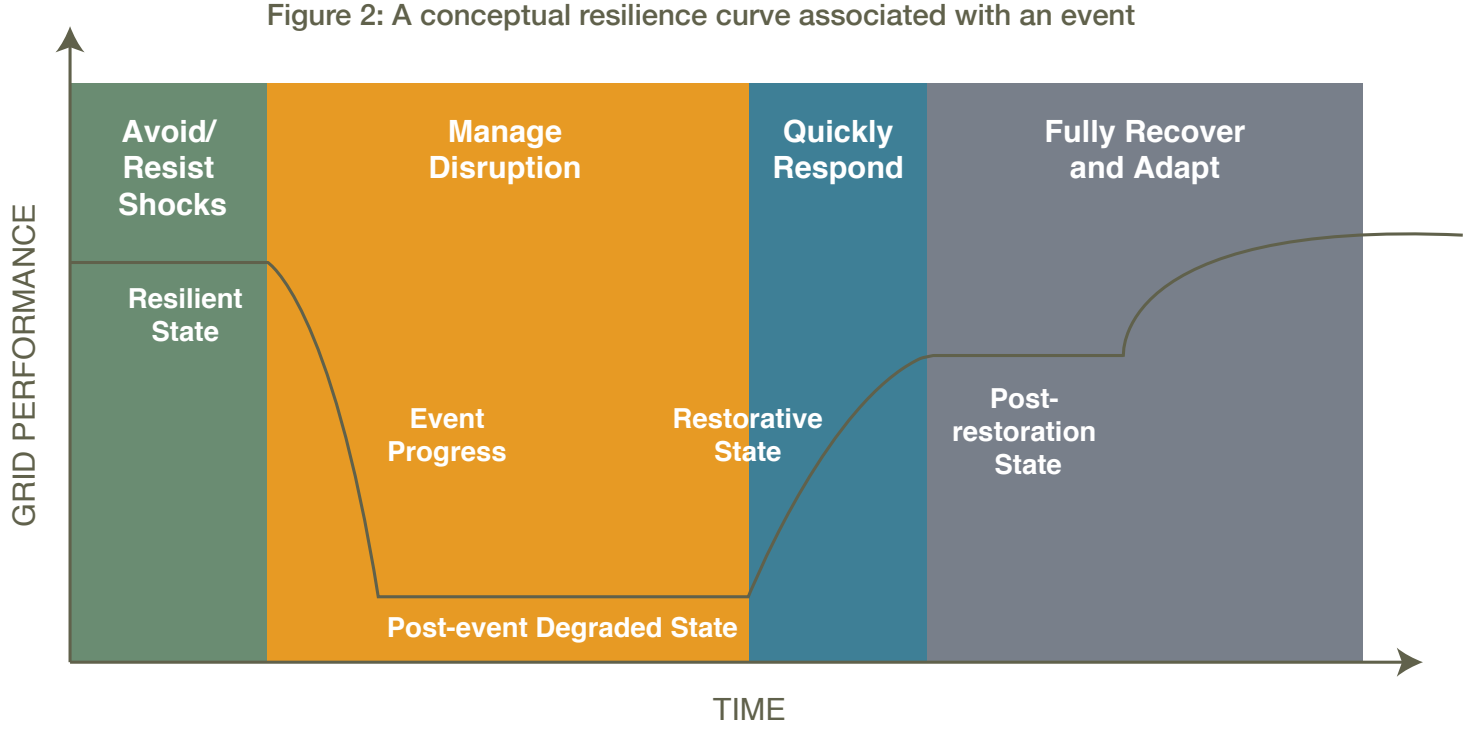
[23] This table is adapted from Watson at 29.

[24] PJM Interconnection, Strengthening Reliability: An Analysis of Capacity Performance (2018), http://pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en.

Putting it Together: The Phases of Electric System Resilience

The four characteristics of a resilient electric system outlined above can be conceptualized as four distinct phases of resilience in the event of a high-impact, low-probability shock, with different metrics and appropriate policy responses applied at each phase. Figure 2 shows a conceptual resilience curve that outlines the phases of resilience before, during, and after a high-impact, low-probability shock. In Figure 2, the vertical axis represents the performance of the system across time, before and after a high-impact, low-probability event.[25]

Figure 2: A conceptual resilience curve associated with an event



Adapted from: Mathaios Panteli & P Mancarella, *The Grid: Stronger, Bigger, Smarter?*, IEEE Power Energy Mag., 59 (2015)

This conceptual graph illustrates that the performance of the system, as measured by the chosen metric, will change over time as the system encounters each phase and exhibits the characteristics of resilience: the ability to (1) resist shocks when an event occurs, (2) manage shocks that disrupt the system, (3) respond to shocks by getting basic systems and services back online, and (4) fully recover from the shock and adapt for the future.

(1) The green area demonstrates an initial level of system performance in the period before an external shock. At this stage, the system's resilience depends on the capability of the system to **prevent and resist any possible hazards, and to reduce the initial damage if a hazard occurs**.[26] During this period, any resource or action that can reduce the probability of a high-impact, low-probability event or any initial damage would improve resilience. For example, when evaluating resilience in the face of a Category-5 hurricane, storm hardening efforts currently underway in many states reduce the probability of outages and increase the grid's ability to resist damage during the hurricane, increasing resilience. As another example, powering down nuclear plants in preparation for a hurricane can help prevent damage and ensure they remain available to provide electricity after the hurricane.

[25] Panteli & Mancarella at 59; Cen Nan & Giovanni Sansavini at 38.
[26] Panteli & Mancarella at 60.

(2) Once the high-impact, low-probability event happens, the system starts degrading (as illustrated in the orange area). At this stage, the system's resilience depends on the operational flexibility and resourcefulness of the system (and its operators) to quickly **manage evolving conditions and reduce the consequence of the event**.[27] During this period, any resource or action that can reduce the level of degradation or slow the system's degradation can improve resilience. For example, in the context of a hurricane, islanding microgrids can help reduce outages during the storm by minimizing the extent to which a single point of failure in the transmission or distribution system knocks out power for critical services, such as hospitals.

(3) Once the event ends, the system enters into a restorative/recovery mode (as represented in the blue area). At this stage, the system's resilience depends on whether it has a capacity to **enable a fast response** and on the amount of time required to repair the damages.[28] During this period, any technology or action that can expedite the recovery process would improve resilience. This is when on-site fuel can play a limited role in the event of a hurricane that has disrupted fuel transportation networks, such as pipelines. But, as the Puerto Rican grid's incredibly slow recovery from Hurricane Maria illustrates, the recovery capabilities of transmission and distribution generally serve as a bottleneck to power restoration and so tend to be far more important than generator resilience.

(4) Finally, the system enters into a post-restoration state and then an **infrastructure recovery period** (as represented in the grey area).[29] Whether the system can return to its initial resilience level depends on the severity of the event and the level of improvement and investment made in restoration.[30] While the system may return to normal operation during phase (3), full infrastructure recovery may take longer. For example, power may be restored quickly after a flood, even though replacing all the damaged equipment may take longer.[31] During this period, any technology or action that can reduce the time to fully recover would improve resilience. On the other hand, during this phase, the steady-state level of performance can exceed the level preceding the event if, for example, policymakers and grid operators operationalize lessons learned from the event or make investments that minimize risks of future events or of the magnitude of damage.

The transition times shown in Figure 2 are as important as the levels of the performance metric in characterizing the system's resilience.[32] It is important not only to minimize the consequence of, and hence the losses resulting from, the event but also to *ensure that the system degradation occurs slowly* and that *recovery occurs quickly*.[33]

Deepening Understanding: Grid Resilience Insights

A number of implications flow from this framework. First, resilience is a long-term, ongoing, and adaptive concept. Resilience is not achieved, but only improved. Second, resilience is about more than avoiding outages. A resilient electric system minimizes the frequency of unexpected post-shock outages. But even a resilient electric system can experience outages in the face of a high-impact shock. When outages occur, a resilient system is one that manages the consequences of outage events and recovers quickly.[34]

---

[27] *Id.*
[28] *Id.*
[29] *Id.*
[30] *Id.*
[31] *Id.*
[32] *Id.*
[33] *Id.*
[34] NAS at 10.

In addition, the definitions and measures of resilience suggest three larger implications:

- Resilience should be evaluated with respect to the full electric system, not just of individual components;
- Resilience should be defined and measured with respect to specific threats; and,
- Resilience and reliability are distinct concepts with different metrics.

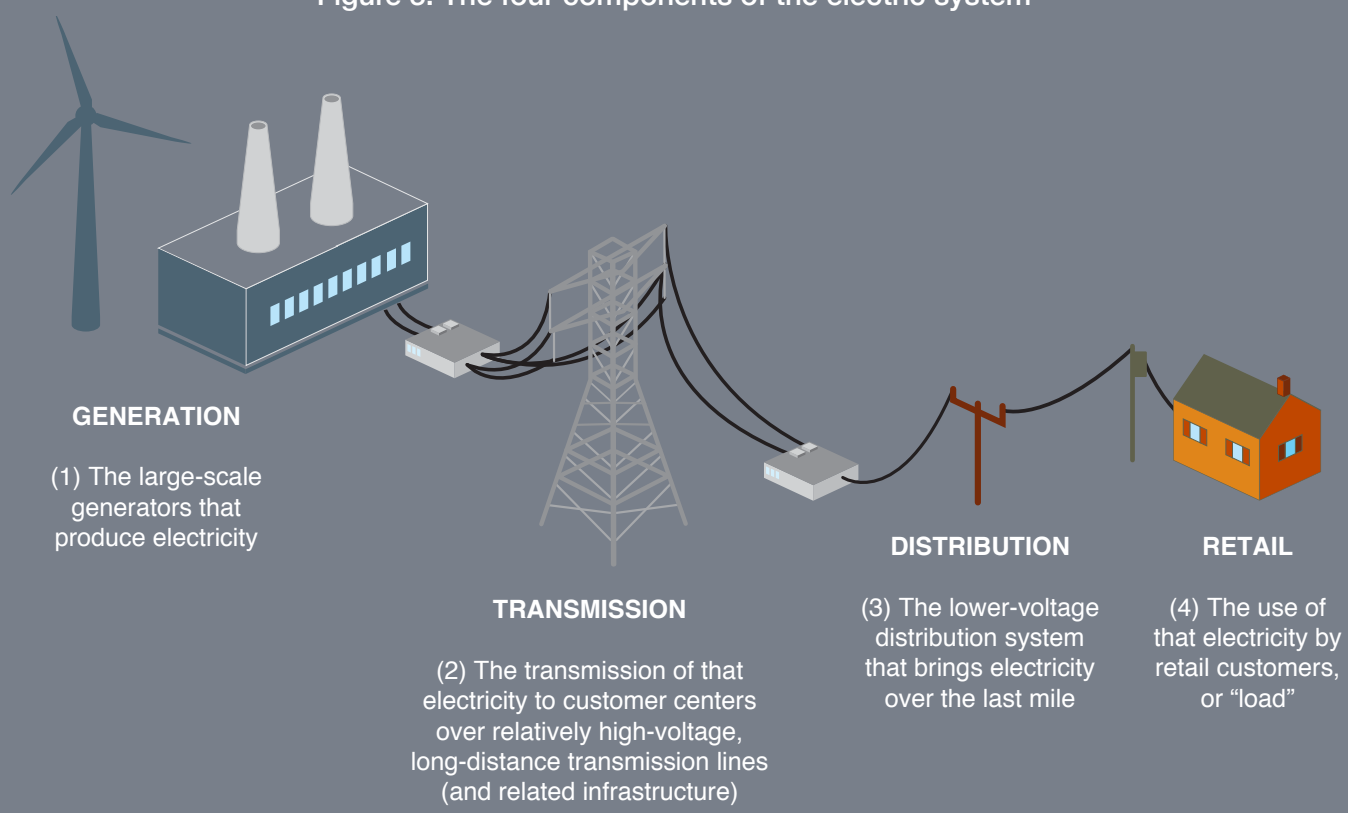
These are discussed in turn.

Resilience Should Be Evaluated with Respect to the Full Electric System

Individual components of the electric system may be vulnerable to high-impact, low-probability external shocks. Poorly maintained distribution infrastructure can cause or be disrupted by fire; a generating plant managed by poorly trained staff may be unprepared for a hurricane, resulting in permanent damage. In some cases, investments and policies that address the identified vulnerabilities of individual components in the electric system can enhance overall system resilience. This type of component-by-component resilience analysis can be characterized as:

- Generation resilience
- Transmission resilience
- Distribution resilience

Figure 3: The four components of the electric system



But resilience is not merely a sum-of-its-parts concept. Individually measuring or improving the resilience of each system component will not necessarily improve the resilience of the entire system. For example, significant investment in generator weatherization may do relatively little to reduce customer outages in the face of a Category 5 hurricane if distribution systems are not also hardened. In fact, interventions that improve the resilience of one system component can reduce the resilience of another, mitigating, and potentially reversing, improvements to system resilience. For example, subsidizing a large centralized generator with on-site fuel in order to mitigate the potential for outages caused by fuel-delivery disruption can increase the consequences of a physical attack on the transmission infrastructure that supports the centralized generator. The net effect of resilience improvements will depend on the relative probabilities of potential high-impact shocks, and the interactions of system components in the face of such shocks.

Therefore, in addition to evaluating whether a particular intervention is economically justified with respect to the appropriate component, regulators, grid planners, and utilities should evaluate the effect of the intervention on the electricity system as a whole. We refer to that concept as "system resilience."

Resilience Should Be Defined and Measured with Respect to Specific Threats

The electric system faces a wide variety of potential high-impact, low-probability shocks that can cause significant customer outages. Relevant threats may include extreme weather (hurricanes, tornadoes, wildfires, drought, extreme cold); sea level rise caused by climate change; other natural events, such as earthquakes and tsunamis; targeted physical attacks on electric infrastructure; cyberattacks; severe geomagnetic disturbances; and electromagnetic pulse events.[35]

Potential Significant Causes of Electricity System Outages		
Extreme Weather Event	**Human-Caused Event**	**Other**
Drought and water shortage Earthquake Flood and storm surge Hurricane Ice storm Tornado Tsunami	Cyberattack Physical attack Intentional electromagnetic pulse Major operation error	Volcanic event Space-based electromagnetic event Fuel supply disruption

Adapted from: Nat'l Acad. of Sci., Eng'g & Med., Enhancing the Resilience of the Nation's Electricity System, 50-69 (2017).

There is no overarching metric of resilience relevant for all known and unknown high-impact, low-probability disruptions; rather, the resilience of a system to one threat will likely be different from resilience to other threats. This is because the magnitude of vulnerability to one threat does not imply similar vulnerability to other threats. A system with weak cybersecurity defenses may have excellent physical security that protects against physical attacks. In addition, the risk of extended outages from different threats may even be inversely related; that is, actions taken in the name of grid resilience may improve the ability of the system to resist or recover from certain disruptive events yet undermine its ability to resist or recover from others. For example, putting wires underground may improve resilience against hurricane-force winds

[35] EPRI, Electric Power System Resiliency: Challenges and Opportunities 6-8 (2016), https://www.naseo.org/Data/Sites/1/resiliency-white-paper.pdf [hereinafter "EPRI"].

but may reduce resilience against earthquakes. Ensuring available on-site fuel may make the grid resilient to fuel-supply disruption but may expose the create new grid vulnerabilities related to significant flooding,[36] leakage,[37] or temperature variations that make stored fuel unusable.[38]

These differences mean that policymakers must prioritize threats. Because resilience focuses on low-probability events, "making every corner of our utility systems resistant to failure would prove cost-prohibitive."[39] Measures to improve electric system resilience should be undertaken selectively to address the specific threats that pose the greatest risk for a given geographic area and electric system component.

Resilience and Reliability are Distinct Concepts with Different Metrics

The definition of resilience is different from the related and often conflated concept of "grid reliability." NERC defines reliability to include two concepts:

- "Operational reliability" is the ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts; whereas
- "Resource adequacy" is the ability of the electric system to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages.[40]

Whereas resilience is concerned with the ability of the system to prevent and recover quickly from outages caused by high-impact, low-probability events, reliability focuses on limiting the occurrence or spread of outages caused by (relatively) low-impact, high-probability events such as power surges and sudden increases in demand.[41] For example, a Category 5 hurricane that destroys substantial portions of the transmission and distribution system creates a resilience problem when it results in long-term electric system outages for a substantial number of customers until infrastructure can be replaced or rebuilt. On the other hand, an unexpected power surge on a distribution line may create a reliability problem by overloading a key circuit, causing some customers to lose power for a relatively short period. Reliability problems can become resilience problems to the extent that, if not properly managed, they result in cascading blackouts and destruction of infrastructure that requires substantial recovery operations.[42]

Reliability interventions generally seek to lessen the likelihood of outages. Resilience is similarly concerned with lessening the likelihood of disruptive but less-common events, but it also recognizes that disruption will likely occur in the case of

---

[36] Mark Watson, *Harvey's Rain Caused Coal-to-Gas Switching: NRG Energy*, S&P Global Platts (Sept. 27, 2017, 5:22 PM), https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527.

[37] Robert Walton, *CAISO Considers Making Aliso Canyon Gas Reliability Measures Permanent*, UtilityDive (June 8, 2017) https://www.utilitydive.com/news/caiso-considers-making-aliso-canyon-gas-reliability-measures-permanent/444522/

[38] N. Am. Elec. Reliability Corp., Polar Vortex Review 3 (2014); *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Winter 2013-2014 Operations and Market Performance in RTOs and ISOs*, 149 FERC ¶ 61145 at 8 (Apr. 1, 2014), https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[39] Miles Keogh & Christina Cody, Nat'l Assoc. Reg. Util. Comm'rs, Resilience in Regulated Utilities 1 (2013), https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D.

[40] NERC, Frequently Asked Questions 1 (2013), https://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf (Operational reliability is also sometimes called "security").

[41] Panteli and Mancarella at 60; Vurgin at 8. Watson at 16.

[42] The 2003 Northeast blackout serves as a good example of a reliability problem that, left untreated, became a resilience problem. *See* FERC, Reliability Primer 31-32 (2016), https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf [hereafter "FERC Reliability Primer"].

a high-impact event. It therefore also focuses on establishing systems to manage and quickly recover from the disruption. As such, the National Academies of Sciences have concluded that "resilience is broader than reliability."[43]

As different (if related) concepts, resilience and reliability must be measured separately. Reliability is a static concept measured by well-defined and consistent metrics.[44] The two most frequently used metrics are measures of the *duration* of system outages (System Average Interruption Duration Index (SAIDI)) and the frequency of system outages (System Average Interruption Frequency Index (SAIFI)).[45]

However, these metrics are not generally appropriate for directing useful resilience decision making. They fail to consider that the impact of an interruption increases the longer the duration of the disruptive event.[46] And regulators often exclude major events when using these metrics because the effect of those events can swamp the smaller events that reliability interventions are generally created to address.[47] Because of the differences between the concepts, the metrics for reliability are not suitable for measuring resilience.[48]

---

[43] NAS at 1.
[44] Panteli and Mancarella at 60; Vurgin at 8; Watson at 16.
[45] *See* Keogh at 6.
[46] *Id.* at 7-8.
[47] *Id.*
[48] *Id.* at 11-12.

Evaluating Resilience Interventions

Resilience of the grid to high-impact, low-probability events is a "public good." Public goods are typically underprovided by the market.[49] During a blackout, no generator is able to sell energy. As a result, when a resilience investment prevents or reduces the time of a blackout, all generators that would have sold power benefit. Similarly, given that no consumer can receive energy during a blackout, all consumers benefit from investments that forestall or mitigate a blackout, regardless of whether they pay directly for that service. Resilience investments made by utilities do not necessarily take into account all potential benefits to other entities, so they often will yield a sub-optimally low level of investment needed to facilitate the socially desirable level of resistance, management, response and recovery from high-impact, low-probability shocks. And, therefore, government must play a critical role in ensuring an efficient level of grid resilience.

One of the key challenges of an open-ended and multifaceted public good such as resilience is that regulators and utilities must determine the optimal level and type of resilience interventions. Resilience interventions could include physical improvements, such as hardening the distribution and transmission networks or weatherizing power plants;[50] operational improvements, such as using advanced awareness systems or adaptive islanding;[51] or increased deployment of distributed energy resources and microgrids.[52]

As discussed above, resilience is not binary; the grid is neither "resilient" nor "not resilient." Resilience exists on a spectrum. The grid can maintain different levels of resilience against different types of threats (weather, cyberattack, physical attack, geomagnetic disturbance) at different phases (resistance, continued operation, response, recovery). Improving any of these aspects requires the investment of time and resources; therefore, society must consider how much resilience is the appropriate amount.

Key Term: Public Good

A "public good" is a good or service that is non-rival and non-excludable. Non-rivalry means that the good or service being enjoyed by some does not prevent others from enjoying it simultaneously. Non-excludability means that it is not possible to prevent individuals from enjoying the benefits of the good or service even if they do not pay for it. Public goods are generally underprovided by the market because market participants cannot capture enough value individually to justify investing in the good at the socially efficient level. In order to ensure economically efficient levels of public goods, government intervention—such as direct investment, subsidy, or regulation—is necessary.

---

[49] NAS at 14.

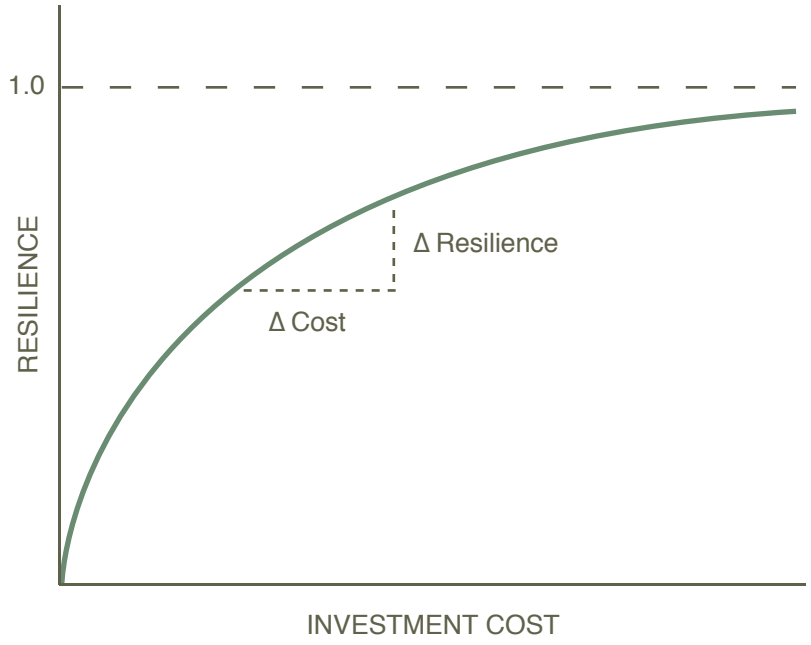
[50] Panteli and Mancarella at 60.

[51] Yi Ping Fang et al., *Resilience-Based Component Importance Measures for Critical Infrastructure Network Systems*, 65 IEEE Transactions on Reliability 502, 502–512 (2016), http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7407429; Mathaios Panteli et al., *Boosting the Power Grid Resilience to Extreme Weather Events Using Defensive Islanding*, 7 IEEE Transactions on Smart Grid 2913, 2913–2922 (2016), http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7407429; Eric D. Vugrin et al., *Optimal Recovery Sequencing for Enhanced Resilience and Service Restoration in Transportation Networks*, 10 Int. J. Critical Infrastructures 218 (2014), http://www.inderscience.com/link.php?id=66356.

[52] NAS at 77-78.

The tradeoff between a given level of resilience and the investment needed to achieve that level of resilience is conceptually represented in Figure 4. This figure shows that a change in investment (ΔCost) will yield a change in resilience (ΔResilience) and that a 100% level of resilience is not achievable.[53]

Figure 4: Incremental cost of resilience



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 53 (2015).

Also, because of the variety of threat types and potential interventions, resource allocation among threats and technological solutions is critical. Government entities and utilities, therefore, need a decision framework that helps them decide which investments or projects to improve resilience are worthwhile and which are not.

In the second installment of its Quadrennial Energy Review, DOE suggests that cost-benefit analysis should be used to evaluate resilience investments.[54] In its recent compliance filing in FERC's resilience docket, the California ISO also advocated using cost-benefit analysis to assess potential resilience interventions.[55]

Using cost-benefit analysis to evaluate resilience policies and investments has two main advantages:

- First, cost-benefit analysis can help policymakers and utilities develop policies and make investments that maximize social welfare. Investments are socially efficient when the incremental cost of achieving the level of resilience—that is, the last dollar needed to achieve a particular level of resilience—is equal to the incremental

[53] Engineers who study resilience represent the performance of a system over the course of an event using formulas where the resilience metrics span the range of 0 (lowest level of performance during an event) to 1 (return to steady-state level of resilience). Yi Ping Fang at 65. This is reflected as the Y-axis in Figure 4.

[54] DOE QER at 7-22.

[55] Comments of California Independent System Operator Corporation at 8, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (March 9, 2018).

resilience benefit—that is, the benefit of the last "unit" of resilience achieved. When choosing among conflicting options, the efficient investment would maximize net benefits to society.[56] This approach can be used regardless of whether the investments will be made by government entities or by utilities at the direction of regulators.

- Second, evaluating potential policies and investments using a systematic and evidence-based framework can help to ensure that proposals are actually effective (and cost-effective) in enhancing resilience, rather than just pretext for providing financial support to favored industries. For example, policymakers can use cost-benefit analysis to evaluate whether proposals to limit retirement of coal and nuclear plants would achieve their goals of reducing the expected costs of a cyberattack on natural gas pipeline infrastructure and reducing outages at defense-critical facilities such as military bases. Such analysis is particularly important for policy proposals, such as this, which would impose substantial costs, upend electricity markets, and potentially fail to achieve resilience goals, according to substantial expert criticism.[57] Cost-benefit analysis can provide the public and courts a transparent basis to evaluate proposals to determine whether the means chosen to enhance resilience match the specific threats identified.

Conducting cost-benefit analysis requires an evaluation of the incremental benefits and incremental costs of various resilience-improving policies and investments. The rest of this section outlines methods for evaluating these benefits and costs, and then highlights examples of state policies and studies that have put similar methodologies into practice.

Incremental Benefits of Resilience Interventions

To determine the efficient level of different resilience policies or investments, decisionmakers must first understand the expected benefits of such actions. Resilience policies and investments are valuable because they allow society to avoid or mitigate costs that would be imposed by a high-impact, low-probability event. For example, an investment that reduces 1000 customer outage hours from a hurricane provides society with benefits equal to the economic value of avoiding those outage hours. Calculating the benefits of resilience investments and policies involves quantifying the probability-weighted costs of disruptions, and how those costs change based on the investments and policies being considered. Therefore, resilience benefits are a function of the probability of each particular high-impact, low-probability event; the social cost if the event were to occur; and the extent to which the investment reduces the event's probability or impact.

In this section, we lay out a streamlined version of a framework for calculating the benefits of resilience investments and policies that was developed by Sandia National Laboratory as part of the DOE Metrics Analysis for Grid Modernization Project.[58]

---

[56] Office of Mgmt. & Budget, Circular A-4 at 10(Sept. 17, 2003), *available at* https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf [hereinafter "Circular A-4"].

[57] *The Electric Grid of the Future: Hearing Before the Energy Subcomm. of the H. Sci. Comm.* (2018) (testimony of Robert E. Gramlich President, Grid Strategies LLC), https://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-115-SY20-WState-RGramlich-20180607.pdf.

[58] Vugrin. Sandia produced a useful example of how this framework can be used to evaluate the benefits of different resilience interventions, including investments in line-burying and flood walls, and policy responses such advanced planning in the event of a hurricane. *See* Wastson et al at 73-80.

Step 1: Characterize Threats

First, policymakers must identify and characterize the specific threats against which the system should be resilient; examples include a hurricane exceeding a specific category, earthquakes exceeding a certain magnitude, a cyberattack that disables physical infrastructure control systems (called "SCADA systems"), and extreme cold or heat for specified durations.

Selecting relevant threats for which the policymaker is responsible will involve a combination of judgment and probabilistic analysis about the events most likely to significantly disrupt the electric system. In many instances, the threats identified will differ by region. The benefit of protecting against hurricane-force winds is likely greater in Tampa than in Los Angeles, whereas the benefit of improving distribution system resilience with respect to wildfires or earthquakes may be greater in San Francisco than in Houston. The probability of human-caused threats, such as cyberattacks or physical security attacks, will differ by region—attacks are more likely in Paris, France than Paris, Texas. Moreover, due to higher population density and economic output, the magnitude of impact and therefore the benefit of an intervention may be greater in New York City than in Duluth.

This step involves not only the identification of types of disruptive events but also a detailed specification of threat scenarios against which resilience improvements will be measured (e.g., the magnitude and location of an earthquake along with the number and magnitude of aftershocks). These scenarios should include probability estimates for the threats, which will be incorporated into later steps.

Step 2: Define Resilience Metrics

Next, policymakers should define the specific resilience metrics that will be used to measure the existing level of system resilience given the threats identified in Step 1, and the potential level if investments or policy changes are made.

In order to be useful in quantitative analyses of resilience, metrics should be performance-based and have the following features:

- Measurable in terms of the *consequences* expected to result from particular threat types.
- Reflect uncertainty (e.g., the expected consequence or the probability of the consequence occurring exceeds an acceptable level).[59]
- Use data from computation models that incorporate historical experience or expert evaluation.

Metrics can be direct (e.g., the cumulative number of customers or hours without power after an event) or indirect (e.g., the number of critical services without power for more than the time they typically have backup power). These metrics should then be monetized for use in a holistic cost-benefit analysis, such as the cost of electric system repair and the economic value of lost load.

For example, in a study of how on-site renewable energy and storage systems can improve the resilience of electricity delivery to buildings in New York City, researchers at the National Renewable Energy Laboratory and the City University

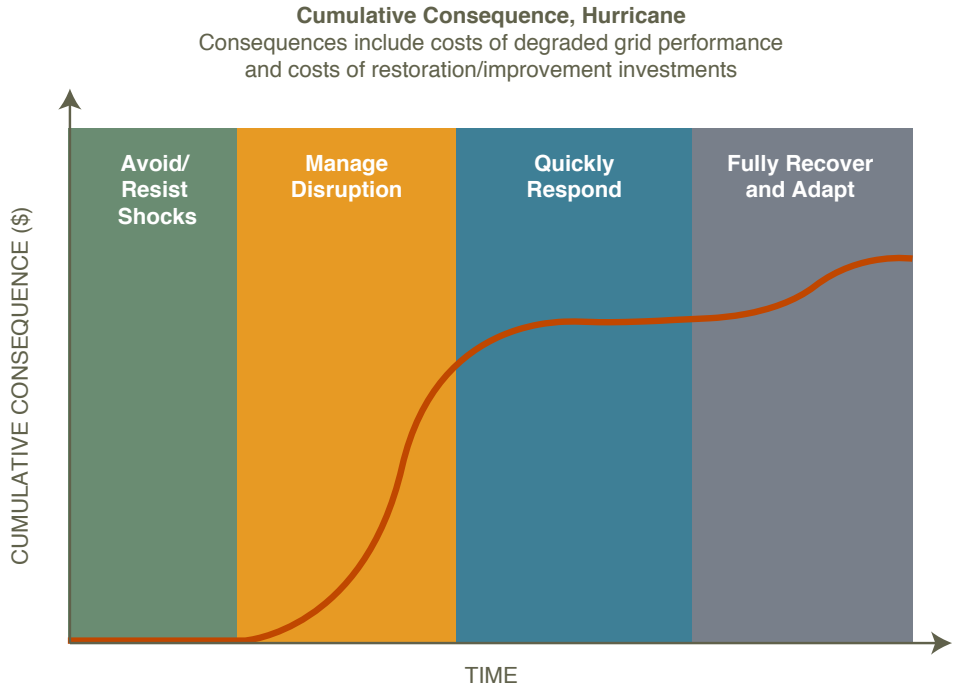
[59] Vugrin at 16-17.

of New York developed a resilience metric—the "value of resiliency."[60] This metric was calculated as the Value of Lost Load multiplied by the increased amount of "critical load" that could be served during a grid outage due to installation of on-site renewable energy and storage.[61]

Step 3: Quantify Baseline Resilience

This step involves the quantification of the baseline level of resilience—how the identified threats are expected to affect generation, transmission, distribution, and customer infrastructure, without any policy intervention. This specification can include which assets may be lost or degraded as well as repair/replacement time and cost. Ranges can be used to incorporate uncertainty. Policymakers and planners can then use system-level computer models to more fully evaluate the systemic effects of that infrastructure disruption. These simulations can facilitate calculation and quantification of the expected consequences of each hazard over time. These consequences should be expressed in terms of the monetized resilience metrics developed in Step 2. As illustrated in Figure 5 the lost economic value caused by power outages and the cost of infrastructure repair can be summed over time to produce a cumulative assessment of the consequences of a threat.

Figure 5: Calculating cumulative consequences of a threat



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 39 (2015).

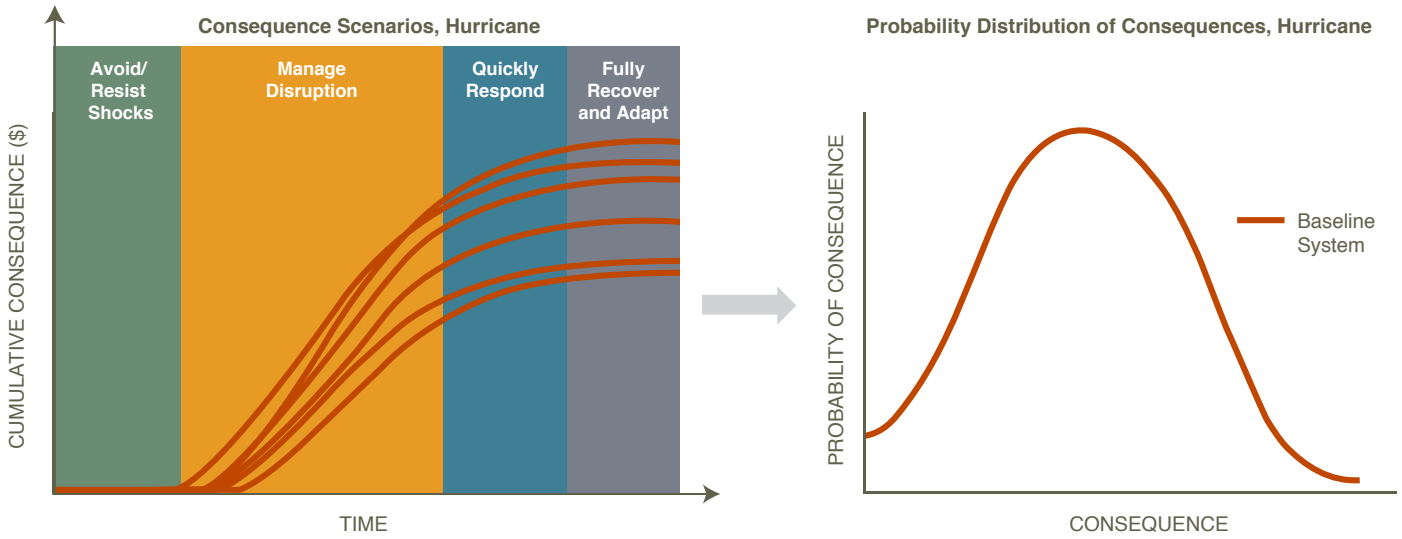
---

[60] *See* Kate Anderson et al., *Quantifying and Monetizing Renewable Energy Resiliency*, 10 Sustainability 933 (2018), http://www.mdpi.com/2071-1050/10/4/933/htm#B13-sustainability-10-00933.

[61] The researchers used a Value of Lost Load of $100 per kWh. Modeling showed that the renewable energy plus storage system under consideration would allow a building to sustain load for three times longer than a diesel backup generator; and so valued the resilience benefit of that system at $781,200. *Id.* § *See also The Interruption Cost Estimate Calculator 2.0*, ICE Calculator, https://icecalculator.com/home (last visited July 31, 2018) for an online tool developed by Lawrence Berkeley National Lab to estimate interruption costs or improvement benefits.

Because resilience is concerned with high-impact, low-probability events, it is important to take into account uncertainty in what level of disruption a given event will cause. In the baseline analysis, regulators can use the computer models to simulate different scenarios that reflect changes in threat significance or other key variables. These various simulations can be combined to produce a probabilistic value of the consequence of a threat. This is demonstrated in Figure 6.

Figure 6: Probabilistic Consequence of a Threat



Adapted from: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 39 (2015).

Step 4: Characterize Potential Resilience Interventions

Once the baseline resilience is identified, the goal is to calculate the value of resilience improvements achievable through particular interventions. These interventions could come in the form of mandated or direct investments in the generation, transmission, or distribution systems (such as fuel storage, hardening, or vegetation management), or they could be regulatory policies, such as requiring coordination among grid operators and utilities; changing market rules to provide market participants performance or investment incentives; or mandating specific actions, such as cybersecurity practices.

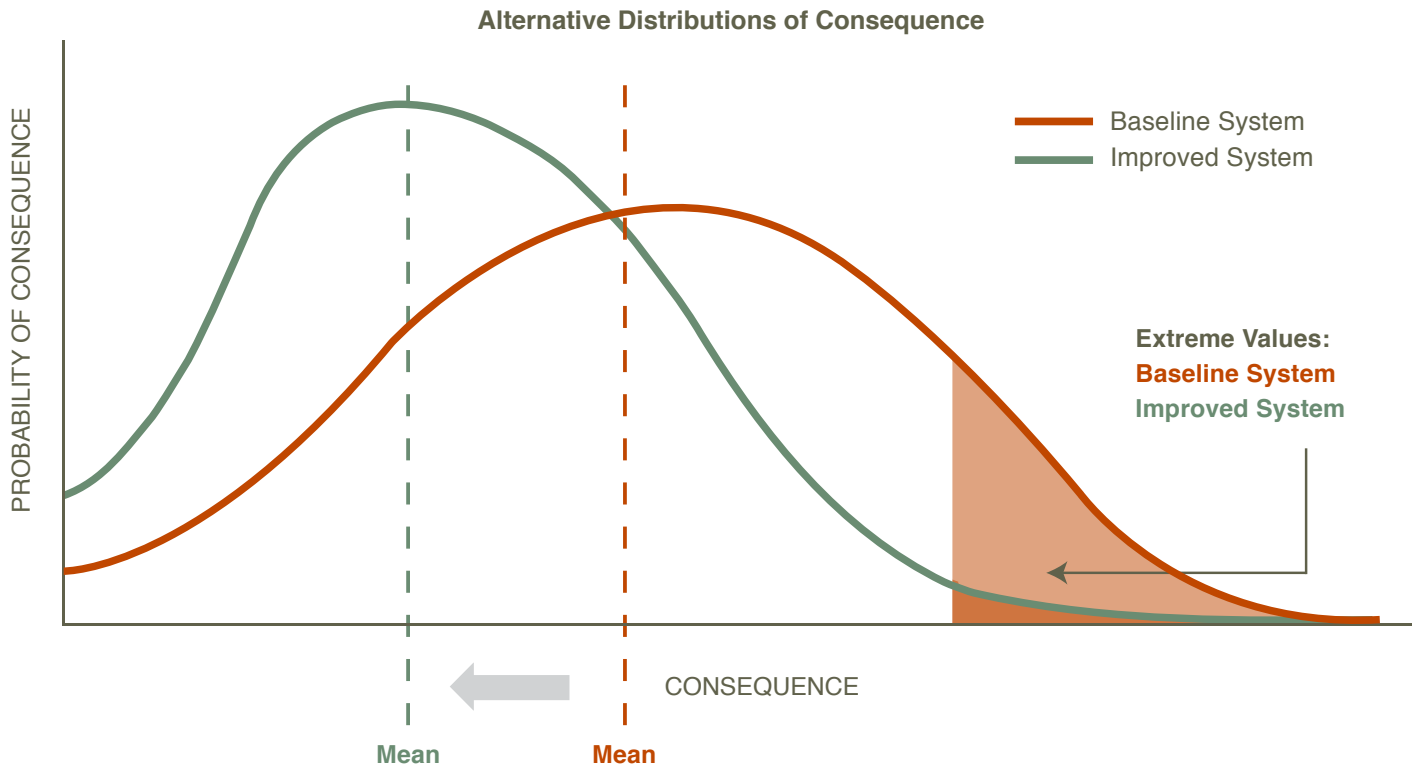
Once a menu of potential interventions is identified, the effects of interventions can be characterized. Some interventions enhance resilience by reducing the probability of specified threats. For example, strict password security protocols can reduce the likelihood that hackers penetrate utility control systems. While quantification of the change in threat probability of an event may be particularly difficult, policymakers can, nonetheless, make reasonable assumptions. Other interventions enhance resilience by reducing the magnitude of disruption that will occur in the face of identified threats. For example, an intervention might reduce the time needed to deploy new infrastructure by maintaining an infrastructure reserve or by facilitating islanding of a slice of the electric system to prevent cascading blackouts.

Step 5: Evaluate Resilience Improvements from Interventions

Evaluating the benefits of each potential intervention involves repeating Step 3, but with appropriate changes made to the electric system simulation models based on the particular policy or investment characterized in Step 4. The monetized savings between the baseline resilience metrics and the improved resilience metrics constitute the benefits of the intervention.

Figure 7 graphically demonstrates how a baseline level of resilience and resilience after an intervention can be compared.

Figure 7. Comparing resilience consequences of baseline and intervention scenarios.



Source: Jean-Paul Watson et al., Sandia Nat'l Labs., Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States 40 (2015).

Limitations

While this framework establishes a pathway for quantifying the benefits of resilience interventions, it carries substantial information requirements. This methodology requires understanding the probability distributions and likely damage functions of the underlying high-impact, low-probability events. We have limited information on these events due to their nature; incorporation of uncertainty into the analyses is therefore critical. In addition to quantifying baseline resilience, the methodology requires sufficient data to predict the extent to which investments and policies will change the probabilities and consequences of threats.

Incremental Costs of Resilience Interventions

There are a number of cost categories when evaluating potential resilience interventions. OMB Circular A-4 provides guidance to federal agencies regarding the estimation of costs and benefits of agency decisions and can serve as a useful guide for the consideration of the costs of resilience interventions.[62] Circular A-4 directs agencies to consider private-sector compliance costs, administrative costs, losses in consumer and producer surpluses, costs associated with countervailing risks, and health and safety costs.[63] Resilience investments and policies can impose costs in all of these categories.

Resilience investments and policies have direct, monetary costs on entities responsible for building or improving infrastructure. These may include project costs to improve or harden existing electric system infrastructure, build new transmission or distribution lines, or stockpile components; investments in cybersecurity and physical security; and costs related to planning or coordination exercises.

Policies that improve resilience by changing market rules can also result in additional consumer costs through increases in the price of electric energy and capacity. Because of the complex relationship between firm and consumer behavior affected by market rule changes, calculation of these costs may require the use of power sector and electric market modeling.

Resilience interventions can entail additional costs related to increases in countervailing risks. Interventions that improve resilience of one phase (resistance, continued operation, response, or recovery) may ultimately undermine the resilience of another phase. For example, putting transmission lines underground may significantly improve the resistance of transmission to disruption, but it will also make recovery more difficult if disruption occurs (e.g., due to flooding). As such, regulators and utilities should also evaluate an intervention's associated trade-offs, and the total effect on electric system resilience across phases. Costs associated with countervailing resilience risks can be calculated using the framework outlined above.

Some resilience interventions may also have environmental costs. Policy changes and infrastructure investments can alter the incentives to operate various power plants with different environmental performance, such as different rates of air pollution emissions. Similarly, investments in new infrastructure can result in environmental impacts associated with project development. These environmental effects can be quantified and monetized as environmental costs.

Relevant Examples from States

While methodologies to quantify the costs and benefits of resilience improvements have not been widely used in regulatory proceedings, there are some recent examples that can serve as a basis for policymakers.

New York State discusses a methodology for quantifying resilience benefits in the Benefit-Cost Analysis Framework associated with the state's Reforming Energy Vision proceeding.[64] Utilities use the Benefit-Cost Analysis Framework

---

[62] *See* Circular A-4.

[63] *Id.* at 26, 28, 37.

[64] Order Establishing the Benefit Cost Analysis Framework, Case No. 14-M-0101 at Appendix C 2 (N.Y. PSC 2016) http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d.

when evaluating certain types of utility expenditures (on distribution projects, distributed energy resources, and energy efficiency programs).[65] While the general method outlined by New York offers a good conceptual example of how state regulators can approach valuing the benefits of resilience, the specific metrics used by utilities appear to better reflect reliability than resilience.[66] New York is not alone; many utilities estimate the value of lost load due to a high-impact, low-probability event using the Interruption Cost Estimate calculator. However, research suggests that this tool, developed primarily for evaluating reliability improvements, is not appropriate to use for evaluating potential resilience improvements.[67] Research is underway to further develop a resilience-focused value of lost load metric.[68]

In the wake of several significant hurricanes, the Public Utility Commission of Texas commissioned a cost-benefit analysis of vegetation management programs, ground-based patrols, infrastructure hardening, and deployment of new technologies.[69] This analysis used a probabilistic hurricane model as well as two primary metrics for evaluating resilience benefits: the avoided cost to repair or replace existing infrastructure, and expected changes in gross domestic product (GDP) for hurricane-prone areas.

Academic researchers are using similar techniques to estimate the resilience value of certain interventions. For example, a group of researchers associated with the National Renewable Energy Laboratory and the City University of New York published a study evaluating the net resilience benefits at the building scale of pairing renewable energy systems with existing backup diesel generators.[70] These existing approaches can serve as a model for regulators and utilities.

---

[65] *Id.* at 1-2.

[66] *See, e.g.,* New York State Electric & Gas Corp., BCA Handbook Version 1.1 55-59 (2016), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF0CC59D0-4E2F-4440-8E14-1DC07566BB94%7D.

[67] EPRI at 46.

[68] Anderson, 10 Sustainability 933.

[69] Quanta Tech., Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs 45-66 (2009), http://www.puc.texas.gov/industry/electric/reports/infra/utlity_infrastructure_upgrades_rpt.pdf.

[70] Anderson, 10 Sustainability 933.

Addressing Resilience within the Federal System

The electric grid is an interconnected whole; however, under U.S. law, the grid is subject to divergent and sometimes overlapping regulatory control by federal and state entities. Any needed grid resilience improvements will require action at different levels of government as well as coordination among regulators, grid operators, and utilities. However, that there is bifurcated jurisdictional authority does not imply that there are gaps. Sufficient authorities exist at the federal and state levels to allow for cost-beneficial resilience-enhancing actions, including investments, policies, planning and coordination.

This section begins with a brief overview of the jurisdictional divide in responsibility between state and federal regulators. It then identifies specific regulatory authorities and tools that states have to enhance electric system resilience and makes some recommendations for improvements. Finally, it identifies authorities that the federal government has to enhance electric system resilience and makes recommendations for which authorities are appropriate under different circumstances.

A Brief Overview of the Electric System Jurisdictional Divide

The Federal Power Act gives the states regulatory responsibility over both retail sales of electricity and electric utilities responsible for local distribution infrastructure.[71] In addition, it provides states authority over electric generators (though not over the wholesale sale of the electricity that they produce), including the ability to enact policies that create preferences for certain power sources over others such as renewable portfolio standards. States also have regulatory responsibility over small generators that are interconnected with the distribution system rather than the transmission system, including responsibility for setting the rates paid for electricity generated from these distributed sources.[72]

On the other hand, the Federal Power Act provides the federal government—and FERC, in particular—responsibility to regulate wholesale sales of electricity, interstate transmission of electricity, and the facilities used for that interstate transmission.[73] In two-thirds of the country, federally regulated ISOs/RTOs manage electricity markets that must constantly balance supply and demand under a set of rules approved by FERC.

In addition, in 2005, Congress enacted Section 215 of the Federal Power Act,[74] which gave FERC, in partnership with NERC,[75] the additional responsibility of ensuring the reliable operation of the "bulk power system."

---

[71] Federal Power Act (FPA) § 201, 16 U.S.C. § 824 (2015).

[72] Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal and State Regulation of Today's Electric Grid*, 36 Energy L.J. 203, 207-08 (2015).

[73] FPA § 201(b)(1), 16 U.S.C. § 824(b)(1).

[74] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).

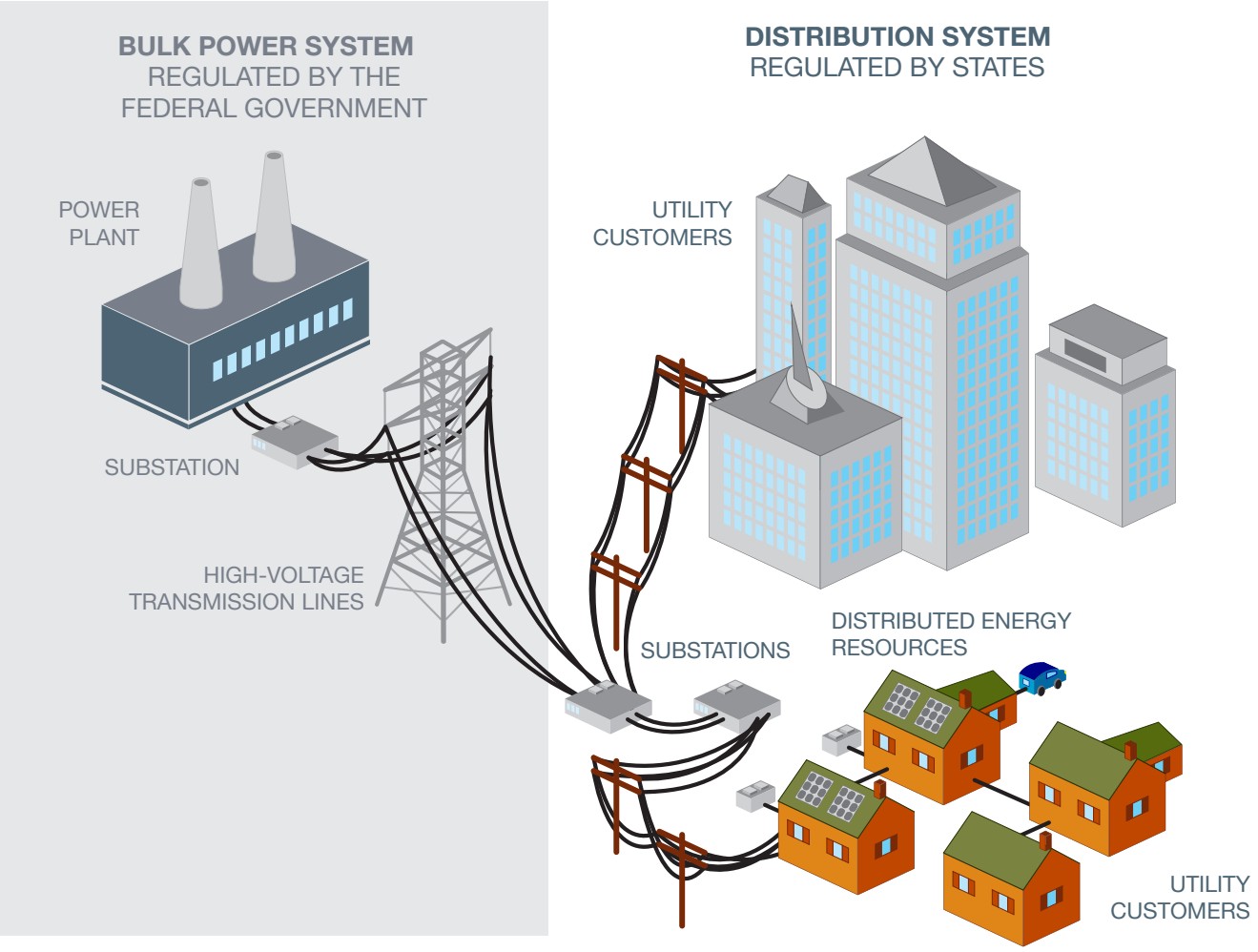
[75] NERC is also responsible for initiating compliance and enforcement actions for mandatory reliability standards, and for *assessing* reliability and resource adequacy, particularly in the face of extreme events. FERC Reliability Primer at 65-71.

Key Term: Bulk Power System

The "bulk power system" includes transmission and related infrastructure and electric generators whose energy is needed to maintain transmission system reliability.[76] The Federal Power Act specifically excludes facilities used in local distribution from the definition of "bulk power system."[77] Figure 8 illustrates the jurisdictional divide between the bulk power system, which is the responsibility of FERC, and the distribution system, which is the responsibility of the states.

Figure 8: Regulatory domains of the electric grid

The electric grid is divided between the bulk power system, subject to FERC and NERC jurisdiction, and the distribution system, subject to state and local regulatory jurisdiction.



[76] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).
[77] FPA § 215(a)(1), 16 U.S.C. § 824o(a)(1).

FERC's responsibility under Section 215 of the Federal Power Act is limited to ensuring *operational* reliability—the ability of the system to withstand sudden disturbances without resulting in cascading blackouts.[78] It does not extend to ensuring resource adequacy—the availability of sufficient generating capacity to meet peak electric demand.[79] Under the FERC regulations issued pursuant to Section 215, NERC proposes—either on its own initiative or at the direction of FERC—mandatory reliability standards to be implemented by bulk power system entities such as generators, transmission owners, or regional entities known as "reliability coordinators."[80] FERC will approve a proposed standard so long as it meets statutory and regulatory criteria, including that the standard is a technically sound and efficient means of achieving a reliability goal; was developed initially by industry experts; was based on sound engineering and technical criteria; and is clear and unambiguous regarding its requirements.[81]

Regulation of resource adequacy is, in practice, split between the federal government and states.[82] States have traditionally had authority over resource adequacy. In regions that do not rely on ISOs/RTOs to manage electricity markets, states retain that authority. Over the past 20 years, the federal government has increased its regulatory influence over resource adequacy in some circumstances. A number of ISOs/RTOs have developed "capacity markets"—market-based constructs for meeting resource adequacy needs. The ISO/RTO rules governing these capacity markets fall under FERC's jurisdiction. Other ISO/RTOs have developed resource adequacy constructs that are explicitly designed to reflect shared power between states and federal regulators.[83]

In addition, the Department of Energy retains some authority to coordinate energy-sector information sharing and best practices for critical-infrastructure protection,[84] and to issue certain emergency orders in the face of a grid emergency.[85]

States' Role in Improving Electric System Resilience

Because states have exclusive jurisdiction over distribution-level facilities, which are the source of the vast majority of customer outages from unexpected events,[86] states have focused on grid resilience for some time. States, particularly those that have faced highly disruptive events, have invested significant resources in analyzing opportunities for improving system resilience. We outline three types of opportunities for states to improve electric system resilience.

Directing Distribution Utilities to Make Resilience Investments

The primary way that states can and do improve grid resilience is by directing public utilities under their regulatory authority to invest in key physical and operational systems, and to ensure that utilities can recover the costs of such investments.

---

[78] NAS.
[79] FPA § 215(i)(2), 16 U.S.C. § 824o(i)(2).
[80] For many regions the relevant ISO/RTO serves as both grid operator and reliability coordinator.
[81] FERC, Reliability Primer at 55-56.
[82] Nordhaus, 36 Energy L.J. at 210.
[83] *See* Brian R. Gish, *Ensuring Resource Adequacy in Competitive Electricity Markets*, POWER (March 1, 2012), http://www.powermag.com/ensuring-resource-adequacy-in-competitive-electricity-markets/?printmode=1 (describing resource adequacy requirements in the Midcontinent Independent System Operator market).
[84] PPD-21 (detailing DOE authority and responsibilities for energy sector critical infrastructure protection).
[85] FPA § 202(c), 16 U.S.C. § 824a(c); FPA § 215A, 16 U.S.C. § 824o-1.
[86] FERC & NERC, Regional Entity Joint Review of Restoration and Recovery Plans 1 (2016)

Several well-identified interventions that states can undertake to improve resilience include:

- improving vegetation management;[87]
- targeted undergrounding of critical distribution lines;[88]
- load-reduction strategies;[89]
- targeted hardening of distribution lines and substations against storm and physical damage, including through the use of innovative pole and line designs;[90]
- adopting regulation and customer communication plans that facilitate the preparation of selected assets prior to an event to reduce damage in the case of extreme weather events;[91]
- developing strategies for selective restoration and load prioritization to most efficiently restore power and recover from high-impact events;[92] and,
- requiring and overseeing more regular testing of backup power generation equipment at critical facilities.[93]

Additionally, states should consider the extent to which climate change will exacerbate resilience concerns and incorporate climate change directly into resilience-related cost-benefit analyses and risk assessment.[94]

States have indeed adopted many of these strategies as part of their mandate to ensure electric service for customers.[95] Examples include:

- A number of Northeast states require utilities to submit vegetation management plans for Public Utility Commission approval.[96]
- In Washington D.C., the Public Service Commission is responsible for considering a triennial plan filed jointly by the local distribution utility and the District's Department of Transportation for the undergrounding of priority distribution infrastructure.[97]
- Since Hurricane Wilma in 2005, the Florida Public Utility Commission directed distribution utilities to invest in strengthening of distribution lines, pole replacements, and vegetation management. These investments significantly reduced customer outages during Hurricane Irma in 2017.[98]

---

[87] EPRI at 35.
[88] *Id.*
[89] *Id.* at 36.
[90] *Id.* at 40.
[91] NAS at 115.
[92] *Id.* at 103.
[93] *Id.* at 96-97.
[94] *See* Justin Gundlach & Romany Webb, Sabin Center for Climate Change Law, Climate Change Impacts on the Bulk Power System: Assessing Vulnerabilities and Planning for Resilience 1-25 (2018), http://columbiaclimatelaw.com/files/2018/02/Gundlach-Webb-2018-02-CC-Bulk-Power-System.pdf.
[95] For an overview of state approaches to resilience, see Edison Elec. Inst., Before and After the Storm: A Compilation of Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency 1-132 (2014), http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.
[96] Lee R. Hansen, State of Connecticut, Utility Tree Trimming in Other States,(2011), http://www.cga.ct.gov/2011/rpt/2011-R-0459.htm.
[97] D.C. Pub. Serv. Comm'n, In the Matter of the Application for Approval of Triennial Underground Infrastructure Improvement Projects Plan (Nov. 12, 2014), https://edocket.dcpsc.org/apis/pdf_files/e8c918a0-d080-4982-83a6-a649d7f64966.pdf.
[98] Alison Silverstein et al., Grid Strategies LLC, A Customer-focused Framework for Electric System Resilience 58 (2018), https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf.

Rules to Encourage Resilience-Enhancing Distributed Energy Resources

States can also use their distinct role in regulating distributed energy resources (DERs) to enhance grid resilience. DERs, including rooftop solar, electric batteries, backup generators, microturbines, and demand response, can enhance resilience in several ways.[99] Because DERs are generally located close to load, they reduce customers' reliance on vulnerable distribution infrastructure. This is particularly true when DERs can operate as islanded microgrids, allowing them to supply limited power to critical loads during large grid outages of long duration.[100] DERs are nonetheless generally interconnected with the distribution system and so can provide redundant generation supplies in the case of a generation, transmission, or distribution disruption that limits traditional sources' ability to supply energy. Because they are typically much smaller and more geographically dispersed than traditional power plants, DERs can reduce the risk that a single point of generation or transmission system failure will have a significant impact on customers.

Additional interventions related to DERs can improve resilience, including:

- revising utility-DER interconnection agreements to include resilience characteristics such as encouraging the use of enhanced inverters and islanding capability;[101]
- developing customer rate structures that compensate DERs for the quantified resilience value they provide;[102]
- encouragement of islanded microgrids for critical load,[103] including establishing special rates to encourage the development of private microgrids that provide resilience benefitis;[104] and,
- establishing contractual agreements and special rates with DER-owning customers that would permit the utility to use the DERs to supply critical loads during a high-impact event.[105]

Motivated in part by the increased frequency of extreme weather events, many states across the country have recently been ramping up their grid-modernization efforts. While the exact policies differ, many states are looking to advance their resilience goals by increasing the deployment of advanced technology and DERs, such as energy storage and microgrids.[106]

In the aftermath of Superstorm Sandy, New York and New Jersey invested significant resources in DERs and microgrids to reduce outages in the face of future natural disasters. In response to a 2016 report,[107] the New Jersey Board of Public Utilities initiated a process to add microgrids to the state and is currently completing the first step of funding feasibility studies for 13 municipal microgrids.[108]

---

[99] Sherry Stout & Eliza Hotchkiss, Nat'l Renewable Energy Lab., Distributed Energy Generation for Climate Resilience (2017), https://www.nrel.gov/docs/fy17osti/68296.pdf. EPRI, Enhancing Distribution Resiliency: Opportunities for Applying Innovative Technologies 11 (2013), https://www.epri.com/#/pages/product/000000000001026889/.

[100] NAS at 106-107.

[101] *Id.* at 107.

[102] *Id.* at 108.

[103] EPRI at 44.

[104] NAS at 107.

[105] *Id.* at 108.

[106] Autumn Proudlove et al., N.C. Clean Energy Tech. Ctr., The 50 States of Grid Modernization: 2017 Review and Q4 2017 Quarterly Report 6 (2018), https://nccleantech.ncsu.edu/wp-content/uploads/Q42017_gridmod_exec_final.pdf.

[107] N.J. Board of Pub. Utils., Microgrid Report (2016), https://www.nj.gov/bpu/newsroom/announcements/pdf/20161130micro.pdf.

[108] N.J. Board of Pub. Utils., Town Center Distrubted Energy Resource Micgrogrid Feasibility Study Incentive Program Application , https://www.nj.gov/bpu/pdf/commercial/TC%20DER%20Microgrid%20Feasibility%20Study%20Application.pdf.

As part of its comprehensive energy strategy known as Reforming the Energy Vision (REV), New York has adopted a series of measures to promote grid resilience through increased deployment of DERs.[109] This includes policies to pay DERs for avoiding needed distribution investments,[110] policies that enable new financing models,[111] and policies that reduce market barriers by facilitating community solar.[112] New York has also implemented policies to expand microgrids. NY Prize is a competition to help local communities develop their own microgrids to "enable the technological, operational, and business models that will help communities reduce costs, promote clean energy, and build reliability and resiliency into the grid."[113]

The Hawaii Public Utility Commission recently approved a Grid Modernization Strategy developed by Hawaii's largest electric utility, Hawaiian Electric Company, at the direction of the Commission.[114] That strategy is intended to "enhance the safety, security, reliability, and resiliency of the electric grid," especially due to the increase in significant weather events.[115] To meet these goals, the plan outlines several steps to facilitate DER integration, such as the deployment of smart meters, enhancement of monitoring technology using SCADA, and use of system inverters to provide greater resilience during voltage deviations.[116] In addition, in January 2018, the Hawaii State Legislature introduced a bill to establish a Homeland Security and Resiliency Council to "assess the resilience of the State's electric grid and other critical infrastructure to natural disasters and other emergencies and make recommendations."[117] In the first sentence of the text of the bill, the legislature references the urgent need for grid resilience in light of Hurricanes Irma and Maria, which struck Puerto Rico in 2017.[118] The goals of the legislation are to prevent the severity of damage to the electric grid from a natural disaster or emergency, enable faster recovery after an outage due to a natural disaster or emergency, and maintain critical loads at critical infrastructure during a natural disaster or emergency.[119] Versions of this legislation have passed both the Hawaii State House and State Senate. As of the time of writing, the two bills are being reconciled.

In 2017, Rhode Island initiated its Power Sector Transformation Initiative, tasking the Public Utilities Commission with reviewing several potential avenues to modernize the grid and designing a new regulatory framework for the state's electric system.[120] The Rhode Island Commission's Phase I report offers seven recommendations with significant resilience implications: microgrid control, fault location and isolation, automated feeder and reconfiguration, remote monitoring, adaptive protection, outage notification, and dynamic event notification.[121]

---

[109] *See generally* N.Y. State Energy Planning Bd., 2015 New York State Energy Plan (2015), https://energyplan.ny.gov/Plans/2015.aspx.

[110] N.Y. Dept. of Pub. Serv., Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, Docket No. 15-E-0751 36-38 (describing demand reduction value and locational system relief value), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b59B620E6-87C4-4C80-8BEC-E15BB6E0545E%7d/

[111] N.Y. State Energy Plan at 32-33.

[112] *Id.* at 27.

[113] *NY Prize*, nyserda.ny.gov, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize (last visited June 14, 2018).

[114] Haw. Pub. Util. Comm'n, Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy, Docket No. 2017-0226 (2018), https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/dkt_2017_0226_2018_02_07_PUC_decision_and_order_35268.pdf

[115] Hawaiian Elec. Cos., Modernizing Hawai'i's Grid For Our Customers 2, 18 (2017), https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf.

[116] *Id.* at 80.

[117] SB2910, 29th Leg., Reg. Sess. (Haw. 2018).

[118] *Id.*

[119] *Id.*

[120] RI Public Utilities Commission, *Power Sector Transformation Initiative*, Nov. 8, 2017, 5:11 PM, http://www.ripuc.org/utilityinfo/electric/PST_home.html.

[121] Div. of Pub. Utils. & Carriers, Office of Energy Res. & Pub. Utils. Comm'n, R.I. Power Sector Transformation 65-66 (2017), http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf.

In March 2017, the Illinois Commerce Commission (ICC) launched NextGrid: an 18-month study to transform the state's grid to be more flexible.[122] NextGrid is designed to be a collaborative process among different working groups comprised of various stakeholders. One working group is dedicated to "Reliability, Resiliency, and Cyber Security" and is tasked with studying solutions to the impacts of feasible risks and attacks both in the present and future.[123]

In 2017, the New Orleans City Council adopted a series of amendments that required utilities to evaluate how the deployment of DERs could increase grid reliability. The objective of the rule change was to "support the resiliency and sustainability of the Utility's systems in New Orleans" and provide the residents of New Orleans with reliable electricity at the lowest cost.[124] To do so, the amendments also require the local utility, Entergy, to determine the appropriateness of implementing new technologies and incorporating renewable energy sources, storage options, and DER.[125]

Local Resilience Rules

Several states have established mandatory standards for enhancing distribution-system reliability. As discussed above, reliability and resilience are distinct concepts, and these reliability standards are generally not designed to address specific resilience concerns. For example, when state regulators establish allowable reliability metrics against which distribution system performance is measured, they often exclude outages caused by major events.[126]

Nonetheless, many states can take advantage of the legal structure and existing institutions tasked with ensuring distribution-level reliability to develop equivalent resilience standards. To the extent that a state identifies a particular resilience vulnerability that can be cost-effectively addressed across utilities, it can consider adoption of a local rule mandating certain performance criteria or operational practices.

Unlike at the federal level, however, there is no single entity tasked with developing distribution-level standards. Institutions that could be responsible for distribution system resilience standards range from Public Service Commissions to customer-owned and publicly owned utilities, and, where they exist, state reliability organizations. For example, the New York State Reliability Council implemented a requirement that natural gas-fired generators interconnected with the ConEd system in New York City must be capable of also burning fuel oil in the case of natural gas supply disruptions.[127] This standard was intended to help address concerns of prolonged outages caused by a disruption in the supply of natural gas.

The Federal Role in Improving Electric-System Resilience

While no part of the Federal Power Act specifically directs any federal agency to improve electric system resilience, existing authorities are, nonetheless, sufficient to address any threats to the bulk power system and to allow the federal

---

[122] Ill. Commerce Comm'n, Re Illinois' Consideration of: the Utility of the Future: "NextGrid": Grid Modernization Study (2017), https://nextgrid.illinois.gov/resolution.pdf.

[123] Ill. Commerce Comm'n, *Working Groups*, https://nextgrid.illinois.gov/WorkingGroups.html, (last visited June 14, 2018).

[124] Council of the City of New Orleans, Resolution Amending the Elec. Util. Integrated Res. Plan Rules, R-17-410, at 4 (2017), http://www.all4energy.org/uploads/1/0/5/6/105637723/2017_08_10_ud-17-01_cno_r-17-429_amend_electric_utility_irp_rules.pdf.

[125] *Id.*

[126] NAS at 28.

[127] DOE Staff Report at 91.

government to play an expansive coordinating role. The Federal Power Act places the primary regulatory responsibility over the bulk power system with FERC. Thus, FERC, and the entities it regulates, will have the primary role in evaluating and adopting policies to enhance the resilience of the bulk power system over the long-term. Nonetheless, the Federal Power Act and some other statutory provisions reserve limited authority for other entities, including DOE and NERC.

This section highlights the legal authorities that federal agencies have to ensure the resilience of the bulk power system:

- FERC can use its authority over transmission rates to encourage cost-beneficial investments in the transmission system;
- FERC, in partnership with NERC, can establish reliability standards that have resilience co-benefits;
- Federal agencies can encourage, require, and facilitate better resilience-related coordination and planning by ISOs/RTOs, reliability coordinators, and other entities;
- FERC can work with ISOs/RTOs to evaluate and, if justified, approve wholesale electricity market changes to enhance generation system resilience by compensating generators for well-defined resilience attributes; and,
- DOE and FERC can exercise their authorities to order specific actions in the face of grid emergencies.

Using these authorities to implement every potential intervention that could improve resilience is not feasible; interventions carry costs and other important tradeoffs that must be considered. Thus, when possible, each of these authorities should be exercised only after the relevant agency has determined that the benefits of a proposed action will exceed the costs, using a methodology like that outlined above.

The authorities described in this section are sufficient for the federal government to evaluate and, if necessary, implement cost-beneficial bulk power system resilience improvements and to facilitate resilience-related coordination among federal agencies, regional entities, state regulators, and private utilities.

Is Immediate Federal Resilience Action Needed?

This report focuses on tools that can be used to evaluate potential resilience improvements and the legal authorities that can be used to implement those improvements, when they are needed. There is, of course, a threshold question: are immediate resilience improvements needed?

Many experts that have studied the resilience of the electric system, including the National Academy of Sciences,[128] the Department of Energy,[129] and the Electric Power Research Institute,[130] have identified potential areas for improvement and made recommendations for investments and policy design changes that could be worthwhile. Where they implicate federal authorities, these proposals would be a reasonable place for regulators to start in evaluating cost-beneficial areas for improvement.

However, notwithstanding the potential for cost-effective improvements, it is important to recognize that there is no record supporting concerns about an imminent resilience threat. In rejecting the Department of Energy's proposal to provide cost-of-service payments to certain coal and nuclear plants in the name of grid resilience, FERC recognized that neither the DOE proposal, nor comments supporting the proposal provided a record sufficient to justify a finding that there is a national resilience emergency rendering current electricity markets unjust and unreasonable, let alone one that required substantial out-of-market compensation.[131] This finding was consistent with NERC's 2018 State of Reliability Report, which it released with the headline "*Grid Shows Improved Resilience*, Decreased Protection Systems Misoperations and Advanced Risk Management."[132] FERC did, however, initiate a proceeding to collect more information from ISOs/RTOs to evaluate the state of grid resilience in these wholesale markets.[133] In response to this proceeding ISOs/RTOs submitted information on the state of resilience in wholesale markets, efforts underway to ensure grid resilience, and opportunities for future improvement. These filings make clear that while grid resilience is a critical issue worthy of continued attention, there is no reason to believe any mandatory, national or even regional action to address acute resilience concerns are needed at this time.[134]

FERC Can Establish Transmission-Compensation Rules that Enhance Resilience

FERC's jurisdiction over interstate transmission gives it a role to play in ensuring the resilience of the transmission system. Most outages associated with high-impact, low-probability events occur due to disruptions of the distribution and transmission systems.[135] Investments in the transmission system, if they are cost-beneficial, have the potential to

---

[128] *See generally* NAS at 134-140.

[129] *See generally* DOE QER at 7-21 to 7-24.

[130] *See generally*, EPRI at 14-44.

[131] FERC Resilience Order, 162 FERC ¶ 61,012 at P 15.

[132] NERC, Media Release: Grid Shows Improved Resilience, Decreased Protection Systems Misoperations and Advanced Risk Management (June 21, 2018), https://www.nerc.com/news/Headlines%20DL/SOR%202018%20Media%20Release.pdf.

[133] FERC Resilience Order, 162 FERC ¶ 61,012at PP 18-19.

[134] *See, e.g.,* Comments of California Independent System Operator Corp., ISO New England Inc., Midcontinent Independent System Operator, Inc., New York Independent System Operator, Inc., and Southwest Power Pool, Inc., *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (filed May 8, 2018). One notable exception may be Puerto Rico, where post-Hurricane Maria rebuilding is underway. The Department of Energy recently compiled recommendations for improving the resilience of the island's electric system. U.S. Dep't of Energy, Energy Resilience Solutions for the Puerto Rico Grid (2018), https://www.energy.gov/sites/prod/files/2018/06/f53/DOE%20Report_Energy%20Resilience%20Solutions%20for%20the%20PR%20Grid%20Final%20June%202018.pdf. The analytical tools and authorities outlined in this report could be useful as Puerto Rico works to rebuild its electric system.

[135] *See* Trevor Houser, John Larsen & Peter Marsters, The Rhodium Group, *The Real Electricity Reliability Crisis* (Oct. 3, 2017), https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/ [hereinafter Rhodium Group Outage Analysis] (showing that only 0.00858% and 0.000007% of major electricity disturbances were caused by generation inadequacy and fuel supply emergencies during 2012-2016).

enhance each phase of grid resilience, including its ability to absorb and resist shocks, manage disruptions as they occur, quickly recover, and respond and adapt to future shocks.[136]

FERC has authority over the rates and tariffs of transmission providers and can use this authority to ensure that transmission developers will be compensated for providing services that enhance the resilience of the transmission system. For example, FERC has already issued an order that requires utilities to have spare transformers, which provide significant system-restoration benefits while reducing the cost needed for all utilities to maintain spare transformers.[137] The National Academy of Sciences has identified mechanisms by which FERC can use its existing transmission authority to cost-effectively expand the availability of spare transformers through a national transformer reserve.[138]

In addition, FERC can use its transmission ratemaking authority to encourage, either directly or through ISOs/RTOs, cost-beneficial investments that will enhance transmission-system resilience, including hardening of vulnerable assets against extreme weather such as flooding or earthquakes; burying of key transmission lines; shielding of critical transmission equipment against electromagnetic attack; and more regular and innovative vegetation management.[139]

FERC Can Approve Reliability Standards that Have Resilience Co-benefits

FERC can use its existing authority to implement mandatory operational, planning, and performance requirements that improve grid resilience when doing so is a co-benefit of actions that enhance reliability. FERC's existing reliability standards have mandated planning, coordination, and investments that have generally supported a resilient electric system.

Under Section 215 of the Federal Power Act, FERC and NERC are responsible for issuing reliability standards—enforceable requirements intended to ensure the operational reliability of the bulk power system. While reliability and resilience are different concepts,[140] protecting against reliability risks can often have significant resilience co-benefits.

Many of the reliability standards that have been proposed by NERC and approved by FERC establish planning, analytical, or operational requirements that also improve the resilience of the bulk power system at each of the phases, including by (1) avoiding and resisting damage to the electric grid during a high-impact, low-probability event, (2) enhancing coordination during the event to manage damage that does occur, (3) speeding up the recovery of the system after such an event, and (4) analyzing past events to identify areas for future recovery and adaptation. For example, the following reliability standards have significant resilience co-benefits:

---

[136] Hardening key weak points on the transmission system can increase the system's ability to absorb and resist shocks. New software and hardware systems are in development that, if deployed, may be able to help grid operators manage disruptions as they occur by rerouting electricity around overloaded elements. *See* Pablo A. Ruiz et. al, Transmission Topology Optimization, *Increasing Market and Planning Efficiency and Enhancing Resilience through Improved Software*, Docket No. AD10-12-0009 (June 26, 2018) Ensuring availability of non-wires transmission assets such as transformers can reduce the time needed to replace damaged equipment. And new tools are being developed to help transmission planners target investments by identifying "weak" points on the system that can cause cascading failures, Yang Yang, Takashi Nishikawa & Adilson E. Motter, *Small vulnerable sets determine large network cascades in power grids*, 358 Science 6365 (2017), http://science.sciencemag.org/content/358/6365/eaan3184.

[137] *Order on Application for Blanket Authorization for Transfers of Jurisdictional Facilities and Petition for Declaratory Order*, 116 FERC ¶ 61,280 (2006).

[138] NAS at 117-19.

[139] EPRI at 25-34.

[140] Policy Integrity Comments on DOE NOPR at 11-12.

- CIP-014-2 (Physical Security), requiring identification of critical transmission substations and performance of physical security risk assessments;
- CIP-009-6 (Cyber Security – Recovery Plans for BES Cyber Systems), requiring development and implementation of recovery plans in the event of cybersecurity threats;
- TPL-001-4 (Transmission System Planning Performance Requirements), requiring assessment of the impacts of "extreme events" on the bulk power system and planning for "N-2" extreme events;
- FAC-008-3 (Facility Ratings), requiring ratings for how well facilities operate in emergency situations; and,
- EOP-010-1 (Geomagnetic Disturbance Operations) and TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events), requiring planning and emergency operation procedures in the event of a geomagnetic disturbance.

To the extent that analyses from the Commission, ISOs/RTOs, or NERC identify gaps that are not appropriately filled by mandatory standards, improvements to existing reliability standards or promulgation of new standards may enhance both reliability and resilience. For example, in 2016 and 2017, FERC and NERC conducted an extensive study of transmission-operator and reliability-coordinator system restoration plans and issued two reports outlining a host of improvements that could further enhance bulk power system recovery from sustained widespread outages.[141] Recently, FERC adopted an order directing NERC to develop a reliability standard that requires mandatory reporting of cybersecurity incidents, which is intended to improve resilience by giving regulators, grid operators, and utilities the information they need to learn and adapt.[142]

One benefit of improving resilience using FERC's reliability standard authority is that it covers a wider range of entities compared to FERC's jurisdiction over wholesale energy and transmission. For example, reliability standards apply to federal power agencies, municipal utilities, rural electric cooperatives, and Texas, which are all largely exempt from FERC's ratemaking jurisdiction.[143] Under its reliability standard authority, FERC can direct NERC to evaluate opportunities to expand existing reliability standards or propose new standards that improve operational reliability, with the co-benefit of improved system resilience. For example, FERC could evaluate the benefits and costs of adopting the currently voluntary NERC reliability guideline aimed at improving generation system resilience, the Reliability Guideline for Generating Unit Winter Weather Readiness, as a mandatory reliability standard.[144] This guideline outlines best practices for the development and implementation of plant-specific winter readiness plans. These plans provide plant owners the tools needed to anticipate, prevent, respond to, and recover from equipment outages caused by extreme cold. On the other hand, investigation may show that existing practices and standards are meeting resilience needs.[145]

---

[141] FERC & NERC, Regional Entity Joint Review of Restoration and Recovery Plans 1 (2016), https://www.ferc.gov/legal/staff-reports/2016/01-29-16-FERC-NERC-Report.pdf [FERC & NERC Joint Review]; FERC, Further Joint Study Report: Planning Restoration Absent SCADA or EMS (PRASE) (2017), https://www.ferc.gov/legal/staff-reports/2017/06-09-17-FERC-NERC-Report.pdf. [FERC & NERC Further Joint Review]

[142] *Cyber Security Incident Reporting Reliability Standards*, Order No. 848, 164 FERC ¶ 61,033 (2018).

[143] FERC Reliability Primer at 6.

[144] NERC, "Reliability Guideline: Generating Unit Winter Weather Readiness—Current Industry Practices," August 2013, http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Relibility_Guideline_Generating_Unit_Winter_Weather_Readiness.pdf.

[145] Staffs of FERC and NERC and its Regional Entities, Recommended Study: Blackstart Resources Availability (2018), https://www.ferc.gov/legal/staff-reports/2018/bsr-report.pdf.

Federal Agencies Can Mandate or Facilitate Planning and Coordination Among Regional Entities

Given the fractured nature of regulatory and planning responsibilities across the federal system, a key opportunity for improving system resilience is increased coordination and planning. In filings as part of FERC's resilience docket, a number of ISOs/RTOs rightly identified planning and coordination as providing important resilience benefits and identified potential improvements.[146] The federal government is well positioned to lead this effort. Enhancing coordination and planning can improve all phases of grid resilience, including by identifying opportunities to avoid or resist damage, enhancing communication so that all responsible actors can manage disruption during a shock, coordinating deployment of resources to quickly responding to a shock after it occurs, and identifying lessons learned and investments needed to recover from and adapt to future shocks.

Transmission Planning and Coordination. FERC has designated regional organizations to be responsible for mandatory transmission planning. While transmission planning has long been a responsibility of ISOs/RTOs, FERC expanded transmission planning to regions without ISOs/RTOs in its Orders No. 890 and 1000.[147] Regional transmission planners are required to work with member transmission and generation owners to complete an Annual Transmission Planning Assessment.[148] This assessment requires planners to evaluate the transmission system against a wide range of contingencies, many of which have resilience implications. These assessments can be used to direct transmission investments using new tools that facilitate targeting high-value investments, such as a model developed for identifying "weak" points on the transmission system that can cause cascading failures.[149] Coordination of transmission planning can also help facilitate transmission-system resilience. Planning must already be coordinated with "appropriate state authorities."[150] FERC can also encourage or require regional transmission planners to coordinate planning across regions.

Reliability Planning and Coordination. NERC has delegated certain authority over bulk power system reliability to regional reliability coordinators.[151] Reliability coordinators already perform important planning and coordination functions that can be leveraged to analyze and recommend resilience improvements. For example, transmission operators are required to have reliability coordinator-approved plans for system restoration following a widespread outage or

---

[146] Comments of Southwest Power Pool, Inc. on Grid Resilience Issues, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 at 8-9 (filed March 9, 2018) [hereafter "SPP Resilience Response"] (discussing SPP's role in general system and contingency planning, including scenario planning that covers high-impact low-probability risks); PJM Resilience Response at 49-50 (identifying a number of ways to think about resilience in the transmission planning process); *id.* at 63-64 (operations plans including load shedding plans help ensure that outages are minimized when they do occur before recovery can begin); Responses of the Midcontinent Independent System Operator, Inc., *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 at 3-4 (filed March 9, 2018) at 3-4 (discussing importance of transmission planning to identify needed expansions in light of grid resilience).

[147] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435 (2007); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011).

[148] NERC Reliability Standard TPL-001-04 – Transmission System Planning Performance Requirement, Eff. Jan. 1, 2015; *See* SPP Resilience Response (describing use of Annual Planning Assessment to address resilience concerns).

[149] Yang Yang et al., *Small Vulnerable Sets Determine Large Network Cascades in Power Grids*, 358 Science 6365 (2017), http://science.sciencemag.org/content/358/6365/eaan3184.

[150] 18 CFR § 35.34(k)(7).

[151] FERC Reliability Primer at 27. Generally ISOs/RTOs serve as the reliability coordinator for their region. *See* http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx. Note that CAISO does not currently act as its own reliability coordinator.

blackout.[152] Similarly, reliability coordinators are required to have area restoration plans.[153] Where improvements to other resilience phases (limiting initial damage, continued operation during an event) can be justified as improving reliability, FERC and NERC can use their reliability authority to require similar coordination and planning applicable to those phases. FERC and NERC can then conduct a comprehensive assessment of relevant plans to identify weaknesses and make cost-beneficial recommendations for improvement, as they recently did in a series of reports assessing existing restoration and recovery plans.[154]

Other Planning and Coordination. The Department of Energy has been designated as the Sector Specific Agency for the energy sector pursuant to Presidential Policy Directive 21.[155] Under this directive, DOE plays an important coordinating role. It is responsible for day-to-day prioritization and coordination of energy-sector critical infrastructure protection activities; carrying out incident management responsibilities; providing support and facilitating technical assistance and consultations with the energy industry; and coordinating with the Department of Homeland Security, other agencies, and the energy sector to implement the directive.[156] In addition, the National Academy of Sciences has outlined several recommendations for DOE, FERC, NERC, and regional entities such as ISOs/RTOs to improve general system planning and coordination with the goal of enhancing resilience. Potential actions include expanding emergency preparedness exercises,[157] information sharing to disseminate resilience best practices,[158] and coordinating natural gas and electric sectors to reduce fuel disruption risks.[159]

FERC Can Approve Market Rules that Create Incentives for Generation-System Resilience

FERC can use its authority over wholesale electricity market rules to evaluate and, if they are just and reasonable, approve proposals from grid operators that align generator incentives with resilience-enhancing entry, exit, and operational behavior. Market-based solutions may be an appropriate tool where services that enhance generation system resilience can be identified and defined with specificity, and where analysis shows that procurement of these services will enhance electric *system* resilience to an extent sufficient to justify the costs. As PJM Interconnection, the grid operator for states in the Midwest and Mid-Atlantic, stated in a filing to FERC regarding resilience improvements in wholesale markets, such solutions, when available, are preferable to alternatives where customers are responsible for cost-based payment to certain identified resources: "assuming that resilience requirements can be clearly articulated, meeting them through market-based solutions that allow resources to compete to meet those requirements is the preferred way to ensure that these objectives are met at the lowest cost to consumers."[160] However, there are limited circumstances where new market rule changes for generators will provide substantial electric system resilience enhancements. Therefore, FERC should

---

[152] NERC Reliability Standard EOP-005-2 - System Restoration from Blackstart Resources, Eff. May 23, 2011, http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-2.pdf.

[153] NERC Reliability Standard EOP-006-2 - System Restoration Coordination, Eff. May 23, 2011, http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-006-2.pdf.

[154] FERC Joint Review; FERC Further Joint Review.

[155] PPD-21.

[156] *Id.* Notably, however, this directive does not provide with DOE with any additionally regulatory authority.

[157] NAS at 134.

[158] *Id.* at 135.

[159] *Id.* at 135.

[160] Comments and Responses of PJM Interconnection L.L.C. at 68, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000 (filed March 9, 2018).

ensure that proposals justified on the basis of resilience are supported by substantial evidence that they will result in measurable enhancements to electric system resilience.[161]

FERC has authority to approve and require such market-based solutions. FERC has jurisdiction over rules and practices affecting wholesale electricity rates,[162] and is responsible for ensuring that those rates are "just and reasonable."[163] Courts have interpreted the Federal Power Act to provide FERC the authority to approve and police a wide variety of ISO/RTO market rules. These rules can ensure just and reasonable wholesale rates by creating incentives for market participants to provide efficient levels of desired generator attributes.[164] And because generation system outages, in the limited circumstances that they occur, impose substantial costs on market participants, market changes aimed at reducing the likelihood and consequence of outages caused by high-impact, low-probability events fits squarely within FERC's authority.

That FERC has authority to approve market changes to enhance resilience does not necessarily mean that additional rules are required. A number of market-based constructs and enhancements have already been implemented to facilitate procurement of generator or electric-system services that enhance the resilience of the generation system.

- **Ancillary Services Markets.** NERC has catalogued the "essential reliability services" needed to ensure operational reliability.[165] Some of these services are provided through market mechanisms—called "ancillary services markets." For example, in some ISOs/RTOs, existing market rules provide for compensation of ancillary services that affect reliability and resilience, such as contingency reserves[166] and black-start.[167]
- **Capacity Markets.** A number of ISOs/RTOs manage capacity markets, market-based constructs intended to meet resource adequacy requirements. While resource adequacy is primarily a reliability attribute, reserve margins can help the system avoid and manage system disruption by lessening the risk that disruption of certain generation assets by high-impact, low-probability events will result in long lasting, widespread outages.

---

[161] Because resilience currently has high salience, there is some risk that advocates attempt to justify preexisting policy proposals using grid resilience even if they are not directly aimed at improving resilience. For example. in its response to FERC's information request on grid resilience, PJM advocated for certain energy market pricing reforms. *Id.* at 78-80. But these price formation reforms, whatever their merits, "do not include even an attempted nexus to bulk power system resilience." FERC Resilience Order, 162 FERC ¶ 61,012 at P 16 & n. 25.

[162] FPA § 205(a), 16 U.S.C. § 824d(a).

[163] *Id.*

[164] *Advanced Energy Mgmt. All. v. FERC*, 860 F. 3d 656 (D.C. Cir. 2017); *Connecticut Dept. of Pub. Util. v. FERC*, 569 F.3d 477 (D.C. Cir. 2009). *FERC v. Elec. Power Supply Assoc'n*, 136 S. Ct. 760 (2016).

[165] NERC, Essential Reliability Standards Working Group, Essential Reliability Services Working Group Sufficiency Guideline Report (2016), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf.

[166] EPRI, Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs at 3-46 to 3-49 (2016), https://www.epri.com/#/pages/product/000000003002009273/ [hereafter "EPRI Market Design"]. Contingency reserves are reserves that may be needed in the case of unplanned outages of significant generation or transmission facilities.

[167] *See* Nitish Saraf et al., The Annual Black Start Service Selection Analysis of ERCOT Grid, 24 IEEE Transactions on Power Systems 1867 (2009). Black-start is the ability to supply initial power to generators so that they can be brought back online and is an important resilience attribute that is critical for system restoration. EPRI at 30. Note, however, that not all ISOs/RTOs procure black-start service through a competitive mechanism. For example, CAISO compensates black-start resources on a cost-of-service basis. *California Independent System Operator*, 161 FERC ¶ 61,116 (2017). Cost-based provision of resilience attributes may be appropriate when market-based solutions are not feasible; however, consistent with FERC's approach to reliability, the use of such mechanisms should be limited and, when possible, time-limited. *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 at P 114 (2005) ("a transparent market process is preferable to cost-of-service rates that can cause high uplift payments . . . . [O]ur policy on reliability compensation will be to rely on markets and proper market design, and to use non-market solutions only as a last resort"); *New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61116 at P 16(2015) ("RMR filings should be made only to temporarily address the need to retain certain generation *until more permanent solutions are in place*") (emphasis added).

- **Generator Performance.** Partially in response to FERC action taken in the aftermath of the Polar Vortex,[168] PJM and ISO New England have implemented market reforms to charge generators that are unable to meet their capacity obligations a penalty and make additional payments to those that can.[169] These initiatives can provide efficient incentives for generators to change their behavior in ways that avoid or reduce the consequence of expected outages caused by high-impact, low-probability events. For example, generators would be incentivized to invest in weatherization to protect against extreme weather events or to sign firm fuel contracts to protect against natural gas supply disruptions.

- **Removal of Market Participation Barriers.** FERC has adopted rules that require grid operators to provide for the participation of new technologies—such as demand response and energy storage—in existing energy, capacity, and ancillary services markets.[170] These market enhancements broaden the scope of resources that are able to provide the resilience-enhancing services beyond traditional generation resources.

It is conceivable that there are additional, measurable services that resources with particular attributes can provide that can be shown to increase resilience, or resource types that are excluded from providing existing services, To the extent that such services and resources are identified, changes to market rules could be appropriate if supported by analysis that the expected benefits of such changes justify the costs.

However, any use of these options is limited in important ways. First, electricity markets primarily affect the entry, exit, and operation incentives for generation resources. Only a very small proportion of electric-system outages are caused by failures of the *generation* system.[171] And additional generation is primarily useful for *resisting* and *avoiding* outages caused by insufficient generation, with limited utility for managing, recovering from, or adapting to high-impact, low-probability shocks. Therefore, even policies that enhance the resilience of the generation system provide limited opportunities to enhance *electric-system* resilience.

Second, market rules are best suited for facilitating the efficient procurement of specific generation resource attributes. As such, changing market rules to incentivize resilience is only appropriate where attributes have been shown to have a direct connection to resilience improvements—that is, that the attributes allow generators to provide services or products that will help the electric system withstand, respond to, or recover from a high-impact, low-probability shock. And to the extent that substantial evidence can demonstrate the connection between particular generator attributes, and resilience-enhancing capabilities, those attributes have to be defined with sufficient specificity to allow price formation. To-date, resilience-specific attributes (as distinguished from those that also facilitate provision of reliability services) have not been identified and defined. Market regulators, therefore, must be careful to ensure that the attributes identified actually support resilience. There is no evidence that many of the generator attributes highlighted as part of recent political discussions actually provide resilience benefits.

---

[168] *Order on Technical Conferences,* 149 FERC ¶ 61,145 (Nov. 20, 2014).

[169] DOE Staff Report at 91-92. PJM instituted its Capacity Performance Proposal, which was approved by the Commission. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 ("Capacity Performance Order"), *order on reh'g and compliance,* 155 FERC ¶ 61,157 (2015). The New York ISO identified, adopted, and implemented its Comprehensive Shortage Pricing enhancements. *New York Independent System Operator Inc.*, 154 FERC ¶ 61,152 (March 1, 2016). ISO New England identified its Pay For Performance capacity market design, to be implemented in 2018. Fuel Assurance Status Report of ISO New England Inc. at 5-9, Docket No. AD14-8-000 (Feb. 18, 2015).

[170] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018) (providing for participation of energy storage); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008) (providing for participation of demand response in ancillary services and capacity markets).

[171] *See* Rhodium Group Outage Analysis; Silverstein at 18-20.

Third, market rules designed to compensate for individual attributes may improve resilience against certain threats but exacerbate resilience against other threats. For example, a resilience proposal aimed at compensating "fuel security"[172] might, in practice, reward large central-station powerplants that have on-site access to fuel. Yet such resources often pose countervailing resilience concerns because unexpected outages of these resources place more strain on the electric system and they are often less resistant to extreme weather conditions. To the extent additional fuel-security payments increase reliance on such generators or slow the replacement of these resources with newer technologies, such payments may ultimately harm resilience on net. Use of narrow definitions of resilience attributes such as "fuel security" also risks under-compensating and, therefore, under-providing, the resilience improvements of generation resources *without* fuel requirements.

Therefore, it is not sufficient for policymakers merely to identify individual attributes that are nominally related to resilience as sufficient justification for market changes. Rather, FERC and ISOs/RTOs should first conduct holistic analyses that evaluate how any contemplated market changes would likely affect *system* resilience against multiple threats, in comparison to the impact of other potential changes.

Moreover, while cost-benefit analysis is an important tool to evaluate any resilience intervention, it is particularly important for market-based solutions. Market changes, if not done well, can impose substantial costs on consumers by distorting efficient entry, exit, and operational decisions. The potential that market changes will result in very large costs and low or ill-defined benefits suggests that a thorough cost benefit analysis should be required in order for FERC to make any determination that market changes intended to enhance resilience are "just and reasonable."

DOE Can Issue Emergency Orders to Address Rare and Unforeseen Events If They Occur

Notwithstanding all responsible planning, coordination, and investment, high-impact, low-probability events can cause significant outages and damage. Grid operators can implement the contingency plans they have developed to facilitate the speedy recovery from such outages. However, in the unexpected and rare case that existing plans and tariffs are insufficient to address recovery needs after a high-impact, low-probability event, federal regulators—specifically DOE and FERC—have been delegated emergency authorities by Congress that can be used under limited circumstances. While these authorities are broad, they come with important limits.

First, under long-standing authority codified in Section 202(c) of the Federal Power Act, DOE can issue emergency orders requiring the interconnection of electric facilities and the generation, transmission, and delivery of electricity.[173] These orders can be issued on DOE's own or after an application by the owner of generation, transmission, or distribution facilities affected by an emergency.[174] DOE can use this authority to enable grid operators to deviate from operations under existing market rules to facilitate recovery and restoration in the event of an emergency. Section 202(c) establishes the limits under which DOE may act. DOE's emergency authority is intended to address relatively short-term and unexpected events, not long-term changes to the electric system. Long-term changes should be handled in the

[172] *See, e.g.*, PJM, Valuing Fuel Security (2018), http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180430-valuing-fuel-security.ashx [hereinafter "PJM Fuel Security Proposal"].
[173] 16 U.S.C. § 824a(c).
[174] 10 C.F.R. § 205.370.

normal course.[175] Moreover, DOE's authority is not intended to address economic concerns of specific generators. The Federal Power Act and DOE's regulations encourage power-sector entities to use existing rates or negotiate mutually acceptable rates with other power-sector entities.[176] But Congress provided FERC, not DOE, the ultimate authority to determine "just and reasonable" compensation for compliance with emergency orders, "in accordance with its standard procedures."[177]

Second, in 2015, Congress delegated to DOE additional authority under Section 215A of the Federal Power Act to impose mandatory security measures to restore critical infrastructure in the case of grid-security emergencies.[178] Grid-security emergencies are limited to cyberattacks, electromagnetic pulse attacks, geomagnetic storms, and direct physical attacks that *have occurred* or pose an *imminent* danger.[179] Under this provision, after the President of the United States has declared a grid-security emergency, DOE can issue emergency orders to utilities, NERC, and regional entities to implement emergency security measures. Like with Section 202(c), this authority is not intended to address economic concerns of generators and authority to set "just and reasonable" compensation is delegated to FERC.[180]

These authorities provide needed flexibility so that relevant generators, utilities, grid operators, and regulators can respond to the particular circumstances caused by a disruptive event. But the emergency powers are appropriately circumscribed by Congress and the courts. Congress authorized DOE and FERC to use these authorities only under specific conditions during and immediately after an incident. Section 202(c) provides DOE authority to issue emergency orders only "*during* the continuance of any war" and "whenever the Commission determines that an emergency *exists*."[181] DOE may only order the "*temporary* connections of facilities" and the "generation, delivery, interchange, or transmission that will *meet* the emergency."[182] And DOE's authority to allow facilities to avoid environmental requirements is limited to a (renewable) 90-day period.[183] Section 215A sets strict time limits on DOE's authority. DOE may only issue emergency orders for periods of 15 days, and may only renew orders if the Secretary of Energy certifies that the emergency continues to exist or the measures continue to be required.[184] That is, these emergency authorities are aimed at the *manage* and *quickly respond* phases of grid resilience, rather than the *resist/avoid* and *recover/adapt* phases.

In addition, any DOE or FERC action is subject to judicial review.[185] This allows courts to exercise oversight in order to ensure that any emergency order issued by DOE has been justified through sufficient record evidence and limits DOE's ability to implement far-reaching emergency orders that are inconsistent with Congress's intent that they be used in limited circumstances.

---

[175] *See* FPA § 202(c), 16 U.S.C. § 824a(c) ("defining "emergency" as ""a *sudden* increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy"); 10 C.F.R. § 205.371 (defining emergency using terms such as "sudden" "unexpected" or "unforeseen"); 10 C.F.R. § 205.375 (outlining factors to be considered when evaluating an energy supply shortage); *see also Richmond Power & Light v FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) ("That section speaks of "temporary" emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor").

[176] FPA § 202(c)(1), 16 U.S.C. § 824a(c)(1) ("If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order . . . . "); 10 C.F.R. § 205.376.

[177] 10 C.F.R. § 205.376; FPA § 202(c), 16 U.S.C. § 824a(c)(1).

[178] *See* FPA § 215A, 16 U.S.C. § 824o-1.

[179] FPA § 215A(a)(7), 16 U.S.C. § 824o-1(a)(7).

[180] FPA § 215A(a)(6), 16 U.S.C. § 824o-1(a)(6).

[181] FPA § 202(c)(1), 16 U.S.c. § 824a(c)(1) (emphasis added).

[182] *Id.* (emphasis added).

[183] FPA § 202(c)(4)(A), 16 U.S.c. § 824a(c)(4)(A).

[184] FPA § 215A(a)(5), 16 U.S.C. § 824o-1(a)(5).

[185] FPA § 313(b), 16 U.S.C. § 825l(b).

Key Takeaways for Proposals to Subsidize Coal and Nuclear Plants Based on Grid Resilience

The Trump Administration has used the concept of grid resilience to argue for policies to provide out-of-market financial support to existing coal and nuclear generators. First, in September 2017, DOE issued a Notice of Proposed Rulemaking ("DOE NOPR") requesting that FERC approve changes to ISO/RTO markets in the name of grid resilience.[186] The DOE NOPR, if adopted, would have guaranteed cost-based compensation to coal and nuclear plants that maintained substantial on-site fuel supplies, thereby shielding those units from competitive market forces. DOE justified this proposal on the grounds that retirement of these units would risk undermining electric system resilience and therefore result in unjust or unreasonable wholesale rates. FERC ultimately rejected the proposed rule, determining that DOE had not provided a sufficient record to support its proposal.[187]

More recently, President Trump issued a directive to DOE to limit the closure of coal and nuclear plants.[188] The Administration is contemplating action under Section 202(c) of the Federal Power Act and under provisions of the Defense Production Act of 1950. Under these authorities, the federal government would mandate that distribution utilities and grid operators purchase electricity from certain coal and nuclear generators. The Trump Administration has asserted that these emergency actions are needed to maintain national security; however, the underlying national security argument for coal and nuclear bailouts generally overlaps with the resilience concerns that motivated the DOE NOPR. Specifically, a leaked memo explains the Administration's concern that, without "fuel-secure" generation such as coal and nuclear, a high-impact, low-probability shock risks disrupting the electric system and leaving critical defense facilities without power. While the contours of a proposal have been reported in the press, no official action has been taken and DOE has not provided a timeline for when it will act in accordance with President Trump's directive.

The insights provided in this report can be useful in evaluating these policy proposals.

Urgent and Unprecedented Action Is Not Necessary or Appropriate Because There Is No Grid Resilience Emergency

With proper analysis and deliberate policymaking, regulators can identify investments or policies that would cost-effectively improve grid resilience. However, as is discussed in this report, the expert judgment of the entities responsible for the continued operation of the bulk power system—FERC, NERC, and the ISOs/RTOs—makes clear that there is not presently a national grid resilience emergency. To the extent that further analyses determine cost-beneficial resilience improvements, the existing authorities described above are available to craft the appropriate transmission investment, minimum standard, planning/coordination, or market-based compensation solution. The use of untested, ill-fitting "emergency" authorities—such as authority under the Defense Production Act designed to ensure that the federal

[186] DOE NOPR at 46,945.
[187] FERC Resilience Order, 162 FERC ¶ 61,012 at P 15.
[188] Brad Plumer, *Trump Orders a Lifeline for Struggling Coal and Nuclear Plants*, N.Y. Times (June 1, 2018), https://www.nytimes.com/2018/06/01/climate/trump-coal-nuclear-power.html.

government has priority in the purchase of needed materials and products—is, therefore, not necessary or appropriate to make national security-related grid resilience improvements.[189]

Policy Focused Narrowly on Certain Threats Obscures Resilience Consequences of Other Threats

The Trump Administration has asserted that it is responding to fuel supply and other disruptions caused by cyber and physical attack.[190] As explained above, adopting policy based on a limited threat assessment risks exposing the electric system to other threats. Even if coal and nuclear units were less exposed to *pipeline* cyberattack , they may be more or equally exposed to a direct cyberattack or an attack on transmission infrastructure.[191] Recent forced outage rates during extreme weather suggest that deepening dependence on older resources may also reduce resilience to those threats.[192] A holistic assessment of reasonable threats and analysis of the type describe in this report would be necessarily to determine whether the contemplated policy will enhance or detract from generation system resilience.

Proposals to Support "Fuel Secure" Generation Demonstrate Why Attribute-Based Resilience Metrics can be Misleading and Unhelpful

Both proposals would support resources because they possess "fuel security" attributes (defined in the DOE NOPR to mean on-site fuel storage, and in recent proposals to mean generation that is not dependent on natural gas pipelines). As explained above, attribute-based resilience metrics are less useful in evaluating resilience improvements than performance-based metrics. Thus, special care must be taken to ensure that if policy is designed to compensate for certain generator attributes, those attributes, in fact, enhance system resilience. Yet, there are no well-established studies that, relying on realistic assumptions, show that increasing the availability of generators with "fuel security" attributes will enhance the resilience of the electric system. Incentivizing plants with on-site fuel storage may reduce some risks of generation outages due to fuel supply disruption, but may increase other fuel disruption risks, including risk to the fuel stored on-site.[193] And by prejudging the importance of a single, narrow attribute, policymakers may miss alternatives such as hardening fuel transportation infrastructure or installing fuel-free resources that more cost-effectively or comprehensively enhance generation system resilience.

---

[189] *See* 50 U.S.C. § 4511(a)(1) (permitting use of priority contracting and allocation authority only for actions "necessary or appropriate to promote the national defense"); *see also* Joint Trade Association Letter to Secretary Rick Perry Regarding Emergency Authorities at 6-10 (May 7, 2018), https://info.aee.net/hubfs/Trade_Letter_Legal%20Analysis_DOE_5-7-18.pdf.

[190] *See* Jennifer A Dlouhy, *Trump Prepares Lifeline for Money-Losing Coal Plants*, Bloomberg (June 1, 2018), https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl (citing a leaked DOE memo that describes cyber and physical threats to the electric and gas systems).

[191] *See* Rebecca Smith, *Russian Hackers Reach U.S. Utility Control Rooms, Homeland Security Officials Say*, Wall Street Journal (July 23, 2018), https://www.wsj.com/articles/russian-hackers-reach-u-s-utility-control-rooms-homeland-security-officials-say-1532388110 (describing compromised electric utility systems that could result in outages of transmission and generation systems).

[192] *See* Ariel Horowitz et al, Synapse Energy Economics, Comments on the United States Department of Energy's Proposed Grid Resiliency Pricing Rule at E-22 to E-25 (2017), http://www.synapse-energy.com/sites/default/files/Grid-Resiliency-Whitepaper-As-Filed-17-085.pdf.

[193] Mark Watson, *Harvey's Rain Caused Coal-to-Gas Switching: NRG Energy*, S&P Global Platts (Sept. 27, 2017), https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527.

Additional Generator Attributes that Are Bad Resilience Metrics

In order to justify support for nuclear and coal plants, the Trump Administration has primarily pointed to narrow definitions of "fuel security" as the relevant resilience attribute. However, DOE has pointed to other generator attributes that are not good metrics for resilience as support for its proposals. These include:

The number of plants operating as baseload resources.[194] The term "baseload" refers to the minimum level of demand on an electrical grid over a span of time. "Baseload resources" is a technology-neutral term and refers to generation resources that would be most often called upon to meet baseload demand. Some generators—often coal and nuclear—have historically operated to meet baseload demand; however, that historical practice has generally been a reflection of plant cost structure rather than any technological capability to operate in the face of or in response to high-impact, low-probability events. Particularly before the recent drop in natural gas fuel prices, coal and nuclear plants had relatively low variable costs and relatively high startup and shutdown costs, and so had been most economic to meet baseload demand.[195] But as natural gas prices have fallen, efficient natural gas-fired plants have more often been the cost-effective option to meet baseload demand. And as demand remains relatively flat while the level of variable resources (such as wind and solar, which generate only when it is sunny or windy) increases,[196] the electric system may not need as many generators to run continuously and may instead benefit more from dispatchable resources that can supply electricity when the variable resources do not. Whether a plant has operated as baseload, therefore, is not a resilience attribute; it is just a feature of the cost structure of electricity generation. As a result, retirement of units that historically operated as baseload resources does not necessarily reflect reduced resilience of the generation system, let alone the electric system as a whole.

Change in generation by fuel type during a high-impact event.[197] Whether a certain type of generator increases its generation during a high-impact event does not necessarily reflect that it possesses attributes that would help it to perform during future such events. Rather, it may reflect the fact that high-impact events cause electricity prices to rise, and that the facility was likely to operate only during periods of high electricity prices due to high generating costs. For example, during the 2018 "bomb cyclone," coal units were available to meet unexpectedly high electricity demand because their relatively high costs meant they were not being dispatched before the event and therefore had unused generating capacity. Once electricity prices rose, it became economic to dispatch these plants. It was these market dynamics and not any particular resilience attributes of the plants that dictated their operation.[198]

Because Resilience Is a Feature of the Electric System, Focusing Only on Generation Resilience Is Improper

Trump Administration coal and nuclear support proposals have been targeted at improving *generation* resilience. Yet, even if policies to limit the retirement of existing coal and nuclear units did improve generation system resilience, such policies would not necessarily improve *system* resilience. Most outages result from disruptions in the distribution and

---

[194] DOE NOPR at 46,943.

[195] *See* DOE Staff Report at 38.

[196] *Id.* at 16.

[197] Peter Balash et al., Nat'l Energy Tech. Lab, Reliability Resilience and the Oncoming Wave of Retiring Baseload Units 12-18 (2018), https://www.netl.doe.gov/energy-analyses/temp/ReliabilityandtheOncomingWaveofRetiringBaseloadUnitsVolumeITheCriticalRoleofThermalUnits_031318.pdf.

[198] *See* Karen Palmer et al., *Understanding Grid Resilience Implications for Market Design: Beyond the NETL Study*, UtilityDive (Apr. 24, 2018), https://www.utilitydive.com/news/understanding-grid-resilience-implications-for-market-design-beyond-the-ne/522052.

transmission systems, leading some analysts to advocate for a primary focus on distribution and transmission resilience policies and investments.[199] Resilience-focused policy should be evaluated with respect to system resilience, not the resilience of a single component of the system.

Resilience Policies Should be Evidence-Based and Justified Using Cost-Benefit Analysis

The Trump Administration proposals provide stark examples of the need for evidence-based policymaking to improve grid resilience. Neither the DOE NOPR, nor the contemplated DOE emergency action included a comprehensive analysis of the benefits or costs of the proposed actions. A number of analyses showed significant economic costs associated with the DOE NOPR. For example, the independent, nonpartisan think tank Resources for the Future developed a limited economic analysis of the DOE NOPR showing that the proposal would result in net economic costs of around $10 billion per year.[200] Modeling conducted by both The Brattle Group and by Energy Innovation Policy & Technology LLP arrive at similar cost estimates.[201] Yet, DOE presented no evidence that the expected value of resilience benefits of these actions would exceed $10 billion per year. Similarly, a preliminary analysis of the DOE emergency action by The Brattle Group estimated it would cost consumers $20 billion to $70 billion over two years in increased energy costs.[202] This increase would be in addition to the $4-$9 billion of welfare loss over two years caused solely by increased conventional pollution and greenhouse gas emissions, as estimated by a recent Resources for the Future analysis.[203] The Trump Administration should adopt federal policies to enhance resilience only if the benefits of doing so exceed the costs. The cost-benefit analysis framework described in this report provide the tools for doing so.

Resilience Improvements Based on Changing Generation Incentives Should Be Made Using Market-Based, Not Cost-Based Compensation

One feature of both the DOE NOPR and the emergency action DOE is currently contemplating is that they would provide targeted resources with compensation based on their costs of operation (cost-based compensation) rather than the value that they provide the system, as determined by the market (market-based compensation). As described above, the use of cost-based compensation will not provide efficient resilience-enhancing entry, exit, and operational incentives for generators, and might significantly distort the existing energy markets. Rather, market-based compensation schemes should be used for policy designed to enhance resilience by changing generator incentives. Grid operators are currently in the process of implementing or developing market-based systems to value the resilience benefits of fuel-security.[204] Getting the design details right for these schemes is critical, and many have criticized the methodologies and assumptions

---

[199] Silverstein et al. at 6.

[200] Daniel Shawhan & Paul Picciano, *Costs and Benefits of Saving Unprofitable Generators: A Simulation Case Study for US Coal and Nuclear Power Plants*, RF WP 17-22 (Nov. 30, 2017), http://www.rff.org/files/document/file/RFF-WP-17-22.pdf.

[201] Metin Celebi et al, Brattle Group, Evaluation of DOE's Proposed Grid Resilience Pricing Rule (Oct. 2017), http://files.brattle.com/files/11635_evaluation_of_the_does_proposed_grid_resiliency_pricing_rule.pdf; Robbie Orvis et al, The Department of Energy's Grid Resilience Pricing Proposal: A Cost Analysis (Oct. 2017), http://energyinnovation.org/wp-content/uploads/2017/12/20171025_Resilience-NOPR-Cost-Research-Note-UPDATED.pdf.

[202] Metin Celebi et al, The Brattle Group, The Cost of Preventing Baseload Retirements (2018), https://info.aee.net/hubfs/Brattle_AEE_Final_Embargoed_7.19.18.pdf.

[203] Daniel Shawhan & Paul Picciano, Retirement and Funerals: The Emissions, Mortality, and Coal-Mine Employment Effects of a Two-Year Delay in Coal and Nuclear Power Plant Retirements, RFF WP18-18 (2018), http://www.rff.org/files/document/file/RFF%20WP%2018-18.pdf.

[204] *See, e.g.* PJM Fuel Security Proposal; *ISO New England Inc.*, 164 FERC ¶ 61,003 (2018) (ordering ISO-NE to develop a market-based fuel security construct).

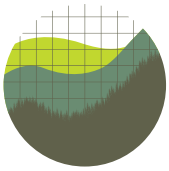
that are being used to develop these market-based schemes.[205] But if done right, market-based compensation is preferable to cost-based compensation for the procurement of real resilience-enhancing grid services.[206]

Conclusion

States and the federal government have a range of authorities to direct investments, implement policies, and facilitate coordination in order to enhance electric system resilience. These authorities can be used to implement a wide variety of actions that help the grid defend against, absorb, or recover from high-impact, low-probability shocks. However, the exercise of these authorities should be consistent with the concept of resilience described in this report and should be evaluated using the cost-benefit framework presented here. By doing so, state and federal regulators will ensure that potential investments and policies enhance the resilience of the electric system as a whole, and that the resilience improvements caused by those policies are justified by their costs.

[205] Kathiann M. Kowalski, *Critics: PJM Fuel Security Plan Ignores Renewables, Won't Build Resilience*, Energy News Network (May 9, 2018), https://energynews.us/2018/05/09/midwest/critics-pjm-fuel-security-plan-ignores-renewables-wont-build-resilience/; Paul Peterson et al, Synapse Energy Economics Inc., Understanding ISO New England's Operational Fuel Security Analysis (2018), https://www.clf.org/wp-content/uploads/2018/05/Understanding-ISO-NE-OFSA1.pdf.

[206] *See* FERC Resilience Order, 162 FERC ¶ 61,012 at PP 11, 16 (rejecting DOE Resilience Pricing, in part, because it used disfavored cost-of-service compensation rather than market-based compensation); *ISO New England Inc.*, 164 FERC ¶ 61,003 at 3 (Glick, Comm'r, *dissenting in part*) (arguing that FERC's preliminary action on fuel security for a natural gas plant would cause "a parade of uneconomic generators seeking cost-of -service rate treatment under the guise of fuel security" rather than "reform [of] the ISO-NE market to address the drivers of whatever fuel security problem may exist"); *Constellation Mystic Power, LLC*, 164 FERC ¶ 61,022 at 1-2 (2018) (Powelson, Comm'r, *dissenting*) (arguing that FERC should have rejected an cost-of-service agreement for a facility in favor of waiting for stakeholders to develop a market-based solution to fuel security concerns).



Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org

Exhibit B

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

ELECTRICITY POLICY INSIGHTS

Valuing Pollution Reductions

How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources

March 2018
Jeffrey Shrader, Ph.D.
Burcin Unel, Ph.D.
Avi Zevin

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Jeffrey Shrader is the 2017-2018 Economic Fellow at the Institute for Policy Integrity at NYU School of Law. Burcin Unel is the Energy Policy Director at the Institute for Policy Integrity. Avi Zevin is an Attorney at the Institute for Policy Integrity.

Executive Summary

Distributed energy resources (DERs)—grid-connected, small-scale electric generators such as rooftop solar installations, micro-turbines, combined heat and power systems, customer backup generators, and distributed energy storage systems—are a growing component of the U.S. electric system. As DERs have become more prominent, state electric utility regulators have begun efforts to more accurately compensate DERs by paying for each of the benefits that they provide.

One such benefit is the avoidance of environmental and public health damages from air pollution (including local air pollution and greenhouse gas emissions) that would have been caused by generation resources that have been displaced by the DERs. This report lays out a practical methodology for calculating this environmental and public health value. It identifies existing tools that states can use, with varying degrees of specificity, accuracy, and complexity, to monetize these pollution reductions. State utility regulators can use the steps outlined here, weighing tradeoffs between accuracy and administrability, to implement their own program to compensate DER for environmental and public health benefits. Regulators can monetize air pollution reductions that DERs provide by using a five-step method:

Step 1 determines what generation will be displaced by DERs. The most accurate methods for determining displaced generation require working with grid operators and, potentially, local distribution utilities, to obtain needed data on which bulk system generators would have operated in the absence of DERs. If sufficient data is not available, utility regulators can use electricity system simulation models to estimate which resources would have operated in the absence of DERs.

Step 2 quantifies the emissions rates for displaced generators. Emissions rates of existing resources vary widely, and therefore, the magnitude of the environmental and public health benefits of DERs will as well. Emissions rates depend on a generator's attributes, including fuel type (for example, coal, oil, natural gas, or renewable), electricity generation technology (for example, inefficient steam boilers or efficient combined-cycle technology), pollution control equipment, and operational practices like capacity factor.

Emission rates of existing generators can be determined based on those generators' historical, measured emissions rates, or can be estimated using engineering analyses, given known information about fuel type, generation technology, pollution control equipment, and operational practices. Databases of historical emissions rates for specific plants and of emission factors broken out by generator attribute (such as fuel type, generation technology, and pollution control equipment) are also available.

Step 3 calculates the monetary value of the damages from emissions identified in Step 2. Air pollutants cause damage to human health, impair ecosystems, harm crops, and make it harder for workers to be productive. Given knowledge of the emissions rate for a power generator, utility regulators can calculate those damages as a function of:

- The type of the pollutant. Particulate matter, especially fine and ultra-fine particulates, cause severe health damages, including death. Oxides like SO_2 and NOx break down into particulate matter and combine with other pollutants to form asthma-causing ozone pollution. Toxic heavy metals like

mercury and lead cause rapid health deterioration even at low concentrations. Greenhouse gases lead to climate change. Researchers have developed monetized damages estimates per unit of emissions for each of these pollutants.

- The location of emissions. Each unit of a pollutant emitted in population-dense areas or in areas with highly vulnerable populations will cause more damage. Emissions also interact with environmental conditions such as prevailing winds to carry pollutants away from the point of emissions. Damage estimates can be modified to account for these concerns.
- The timing of emissions. Some pollutants, such as ozone, only form when precursors are exposed to direct sunlight. Therefore, emissions that occur at night or in winter may cause less damage than those during the day or in the summer. Granular damage estimates account for these timing issues.

A method that accounts for all of these factors would lead to the most accurate calculations of damage per unit of emissions. However, data constraints and ease of use might make alternative, less granular methods more desirable. There are multiple tools produced by various researchers as well as EPA that provide estimates of pollution damages at the county level, and many of these tools allow for partial customization to meet specific needs of regulators.

Step 4 uses the emissions rates from Step 2 and damage estimate per unit of emissions from Step 3 to monetize the value of avoided emissions from displaced generation. Adjustments are needed if existing policies already put a price on emissions of some or all of the pollutants covered in Steps 1-3.

Step 5 takes into account any emissions produced by the DER itself. DERs such as diesel generators or combined heat and power generators emit pollutants. To arrive at an accurate environmental and public health value, those emissions and the damage they cause must also be taken into account. If damage per unit of generation from the DER is high enough, then the net environmental and public health value of the DER could be negative.

Distributed energy resources can provide substantial value to a state by reducing air pollution from conventional electric generators and the resulting environmental and public health damages. DERs can be particularly valuable to the extent that they avoid local air pollution imposed on vulnerable populations. As state utility regulators implement new compensation policies for these resources, those policies should include payment for DERs' environmental and public health value.

This report presents a straightforward five-step methodology that can be used to calculate this value in a technology-neutral manner while relying on existing, readily accessible tools. The methodology outlined in this report is flexible enough to accommodate a variety of data and resource constraints. State regulators can weigh the tradeoffs between accuracy and administrability of different methods to calculating environmental value, pick the tools that are most accurate given the tradeoffs, and then update their methodology when feasible.

While more comprehensive reforms such as an economy-wide tax on greenhouse gases and local air pollutants are needed to fully value the environmental and public health benefits of all DERs, this methodology would allow utility regulators to implement a DER compensation scheme that incentivizes DERs when and where they are most beneficial to the society.

Table of Contents

Executive Summary i

Introduction 1

Valuing Environmental Benefits of Distributed Energy Resources – An Overview 4

Step 1: Identify Displaced Generation 6

- Running Counterfactual Dispatch Scenarios 6
- Identifying the Marginal Generator 7
- Electric Grid Dispatch Modeling 8

Step 2: Identify Emission Rates of the Displaced Generation and DERs 10

- Generator Features Affecting Emission Rates 10
  - Fuel Type 10
  - Generation Technology 10
  - Pollution Control Equipment 11
  - Operational and Environmental Considerations 11
- Methods for Determining Emission Rates 12
  - Historical Emission Rates 12
  - Engineering Estimates 12
  - Selecting Between Historical Emissions and Engineering Estimates 13
- Existing Tools and Databases 13
  - Generator-Specific Historical Emissions Databases 15
  - Generator-Specific Historical Generation Databases 16
  - Engineering Estimate Databases 16
  - Integrated Emissions and Generation Database 17

Step 3: Calculate the Monetary Damages from Emissions 19

- Relevant Factors for Calculating Monetary Damages 19
  - Pollutants Emitted 19
  - Ambient Concentration 20

Pollution Transport 20

Secondary Pollutants 20

Exposed Population 21

Population Health 21

Methodologies for Calculating the Damage per Unit of Emissions for Pollutants that Depend on Time and Location 22

Custom Solutions 22

Estimating Air Pollution Social Impact Using Regression 22

BenMAP 23

Air Pollution Emission Experiments and Policy Analysis Model 23

Co-Benefits Risk Assessment 23

Greenhouse Gases – Methodology for Calculating Damage per Unit of Emissions 24

Step 4: Monetize the Avoided Externality from Displaced Generation 26

Step 5: Monetize and Subtract DER Damages 28

Step 5A: Monetize the Externality from DER 28

Step 5B: Subtract the Value of DER Emissions from the Value of Avoided Emissions 28

Example Calculation 30

Conclusion 33

Introduction

The electric grid is quickly evolving from its traditional structure, where electricity is generated by large power plants located far from end-users, into a multi-dimensional platform. The modern grid allows a variety of new distributed resources that are located near end-users, such as solar panels, energy storage, and demand response, to provide a multiplicity of electricity services. With rapid innovation and declines in costs, these "distributed energy resources" (DERs) are becoming an integral part of the modern grid, and thus, creating new challenges for regulators.[1]

As technology is transforming the grid, policymakers around the nation are working to reform utility regulation in order to harness the full benefits that these technological changes offer. A number of states have initiated proceedings to implement compensation schemes for electricity generated from DERs, or a subset of DERs, that reflect all of the benefits that those resources provide.[2]

DERs help reduce the need for generation from large-scale generators interconnected to the transmission system ("bulk system generators") such as fossil-fuel-fired power plants, which are often costly to build and highly polluting. Depending on the type of DER, they do so in two ways: by reducing customer demand at a given time, or by actually generating electricity. DERs such as demand response and energy efficiency reduce customer demand for electricity at a particular time. Other DERs, such as distributed solar, generate electricity, which can then be used by consumers to offset grid purchases and/or can be exported to the grid. Energy storage can provide benefits by shifting consumer demand, by charging and discharging at different times.

By avoiding the need for generation from the bulk system, DERs can provide many benefits to grid such as avoided energy costs, avoided or deferred capacity costs, and reduced line losses.[3] This report, however, focuses on one regularly overlooked category in utility regulation: environmental and public health benefits.

Bulk system generators often burn fossil fuels—coal, natural gas, and petroleum—or biogenic fuels—agricultural and wood waste, municipal solid waste, animal waste, and landfill gas—and in doing so, they emit air pollutants. When DERs avoid the need for such bulk system generation, they can help reduce air pollution, benefiting society at large. Currently, however, these benefits are not explicitly valued.

Air pollutants emitted by power plants

Combustion of fossil fuels and biogenic fuels results in the emission of air pollutants, which fall into several categories. Air pollutants that affect human health and are dispersed in the ambient air are referred to under the federal Clean Air Act as "**criteria pollutants**." These include particulate matter (PM_{10}), fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NOx), and carbon monoxide (CO). These pollutants also combine in the atmosphere with each other and with volatile organic compounds (VOCs) to make other "secondary" criteria pollutants, including $PM_{2.5}$ and ozone.

In addition, combustion releases **greenhouse gases**—including carbon dioxide (CO_2) and nitrous oxide (N_2O)—that alter the climate and so cause a wide range of disruptive health, social welfare, and environmental effects.

Finally, combustion of some fuels results in emission of **hazardous air pollutants** (HAPs), also referred to as "air toxics," which cause significant damage even in small amounts. This category includes mercury and ammonia.

Air pollution is a textbook example of what economists call an "externality." Externalities are costs or benefits of market transactions that are incurred by parties other than the market participants, and thus are not taken into account by market participants. When externalities are present, market prices do not reflect the external costs and benefits of production or consumption, and therefore fail to provide an economically efficient signal for the true social value of the particular good or service, leading to an inefficient outcome. For example, because fossil-fuel-fired power plants are not paying for the environmental and public health damages their electricity generation causes, we get more air pollution than is socially desirable.

When negative externalities are present, social welfare can be increased by imposing a tax on the source of the externality—in this case, the emission of air pollutants—based on the amount of external damage caused. In the absence of efficient pollution taxes, alternative policies can help improve the efficiency of market outcomes.

One such policy approach is to pay generating resources that reduce air pollution. DERs provide environmental and public health benefits by displacing generation from other resources that would have emitted more air pollution.[4] Therefore, utility regulators can improve social welfare by ensuring that low and zero-emitting DERs are paid for the environmental and public health benefits they produce by displacing higher-emitting generation.

Appropriately valuing these benefits involves identifying the extent to which air pollution is avoided due to DERs, and then monetizing the economic, health, and climate damages those emissions would have caused. This report lays out a practical, technology-neutral methodology for identifying those values. Utility regulators can incorporate this methodology into proceedings aimed at establishing compensation structures for DERs.

It is important to note that, ideally, the same framework would be used to compensate all types of DERs for all the value they provide. However, because the price signals for load reductions manifest as avoided electricity purchases (at the retail electricity rate that customers pay), such comprehensive compensation would require complementary retail rate reforms in order to internalize the externalities.[5] Addressing this is beyond the scope of this report.

The methodology outlined in this report, therefore, is appropriate for compensating energy supplied to the grid by DERs. This limitation likely leads to an underestimation of the environmental and public health benefits of DERs that reduce on-site electricity consumption. However, despite the limitation of the methodology outlined here, compensating even just injections to the grid for the environmental and health benefits DERs provide would significantly improve social welfare.

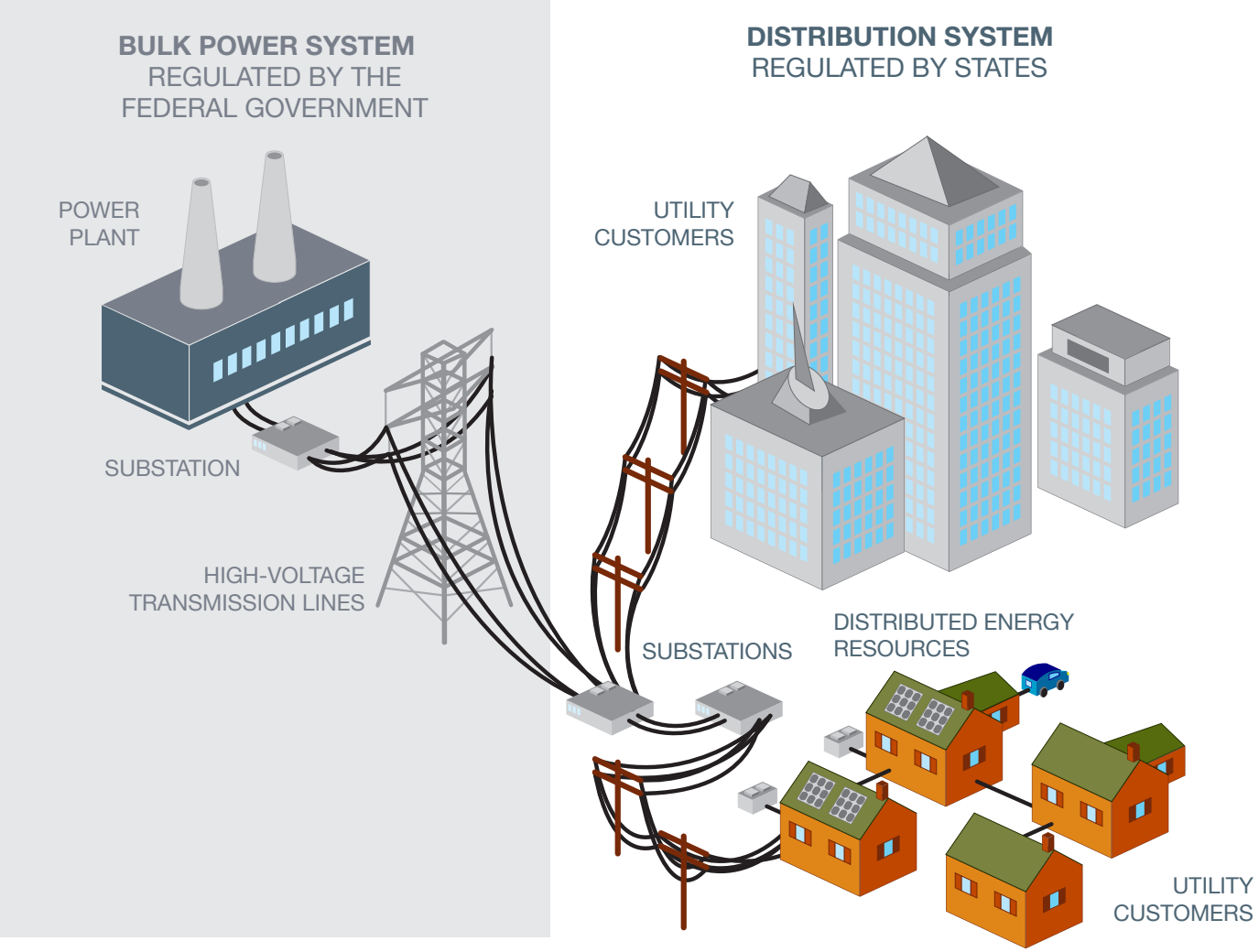
A brief overview of distributed resources, utility regulators, and grid operators

The regulation of electricity is divided between the federal government and the states.[6] Federal regulators have primary responsibility over interstate transmission and wholesale electricity, or the bulk power system, and state regulators have primary responsibility over the distribution system.

State regulators, commonly called "public utility commissions" or "public service commissions," are responsible for regulating local distribution utilities and setting retail rates, as well as deciding on other state-level policies such as DER compensation, renewable portfolio standards, and energy efficiency programs.

In much of the country, the bulk power system, consisting of most generators and large transmission lines, is regulated by the Federal Energy Regulatory Commission and operated by grid operators called "independent system operators" ("ISOs") or "regional transmission organizations ("RTOs"). ISOs/RTOs ensure that supply and demand of the bulk power system are constantly balanced using complex algorithms that take into account the location of both generators and demand, the costs of generation, and congestion on the transmission system. Grid operators dispatch resources from least expensive to most expensive (taking into account the congestion on the transmission system), until demand has been met.

Figure 1: Regulatory Domains of the Electric Grid



Valuing Environmental Benefits of Distributed Energy Resources – An Overview

Public Utility Commissions can calculate the environmental and public health value of DERs based on emissions avoided by the DER and the monetary value of the damage that those emissions would have caused. These two values will depend on the location of the DER and the avoided emissions, the time of day and year when emissions are avoided, and the type of pollutants avoided.[7]

DERs in different locations or generating at different times will displace different sources of generation, with various levels of emissions. Because different generators use a variety of fuel types, electricity generation technologies, control equipment, and operation practices that result in a wide range of air pollutant emissions rates, the type of generators displaced is an important driver of the value. DERs are worth more to society when they offset generation from higher-emitting sources.[8]

DERs are also more valuable when they reduce air pollution in areas with high population density and more vulnerable populations. The time of year also matters because NOx and VOC emitted in the summer carry greater health consequences, due to their role in the formation of ozone in the presence of sunlight. Therefore, DERs that can reduces pollutants in such areas and times are more valuable.

Finally, different pollutants cause different levels of public health and climate damage. If a DER offsets a generator that emits more damaging pollutants, it should receive a higher payment to reflect its environmental and public health value.

Any approach should take into account not only the generation displaced by a DER but also the emissions created by the distributed resource. For example, behind-the-meter DER generators include oil, gas/coal combined heating and power, and storage systems charged by fossil-fuel-fired generation resources. For emitting DERs, payment should be reduced based on their emissions and could potentially be negative if the negative impact of emissions from the DER is higher than the value of emissions avoided by that DER.

Key Terms

Emissions rate

The emissions rate is the amount of pollution emitted by a generator per unit of generation. If a generator emits 1 metric ton of SO_2 and generates 1 megawatt-hour (MWh) of electricity, then its emission rate of SO_2 is 1 metric ton/MWh, or 1 kilogram (kg)/kWh. The emissions rate can be affected by, among other things, installation of pollution control equipment, changes in the efficiency of the generator, or use of different fuels by generators that have fuel flexibility.

Damage per unit of avoided emissions

The damage per unit of avoided emissions is the monetized value of the harm that the pollution would have done had it been emitted. For instance, each kilogram of SO_2 released by a generator causes roughly $50 of damage. Therefore, if a DER avoids the emission of one kilogram of SO_2 by displacing generation of a fossil fuel power plant, then it would avoid $50 of damage.

Environmental value of displaced generation

The value of displaced generation is the dollar value of damages avoided, per unit of displaced generation. It is the product of the emissions rate and the damage per unit of avoided emissions.

Harnessing all the benefits DERs can provide requires compensating them for their environmental and public health value in a technology-neutral way that can take into account these different factors, while balancing accuracy and administrability. To achieve this goal, regulators must first identify the generation that is displaced by DERs, determine the emissions avoided by this displacement based on the emissions rates of the displaced resources, calculate the monetary damages per unit of avoided emissions, and then calculate the monetary value of the net damages avoided by DERs.

Below, we outline the necessary steps and then explain each step in detail.

Methodology Outline for Valuing the Environmental Benefits of DERs:

1. Identify the generation that is displaced by a DER
2. Calculate emissions rates (kg/kWh) of the displaced resource
3. Calculate the damage per unit ($/kg) of avoided emissions
4. Monetize the value of avoided damage from displaced generation ($/kWh)
5. Subtract any damages from the DER itself from the displaced generators' damages, to calculate *net* avoided damages

Step 1: Identify Displaced Generation

Distributed energy resources produce environmental and public health benefits by displacing generation from emitting power generators. The first step in calculating the value of those benefits, then, is to identify what generation will be displaced by a DER.

If sufficient grid operation and market information is available, it is possible to identify, with a reasonable degree of precision, the specific generator or generators that would have operated in the absence of DERs. If such data is not available, there are techniques that can be used to approximate which generators were displaced by DERs.

This section outlines three techniques for identifying displaced generation: (1) using counterfactual dispatch scenarios, (2) identifying the marginal generator, and (3) using electric market simulation models. These options are explained in order of decreasing levels of precision and decreasing information requirements.

All of these methodologies will identify those generators that have been displaced by DER resources *in the short run*. That is, these methodologies identify which of the *existing* resources would have generated in the absence of the DERs. They do not account for the potential effect that DERs have on the longer-term entry and exit incentives for emitting resources. Installation of DER capacity may contribute to the retirement of an existing fossil fuel-fired generator or may avoid the need for a new fossil fuel-fired generator. Therefore, methodologies presented in this section likely understate the extent to which DERs reduce emissions. Complex methodologies have been developed to account for these emissions effects; however, incorporating these effects into a DER valuation methodology is beyond the scope of this report.[9]

Running Counterfactual Dispatch Scenarios

Overview. It is possible for market operators to identify all of the generating resources that would have operated in the absence of DERs with precision and confidence. A market operator can run a counterfactual dispatch scenario in which the operator runs its regular dispatch algorithm while assuming no DERs. The generators that would have operated in this counterfactual dispatch scenario but were not actually dispatched are the generators that were displaced by DERs. These identified resources can be used in Steps 2-3 to calculate the avoided damages attributable to DERs.[10]

Advantages. The primary advantages of this approach are that it is accurate, granular, and flexible. Because it relies on actual grid operations and market data used to make dispatch decisions, this method can accurately capture which resources would have operated in the absence of DERs. Because this approach can identify the specific generators that have been displaced, it will also provide specific information on the location of displaced emissions, which is useful for calculating accurate public health damages in Step 3.

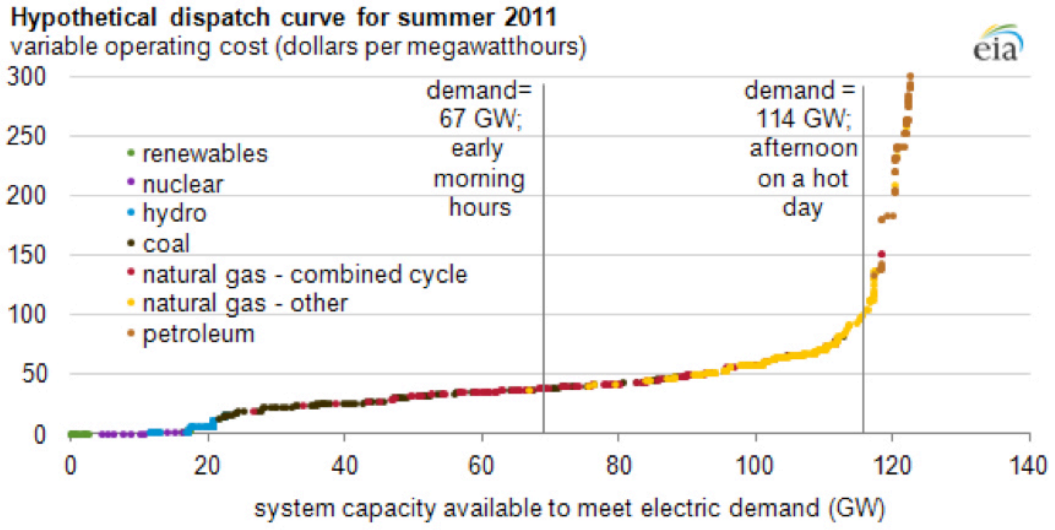
Counterfactual dispatch scenarios could be run as often as the grid operator reruns its dispatch algorithm. However, this approach is also flexible and can be updated less frequently if the administrative costs of frequently identifying counterfactual dispatch outweigh the benefits. For example, if there is limited variability in which resources are displaced over short intervals, grid operators could run counterfactual dispatch scenarios once per hour; during key parts of the day (such as during periods that typically have high electric demand and periods with low electric demand, or periods with high DER injections and periods with low DER injections); or during key times over each season of the year.

Limitations. The primary limitation of this approach is its significant data requirement. Regulators will have to work with distribution utilities to obtain the information—location, timing, and magnitude of DER penetration—needed for counterfactual dispatch scenarios, and then work with grid operators to produce counterfactual dispatch scenarios.

Identifying the Marginal Generator

Overview. An alternative approach to identifying displaced generation is to use information from the grid operators on marginal generators. Grid operators usually dispatch generators based on their cost of operation, as well as technical constraints of the system, until the total generation is high enough to meet the demand. The "marginal generator" for a given interval is the last generator that is needed to satisfy demand at that interval. Additional DERs at this time will reduce the need for generation from the marginal generator, and therefore avoid emissions from the marginal generator. States can work with grid operators to identify the generator on the margin at the time of DER operation, which can provide an accurate up-to-date estimate of which generators DERs are displacing.

Figure 2: Illustrative Market Supply Curve[11]



Source: Energy Information Administration (2012)

Figure 2 is an illustrative market supply curve, which shows available generators in ascending order of marginal cost from left to right. Different levels of demand are illustrated by the vertical lines. The marginal generator for a given level of demand is the generator at the intersection of the vertical line and the supply curve. Based on this curve, when load is at its minimum, a gas generator with a relatively low bid will be on the margin. Any DER at this time will reduce the need for generation from that gas generator. When load is at its maximum, the marginal generator may be an oil-fired generator. DER will replace generation from the oil-fired generator.

Because the transmission system can be congested, the marginal generator will often be location dependent. If transmission lines are congested, electricity cannot be transmitted from distant locations even if there are available cheap generators, and therefore grid operators must rely on more expensive local resources. Take, for example, the New York Independent System Operator. When there is no congestion, a DER in New York City can indeed displace a system-wide marginal

generator, which can be located anywhere in the state. However, the transmission lines going in and out of New York City are often congested. During periods of such congestion near New York City, the marginal generator displaced by a DER in New York City will likely be local and different from the marginal generator displaced by a DER located in other parts of the state. States should therefore identify marginal generators at a level of geographic granularity appropriate given the level and location of congestion on the system.

If real-time information is not available from grid operators, regulators could identify marginal generators by matching load levels with generators on representative dispatch curves, such as the one outlined in Figure 2 above.[12] Such use of historical dispatch curves rather than actual dispatch curves for a given interval reduces the accuracy of this measure but it can be done with less involvement of the grid operator. These curves can be constructed using grid operator data, based on historical information on generator operation and energy bids. To most accurately reflect the generation mix available at a particular time, regulators should use historical dispatch curves applicable for times of day and seasons to reflect variations in renewable energy and seasonal outages.

Advantages. While identifying the marginal generator will require working with the grid operator, this approach requires significantly less involvement and data from the grid operator. This approach also will not require specific information from distribution utilities on the location, timing, and magnitude of DER load and generation profiles.

Limitations. This approach assumes that the magnitude of DERs is not large enough to change the marginal resource. Currently the level of DER penetration is small enough to meet this requirement in most contexts. In addition, especially during high-demand times when a small generator is on the margin, the next resource that would be marginal if that small generator is displaced may have quite similar emission characteristics. However, as DER penetration increases, it is possible that DERs will begin to change which generators are on the margin. This will reduce the accuracy of this approach as compared to the counterfactual dispatch scenario approach.

Electric Grid Dispatch Modeling

Overview. A number of sophisticated models of the electric grid have been developed that can be used to simulate the dispatch of generators under a variety of conditions.[13] These models generally incorporate databases of generators (including the location, size, fuel type, and other operational characteristics) and transmission, assumptions about fuel and other operational costs of generation, and assumptions about electric demand to simulate operation of a given electric grid. Regulators can use these dispatch models to identify the resources that have been displaced by DERs, similar to how a grid operator would identify displaced generation through counterfactual dispatch scenarios. The electric model would be run both with and without DERs to identify the resources that have been displaced.

Regulators should perform model runs under a variety of assumed operating conditions (e.g., varying levels of electric demand, transmission congestion, and DER availability). They can then use the simulation that best matches the appropriate real-world circumstance.

Advantages. The primary advantage of this approach is that it can be used without involvement of the ISO/RTO or distribution utility. While the relevant models are complex and require expertise to use, Public Utility Commissions can develop this expertise rather than having to rely on outside entities for ongoing data requirements.

Limitations. Because these models rely on assumptions, rather than realized outcomes, they are not likely to be as accurate as the first two approaches outlined. In addition, this approach will be even less likely to incorporate any sectoral changes over time including generator entry and exit and generator outages, unless the model used is updated to reflect these changes.

An Approach to Avoid: Grid-Average Generators and Grid-Average Emissions rates

While there are many acceptable options to identify generators that will be displaced by DERs, regulators should *not* assume that DERs displace all generators in equal amount (either numerically or generation-weighted). Similarly, regulators should not use grid average emission factors when determining the avoided emissions attributable to DERs. Assuming DERs displace all resources equally or using *average* emissions rates will incorrectly include substantial zero-emission generators that are unlikely to be affected by DERs. Use of averages will also miss significant temporal and locational variation in the amount of air pollution displaced by DERs. Research has shown that using average emissions rates significantly misstates emission impacts of new resources.[14] While this approach is computationally easy, and therefore appealing, using grid averages will not lead to accurate estimates.

Step 2: Identify Emissions Rates of the Displaced Generation

Once the resources that are displaced by DERs have been identified, the next step is to determine the emissions rates of those displaced resources. These emissions rates are necessary to determine the economic benefits of avoiding emissions from each kWh of the displaced emitting generation. Table 1 presents average emissions rates of select criteria and greenhouse gas pollutants by fuel burned.

Table 1: Average Emissions Rates of Select Pollutants for Generators in 2016[15]

Fuel Type	NOx (kg/MWh)	SO_2 (kg/MWh)	CO_2 (kg/MWh)
Oil	2.92	2.86	862.80
Coal	0.75	1.08	1003.38
Biomass	1.58	0.67	211.06
Gas	0.16	0.00	405.94

Generator Features Affecting Emissions rates

Emissions rates are a function of (1) the type of fuel combusted, (2) the combustion and electric generation technology, (3) any pollution control equipment, and (4) environmental and operational considerations.

Fuel Type

The type and amount of pollutants emitted by electricity generators is primarily a function of the type of fuel used. Some plants are designed to burn only one type of fuel. Others, called "dual fuel" plants, are able to switch between fuels depending on fuel availability and price. Dual fuel plants generally can burn either natural gas or oil-based fuel (e.g., diesel fuel).

Uncontrolled combustion of coal, oil and wood biomass emits relatively large quantities of most criteria pollutants, HAPs, and greenhouse gases.[16] Combustion of gas, including natural gas and landfill gas, primarily emits NOx, CO, VOCs, and CO_2, with little to no direct emissions of PM, SO_2 and HAPs.[17] On the other end of the spectrum, nuclear, hydroelectric, solar, and wind generation do not emit any air pollution.

Generation Technology

For a given fuel type, the primary determinant of the emissions rate is the efficiency by which a combustion technology converts fuel into electricity, called the generator's "heat rate".

Key Term

Heat rate is a measure of power plant efficiency. It is a measure of the amount of energy, embedded in the combusted fuel, measured in British Thermal Units, that it takes to generate a kWh of electricity.[18] The higher the heat rate, the *less* efficient the plant.

Steam boilers generate electricity by combusting fuel to produce heat, which warms water to produce steam that turns an electric turbine. Steam boilers generally have high heat rates.[19] In other words, they are not efficient. Steam boilers primarily use coal (and almost all coal plants use steam boilers), but they can also combust natural gas, fuel oil, or biomass.[20]

Stationary internal combustion engines (ICE), which generally burn fuel oil, have similar heat rates to steam boilers and are most often used as "peaker plants" when demand is particularly high, for backup power, or as distributed generation.[21]

Combustion turbines use heat produced from fuel combustion to turn a turbine that generates electricity. They use liquid or gaseous fuel, including natural gas, fuel oil and biogenic fuels (e.g., landfill gas).[22] Combustion turbines can range in efficiency and often function as peaker plants.

Finally, highly efficient combined-cycle plants combine the technologies to produce more electricity for the same amount of fuel.[23] In a combined-cycle plant, a combustion turbine produces electricity and heat, while the excess heat produces steam that generates more electricity. These plants primarily use natural gas (and much less often fuel oil).

Pollution Control Equipment

Emissions rates can also vary significantly depending on whether a plant has installed air pollution control technology. Almost all plants can implement some pollution control equipment, but there is significant variation in the type and effectiveness of installed equipment. For instance, flue gas desulfurization technology can reduce SO_2 concentrations of coal plant emissions by 98%, while catalytic reactions reduce NOx pollution by 80%.[24] Pollution control equipment can also negatively affect the efficiency of power plants.[25]

Operational and Environmental Considerations

A variety of environmental and operational considerations affect emissions rates. These include:

- **The age of the plant.** Plant efficiency generally declines with age.
- **The utilization of the plant.** Power plants that are operating below full capacity are generally less efficient and so have higher emissions rates.
- **Ambient weather conditions.** Ambient weather conditions including temperature, humidity, and pressure can affect the efficiency of a power plant.[26]

These operational and environmental considerations vary over time, while other features like fuel type, generation technology, and pollution control equipment are relatively static. Therefore, it is not possible to know a particular

generator's emissions rate without measuring, in real time, its emissions and generation. Even though such data is rarely available, there are a number of existing or easy-to-develop tools that states can use to determine reasonably accurate emissions rates for generators.

Methods for Determining Emissions rates

States can use one of two primary options for determining reasonably accurate emissions rates: (1) historical, measured emissions rates of the generator, and (2) engineering estimates of a generator's emissions rates based on design characteristics and operational assumptions.

Historical Emissions Rates

Historical emissions rates calculate a given generator's emissions rate for each pollutant based on measured historical emissions and measured historical generation.

Historical Emissions. Generators above a specific size threshold are required to directly measure and report the volume of emissions for some pollutants to state environmental agencies and/or the U.S. EPA Clean Air Markets Division (CAMD). Continuous emission monitors are used to measure and report NOx, SO_2, and CO_2 emissions from generators subject to certain federal environmental program requirements.[27] For pollutants where continuous emission measurement is not feasible or is particularly expensive (such as for PM), generators calculate and report emissions through monitoring of parameters that have a known relationship with emissions, such as operational characteristics of plant systems (temperature, pressure, liquid flow rate, pH), through periodic emissions testing, or based on quantities of fuel consumed and the technology used to generate electricity.[28]

Historical Electric Generation. Generators are required to measure and regularly report various characteristics and operational performance of their plants to the U.S. Department of Energy's Energy Information Agency (EIA).

Dividing historic emissions by historic generation yields historic emissions rates. This calculation should be done with as high degree of granularity as possible in order to yield representative emissions rates for a generator's operational performance. For example, for a dual fuel generator, dividing annual total emissions of SO_2 by annual generation will not yield an accurate SO_2 emissions rate because SO_2 is only emitted in the hours that the generator burns fuel oil. Significant emissions rate changes for a generator can be captured by more daily or hourly emissions rate calculations.

Engineering Estimates

Engineering estimates of emissions rates are based on assumptions about known characteristics of generators. Accurate engineering estimates use the considerations identified above (fuel type, heat rate of generating technology, emission control technology, and environmental and operational considerations) to develop emissions rates that can be applied to generators with similar characteristics. Because of this, engineering estimates are sometimes referred to as "emission factors."

Selecting Between Historical Emissions and Engineering Estimates

Short of real-time continuous measurements, historical measured emissions rates are generally the best measure of a particular generator's emissions rate. Therefore, they should be used when available.

However, measured historical emissions rates are not always available for all sources. Existing databases are limited to those generators that exceed certain size and operational thresholds. Smaller generators, newer generators, or generators that did not operate over the historical period used to set emissions rates are not included in certain databases. In addition, because it is difficult to directly measure certain pollutants such as PM and air toxics, historical emissions rates for all pollutants may not be known for a given generator.

Finally, lack of temporal granularity of may produce misleading emissions rate estimates. In particular, the use yearly-average emissions rates may be problematic for generators that do not operate consistently over the course of a year, such as dual fuel peaking plants that may burn oil instead of natural gas when natural gas is unavailable or particularly expensive.

Where historical emissions rates are not available at all, or lack sufficient granularity, engineering estimates should be used.

Existing Tools and Databases

There are a number of existing databases that regulators can use to determine emissions rates. Different tools may be appropriate for different pollutants or for different desired levels of granularity.

This section outlines tools that fall into a number of categories: (1) Databases of generator-specific historical measured emissions; (2) databases of generator-specific historical measured generation, which, together, can be used by a state to develop generator-specific historical emissions rates; (3) databases of engineering estimates of emission factors; and (4) integrated databases that combine data from other sources to produce readily available emissions rates.

Table 2: Databases for Calculating Emission Rates

Tool	Data type	Pollutants covered	Covered sources	Data source	Update Frequency (last data year)
Historical Emissions Databases					
EPA CAMD	Generator-specific hourly emissions (can be aggregated)	NOx, SO_2, CO_2	Boilers > 25MW; combustion turbines, combined-cycle plants, & ICE online after 1990	Mandatory source-level reporting based on continuous monitoring	Monthly (Sept. 2017)
National Emissions Inventory	Unit-specific annual emissions	SO_2, NOx, PM_{10}, $PM_{2.5}$, CO, VOC, NH_3, Hg, HCl	Power plants with criteria pollutant emissions over certain thresholds	State environment office reporting, supplemented by EPA CAMD data and emission factors	3 years (2014)
Historical Electric Generation Databases					
EIA Form 923	Unit-specific monthly electric generation and fuel consumption	n/a	Sources > 1 MW	Operator-level reporting	Monthly (Oct. 2017)
Engineering Estimate Databases					
EPA AP-42	Engineering-based estimates by fuel and technology type	SO_2, NOx, PM_{10}, $PM_{2.5}$, CO, VOC, CO_2, CH_4	Boilers, combustion turbines, and ICE using coal, natural gas, fuel oil, and biomass	EPA tests of representative technology	Infrequent (1998-2008)
National Energy Technology Lab	Engineering estimates	CO_2, SO_2	Modern highly-efficient natural gas combined-cycle plants	Department of Energy engineering analysis of modern plants	Infrequent (2010)
Integrated Databases					
eGrid	Unit-specific annual emissions and electric generation	NOx, SO_2, CO_2	Electric generating units that report electric generation data on EIA-923	Emissions: EPA CAMD and AP-42 Generation: EIA-923	Sporadic, generally 1-4 years (2016)
Argonne National Labs GREET	Attribute-based emission factors using statistical analysis of historic emissions rates and open literature review	CO_2, CH_4, NOx, SO_2, CO, VOC, PM_{10}, $PM_{2.5}$	Boilers, combustion turbines, combined-cycle plants, ICE burning coal, nat. gas, fuel oil, and biomass, with various pollution control equip.	EPA eGRID, AP-42, open literature	Sporadic (2012 for full update, 2017 for limited update)

Generator-Specific Historical Emissions Databases

EPA maintains a number of databases of power plant emissions. However, no single database contains information on all important pollutants. Combining datasets is necessary to get a full picture of generator emissions.

EPA Clean Air Markets Division

Overview. EPA's CAMD collects emission data from large air pollution sources, including power plants, in order to administer a number of federal environmental programs. Electric generators subject to reporting requirements include steam generators with at least 25 MW capacity, non-steam generators – gas turbines, combined cycles, internal combustion engines – that came on-line after 1990, and independent power producers/co-generators that sell over a specific amount of electricity.[29] These generators report hourly emissions of NOx, SO_2, and CO_2, collected from CEMs, to EPA on a quarterly basis. The hourly data can then be aggregated into daily, monthly, or seasonal data.

Advantages. Using hourly emission data would allow state utility regulators to calculate emissions rates that take into account environmental and operational characteristics. Because the data is collected from continuous monitoring, it is also more accurate than data collected through other means.

Limitations. The biggest limitation is that CAMD does not include historical data on a number of key pollutants, such as PM. CAMD only recently began collecting data on mercury, hydrogen chloride, from some coal and oil-fired steam generators.[30]

National Emissions Inventory

Overview. The National Emission Inventory (NEI) is a database of annual emissions for a wide variety of sources, including power plants with a potential to emit criteria pollutants above a 100 tons per year threshold.[31] NEI data includes generator-specific emissions of PM_{10}, $PM_{2.5}$, VOCs, CO, HAPs, SO_2 and NOx emissions.[32] Data is based primarily on data reported to EPA from state environmental agencies, supplemented and modified by data that EPA itself collects and other EPA assumptions.[33] New data is collected by EPA every three years, and released three years later after it goes through a substantial quality assurance process. The 2014 National Emissions Inventory was released in 2017.

Advantages. The primary advantage of NEI data is that it contains emissions of a wider variety of air pollutants than CAMD, including PM.

Limitations. Infrequent updating is the primary limitation of the NEI. The NEI is updated only every 3 years, on a 3-year delay. Therefore, accurate emissions rates will not be available for sources built or substantially modified after 2014. In addition, NEI contains only annual (and for NOx, summer season) emissions.[34] Therefore, emissions rates calculated using this data source will be limited to annual average emissions rates (and, for NOx, ozone season average emissions rates), and will have limited accuracy for plants whose emissions rates vary with operational changes, such as mid-year changes in fuel used.

Generator-Specific Historical Generation Databases

EIA-923

Overview. Operators of electric generators greater than 1 MW report net electric generation (as well as fuel consumption) to the Department of Energy's Energy Information Agency (EIA) on form EIA-923.[35] All generators report generation annually, and a large subset report generation on a monthly basis.[36] For generators that are not included as part of the sample, EIA imputes monthly generation data using statistical techniques.[37]

Advantages. EIA data is readily accessible online and practitioners consider it as the best source of widely available generation data.

Limitations. Emissions rates more granular than monthly averages are not available.

Engineering Estimate Databases

EPA AP-42

Overview: EPA has developed *AP-42 Compilation of Air Pollution Emission Factors* for a wide variety of pollutants and source categories. These factors are often used by EPA when measured data is not available and can be used by states to develop assumed emissions rates for sources where EPA data is not available.[38]

AP-42 provides emission factors for the following combustion technologies: steam boilers;[39] stationary combustion turbines;[40] and large stationary diesel and dual-fuel engines.[41] It generally includes emission factors for criteria pollutants and their precursors, HAPs, and greenhouse gases (including CO_2 and methane).

Advantages. AP-42 provides a standard set of widely used emissions factors. It is therefore easy to use when historical emissions data is not available.

Limitations. AP-42 emission factors have not been updated since the late 1990s and early 2000s. This is particularly an issue for generation technology that has seen significant advancements since the last AP-42 update, including natural gas combined-cycle combustion technology. In addition, recent analysis has shown that the factors do not capture the wide variety of emissions rates from actual facilities.[42]

NETL Natural Gas Combined-Cycle Analysis.

Overview: In 2010, the Department of Energy's National Energy Technology Laboratory (NETL) evaluated the cost and performance of representative fossil fuel-fired power plants, including new NGCC power plants. As part of this report, NETL developed air pollution emissions rate estimates for a standard NGCC plant.[43] These emission factors have been used by academic researchers studying the economic costs of air pollution externalities from power plants.[44] For relatively modern, large NGCC plants, states could use generic emissions rates based on this research.

Advantages. Up-to-date and widely used emission factors for modern NGCC technology.

Limitations. Limited to emission factors for a single generation technology type.

Integrated Emissions and Generation Database

There are two integrated databases that combine available emissions and generation data from the databases outlined above and other sources. These databases can help determine emissions rates with minimal additional work by utility regulators.

EPA eGrid Database

Overview. EPA maintains the eGrid database[45], which contains annual average emissions data and annual average generation data for most electric generators, compiled from a variety of data sources. The primary source for generation data is EIA form 923.[46] The primary source of EPA's emission data is EPA CAMD.[47] For generators that do not report to CAMD, EPA calculates annual emissions by multiplying emissions factors from AP-42 by the plant's heat rate (as reported to EIA).[48]

Advantages. The primary advantage of eGrid is that EPA has already done the work to compile and validate relevant data from CAMD, AP-42, and EIA.

Limitations. eGrid does not include data on key pollutants, such as PM and air toxics. Because eGrid provides *annual* emissions and generation data,[49] eGrid data does not take into account emissions rate changes that could result from variation in the fuel used by a plant throughout the course of a year, changes in capacity factor, or other operational and environmental characteristics.

Argonne National Laboratory GREET Emission Factor Database

Overview. Argonne National Laboratory (ANL) has developed a model for estimating lifecycle greenhouse gas and criteria pollutant emissions associated with various vehicle technologies: the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model.[50] In order to estimate lifecycle emissions of electric vehicles with this model, ANL has compiled a database of power sector emission factors broken out by relevant attributes such as fuel type, generation technology, and pollution control equipment.[51] The GREET emission factor database was developed using data from CAMD, EIA, AP-42 and the open literature.

Advantages. The GREET emission factor database includes emission factors for a wide variety of pollutants, including those not included in eGrid, such as $PM_{2.5}$. The database is broken out by many generator characteristics, so more accurate emissions rates can be identified, so long as relevant attributes of a given generator are known. It is updated more frequently than AP-42 (the last comprehensive update was in 2012, but limited updates were made in 2013 and 2017).[52] ANL conducted robust statistical analysis to arrive at emission factors.

Limitations. The GREET emission factor database includes general attribute-based emissions rates. Therefore, it is not as accurate as historical emissions rates for specific generators when such rates are available.

Estimating Displaced Emissions if Step 1 is Not Feasible

The methodologies described in Steps 1 and 2 of this report identify the emissions avoided by a DER by identifying specific generators that would be displaced and determining the emissions rate of those generators. However, when it is not possible to identify specific generators due to lack of data, it is possible to estimate the emissions displaced by DER by using econometric techniques.

Academic researchers have been using regression analysis to directly estimate the grid's marginal emissions rates.[53] This method requires high-frequency data on emissions of the pollutant of interest and the quantity of electricity demand – the load – for a particular electric grid. A linear regression of emissions on load will yield the relationship between changes in measured emissions from all generators on the grid and changes in electricity demand. The marginal emissions rates at a given time and location can then be estimated based on the level of electricity demand at that location and time.

The granularity of this method depends on the granularity of the underlying data. For example, if data are available on zonal level emissions and load, then marginal emissions can be calculated to the zonal level for each season or time of day.

Limitations: Because marginal emissions rates are estimated for a given area, assumptions are required about where specifically emissions will occur. This will limit the accuracy of damage estimates outlined in Steps 3-4 below. In addition, this approach will not be responsive to changes in the electric sector such as short-run changes caused by generator outages and medium-run changes in the composition of generators over time. Therefore, this approach should be used only to the extent that utility regulators are not able to obtain information from grid operators and cannot use electric market models.

Step 3: Calculate the Monetary Damages from Emissions

Air pollutants cause damage to human health, impair ecosystems, and harm crops and other production activities. The goal of this step is to find the monetary value of the damages from each unit of emissions identified in the previous step. Given knowledge of the emissions rate for a power generator, regulators can calculate damages as a function of the pollutants being emitted, the location where those emissions occur, the time of day and year when they occur, and ambient environmental conditions like weather and pollution concentrations. The most accurate calculation of damages would incorporate each of these elements.

Relevant Factors for Calculating Monetary Damages

The sections below discuss the factors needed for calculating monetary damages from emissions, as well as the motivation for incorporating these different elements and the key issues related to granularity versus ease of administration.

Pollutants Emitted

The previous section identified a number of pollutants emitted by fossil power generators. Each pollutant has its own relationship between exposure and impact, called the *dose-response function* or *damage function* in epidemiological and economic research. These different damage functions should be accounted for when calculating damage per unit of emissions for accurate assessment of the value of avoided emissions.

Toxic Heavy Metals

Toxic heavy metals like mercury or lead cause rapid health deterioration even for low concentrations and quickly become fatal. Heavy metals like mercury and lead can also decrease brain function, leading to marked reduction in IQ.[54] The harms also occur over long periods of time because heavy metals do not break down once they are released, leading to long-run harms as the public is exposed the pollutant over longs periods of time and permanent, negative health effects for individuals whose bodies cannot get rid of the toxins. Because the harm caused by these metals is so extreme, the damage per unit of emissions is correspondingly high.[55]

Sulfur Dioxide (SO_2)

Sulfur dioxide (SO_2) is a gas released during combustion of oil and coal that negatively affects the environment and human health. SO_2 irritates mucous membranes in the lungs, eyes, nose, and throat, exacerbating conditions like asthma.[56] SO_2 also breaks down into particulate matter. Fine particulates, especially those smaller than 2.5 micrometers, called $PM_{2.5}$, penetrate into the lungs, causing or exacerbating cardiovascular problems like asthma and heart disease. Fine particulate matter is also a primary contributor to haze and visibility reduction in much of the United States.[57] SO_2 is also a major contributor to acid rain.[58]

Nitrogen Oxides (NOx)

Nitrogen oxides are gases including nitrogen dioxide, nitrous acid, and nitric acid. Collectively, these gases are referred to as NOx.[59] Like SO_2, NOx breaks down into particulate matter, causing cardiovascular health effects and contributing to haze.[60] NOx, along with other pollutants like VOCs, react with sunlight to create ozone pollution, which is a respiratory irritant that aggravates conditions like asthma.[61]

Greenhouse Gases

Greenhouse gases, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), lead to climate change.[62] Greenhouse gases exert a warming effect on the global climate. This warming is already having noticeable, damaging effects on the environment and the economy.[63] These damages are expected to increase in the future as further climate change occurs.[64]

Ambient Concentration

Ambient pollution concentrations affect the amount of damage that results from additional pollution emissions. Some pollutants cause severe health effects at low concentrations, so even small emissions of such pollutants can be dangerous, depending on ambient levels. One such pollutant is mercury. Even small concentrations of mercury can cause mortality, so an increase in emissions of mercury in an area with a high pre-existing concentration can cause severe health effects.[65] In contrast, an increase in emissions of a pollutant like particulate matter will cause declining marginal damage as the ambient concentration rises.[66]

Pollutants can also interact, exacerbating effects. For instance, ozone creation is more likely in the presence of both VOCs and NOx.[67] Pollutant interaction makes it potentially important to account for ambient concentration of other pollutants when calculating damages per unit of emissions. Such interaction effects might be challenging to quantify in a way that is also easy to administer, so a reasonable alternative would be to incorporate damages that vary by location depending on the average or usual concentration of important ambient pollutants.

Pollution Transport

Pollution can be carried away from the area where it is created through a process called pollution transport. Wind and water carry pollutants away from the point of emission, potentially exposing populations far from the emission source.[68] Rain washes particulate matter out of the air and into bodies of water.[69] Pollution transport models are useful for understanding this movement of pollutants from source to final location. For instance, lighter pollutants like fine particulates can be carried farther than heavier pollutants like PM_{10}, making modelling of transport for fine particulates relatively more important for correct damage estimation.[70]

Secondary Pollutants

Related to pollution transport, pollutants break down and potentially create other, secondary pollutants as they travel through the atmosphere. As discussed above, SO_2 and NOx break down to create particulate matter. Ozone forms when sunlight reacts with oxides and organic compounds in the air.[71] Thus, ozone is less likely to form at night and is also less likely to form in the winter, making time of day and year important for damage from this pollutant.[72]

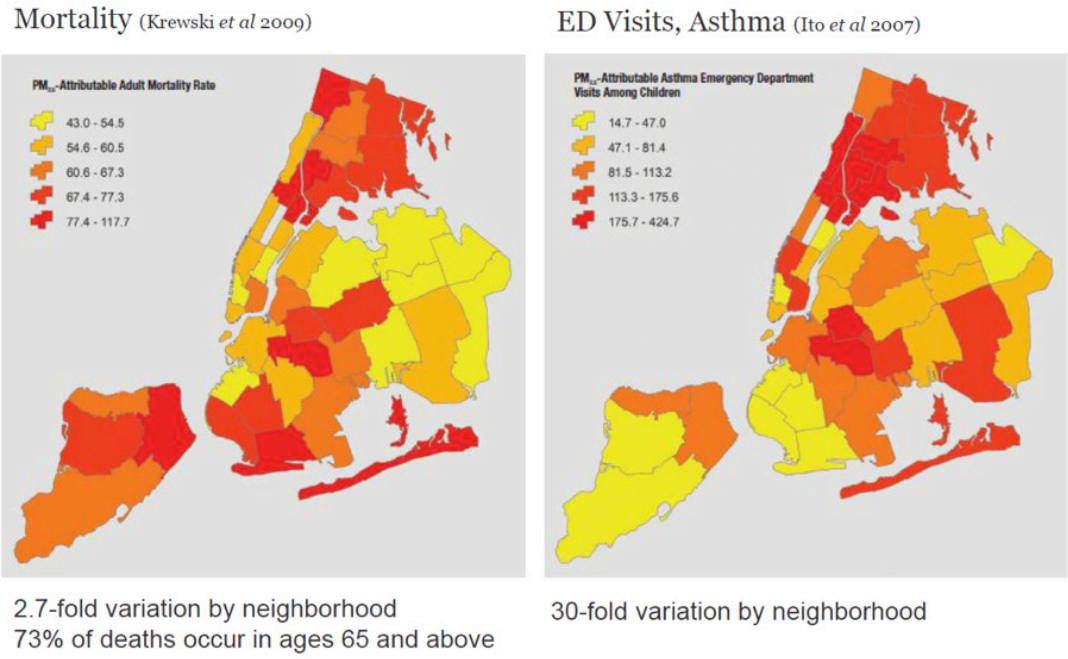
Exposed Population

Pollution causes damage when individuals are exposed to that pollution, so the size of the exposed population is one of the most important drivers of changes in damage from pollution. Densely populated areas experience more damage from a given amount of pollution simply because more people are exposed to that pollution. For instance, $PM_{2.5}$ released in the eastern region of the United States causes between $130,000 and $320,000 in damages per ton according to EPA estimates. A ton of $PM_{2.5}$ emitted in the western part of the United States, however, causes $24,000 to $60,000 in damage.[73] The difference in these estimates is primarily attributable to differences in population density.

Population Health

The healthiness of the exposed population also affects damage. Ozone created in an area with high asthma rates will cause more health damage than ozone released in an area with very few asthma sufferers. Overall health affects the vulnerability of individuals to mortality from pollutants. For example, Figure 3 shows that in New York City, $PM_{2.5}$-attributable mortality rate is higher in portions of Brooklyn than in southern Manhattan.[74]

Figure 3[75]



Source: NYC Department of Health and Mental Hygiene Bureau of Environmental Surveillance and Policy (2013).

The left panel shows the relationship between $PM_{2.5}$ and adult mortality for neighborhoods in New York City. The same quantity of $PM_{2.5}$ causes about twice as much mortality in a neighborhood colored red versus yellow. The right panel shows the relationship between $PM_{2.5}$ and child emergency room visits for asthma in New York neighborhoods. For asthma, the same quantity of $PM_{2.5}$ causes about ten times more emergency room visits in a neighborhood colored red versus yellow. Both panels show that the damage from air pollution usually depends on local characteristics like population health.

Methodologies for Calculating the Damage per Unit of Emissions for Pollutants that Depend on Time and Location

Accounting for all of the factors that affect damages using custom models would lead to the most accurate calculations of damage per unit of emissions. However, data constraints and ease of use might make alternative, less granular methods more desirable. Table 1 shows examples of different damage calculation methods that tradeoff between these two goals of accuracy and administrability. The most granular methods use high-resolution population data with time-varying pollution transport models. Less granular methods make stronger assumptions or use more aggregated data to reduce the complexity of calculation.

Custom Solutions

On the most granular side, policymakers could build a custom model that takes into account as many factors affecting damage per unit of emissions as possible. A recent example of such an approach is the Bay Area Clean Air Plan.[76] The Bay Area Air Quality Management District created a custom tool that translates emissions of multiple different pollutants into changes in pollution concentration throughout the Bay Area. The tool uses weather data to understand how pollutants are transported around the Bay Area, and it uses atmospheric chemistry models to understand how different primary pollutants cause secondary pollutants in the region. For instance, ozone is created by a complex interaction between different pollutants and sunlight, so the atmospheric chemistry models are important to understanding how ozone pollution can be addressed.

The model then uses population density to translate pollution concentration changes into human exposure. The exposure determines health effects according to the pollutant being considered and the health conditions of the exposed population.[77] The Bay Area Air Quality Management District focuses on PM, ozone, and greenhouse gas pollution, but in principle, any pollutants could be incorporated into a similar methodology.

One of the primary benefits of a custom method is the ability to incorporate variation in population density and population health. This ability is especially important for states that are characterized by a high degree of heterogeneity in population density. Pollutants emitted in areas near big urban cities would cause substantially higher exposure than the same pollutant emitted in more sparsely populated rural regions. This effect might be exacerbated if higher-emission power plants are located in the higher-population areas, leading to higher ambient pollution levels.[78] This correlated heterogeneity means that policymakers should avoid an approach that uses a state-wide average damage per unit of emissions, since such an approach would vastly understate damages in some areas of the state while overstating damages in others.

Estimating Air Pollution Social Impact Using Regression

Estimating Air Pollution Social Impact Using Regression (EASIUR) is a model of the damages from emission of primary $PM_{2.5}$, SO_2, NOx, and NH_3. The damage estimates are based on mortality due to secondary particulate matter.[79] One of the primary benefits of EASIUR is easy-to-use but accurate modeling of pollution transport. EASIUR was created by taking high-resolution, detailed pollution transport model output from the Comprehensive Air Quality Model with Extensions (CAMx)[80] to derive simple estimates of pollution transport on a 36 by 36-kilometer grid for the United States.[81] As a result, EASIUR provides relatively accurate estimates of air pollution damage based on the location of

emissions without the cost of complex and time-consuming modeling of detailed pollution transport. EASIUR also provides estimates of damages for three different stack heights—ground level, 150m, and 300m.

BenMAP

BenMAP is a tool created by EPA to calculate and map damages from ozone and $PM_{2.5}$ in the United States. BenMAP does not include pollution transport modeling. Users specify the change in ambient concentration of pollution that they expect will occur due to a policy, and BenMAP monetizes the health impacts of that change based on population density and pollution damage functions derived from academic publications. It includes high-resolution population data (a 12 by 12-kilometer grid) and can be customized with user-defined population data, baseline health data, and pollution damage functions.[82]

Air Pollution Emission Experiments and Policy Analysis Model

Air Pollution Emission Experiments and Policy analysis models county-by-county marginal damage estimates for SO_2, NOx, $PM_{2.5}$, PM_{10}, NH_3, VOCs. This model allows specification of stack height. This is important in locations like New York City, where the combination of low stacks and large population combine to create high marginal damages for peak generators that often have relatively high emissions rates.[83]

Co-Benefits Risk Assessment

The Co-Benefits Risk Assessment (COBRA) tool from EPA uses a simple pollution source-receptor matrix and a subset of the BenMAP health damage functions to estimate county-level damages from the creation of secondary $PM_{2.5}$ from emissions of NOx, SO_2, NH_3, $PM_{2.5}$, and VOCs. Like BenMAP, COBRA can be modified with custom population, baseline health, and baseline emission data as well as custom damage functions. COBRA damages are based on mortality and morbidity due to nonfatal heart attacks and cardiovascular illness.[84]

Table 3: Tools to Calculate Damage per Unit of Emissions

Tool	Geographic Granularity	Additional Data Requirement	Pollutants Covered	Notes	Source
Custom model	Variable	High	ozone (NOx,VOC), $PM_{2.5}$ (directly emitted $PM_{2.5}$, NOx, VOC, SO_2), air toxics	Geographic-specific damage estimates based on: • Air transport • Ambient concentrations • Population • Comorbidity	Bay Area Air Quality Management District Multi-Pollutant Evaluation Method (2017)
BenMAP	High (default); Variable (custom)	Medium (default); Varies (custom)	ozone, $PM_{2.5}$	• Translates all pollutants into secondary PM & ozone • Driven primarily by mortality • Can input own data	U.S. EPA
EASIUR	36 km	Low	SO_2, NOx, NH_3, $PM_{2.5}$	• Detailed air transport model • Seasonal damages	Heo, Adams, and Gao (2016)
AP2	County	Low	SO_2, NOx, VOC, NH_3, $PM_{2.5}$, PM_{10}	• Accounts for air transport • Broader monetized damage categories	Muller, Mendelsohn, Nordhaus (2011)
COBRA	State or county	Low	$PM_{2.5}$ (directly emitted $PM_{2.5}$, NOx, VOC, SO_2)	• Recently updated (2017) • Previously used by NY PSC • Accounts for air transport • Driven primarily by mortality	U.S. EPA (2017)

Greenhouse Gases – Methodology for Calculating Damage per Unit of Emissions

Damages from greenhouse gases do not depend on the time or location of release, making the calculation of their damage per unit of emissions particularly straightforward.[85] The Interagency Working Group's Social Cost of Carbon is the best estimate of the damages caused by greenhouse gas emissions.[86]

The Social Cost of Carbon is the net-present value of damage caused by the emission of one metric ton of carbon dioxide today. The emissions of greenhouse gases like methane and nitrous oxide from electricity generation can be translated

into carbon dioxide-equivalent units using methodologies developed by EPA.[87] The Social Cost of Carbon can then be used to calculate the damage per unit of emissions of all greenhouse gases.

The Interagency Working Group first developed the Social Cost of Carbon in 2010 and updated the estimate in 2013 and 2015.[88] In 2016 and 2017, the National Academies of Sciences issued two reports that recommended future improvements to the methodology.[89] In response to those reports, researchers at Resources for the Future and the Climate Impact Lab are working on further updates.[90]

The Interagency Working Group's estimate has been repeatedly endorsed by government reviewers, courts, and experts. In 2014, the U.S. Government Accountability Office reviewed the Interagency Working Group's methodology and concluded that it had followed a "consensus-based" approach, relied on peer-reviewed academic literature, disclosed relevant limitations, and adequately planned to incorporate new information through public comments and updated research.[91] In 2016, the U.S. Court of Appeals for the Seventh Circuit held that relying on the Interagency Working Group's estimate was reasonable.[92] And though the current Administration recently withdrew the Interagency Working Group's technical support documents,[93] experts continue to recommend that agencies rely on the Interagency Working Group's Social Cost of Carbon estimate as the best estimate for the external cost of greenhouse gases.[94]

Step 4: Monetize the Avoided Externality from Displaced Generation

Once the displaced resource has been identified and both the emissions rates and the damage per unit of emissions are known, these two values can be multiplied to get the monetary value of avoided damages per unit of generation.

If other existing policies already internalize externalities, such as a cap-and-trade program, an additional step to take these policies into account is necessary. Failing to take these policies into account could lead to double counting of the benefits generated by pollution reduction. To see this, consider a case where bulk system generators are subject to a policy that requires payment per ton of CO_2 emitted. The cost of operation for such emitting generators will be higher, and therefore they would submit higher bids to the wholesale electricity market. These higher bids would result in a higher equilibrium price in the market, so any resource that did not emit CO_2 (or emitted less CO_2 than the marginal resource) would receive the benefit of this higher price. In this way, zero or low emitting resources—like a clean DER—would be incentivized to produce more, and high emitting resources would be incentivized to either reduce their emissions or to produce less. If DERs also received direct payments for the full environmental and public health externality of emissions on top of this price increase, the result would be double payment for the same benefits.

If the existing policies do not fully internalize the externality from pollution, then DERs should receive payment that is sufficient to achieve full internalization. States participating in the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program run by nine states in the Northeast, provide a good example. Generators in these states that are larger than 25 megawatts must pay for emissions of CO_2 by purchasing emissions permits under RGGI.[95] If the generator displaced by a DER is a participant in RGGI, then the price in the wholesale market already incorporates a payment for CO_2 emissions, and the monetized value of avoided emissions should take that into account. Current and forecasted RGGI permit prices, however, are not sufficient to fully internalize the external damage from CO_2, so clean DERs should still receive a payment for CO_2 emissions that they avoid. The payment should be reduced to reflect the degree to which the CO_2 externality has been internalized by RGGI.

Numerically, consider a case where the displaced resource is a combined-cycle natural gas plant that emits one ton of CO_2 per MWh of generation.[96] If there were no policies that required the displaced generator to pay for carbon emissions, then the value of avoided damages from each kWh injection would be the emissions rate times the external damage per unit of emissions. The external damage caused by carbon dioxide, as discussed in the previous section, is given by the Social Cost of Carbon and the central estimate is currently around $46 per metric ton in 2017 dollars.[97]

$$\textbf{External value of avoided } CO_2 = 1 \frac{kg\ CO_2}{kWh} \times 0.046 \frac{\$}{kg\ CO_2 e} = 0.046 \frac{\$}{kWh}$$

Therefore, for every kWh of displaced generation, a zero-emitting DER would provide a benefit of roughly 5 cents by internalizing the externality from CO_2 emissions.

The payment for a concurrently existing cap-and-trade policy such as RGGI changes this calculation. The current RGGI price is around $4 per metric ton of CO_2. If the displaced generator is paying for RGGI permits, then $4 of the external cost of CO_2 has already been internalized, meaning that the uninternalized damage from CO_2 is $46−$4=$42. The value of avoided damage from CO_2 in this case would be:

$$\textbf{External value of avoided } CO_2 \textbf{ with RGGI} = 1 \frac{kg\ CO_2}{kWh} \times (0.046 - 0.004) \frac{\$}{kg\ CO_2} = 0.042 \frac{\$}{kWh}$$

The value of avoided external damage falls to reflect the fact that some of the external damage from carbon has already been internalized.

As another example, consider an alternative policy that is being discussed in several jurisdictions: carbon pricing. If a carbon charge is levied on electricity sold in a state, the charge would raise the price that wholesale electricity generators pay for carbon emissions and hence help internalize the externality. If this charge is based on the Social Cost of Carbon, then the external value of avoided emissions of CO_2 would fall to zero since the externality would be fully internalized.

$$\textbf{External value of avoided } CO_2 \textbf{ with charge} = 1 \frac{kg\ CO_2}{kWh} \times (0.046 - 0.046) \frac{\$}{kg\ CO_2} = 0.00 \frac{\$}{kWh}$$

In practice, the benefits from implementing a carbon charge in the state would come from both the incentive it would provide to clean generation and the disincentive to emitting generation, leading to a higher likelihood of the displaced generator having a lower emissions rate as well.

When setting the level of payment for other pollutants, policies including the Cross-State Air Pollution Rule (CSAPR) for NOx and SO_2, the Mercury Air Toxics Standard (MATS), and other future policies should also be taken into account. In the case of a policy like the RGGI cap-and-trade program, discussed above, a positive permit price that results from a binding cap should be taken into account by reducing the payment to DERs in proportion to the amount of the environmental and public health externality that has been internalized. For other programs, like CSAPR, where the cap is currently not binding and the permit price has settled near $0, no adjustment needs to be made.[98] If the cap binds in the future and prices rise above zero, then the payment to DERs would need to be adjusted.

The table below summarizes recent values of the damage per unit of generation from three different analyses done by different state and federal agencies. As the table shows, these different agencies come to similar conclusions regarding the value of avoiding these different pollutants.

Table 3: Examples of Dollar Value of Average Damage per MWh[99]

Pollutant	2016 EPA RIA	New York DPS	Bay Area Clean Air Plan
SO_2	$76 to $171 per MWh	$52 to $55 per MWh	$77 per MWh
NOx	$4 to $12 per MWh	$5 per MWh	$3 per MWh
$PM_{2.5}$	$7 to $16 per MWh		$22per MWh

Step 5: Monetize and Subtract DER Damages

The final step is to take into account any emissions generated by the DER itself. Distributed energy can come from non-emitting resources like solar panels or small wind turbines or it can come from emitting resources like combined heating and power generators, diesel generators, or small natural gas fuel cells. In fact, the Department of Energy estimates that the majority of DERs in the United States are emitting backup generators, and that in 2006, 42% of DER energy produced in the country came from combined heating and power.[100] If the DER emits pollutants, then those emissions and the damage they cause must be taken into account to accurately quantify the environmental and public health values of the resource. Damages from energy storage systems that are charged by emitting resources should be calculated similarly. In this case, damages from the DER's own emissions must be calculated and netted out from the value of emissions avoided by the DER. In cases where the DER does not emit, this additional step is not necessary, and the calculation of environmental value is simply the external value of avoided emissions calculated in the previous step.

Step 5A: Monetize the Externality from DER

If the DER emits pollutants, then the externality associated with emission of those pollutants must be accounted for, in the same way that the value of emissions from displaced generation was calculated in Steps 2, 3, and 4. First, policymakers need to know the DER's emissions rate for each pollutant. Lack of data on emissions rates presents a unique challenge for calculating damages from DERs. Resources like eGrid and the National Emissions Inventory do not record emissions or generation for very small generators. Instead, policymakers will likely need to rely on engineering estimates of emissions rates. As an alternative, policymakers could also use EPA emissions standards for non-road generators to estimate emissions.[101] Note that fossil-fuel-burning DERs generally produce higher emissions per unit of generation than otherwise comparable, large generators because the latter benefit from returns to scale in generator efficiency.[102]

Second, the policymaker must determine the damage per unit of emissions given the DER's location, time, and pollutants emitted. Damages per unit of emissions from DERs will also likely be different than from a similarly located large generator given that large generators generally have tall stacks that allow pollutants to disperse their over a larger area. Moreover, since DERs are generally located near load centers, they are also generally located nearer to areas of relatively high population density.[103] Proximity to higher population will raise the damage per unit of emissions from emitting DERs.

Using these numbers, the value of damage per unit of electricity generation can be calculated for the DER in the same way that the value is calculated for larger generators. In particular, the value per unit of generation will be the sum across all pollutants of the emissions rate times the damage per unit of emissions.

Step 5B: Subtract the Value of DER Emissions from the Value of Avoided Emissions

The last step for finding the environmental and public health value of DERs is to subtract the value of emissions from the DER calculated in Step 5A from the value of avoided emissions calculated in Step 4. Subtracting these two values must be the last step of the process. In other words, the dollar value of damages per unit of generation from the two resources

should be calculated first, then the value of damage from the DER should be subtracted from the value of damage from the displaced resource. This procedure will correctly estimate the net environmental value of the DER by including differences in emissions rates and damage per unit of emissions discussed above. Incorrect calculations would net out either generation or emission before calculating the damages. Netting out generation first would not account for unique emissions by the two resources. Netting out emissions first would not account for the differences in location and exposed population between the two resources.

For instance, consider a case where the DER emits pollution in a high population area while the displaced resource would have emitted pollution in an area with lower population. The damage per unit of emissions is higher from the DER, but if the emissions are first subtracted from each other, then this difference between the two resources would be lost. In such a case, the DER would be erroneously incentivized to produce more electricity, increasing the damage experienced by the high population area.

If damage per unit of generation from the DER is high enough, then the net environmental value of the DER could be negative. This might be the case, for instance, if a diesel generator located in close proximity to a high-population area is displacing generation from a relatively clean natural gas plant located further from a populated area.[104] In these cases where the DER causes more environmental damage than it avoids, it should be penalized for that damage. In other words, the "compensation" for the environmental and public health value may be negative. Failing to do so would also fail to fully internalize the environmental externality associated with emissions.

Example Calculation

To illustrate the calculation of the value of DER using all of the above steps, consider an example of DERs in New York State. New York's current generation mix primarily includes hydropower, nuclear, natural gas, oil, and renewables.[105] Figure 2 shows a representative dispatch curve for New York. During periods of low electricity demand, a DER might offset hydro or nuclear generators, resulting in no avoided emissions. During these periods, the environmental and health value paid to the DER would be zero for a zero-emitting DER and would be negative for any DER like a diesel generator that produces emissions.

During periods with near-average load, the marginal fuel is natural gas. Typical natural gas generators in New York emit relatively low levels of NOx and PM, and moderate levels of CO_2. They do not emit SO_2. As demand rises during periods of particularly high load, oil becomes the marginal fuel and the emissions per unit of generation rise. Currently, New York does not produce any power from coal. A small amount of biomass production occurs in the state, but biomass has, historically, not been the marginal fuel in any region of the state.[106] During the course of a single day, the marginal generator might change from zero-emitting nuclear, to gas, and to oil and back again as load shifts. Table 4 summarizes the emissions rates for typical gas and oil generators in the state. These emissions rates provide the necessary data for Step 2 of the method described above.

Table 4: Average Emissions Rates for Fossil Fuel Generators in New York[107]

Fuel Type	SO_2 (kg/MWh)	NOx (kg/MWh)	CO_2 (kg/MWh)	$PM_{2.5}$ (kg/MWh)
Oil	2.10	2.62	1059.3	0.35
Biomass	0.16	2.71	481.7	0.02
Gas	0.00	0.12	397.3	0.02

The damages from emissions depend on both the location of the avoided emissions and the time of year. For this example, consider the damages from primary $PM_{2.5}$, SO_2, and NOx as given by EASIUR for two locations in the New York. These damages are shown in Table 5. Per unit of emissions, fine particulate matter is the most damaging of the three pollutants. In densely populated Queens County in New York City, damages per unit of particulate matter are much higher than damages in sparsely populated Franklin County. Moreover, pollution emitted in the two locations disperses to areas with much different populations. Emissions from a generator in Queens affect not only residents of Queens County, but other residents in New York City and Long Island. For these three pollutants, damages are higher in the spring and summer than in the winter or fall. In the EASIUR model, these different damages are largely a function of changes in pollution transport due to seasonal weather changes as well as seasonal differences in the rate at which primary pollutants become particulate matter.

The bottom of Table 5 shows the damages from emissions of CO_2.[108] As discussed above, damages from CO_2 do not depend on the time or location of the emissions. In this example, we have chosen the current Social Cost of Carbon minus a hypothetical $5 price for permits in the Regional Greenhouse Gas Initiative.

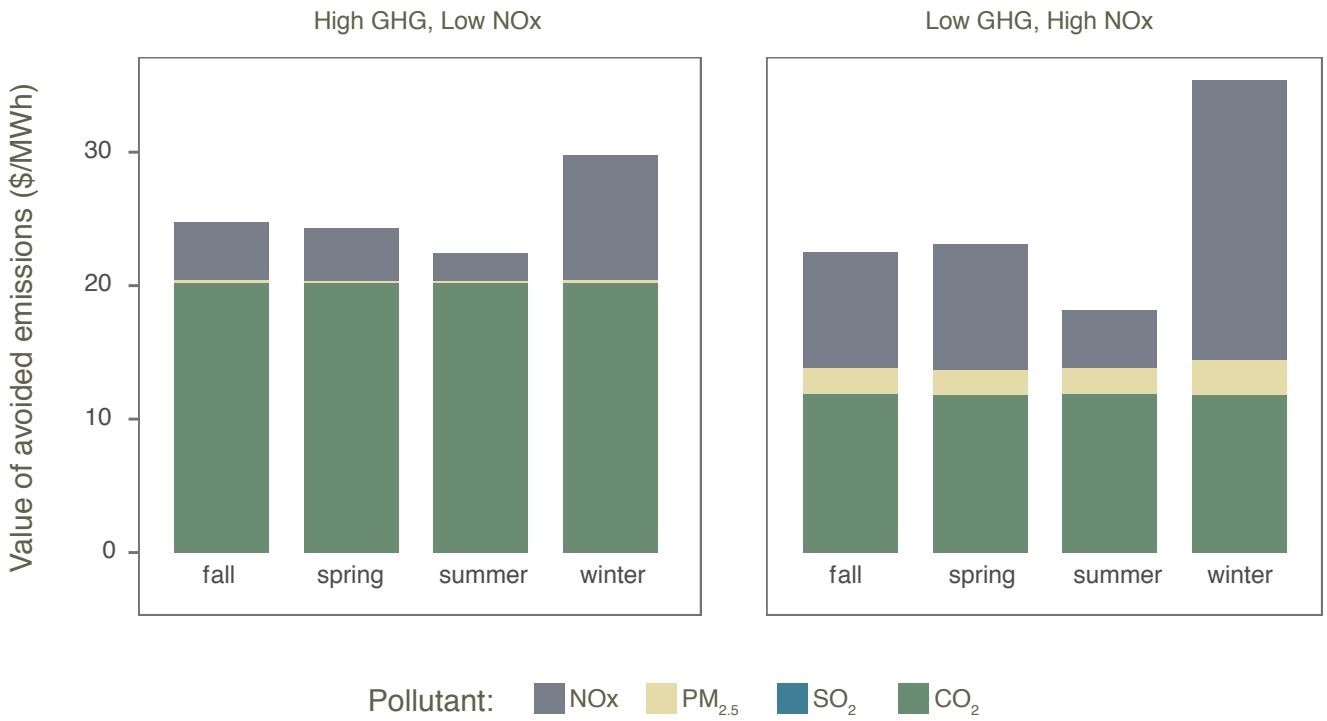
Table 5: Damage Per Unit of Emissions in Two Regions of New York[109]

$PM_{2.5}$ ($/kg)				
Population	Winter	Spring	Summer	Fall
High	355	872	712	316
Low	107	48	50	80
NOx ($/kg)				
Population	Winter	Spring	Summer	Fall
High	19	133	38	38
Low	21	4	2	4
SO_2 ($/kg)				
Population	Winter	Spring	Summer	Fall
High	12	102	71	21
Low	23	31	35	23
CO_2 ($/kg)				
Population	Winter	Spring	Summer	Fall
High	0.04			
Low	0.04			

Putting together the emissions rates from Table 4 and the damage per unit of emissions in Table 5, the environmental and health value for a zero-emitting DER can be calculated. For example, if a typical gas-powered generator was on the margin in the high-population, downstate region in the spring, then a zero-emitting DER would create roughly 5 cents of value per kWh of generation. In the lower-population upstate region, this value would be lower—around 2 cents per kWh. If higher-emitting fuels like oil were on the margin, then the value of DERs would be even higher. Previous publications show that oil heating and power generation lead to particularly high environmental and health damages in the New York City area.[110] In contrast, if a zero-emitting resource like hydro power were on the margin, then a zero-emitting DER would create zero additional environmental value.

Figure 4 shows how the environmental and health value varies even among similar generators. The generator in the left panel is relatively inefficient—emitting a larger amount of carbon dioxide per unit of electricity generation than a typical plant in the state—but it is located in a sparsely populated area where NOx and $PM_{2.5}$ emissions reach a smaller population. The generator in the right panel is relatively efficient, but its emissions of local air pollutants reach a larger population, increasing the value of avoiding those emissions.[111]

Figure 4: Value of Avoided Emissions from Two Natural Gas Plants



The figure shows the value of avoided emissions for natural gas generators in New York state. The generator in the left panel emits more pollution per unit of generation than the typical gas generator in New York, but it is located in a sparsely populated area where NOx and PM2.5 emissions reach a smaller population. The generator in the right panel is located in a heavily populated area, so despite being relatively low emitting, its emissions of local air pollutants cause more health damage, increasing the value of avoiding those emissions.

Conclusion

Distributed energy resources can provide substantial value to a state by reducing the need for large-scale bulk system generation, thereby reducing pollutant emissions. The environmental and public health damage from this pollution is often imposed on vulnerable populations. As state utility regulators implement new compensation policies for these distributed resources, a key component of those policies should include payment for that value.

A straightforward five-step methodology, relying on existing or readily accessible tools, can be used to calculate the environmental and public health value of DERs. These tools can allow utility regulators to implement a compensation scheme that rewards DERs when and where they most enhance social welfare.

The methodology presented here is flexible enough to accommodate a variety of data and resource constraints. State regulators should weigh the tradeoffs between accuracy and administrability of different methods to calculating environmental and health value, pick the tools that are as accurate as possible given the tradeoffs, and then update their method when feasible.

Endnotes

1 Different states have implemented different definitions of DERs. *See* Staff Subcommittee on Rate Design, Nat'l Ass'n Regulatory Util. Comm'rs, Distributed Energy Resources Rate Design and Compensation 43 (2016), https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

2 *Id.* at 133-136, 142.

3 Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 Harv. Envtl. L. Rev. 43, 78-91 (2017), http://policyintegrity.org/files/publications/Managing_the_Future_of_the_Electricity_Grid.pdf [hereafter Revesz & Unel, *Distributed Generation*]; Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas Emissions*, 42 Harv. Envtl. L. Rev. (2018), http://harvardelr.com/wp-content/uploads/2018/03/revesz_unel.pdf [hereafter Revesz & Unel, *Energy Storage*].

4 In fact, every resource that avoids emissions—that is, any generating resource that emits less than the resource that would have generated instead—should be paid commensurate with the value of avoided health, climate, and economic damage. This report is specifically focused on DER because Public Utility Commissions in different states are presently focused on reforming the compensation structure of those resources. However, the methodology discussed could be applied more generally.

5 Revesz & Unel, *Distributed Generation*, *supra* note 3, at 101-108.

6 For more detail on the changing nature of federal-state divide over regulation of electricity, *see* Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal and State Regulation of Today's Electric Grid*, 36 Energy L.J. 203 (2015), http://felj.org/sites/default/files/docs/elj362/19-203-216-Nordhaus_FINAL%20%5B11.10%5D.pdf.

7 Revesz & Unel, *Distributed Generation*, *supra* note 3, at 85-86; Revesz & Unel, *Energy Storage*, *supra* note 3.

8 Revesz & Unel, *Distributed Generation*, *supra* note 3, at 85-86; Revesz & Unel, *Energy Storage*, *supra* note 3.

9 *See* Derik Broekhoff et al., World Resources Institute, Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects (2005), http://www.ghgprotocol.org/sites/default/files/ghgp/standards_supporting/Guidelines%20for%20Grid-Connected%20Electricity%20Projects.pdf.

10 To the extent that the counterfactual scenario identifies multiple generators that are offset by DERs, a generation-weighted average of displaced generators can be used in Steps 2-3.

11 *Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation*, Energy Info. Agency: Today in Energy (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590.

12 *See* Broekhoff et al., *supra* note 9, at 63-65.

13 *See* Erin Boyd, Dep't of Energy Office of Energy Policy & Sys. Analysis, Overview of Power System Modeling 17-19 (2016), https://energy.gov/sites/prod/files/2016/02/f29/EPSA_Power_Sector_Modeling_020416.pdf. The models particularly well suited to this type of analysis are "grid operation models" (otherwise known as "unit commitment and dispatch models" or "production cost models"). Models primarily designed for policy assessments, screening, and data analysis are not as well suited to this use. This includes EPA's AVoided Emissions and geneRation Tool (AVERT), a "high-level gross analysis" tool intended to estimate the emissions implications of new renewable capacity. *Id.* at 8. Nor are "capacity expansion models," such as IPM, NEMS, Haiku, ReEDS, and PLEXOS, which simulate generation and transmission *investment* decisions. *Id.* at 9, 11.

14 Nathaniel Gilbraith & Susan E. Powers, *Residential Demand Response Reduces Air Pollutant Emissions on Peak Electricity Demand Days in New York City*, 59 Energy Policy 459, 461 (2013); Kyle Siler-Evans et al., *Regional Variations in the Health, Environmental, and Climate Benefits of Wind and Solar Generation*, 110 Proc. Nat'l Acad. Sci. 11768 (2012), www.pnas.org/cgi/doi/10.1073/pnas.1221978110.

15 *Emissions & Generation Resource Integrated Database* (eGRID), U.S. Envtl. Prot. Agency (Feb. 15, 2016), https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid [hereafter eGrid (2016)].

16 *See* Hao Cai et al., Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units (2012), https://greet.es.anl.gov/publication-updated-elec-emissions.

17 *Id.*

18 *Frequently Asked Questions: What is the Efficiency of Different Types of Power Plants?*, U.S. Energy Info. Agency (May 10, 2017), https://www.eia.gov/tools/faqs/faq.php?id=107&t=3 (defining "heat rate").

19 U.S. Energy Info. Agency, Electric Power Annual 2016 169 (2018), https://www.eia.gov/electricity/annual/pdf/epa.pdf.

20 U.S. Envtl. Prot. Agency, Compilation of Air Pollutant Emission Factors Vol. I [hereafter AP-42] at 1.0-1 (5th ed. 1995), *available at* https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s00.pdf.

21 *Id.* at 3.4-1, *available at* https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf.

22 *Id.* at 3.1-1, *available at* https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

23 *Id.*

24 Coal plants can install selective catalytic reduction technology that reduces NO_x pollution by over 80%, flue gas desulfurization (aka "scrubbers") that can reduce SO_2 by up to 98%, and electrostatic precipitators and baghouse fabric filters that can drastically reduce PM emissions. Emanuele Massetti et al., ORNL/SPR-2016/772, Environmental Quality and the U.S. Power Sector: Air Quality, Water Quality, Land Use and Environmental Justice 24-27 (2017), https://energy.gov/sites/prod/files/2017/01/f34/Environment%20Baseline%20Vol.%202--Environmental%20Quality%20and%20the%20U.S.%20Power%20Sector--Air%20Quality%2C%20Water%20Quality%2C%20Land%20Use%2C%20and%20Environmental%20Justice.pdf. Combustion Turbines can utilize water injection, dry controls (varying the amount of air needed for combustion), and selective catalytic reduction technology. AP-42, *supra* note 22, at 3.1-7. For combined cycle plants and stationary ICE, there are not pollution control technologies that are in wide use, beyond technologies and operational practices to improve plant efficiency.

25 Massetti, *supra* note 25, at 110-111

26 Felipe R. Ponce Arrieta & Electo E. Silva Lora, *Influence of Ambient Temperature on Combined-Cycle Power-Plant Performance*, 80 Applied Energy 261 (2004).

27 *See* 40 C.F.R. part 75.

28 *See* National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 77 Fed. Reg. 9,304, 9,370-72 (Feb. 16, 2012) (outlining compliance reporting options for the EPA Mercury and Air Toxics rule); *Stationary Source Emissions Monitoring*, , U.S. Envtl. Prot. Agency (last visited March 11, 2018), https://www.epa.gov/air-emissions-monitoring-knowledge-base/basic-information-about-air-emissions-monitoring#stationary.

29 U.S. Envtl. Prot. Agency, The Emissions & Generation Resource Integrated Database Technical Support Document for eGRID with Year 2016 Data 18 (2018), https://www.epa.gov/sites/production/files/2018-02/documents/egrid2016_technicalsupportdocument_0.pdf [hereafter eGrid (2016) TSD].

30 *See Air Markets Program Data*, U.S. Envtl. Prot. Agency (last visited March 11, 2018), https://ampd.epa.gov/ampd/.

31 *2014 National Emissions Inventory (NEI) Data*, U.S. Envtl. Prot. Agency, https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data (last visited March 11, 2018) [hereafter NEI (2014)]; U.S. Envtl. Prot. Agency, 2014 National Emissions Inventory Version 1Technical Support Document at 1-1, 1-5, 3-1 (Dec. 2016), https://www.epa.gov/sites/production/files/2016-12/documents/nei2014v1_tsd.pdf [hereafter NEI TSD].

32 *Id.*

33 Where state data was not available, EPA supplements the NEI with emissions using data reported directly to EPA (from CAMD data) and by multiplying heat input data by predetermined emission factors (based on AP-42). EPA also performs some modifications to state-reported data, including PM emission data. NEI TSD, *supra* note 32, at 2-7.

34 EPA defines the NO_x ozone season as the period between May 1 and October 1. During this period, NO_x emissions are more likely to lead to the formation of ozone. *See, e.g.* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57,356 (Oct. 27, 1998).

35 U.S. Energy Info. Agency, Form EIA-923 Power Plant Operations Report Instructions https://www.eia.gov/survey/form/eia_923/instructions.pdf [hereafter Form EIA-923 Instructions]. Power plant owners report additional facility-level information on EIA form 860, which can be used to supplement the generation information reported on EIA form 923. *Form EIA-860 Detailed Data*, U.S. Energy Info. Agency (Nov. 9, 2017), https://www.eia.gov/electricity/data/eia860/.

36 Form EIA-923 Instructions, *supra* note 35.

37 EIA form 923 is submitted monthly by a large sample of potential respondents and annually by all units. U.S. Energy Info. Agency, Electric Power Monthly Technical Notes 14-15 (Feb. 2018), https://www.eia.gov/electricity/monthly/pdf/technotes.pdf.

38 Emission factors are provided as pounds of emission per unit of fuel input. Therefore, in order to develop emission rates denominated in kWh, states would have to use the unit's heat rate. This may be available from EIA or through engineering estimates provided by the unit's manufacturer.

39 AP-42, *supra* note 21, at Chapter 1, https://www3.epa.gov/ttn/chief/ap42/ch01/index.html

40 *Id.* at Section 3.1, at https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

41 *Id.* at Section 3.4, https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf.

42 Rachel Leven, *Bad Science Underlies EPA's Air Pollution Program*, Scientific American, (Jan 29, 2018), https://www.scientificamerican.com/article/bad-science-underlies-epa-rsquo-s-air-pollution-program.

43 Nat'l Energy Tech. Lab., Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity 458 (Nov. 2010), https://www.nrc.gov/docs/ML1217/ML12170A423.pdf.

44 Gilbraith & Powers, *supra* note 14.

45 eGrid (2016), *supra* note 15.

46 eGrid (2016) TSD, *supra* note 29, at 16.

47 *Id.*

48 *Id.* 17.

49 The notable exception is the inclusion of both annual NO_x emissions and ozone season-specific NO_x emissions. *Id.*

50 *The Greenhouse Gases, Regulated Emissions, and Energy Use in Transpiration Model*, Argonne Nat'l Lab. (Oct. 9, 2017), https://greet.es.anl.gov/index.php.

51 Hao Cai et al., *supra* note 16.

52 Hao Cai et al., Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010 (2013), https://greet.es.anl.gov/publication-electricity-13; Hao Cai et al., Update on Generation Efficiency and Criteria Pollutant Emissions of Integrated Coal Gasification Combined-Cycle Power Plant (2017), https://greet.es.anl.gov/publication-coal_igcc_2017.

53 *See* Joshua Graff Zivin, Matthew Kotchen & Erin Mansur, *Spatial and Temporal Heterogeneity of Marginal Emissions*, 107 J. Econ. Behavior & Org. 248 (2014).

54 Daniel A Axelrad et al., *Dose-Response Relationship of Prenatal Mercury Exposure and IQ: An Integrative Analysis of Epidemiologic Data.*, 115 Environ. Health Perspect. 609 (2007).

55 Richard L. Revesz & Jack Lienke, Struggling for Air: Power Plants and the "War on Coal" 11 (2016).

56 *Id.* at 10.

57 *Particulate Matter (PM) Basics*, U.S. Envtl. Prot. Agency (last visited March 11, 2018), https://www.epa.gov/pm-pollution/particulate-matter-pm-basics#PM; For a more detailed description of the health effects of $PM_{2.5}$ and ozone, *see* U.S. Envtl. Prot. Agency, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants at 4-16 to 4-24 (2014), https://www3.epa.gov/ttn/ecas/docs/ria/utilities_ria_proposed-carbon-poll-existing-egus_2014-06.pdf.

58 Revesz & Lienke, *supra* note 55, at 11.

59 *Id.*

60 *Id.*

61 Matthew MJ Neidell, *Information, Avoidance Behavior, and Health: The Effect of Ozone on Asthma Hospitalizations*, 44 J. Hum. Resources 450 (2009).

62 Endangerment and Cause or Contributed Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,495 (Dec. 15, 2009).

63 D. B. Lobell, W. Schlenker & J. Costa-Roberts, *Climate Trends and Global Crop Production Since 1980*, 333 Science. 616 (2011).

64 Intergovernmental Panel on Climate Change [IPCC], *Climate Change 2014 Impacts, Adaptation, and Vulnerability Part A: Global and Sectoral Aspects*, 1132 (2014), http://www.ipcc.ch/report/ar5/wg2/.

65 Axelrad et al., *supra* note 54.

66 For instance, EPA, in their BenMAP tool for calculating the health effects of particulate matter exposure, estimate that the relationship between myocardial infarction and $PM_{2.5}$ follows the function (1-(1/((1-Incidence)*exp(b*(change in $PM_{2.5}$))+Incidence))), where "Incidence" is a measure of the baseline rate of myocardial infarction and b is a parameter derived from Annette Peters et al., *Increase Particulate Air Pollution and the Triggering of Myocardial Infarction*, 103 Circulation 2810–2815 (2001).

67 Claire E. Reeves et al., *Potential for Photochemical Ozone Formation in the Troposphere Over the North Atlantic as Derived from Aircraft Observations During ACSOE*, 107 J. Geophys. Res. Atmos, no. D23, 2002, at ACH 14-1. Paola Michelozzi et al., *High Temperature and Hospitalizations for Cardiovascular and Respiratory Causes in 12 European Cities*, 179 Am. J. Respiratory Critical Care Med. 383 (2009).

68 *See, e.g.*. Jerald L. Schnoor, Environmental Modeling: Fate and Transport of Pollutants in Water, Air, and Soil (1996).

69 *Id.*

70 Alex A. Karner, Douglas S. Eisinger & Deb A. Niemeier, *Near-Roadway Air Quality: Synthesizing the Findings from Real-World Data*, 44 Envtl. Sci. Tech. 5334 (2010).

71 Reeves *et. al.*, *supra* note 67.

72 Revesz & Lienke, *supra* note 55, at 108.

73 U.S. Envtl. Prot. Agency, Regulatory Impact Analysis for the Clean Power Plan Final Rule at 4-23 (2015), https://www3.epa.gov/ttn/ecas/docs/ria/utilities_ria_final-clean-power-plan-existing-units_2015-08.pdf.

[74] *See* N.Y.C. Department of Health and Mental Hygiene, Air Pollution and the Health of New Yorkers: The Impact of Fine Particles and Ozone at 16, 22 (2013), https://www1.nyc.gov/assets/doh/downloads/pdf/eode/eode-air-quality-impact.pdf.

[75] Iyad Kheirbek, N.Y.C. Department of Health and Mental Hygiene, Estimating Morbidity and Mortality Attributable to Air Pollution in New York City 10 (2013), https://www.epa.gov/sites/production/files/2014-10/documents/hia_for_benmap_webinar_8.7.13.pdf.

[76] Bay Area Air Quality Mgmt. District, Spare the Air Cool the Climate: Final 2017 Clean Air Plan (2017), http://www.baaqmd.gov/~/media/files/planning-and-research/plans/2017-clean-air-plan/attachment-a_-proposed-final-cap-vol-1-pdf.pdf.

[77] David Fairley & David Burch, Bay Area Air Quality Mgmt. District, Multi-Pollutant Evaluation Method Technical Document 2016 Update 7 (2016), http://www.baaqmd.gov/~/media/files/planning-and-research/plans/2017-clean-air-plan/mpem_nov_dec_2016-pdf.pdf.

[78] Aleksandr Rudkevich & Pablo A Ruiz, *Locational Carbon Footprint of the Power Industry: Implications for Operations, Planning and Policy Making*, in Handbook of CO_2 in Power Systems 148 (Qipeng P. Zheng et al. eds., 2012) (showing that the highest levels of carbon dioxide emissions occur in the southern part of the state). Kathryn Hansen, *New NASA Images Highlight U.S. Air Quality Improvement*, NASA (June 26, 2014), https://www.nasa.gov/content/goddard/new-nasa-images-highlight-us-air-quality-improvement/ (showing that this same area also experiences higher ambient levels of non-carbon dioxide air pollution).

[79] Jinhyok Heo, Peter J. Adams & H. Oliver Gao, *Public Health Costs of Primary $PM_{2.5}$ and Inorganic $PM_{2.5}$ Precursor Emissions in the United States*, 50 Envtl. Sci. & Tech. 6061 (2016) (hereafter "EASIUR").

[80] *See* CAMx, http://www.camx.com/ (last visited March 11, 2018).

[81] Jinhyok Heo, Peter J. Adams & H. Oliver Gao, *Reduced-form Modeling of Public Health Impacts of Inorganic $PM_{2.5}$ and Precursor Emissions*, 137 Atmospheric Env't 80 (2016).

[82] Erik P. Johnson & Juan B. Moreno-Cruz, *Air-quality and Health Impacts of Electricity* (June 2015) (unpublished manuscript), http://jmorenocruz.econ.gatech.edu/wp-content/uploads/sites/62/2015/03/Health_Electricity_Congestion.pdf.

[83] Gilbraith & Powers, *supra* note 14, at 460.

[84] U.S. Envtl. Prot. Agency, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) (3rd ed. 2017), https://www.epa.gov/sites/production/files/2017-10/documents/cobra_user_manual_september2017_508_v2.pdf.

[85] Leo Goldberg & Edith A. Müller, T*he Vertical Distribution of Nitrous Oxide and Methane in the Earth's Atmosphere*, 43 J. Optical Soc'y. Am. 1033 (1953); *and* IPCC, *supra* note 64.

[86] *See* Comments of Institute for Policy Integrity, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Case No. 14-M-0101 (August 21, 2015), http://policyintegrity.org/documents/REV_Comments_Aug2015.pdf; Comments of Institute for Policy Integrity, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Case No. 15-E-0302 (April 22, 2016), http://policyintegrity.org/documents/Comments_on_Clean_Energy_Standard_White_Paper.pdf; Comments of Institute for Policy Integrity, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Case No. 15-E-0302 (July 22, 2016), http://policyintegrity.org/documents/Policy_Integrity_Comments_on_Staffs_Responsive_Proposal_for_Preserving_Zero-Emissions_Attributes.pdf; Joint Comments of Environmental Defense Fund and the Institute for Policy Integrity, *Proceeding in the Matter of the Value of Distributed Energy Resources*, Case 15-E-0751 (April 18, 2016), http://policyintegrity.org/documents/NYPSC_Comments_April2016.pdf.

[87] Alex L. Marten et al., Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates, 15 Climate Policy 272 (2015).

[88] *See* Nat'l Acad. Sci., Eng'g & Med., Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update 6 (2016), https://www.nap.edu/catalog/21898/assessment-of-approaches-to-updating-the-social-cost-of-carbon.

[89] Nat'l Acad. Sci., Eng'g & Med, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide 3 (2017), https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of; eGrid (2016) TSD, *supra* note 29, at 6.

[90] *RFF's Social Cost of Carbon Initiative*, Resources for the Future, http://www.rff.org/research/collection/rffs-social-cost-carbon-initiative (last visited March 11, 2018); *Social Cost of Carbon*, Climate Impact Lab, http://www.climateprospectus.org/research-area/social-cost/ (last visited March 11, 2018).

91 U.S. Gov't Accountability Off., GAO-14-663, Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates 12-19 (2014), https://www.gao.gov/products/GAO-14-663.

92 *Zero Zone, Inc. v. Dep't of Energy*, 832 F.3d 654, 677-79 (7th Cir. 2016).

93 Exec. Order No. 13,783 § 5, 82 Fed. Reg. 16,093, 16,095-96 (Mar. 31, 2017).

94 *See* Richard Revesz *et al.*, *Best Cost Estimate of Greenhouse Gases*, 357 Science 655 (2017).

95 *See Elements of RGGI*, The Regional Greenhouse Gas Initiative https://www.rggi.org/design/overview/regulated_sources (last visited March 11, 2018).

96 These example values are based on the Bethpage combined-cycle natural gas generator and come from the 2014 editions of eGrid and NEI. The calculations are the authors' own.

97 Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis (2016), https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf [hereafter IWG (2016)].

98 *See 2017 SO_2 Allowance Auction*, U.S. Envtl. Prot. Agency (Apr. 20, 2017), https://www.epa.gov/airmarkets/2017-so2-allowance-auction-0.

99 Each column shows examples of the dollar value of damages from emissions of SO_2, NO_x, and $PM_{2.5}$ (direct) in 2016 dollars. U.S. Envtl. Prot. Agency, *supra* note 73, at 4-23; Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Staff White Paper on Ratemaking and Utility Business Models, PSC Case No. 14-M-0101 (July 28, 2015), at C-9; and the Bay Area Air Quality Mgmt. District, *supra* note 76, at C/3.

100 U.S. Dep't of Energy, The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion ii (2007), https://www.ferc.gov/legal/fed-sta/exp-study.pdf.

101 *See, e.g.*, U.S. Envtl. Prot. Agency, EPA-420-B-16-022, Nonraod Compression-Ignition Engines: Exhaust Emission Standards (2016), https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf.

102 *Environmental Impacts of Distributed Generation*, U.S. Envtl. Prot. Agency, https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts#impacts (last visited March 11, 2018).

103 U.S. Dep't of Energy, *supra* note 100, at 7-3.

104 If the displaced resource is non-emitting like utility scale renewables or hydro power, then any emitting DER would have a negative environmental value.

105 *Real Time Fuel Mix*, N.Y. Indep. Sys. Operator (March 12, 2018 2:55 pm EST), http://www.nyiso.com/public/markets_operations/market_data/graphs/index.jsp?load=pie

106 David Patton, Pallas LeeVanSchaick, & Jie Chen, Potomac Economics, 2016 State of the Market Report for the New York ISO Markets at A-10 (2017), http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf.

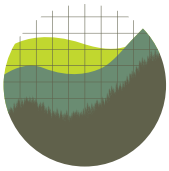
107 Emissions rates are calculated based on data from eGrid (2016), *supra* note 15, and NEI (2014), *supra* note 31.

108 The values are for CO_2e, or carbon dioxide equivalent. This includes carbon dioxide as well as other greenhouse gas emissions in CO_2 equivalent values.

109 Damages from SO_2, NO_x, and $PM_{2.5}$ come from EASIUR, *supra* note 79. Damages from CO_2 come from the IWG (2016), *supra* note 97.

110 Kevin R. Cromer & Jason A Schwartz, Inst. for Policy Integrity, Residual Risks: The Unseen Costs of Using Dirty Oil in New York City Boilers (2010), http://policyintegrity.org/files/publications/ResidualRisks.pdf.

111 Data are from EPA eGrid (2016), *supra* note 15 and EPA NEI (2014), *supra* note 31. The $PM_{2.5}$ measure from NEI are based, in some cases, on engineering estimates and interpolation, which both introduce measurement error into the calculation.



Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org

Exhibit C

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

How States Can Value Pollution Reductions from Distributed Energy Resources

JULY 2018

Distributed energy resources (DERs) are grid-connected, small-scale electric devices, such as rooftop solar installations, micro-turbines, combined heat and power systems, customer backup generators, and distributed energy storage systems. DERs are a growing part of the U.S. electric system and many state electric utility regulators are looking to more accurately compensate them by paying for a variety of the benefits that these resources provide. Most states are currently focusing on energy and distribution-level benefits,[1] but this approach overlooks the environmental and public health impacts of DERs. Even though some states like California and New York have been working on analyses that include environmental attributes of DERs, few regulators have attempted a thorough evaluation of the environmental and public health benefits.

However, these environmental attributes provide some of DERs' largest benefits. Because DER use often displaces the use of traditional, fossil-fuel-fired generators, the substitution reduces emissions of many air pollutants, including greenhouse gases and local pollutants such as particulate matter, SO_2, and NOx, which can contribute to climate change, worsen human health, impair ecosystems, harm crops, and make it harder for workers to be productive. Furthermore, DERs can be particularly valuable if they avoid local air pollution imposed on populations that are especially vulnerable to this pollution, such as low-income communities and communities of color.

[1] EnerKnol Research. How Utilities are Navigating the New Distributed Energy Landscape (Apr. 2018). *Available at:* https://enerknol.com/how-utilities-are-navigating-the-new-distributed-energy-landscape/.

Photo © U.S. Air Force/Roland Balik

The environmental, climate, and public health value (often called the "E value") of a DER depends on two main factors: the emissions being avoided (i.e., what resources does the DER replace?) and the monetary value of these emissions that are being replaced. The perceived complexity of this analysis is the basis for a common criticism of including an E value in DER compensation analysis, in part because the E value is contingent on a number of variable factors, like time and location of emissions, as well as weather patterns.

The Institute for Policy Integrity at NYU School of Law (Policy Integrity) recently released a report that addresses this criticism. The report lays out a practical methodology for calculating the E value,[2] the highlights of which are captured here. Specifically, the report describes how to appropriately value environmental and public health benefits by monetizing the economic, health, and climate damages avoided emissions would have caused. State utility regulators can use the steps described in the report, weighing tradeoffs between accuracy and administrability, to implement their own program to holistically compensate DERs. Policy Integrity has already applied this methodology in New York State, using the best available data from state entities and making appropriate inferences.[3]

The E Value Method

Step 1 – Determine what generation will be displaced by DERs. The most accurate methods for determining displaced generation require working with grid operators and local distribution utilities to obtain needed data on which bulk system generators would have operated in the absence of DERs.

Step 2 – Quantify the emissions rates for displaced generators. Emission rates of existing generators can be determined based on those generators' historical, measured emissions rates, or can be estimated using engineering analyses, given known information about fuel type, generation technology, pollution control equipment, and operational practices.

Step 3 – Calculate the monetary value of the damages from emissions identified in Step 2. Damages can be monetized by calculating the value of emissions based on:

- **The type of the pollutant.** Researchers have developed monetized damages estimates per unit of emissions for many types of pollutants, including particulate matter, SO_2, NOx, and greenhouse gases.
- **The location of emissions.** Each unit of a pollutant emitted in densely populated areas or near highly vulnerable populations will cause more damage. Emissions can also interact with environmental conditions. Damage estimates can be modified to account for these concerns.
- **The timing of emissions.** Some pollutants only form when precursors are exposed to direct sunlight. Therefore, emissions that occur at night or in winter may cause less damage than those during the day or in the summer.

A method that accounts for all of these factors would lead to the most accurate calculations of damage per unit of emissions. Regulators can use a variety of tools to calculate these damages, including those recommended to New York.[4]

---

[2] Jeffrey Shrader, Burcin Unel, and Avi Zevin. Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources. Institute for Policy Integrity at NYU School of Law (Mar. 2018). *Available at:* http://policyintegrity.org/publications/detail/valuing-pollution-reductions.

[3] "Value of Distributed Energy Resources – E/EJ Value Informal Subgroup – Track 1 and 2 Report." In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design. 17-01277. (Hereinafter "VDER report.") *Available at:* http://policyintegrity.org/documents/DER_Value_Stack_E_Value_Report_07.09.18.pdf.

[4] E.g. COBRA, EASIUR, BenMap, *see* VDER Report at 11-16.

Step 4 – Use the emissions rates from Step 2 and damage estimates per unit of emissions from Step 3 to monetize the value of avoided emissions from displaced generation. If existing policies already put a price on emissions of some or all of the pollutants covered in Steps 1-3, regulators should make necessary adjustments.

Step 5 – Take into account any emissions produced by the DER itself. DERs such as diesel generators or combined heat and power generators emit pollutants. To arrive at an accurate environmental and public health value, regulators must take into account those emissions and the damage they cause.

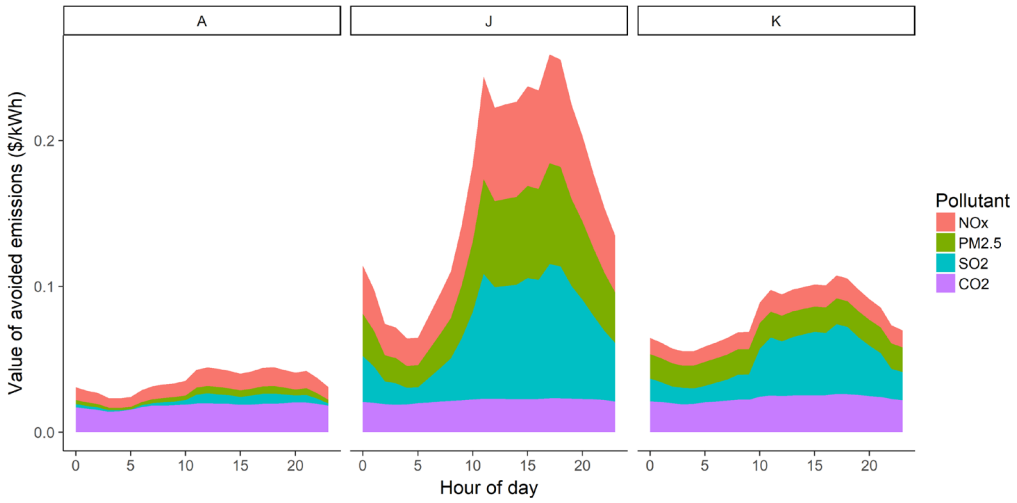
Valuing Pollution Reductions in New York State

Policy Integrity employed this methodology in New York, and the details of that analysis are available in a report that was filed with the Public Service Commission.[5] As the report demonstrates, zonal and temporal variations can have a significant impact on the environmental and public health value of a DER. Below are two figures showing examples of how this value might change on an intra- and inter-daily basis or depending on location.

Figure 1 below shows hourly sets of environmental values (also known as "E value stack") for three representative zones of New York's grid, using one of the two damage values calculated by the Environmental Protection Agency's Co-Benefits Risk Assessment (COBRA) model. The average value of avoided emissions is about 3.6 cents in Zone A, which is in upstate New York. In Zone J, where New York City is located, values are vastly higher at 16.2 cents per kWh, largely due to the high population density. In Zone K, Long Island, the value is 8.0 cents per kWh.

Most importantly, this figure reveals that the value of avoided emissions is not constant during the day. One can see that in all locations, the highest value occurs between 10 a.m. and 6 or 7 p.m. This intra-daily pattern of value occurs because as the electricity demand increases during the day, less-efficient and higher emitting generators start operating to meet that demand.

Figure 1: Hourly Zonal Environmental Value Stack Using High COBRA Damages



[5] *See* VDER report for details on the exact methodology and data used in New York, and their limitations.

Figure 2: Daily Environmental Value Stack Using High COBRA Damages

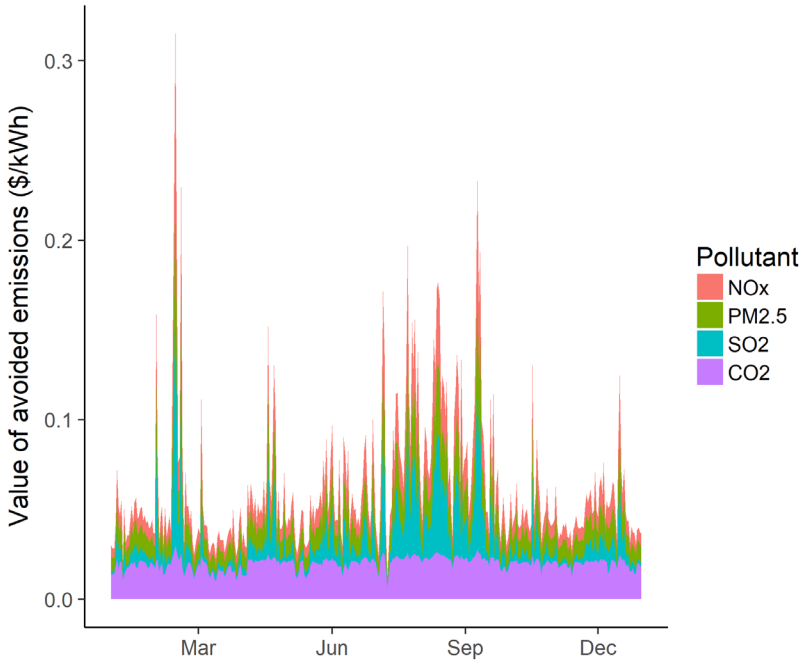


Figure 2 shows that damages also vary seasonally. The figure shows the New York State-wide average daily value stack for each day of 2016 using the high-damage COBRA model. One can see that on days when high-emitting resources are often on the margin, like in the very cold days of winter and the very hot days of summer of 2016, the value of avoided emissions can spike. Conducting a more detailed analysis that includes time variation will allow dispatchable DERs to capture this value and, therefore, provide economically efficient incentives for DER deployment and use while creating significant environmental and public health benefits.

While more comprehensive reforms such as an economy-wide tax on greenhouse gases and local air pollutants would be needed to fully value the environmental and public health benefits of all DERs, the methodology outlined here allows utility regulators to implement a DER compensation scheme that incentivizes DERs when and where they are most beneficial to society.

For more information, see Policy Integrity's full report,
"Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources"
or contact Burcin Unel, Energy Policy Director, at burcin.unel@nyu.edu.

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org

Exhibit D

MANAGING THE FUTURE OF THE ELECTRICITY GRID: ENERGY STORAGE AND GREENHOUSE GAS EMISSIONS*

*Richard L. Revesz*** and Burcin Unel****

Recent advances in technology and the consequent decline in manufacturing costs are making energy storage systems a central element of energy and climate change policy debates across the nation. Energy storage systems have the potential to provide many benefits such as lower electricity prices at peak demand times, deferred or avoided new capacity investments, and reduced greenhouse gas emissions. Indeed, both federal and state policymakers are enthusiastically encouraging more energy storage deployment with the belief that energy storage systems will help reduce greenhouse gas emissions from the electricity sector by making intermittent and variable renewable energy resources such as solar and wind more attractive.

This Article challenges the common assumption that increased energy storage will necessarily reduce greenhouse gas emissions. We first explore the conditions under which energy storage systems can cause an increase in greenhouse gas emissions contrary to the intent of policymakers. As policymakers start to rely more heavily on energy storage systems to achieve clean energy goals, this insight is crucial to inform stakeholders in the energy and climate policy debates. Next, we show that the current regulatory and policy landscape falls short of providing sufficient incentives for a desirable level of deployment of energy storage or sufficient safeguards to ensure that more energy storage deployment is indeed environmentally beneficial and economically efficient. Last, we suggest policy reforms that can correct these inefficiencies and discuss the jurisdictional roles that state and federal regulators have in implementing these reforms.

Introduction 140
I. Benefits of Energy Storage 144
A. Balancing the Grid 145
B. Role of Energy Storage 147
C. Technologies, Performance Characteristics, and Market Presence 150
II. Potential Undesirable Consequences of Energy Storage 155
A. Operation of the Electricity Markets 156
B. Standard Policy Arguments for Energy Storage 159
C. Integrating Renewable Energy Resources Without Energy Storage 162
D. Potential Negative Effects of Energy Storage on Greenhouse Gas Emissions 163
1. Effects on Existing Fossil Fuel-Fired Plants 163

---

* This is the second Article in the Managing the Future of the Electricity Grid series. For the first Article, see Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 HARV. ENVTL. L. REV. 43 (2017).

** Lawrence King Professor of Law and Dean Emeritus, New York University School of Law. The generous financial support of the Filomen D'Agostino and Max E. Greenberg Fund at NYU Law School is gratefully acknowledged. Paul-Gabriel Morales and Kartik Madiraju provided exceptional research assistance.

*** Energy Policy Director, Institute of Policy Integrity, New York University School of Law.

2. *Effects on Efficiency Losses* 165
3. *Effects on Incentives for Future Fossil Fuel-Fired Plants* ... 166
4. *Interactions with Existing Policy, Regulatory, and Market Structures* 168

III. Inadequacy of the Current Regulatory and Policy Landscape 169

A. *Inadequacy of Direct Investment Incentives* 170
1. *Distinguishing Between Beneficial and Harmful Energy Storage* 170
2. *Quest for Efficiency* 172

B. *Inadequacy of Indirect Price Incentives* 173

IV. Policies Needed to Achieve Efficient Incentives 179

A. *Achieving Efficiency* 180
1. *Internalizing Externalities* 180
a. *Reflecting Marginal External Damage of Greenhouse Gas Emissions in the Wholesale Markets* 181
b. *Using Cost-Benefit Analysis in Procurement* 183
2. *Eliminating Barriers to Entry* 184
3. *Eliminating Barriers to Earning Multiple Value Streams* .. 186

B. *Jurisdictional Roles* 191
1. *Roles for FERC* 192
2. *Roles for States* 195

Conclusion 196

Introduction

The term "energy storage" refers to technologies capable of receiving electric energy from the grid and storing it for the purpose of releasing it back to the grid at a later time.[1] These technologies have the potential to provide different services to a variety of the stakeholders of the electricity system: power plants that generate electricity on a large scale; owners of distributed energy resources that produce it in a decentralized manner on a smaller scale; utilities that distribute it; grid operators that balance its demand and supply; and end-use customers that consume it. The benefits of energy storage include lower electricity prices, deferred or avoided new capacity investments due to reduced need and urgency for new capacity, and the provision of a variety of ancillary services, which are necessary to support the reliable transmission of electricity from generators to end users.

1. *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121, para. 1 n.1 (proposed Nov. 17, 2016) (to be codified at 18 C.F.R. pt. 35).

Energy storage systems are now economically viable as a result of advances in technology and the consequent declines in their manufacturing costs.[2] A comparison of levelized costs—the unit cost of providing electricity over the lifetime of a resource—reveals that several energy storage technologies are now competitive with forms of electricity generation. Moreover, energy storage costs are expected to fall even further as a result of economies of scale achieved by the large production scale of leading companies like Tesla and its international competitors, making energy storage an even more attractive option.[3]

Currently, there are 24.26 gigawatts ("GW") of operational energy storage in the United States, with an additional 7.51 GW announced, contracted, or under construction.[4] The current total corresponds to about 2.7% of the current U.S. generation capacity.[5] It is expected that annual new deployment of energy storage will exceed 1 GW in 2019 and 2 GW in 2020.[6] By comparison, annual capacity additions of all other technologies are expected to be 11.1 GW in 2019 and 14.8 GW in 2020, making energy storage an increasingly important component of the electricity grid in the near future.[7]

While the decline in costs has been a major driver of the increase in the adoption of energy storage systems, policymakers at both the state and federal level have also been taking significant actions to speed up the process. In June 2016, President Obama announced public and private procurement, deployment, and investment commitments, which could lead to about $1 billion in investments, and at least 1.3 GW of additional storage procurement or deployment by 2021.[8] These commitments include the U.S. Department of Energy initiatives to promote access to and standardization of energy data to help utili-

---

2. *See* LAZARD, LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 1.0 (2015), https://perma.cc/A3NV-VXV6 [hereinafter LAZARD'S].
3. *See, e.g.*, Katherine Hamilton, Energy Storage Ass'n, *Energy Storage: State of the Industry*, PRESENTATION AT THE ENERGY INFORMATION ADMINISTRATION ENERGY CONFERENCE 16 (2015), https://perma.cc/XL4Y-D9P6; David Fickling, *Battery Assault*, BLOOMBERG GADFLY (Sep. 4, 2016), https://perma.cc/6GKX-SKSE; Nadya Ivanova, *Lithium-Ion Costs to Fall by up to 50% within Five Years*, NEWENERGYUPDATE (Jul. 30, 2015), https://perma.cc/Z2ZW-Z2B9.
4. DEP'T OF ENERGY GLOBAL ENERGY STORAGE DATABASE, https://perma.cc/6S2W-3V3T [hereinafter DOE DATABASE]. The numbers used in this article reflect data at the time this manuscript was authored, using the DOE Database. These data may change as energy storage systems are deployed. The DOE Database was used to generate a variety of data used in this article.
5. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2015 70 (2016).
6. RAVI MANGHANI, GMT RESEARCH/ENERGY STORAGE ASS'N, U.S. ENERGY STORAGE MONITOR: 2015 YEAR IN REVIEW 17 (2016).
7. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2017 71 (2017), https://perma.cc/4BBB-SLBK.
8. Press Release, The White House, Obama Administration Announces Federal and Private Sector Actions on Scaling Renewable Energy and Storage with Smart Markets (Jun. 16, 2016), https://perma.cc/MLP9-B752.

ties, consumers, and energy companies coordinate, collaborate, and benefit from energy storage more easily; procurement commitments from states and utilities; and deployment commitments from developers and power companies.[9]

President Trump's view on energy storage, however, is not clear. A list of infrastructure priorities compiled by the Trump administration prior to his inauguration included a project to expedite the procurement of local energy storage resources.[10] However, since the inauguration, there has not been any formal initiative by his administration to bring this goal to fruition. On the contrary, Trump has proposed budget reductions that would directly harm the development of energy storage technologies.[11] For example, proposed reductions cut the funding for the U.S. Department of Energy's Advanced Research Projects-Energy ("ARPA-E") program,[12] which currently provides $43 million to nineteen energy storage projects in fourteen states.[13]

Policymakers have been enthusiastic about energy storage systems primarily because of their belief that cheaper and more prevalent storage options could help facilitate the integration of increased renewable energy generation and speed up the transition to a low-carbon grid.[14] Generation from renewable resources such as solar and wind is intermittent and variable based on daylight and weather patterns.[15] In contrast, electricity is demanded continuously at every instant, though this demand fluctuates throughout the day. This mismatch makes renewable energy relatively less attractive than energy that can be produced in a more continuous manner by burning fossil fuels. Energy storage systems can eliminate this disadvantage by storing electricity at times when generation exceeds demand and delivering it subsequently when demand exceeds generation. By making investments in renewable energy relatively more attractive, energy storage systems can help reduce greenhouse gas emissions (and the emissions of other air pollutants) by reducing the use of fossil fuels.

---

9. *See id.*

10. *See* Gavin Bade, *Trump Infrastructure Priority Plan Includes Transmission, Wind, Energy Storage*, UTIL. DIVE (Jan. 25, 2017), https://perma.cc/F3HQ-2WVD.

11. *See* Gavin Bade, *Trump Budget would Slash EPA Funding 31%, Eliminate ARPA-E in DOE Cuts*, UTIL. DIVE (Mar. 16, 2017), https://perma.cc/3EWU-25KU.

12. *See id.*

13. Alexa McClanahan, *ARPA-E's 19 New Projects Focus on Battery Management and Storage*, ARPA-E (Aug. 7, 2012), https://perma.cc/PWE6-V4YN.

14. *See, e.g.*, U.S. DEP'T OF ENERGY, GRID ENERGY STORAGE 5 (2013), https://perma.cc/J62X-JYED.

15. *See* Allen McFarland & Cara Marcy, *Wind Generation Growth Slowed in 2015 as Wind Speeds Declined in Key Regions*, TODAY IN ENERGY (Apr. 21, 2016), https://perma.cc/2K46-22C9; George Musser, *A Solar Detective Story: Explaining How Power Output Varies Hour by Hour*, SCI. AM. SOLAR AT HOME (Jul. 30, 2010), https://perma.cc/D5FP-W3XW.

The view that promoting the use of energy storage systems produces environmentally attractive results has been standard in policy circles.[16] This beneficial outcome, however, is not guaranteed. Indeed, cheaper storage could also facilitate a higher usage of fossil fuels than the current fuel mix, causing an increase in greenhouse gas emissions. Historically, coal plants have been able to generate electricity more cheaply than natural gas plants.[17] As a result, at times during the day when the demand for electricity is low, coal plants can meet this demand at a low price, and more expensive natural gas plants are not needed. As demand increases during "peak" time periods, and the capacity of already operating plants is not enough to meet that demand, more expensive natural gas plants are also needed. But this natural gas generation might not be necessary if coal-produced energy could be stored during periods of low demand. In this scenario, energy storage would make it possible for more electricity to be generated by burning coal rather than natural gas, which emits less greenhouse gas when burned. As a result, the availability of energy storage systems would lead to higher levels of greenhouse gas emissions from electricity generation. And, the problem is compounded because of the energy losses that occur during the charging and discharging process.[18]

Thus, cheaper energy storage systems can have either beneficial or perverse results, as opposed to the uniformly beneficial results generally attributed to them. Therefore, it is important to design policies that help ensure that the increased use of storage leads to a reduction of greenhouse gas emissions, rather than to an increase. To do so requires a thorough understanding of the operation of the grid and of the manner in which storage systems affect this operation.

---

16. *See* ETHAN L. ELKIND, U.C. BERKELEY LAW & UCLA LAW, THE POWER OF ENERGY STORAGE 8–10 (2010), https://perma.cc/73MZ-ZUV6; Jeff St. John, *How Energy Storage Can Cut Peaker-Plant Carbon for the Clean Power Plan*, GREENTECH MEDIA (Sep. 24, 2015), https://perma.cc/56CP-ZUYT; Bobby Magill, *California Takes Lead In Developing Energy Storage*, CLIMATE CENT. (Jan. 13, 2015), https://perma.cc/QX45-NMRU (quoting Anne Gonzales, spokeswoman for California Independent System Operator, "[E]nergy storage systems are able to charge at night when greenhouse gas emissions are low or can be charged directly from renewable sources such as solar or wind, and then injected into the grid later during peak demand times or other critical times"); *Advancing Energy Storage Technology in California*, CAL. ENERGY COMM'N, https://perma.cc/GJR6-Z9X4.
17. *See* Tyler Hodge, *Natural Gas Expected to Surpass Coal in Mix of Fuel Used for U.S. Power Generation in 2016*, TODAY IN ENERGY (Mar. 16, 2016), https://perma.cc/ZG8S-RW5V.
18. The extent of this depends on the type of the energy storage system. Inefficiencies in the storage process are the dominant source of greenhouse gas emissions from stored fossil-generated electricity, particularly for pumped hydro and battery energy storage ("BES") systems. Of the storage technologies considered, the polysulfide bromide BES has the highest greenhouse gas emissions coupled with fossil sources, while compressed air energy storage has the least. *See generally* Paul Denholm & Gerald L. Kulcinski, *Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems*, 45 ENERGY CONVERSION & MGMT. 2153 (2004).

The design of desirable policies is further complicated by jurisdictional uncertainties regarding the regulation of energy storage systems. An energy storage system can be installed behind the meter of a customer, at the local distribution system level, or at the wholesale level. Some of the benefits of energy storage affect the wholesale electricity markets, which are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), whereas others affect the retail electricity markets, which are subject to state regulation. Providing the right incentives for energy storage is challenging under this jurisdictional division. Coordination between federal and state regulators is therefore necessary to ensure full, but not duplicate, compensation for the services rendered. Failure to do so would lead to inefficient levels of storage and potentially to undesirable environmental consequences.

The first goal of this Article is to challenge the common belief that increased energy storage would necessarily reduce greenhouse gas emissions. We show, instead, that under certain scenarios the opposite could be true. This insight is significant because the increased use of energy storage is regarded as an important component of the fight against climate change.

Our second goal is to analyze the failure of the current regulatory and policy landscape to provide incentives for a desirable level of deployment of energy storage and the reduction of greenhouse gas emissions. In contrast, poorly designed policies could provide perverse incentives and lead to the increase of such emissions. We propose policies that would correct these inefficiencies.

This Article is organized as follows: Part I first provides a brief technical overview of the electricity system, and then describes energy storage systems and their potential benefits. Part II explains the functioning of electricity markets and challenges the prevailing view that increased use of energy storage necessarily leads to a decrease in greenhouse gas emissions. Part III describes the inadequacy of the current regulatory and policy framework to provide efficient incentives of energy storage. Part IV outlines the policy reforms needed to ensure that energy storage fulfills its promise of reducing greenhouse gas emissions and discusses the jurisdictional roles in implementing these reforms.

I. Benefits of Energy Storage

While a detailed technical analysis of the electricity grid and the services that energy storage can provide to the electricity system is beyond the scope of this Article, a brief overview is necessary to understand the potential benefits of energy storage. Therefore, in this Part, we first provide a basic overview of the operational requirements of the electricity grid. We then explain the role energy storage systems can play in achieving these operational requirements.

Developing an efficient policy for energy storage also requires an understanding of different types of energy storage systems, and the relative value of

different technology in providing different kind of services. An analysis of the services each type of energy storage technology can provide, as well as a discussion of their respective "levelized cost"—the per kilowatt hour (kWh) cost of operation over system's lifetime that is often used to compare different technologies[19]—is necessary to provide a foundation for our later discussion on the need for a new policy framework. Therefore, in the last Section of this Part, we describe different energy storage technologies, their potential uses, and their costs.

A. Balancing the Grid

The electricity system has three main components: generation, transmission, and distribution. Electricity is generated by converting a primary source of energy into electric energy. This primary source of energy can be derived from a variety of sources such as the thermal energy of nuclear reactions or burning fossil fuel, the kinetic energy of water and wind, solar radiation, or geothermal energy.[20] Once the source energy is converted into electricity, it is carried long distances over high-voltage transmission lines.[21] Then, it is carried over low-voltage distribution lines for the last few miles before being delivered to the consumers.[22] Both transmission and distribution networks have capacity constraints.[23]

The electricity grid requires that the demand and the supply of electricity be equal at all times.[24] Reliably transmitting electricity from generators to consumers also requires meeting a variety of other operational constraints such as ensuring that the amount of electricity that flows through the transmission and distribution networks is not higher than the capacity of these networks and that the electricity's cycle frequency and voltage level are maintained throughout the grid.[25] If these constraints are not met, the system may become unstable, blackouts may occur, or the grid may sustain damage.[26] In the absence of significant amounts of energy storage, this balancing requirement means that generation has to follow changing customer demand in real time.

---

19. *See* Office of Indian Energy Dep't of Energy, Levelized Cost of Energy (LCOE) 3, https://perma.cc/H4KQ-VDEP; *see also Glossary*, Dep't of Energy Global Energy Storage Database, https://perma.cc/XTE8-MSJR.

20. *See* Ignacio Perez-Arriaga & Christopher Knittel, Mass. Inst. of Tech. Energy Inst., Utility of the Future 4–6, 9 (2016), https://perma.cc/E9D9-HRAL.

21. *See* Richard Schmalensee & Vladimir Bulovic, Mass. Inst. of Tech. Energy Inst., The Future of Solar Energy 154 (2015), https://perma.cc/S478-9CNH.

22. *See id.*

23. *See* Perez-Arriaga & Knittel, *supra* note 20, at 302–03.

24. *See* Schmalensee & Bulovic, *supra* note 21, at 182–83.

25. *See* Perez-Arriaga & Knittel, *supra* note 20, at 21, 87.

26. *See id.* at 167–69.

The demand for electricity during the night is usually low; it starts increasing in the morning, and peaks in the late afternoon and early evening.[27] Also, the demand is generally higher during the summer as a result of the use of air conditioning.[28] While this rough shape of customer demand on a typical day is known based on general patterns, the exact customer demand on a specific day cannot be predicted with certainty.

Instantaneously balancing electricity supply and demand requires both long-term planning and real-time response. Long-term planning is necessary to ensure that there is enough capacity planned and built to meet all of the consumer demand during the times when such demand is greatest, usually during the daytime. In particular, there should be adequate resource capacity to meet the demand on the hottest few days of the summer, which is when the demand is usually at its annual peak, even if this capacity will sit idle for the rest of the year when the demand is not as high. The resulting costs of this additional capacity are high. Historically, however, they needed to be expended to meet the demand at all times.

The instantaneous balancing of the grid, however, requires more than capacity building: it also requires a variety of ancillary services. Frequency regulation is used to reduce the minute-to-minute, or shorter, fluctuations caused by differences in electricity supply and demand.[29] Ramping resources are needed to manage longer-duration fluctuations in the supply due to factors that affect generation such as changes in wind speed or cloud cover.[30] Voltage support helps maintain voltage levels throughout the system.[31] Reserve capacity is the extra capacity needed that can respond quickly to ensure system stability in the case of unexpected changes in customer demand.[32] Spinning reserves are already online and can respond in less than ten minutes, while non-spinning reserves are offline but also can come online and respond in less than ten minutes.[33]

Energy storage systems have the potential to help meet some or all of these requirements for balancing the grid, and help reduce overall system costs by avoiding the need for new capacity or by providing ancillary services at a lower

27. *See generally id.* at 253–70.

28. *See id.* at 133.

29. *See id.* at 289; GARRETT FITZGERALD ET AL., ROCKY MOUNTAIN INST., THE ECONOMICS OF BATTERY ENERGY STORAGE 15 (2015), https://perma.cc/A6PY-V66E.

30. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, MOVING ENERGY STORAGE FROM CONCEPT TO REALITY 19 (2011), https://perma.cc/G7L2-4WET; SCHMALENSEE & BULOVIC, *supra* note 21 at 287.

31. *See* PEREZ-ARRIAGA & KNITTEL, *supra* note 20, at 50; FITZGERALD ET AL., *supra* note 29, at 15.

32. *See* PEREZ-ARRIAGA & KNITTEL, *supra* note 20, at 23; FITZGERALD ET AL., *supra* note 29, at 15.

33. *See* FITZGERALD ET AL., *supra* note 29, at 15.

cost than the resources that have been traditionally used for these services, such as gas turbines.

B. Role of Energy Storage

There have been numerous studies on the potential benefits of energy storage, including reports from consulting firms, industry trade associations,[34] governmental agencies, and independent third parties.[35] Some of the studies are state-specific,[36] whereas others perform nationwide analyses.[37] While these studies classify the services provided by energy storage in different ways, a classification based on the level of the grid at which the benefits accrue is most useful when evaluating regulatory and policy frameworks. Therefore, this Article will classify the services provided by energy storage systems into four groups based on where the benefits accrue: generation, transmission, distribution, or end-users.[38]

At the generation level, energy storage systems can help optimize the supply from existing resources and ensure grid reliability by providing a variety of the ancillary services needed to balance the grid. Energy storage can help improve the efficiency of existing resources by providing services such as energy arbitrage, resource adequacy, variable resource integration, and management of must-take resources.[39] Energy arbitrage—purchasing wholesale electricity when the price is low and selling it when the price is high—can help lower the total

---

34. *See* JUDY CHANG ET AL., THE BRATTLE GRP., THE VALUE OF DISTRIBUTED ELECTRICITY STORAGE IN TEXAS (2014), https://perma.cc/D37X-DFTM [hereinafter CHANG, DISTRIBUTED ELECTRICITY STORAGE IN TEXAS]; JUDY CHANG ET AL., THE BRATTLE GRP., RENEWABLES AND STORAGE: DOES SIZE MATTER? (2010), https://perma.cc/VC2U-3GCE [hereinafter CHANG, DOES SIZE MATTER?]; Hamilton, *supra* note 3; SAM JAFFE, NAVIGANT RESEARCH, ENERGY STORAGE SUPPLY CHAIN OPPORTUNITIES (2014), https://perma.cc/PV27-7R4J.

35. *See* U.S. DEP'T OF ENERGY, GRID ENERGY STORAGE, *supra* note 14, at 18; PAUL DENHOLM ET AL., NAT'L RENEWABLE ENERGY LAB., THE VALUE OF ENERGY STORAGE FOR GRID APPLICATIONS (2013), https://perma.cc/UX5V-RZR5; ABBAS A. AKHIL ET AL., SANDIA NAT'L LABS, DOE/EPRI 2013 ELECTRICITY STORAGE HANDBOOK IN COLLABORATION WITH NRECA (2013), https://perma.cc/EQU8-V8UD; FITZGERALD ET AL., *supra* note 29.

36. *See* MASS. ENERGY STORAGE INITIATIVE, STATE OF CHARGE 41 (2016), https://perma.cc/37UA-SC6N [hereinafter STATE OF CHARGE]; S. CAL. EDISON, *supra* note 30, at 18–23; RANDY SIMON, N.Y. BATTERY & ENERGY STORAGE TECH. CONSORTIUM, N.Y. ENERGY STORAGE ROADMAP FOR NEW YORK'S ELECTRIC GRID (2016), https://perma.cc/C6MB-S2YU.

37. *See* U.S. DEP'T OF ENERGY, GRID ENERGY STORAGE *supra* note 14, at 18; DENHOLM ET AL., *supra* note 35; AKHIL ET AL., *supra* note 35.

38. *See* FITZGERALD ET AL., *supra* note 29.

39. *See* FITZGERALD ET AL., *supra* note 29, at 15; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.

cost of meeting the electricity demand by reducing the need to generate electricity when it is costly to do so.[40] Energy storage can help meet resource adequacy requirements that are needed to ensure system reliability during system peaks by charging during off-peak times and discharging during peak times.[41] This feature helps defer or reduce the need for capacity investment in more traditional resources, such as new natural gas combustion turbines, to meet peak demand.[42] In addition, when paired with a renewable generator, energy storage can help "firm" the variable output from that generator by charging when there is not enough demand for the generator's output and discharging when there is need.[43] Finally, energy storage can also help improve the use of the "must-take" resources, such as hydro, nuclear, and wind that must be taken by the buyers regardless of market prices due to regulatory or operational constraints, because it can help them manage their generation and prevent them from dumping excess energy at low demand times.[44]

Energy storage can also help provide a variety of ancillary services, such as frequency regulation, ramping, spinning/non-spinning reserves, voltage support, and black start. Frequency regulation is necessary to prevent grid instability by ensuring that generation is matched with consumer demand at every moment.[45] Ramping is necessary to counteract the effects of varying renewable generation during the day.[46] Spinning and non-spinning reserves can respond to unforeseen events such as generation outages.[47] Voltage support helps maintain the voltage within an acceptable range to match demand.[48] Finally, black start services help restore operation in the event of an outage.[49]

In turn, energy storage can help improve the transmission system by providing transmission congestion relief, transmission system upgrade deferral, and

---

40. *See* FITZGERALD ET AL., *supra* note 29 at 15; S. CAL.EDISON, *supra* note 30, at 19; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
41. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
42. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
43. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
44. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
45. *See* FITZGERALD ET AL., *supra* note 29, at 15; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
46. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
47. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
48. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
49. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.

improving performance.[50] Congestion relief means that energy storage can reduce the bottlenecks caused at certain locations of the transmission system during high-demand times by discharging at those locations during those periods.[51] Transmission system upgrade deferral means that energy storage can help reduce the need, the size, or the urgency of new investment in the transmission systems by shifting the electricity demand to less congested times, and, thus, preventing the overload of the system.[52] Lastly, energy storage can help improve transmission system performance and reliability by maintaining system voltage or providing capacity during system faults.[53]

At the distribution level, energy storage can help provide congestion relief, defer upgrades, mitigate outages, and integrate distributed generation.[54] As in the case of the transmission system, the distribution system can get congested at some locations during peak demand times. Energy storage can help reduce this congestion, and defer or avoid the need for costly upgrades.[55] A storage system that is located at the distribution level can help provide uninterrupted service by discharging in the event of an unexpected power outage.[56] Finally, energy storage can help with some of the challenges distributed generation systems create for the distribution network, such as excessive bidirectional flows.[57]

End-users with behind-the-meter energy storage systems get benefits beyond the cost savings that storage can provide at the generation, transmission, and distribution phases. When a customer is facing time-of-use rates that vary during the day, energy storage can help reduce consumption from the grid when the rates are highest by allowing the customer to charge when the rates are low and use the stored electricity when the rates are high.[58] Or, by reducing a customer's demand at peak times, energy storage can help reduce demand charges that an end-user has to pay, which are charges that are based on the

---

50. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 18–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
51. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 21; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–87.
52. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 21; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–87.
53. *See* FITZGERALD ET AL., *supra* note 29, at 15; S. CAL. EDISON, *supra* note 30, at 21; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–88.
54. *See* FITZGERALD ET AL., *supra* note 29, at 15–16; S. CAL. EDISON, *supra* note 30, at 22–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–87.
55. *See* FITZGERALD ET AL., *supra* note 29, at 15–16; S. CAL. EDISON, *supra* note 30, at 22; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–87.
56. *See* FITZGERALD, *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 22; *see also* SCHMALENSEE & BULOVIC, *supra* note 21, at 285–88.
57. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 20–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 287.
58. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 23; SCHMALENSEE & BULOVIC, *supra* note 21, at 286–88.

amount of a customer's maximum demand during a certain time period.[59] When rooftop solar panels, or other distributed energy resources, produce more electricity than the customer's demand at the time, energy storage can help customers manage their demand from the grid by storing that energy for later use rather than exporting it to the grid.[60] Finally, in the event of grid failure, energy storage can provide backup power.[61]

The benefits that an energy storage system can provide depend on its location. While a system stored behind a customer's meter has the ability to provide benefits at all levels, a system that is located at the transmission level provides the kind of services that benefit only the transmission and the generation system. For example, an end-user with a behind-the-meter energy storage system can provide frequency regulation services, or help avoid costly distribution system upgrades by relieving a congested distribution network location, while helping the end-user manage her own demand. However, a system that is located at the transmission level, by its nature, cannot help a customer manage her demand. Understanding this variation, as will later be discussed in more detail, is important to designing desirable policies.

C. Technologies, Performance Characteristics, and Market Presence

The broad label of "energy storage systems" includes a variety of technologies that are commonly grouped into four families: mechanical storage technologies, electro-chemical storage technologies, thermal storage technologies, and electrical storage technologies.[62] System design features and performance characteristics can also be helpful for further evaluating different storage resources and their potential applications. A storage system's "rated power capacity" and "duration of discharge" might make it uniquely advantageous to serve certain needs and ill-suited to others. The "rated power capacity" is a storage unit's total output, expressed in kW or megawatt (MW).[63] "Duration of discharge"

59. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 23; SCHMALENSEE & BULOVIC, *supra* note 21, at 288.

60. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 22–23; SCHMALENSEE & BULOVIC, *supra* note 21, at 288.

61. *See* FITZGERALD ET AL., *supra* note 29, at 16; S. CAL. EDISON, *supra* note 30, at 23; SCHMALENSEE & BULOVIC, *supra* note 21, at 288.

62. *See* ELLEN ANDERSON ET AL., UNIV. OF MINN. ENERGY TRANSITION LAB, ENERGY STORAGE 101 1–2 (2015), https://perma.cc/9LYG-S3J7.

63. *See, e.g.*, *Glossary*, DEP'T OF ENERGY GLOBAL ENERGY STORAGE DATABASE, *supra* note 19. One might, conceptually at least, compare the "rated power capacity" of a storage system to the "nameplate capacity" of conventional generators. There exists, however, one notable difference between the capacity of conventional generators and that of storage systems: storage system capacity is bidirectional. That is, a storage system is capable of discharging as well as absorbing energy. Thus, it may be more accurate to describe a storage system's capacity as 10 kW *and* also -10 kW, or alternatively as 20 kW. Nonetheless, this Article follows indus-

refers to the time a given system can output electricity at its rated power capacity.[64] Lastly, the levelized cost of each technology plays an important role in deployment and procurement decisions.

Mechanical storage technologies, typified by pumped hydroelectric storage facilities,[65] supply the overwhelming majority of storage capacity in the United States.[66] These systems—commonly referred to as "pumped hydro"—use off-peak electricity to pump water uphill, where it is stored in a reservoir and subsequently released back downhill, through a generating turbine, at times when electricity demand is greater.[67] Typically, pumped hydro systems have a rated power capacity between 400 and 600 MW.[68] Yet, because the single largest constraint on a system's potential capacity is the physical size of the water reservoir, many projects exceed this average, and large facilities can hold as much as 3,000 MW of capacity.[69] System response times range between seconds and minutes,[70] and the average duration of discharge—that is, the length of time a system can output at its power capacity—is between four and thirty hours.[71] Siting, permitting, and land-use considerations restrict where facilities may be built, and add years to project development timetables.[72] As a result of these difficulties, no new pumped hydro facilities have been commissioned since 1995.[73] Pumped hydroelectric facilities are most commonly used to time-shift cheap generation to periods of high demand, meet spot demand when primary generation resources are temporarily off-line, and provide ancillary service like

---

try convention regarding storage system capacity figures, and the capacity figures given here reflect capacity in only a single direction, like discharge capacity. *See* Andrew H. Meyer, *Federal Regulatory Barriers to Grid-Deployed Energy Storage*, 39 COLUM. J. ENVTL. L. 479, 494 n.77 (2014).

64. *See Glossary*, DEP'T OF ENERGY GLOBAL ENERGY STORAGE DATABASE, *supra* note 19.

65. *See* Meyer, *supra* note 63, at 488; AKHIL ET AL., *supra* note 35, at 32.

66. *See* DOE DATABASE, *supra* note 4. Pumped hydro facilities account for 22.6 GWs as part of the total 24.2 GWs of energy storage systems in the U.S. in 2016.

67. *See* Meyer, *supra* note 63, at 488–89; AKHIL ET AL., *supra* note 35, at 32.

68. *See* AKHIL ET AL., *supra* note 35, at 30–35. *See* STANLEY J. HAYES, U.S. ARMY CORPS OF ENG'RS, TECHNICAL ANALYSIS OF PUMPED STORAGE AND INTEGRATION WITH WIND POWER IN THE PACIFIC NORTHWEST § 2.3.3 (2009), https://perma.cc/V6UN-B6XJ.

69. *See* DOE DATABASE, *supra* note 4.

70. BEN BOVARNICK, CTR. FOR AM. PROGRESS, INTEGRATED ENERGY STORAGE IN THE UNITED STATES 5, tbl. 1 (2015), https://perma.cc/7LHH-SU6E.

71. *See* DOE DATABASE, *supra* note 4. When describing the "average" storage capacity range, the text shows a number span between the "mean" and "median" of all storage facilities of a given type, unless otherwise noted. *See* AKHIL ET AL., *supra* note 35, at 30. The extended discharge helps amortize the cost of storage reservoirs, dams, and civil engineering work critical to this technology.

72. *See* AKHIL ET AL., *supra* note 35, at 34.

73. *See id.* at 30.

frequency regulation and "black start" capability.[74] Pumped hydroelectric systems alone contribute about 95% of all storage capacity in the United States,[75] and as much as 99% of storage capacity world-wide.[76] The levelized cost of operation is between $188 and $247 per MWh, making pumped hydro among the lowest cost storage resource.[77]

Compressed air energy storage is another type of mechanical storage. These systems use off-peak electricity to compress air and store it in a reservoir, usually an underground cavern or above-ground chamber.[78] When called upon, the compressed air is heated, expanded, and then channeled through a turbine-generator to produce electricity.[79] As with pumped hydroelectric systems, compressed air systems typically have sizable power and discharge capacities, in part to amortize the large capital costs associated with construction and operation of a compressed air or pumped hydro facilities.[80] To date, there are only two compressed air storage facilities operating in the United States. One such system, located in Alabama, holds about 110 MW of storage capacity, dischargeable over twenty-six hours, while a second facility in Texas has a more modest capacity of about 2 MW, dischargeable over twenty-five hours.[81] Like pumped hydro, compressed air energy storage facilities are typically called upon to time-shift generation, mitigate unexpected shifts in supply or demand, and provide ancillary services.[82] These systems constitute about 45% of all non-pumped-hydroelectric storage capacity in the United States.[83] The levelized cost of compressed air storage is approximately $192 per MWh.[84]

Flywheels, which also store energy mechanically, hold kinetic energy in rotating discs, the speed of which can be increased or decreased to shift energy into or out of the grid.[85] In this way, flywheels are well suited to provide ancillary services like frequency regulation, injecting very small and precise amounts

---

74. DEP'T OF ENERGY, ENERGY STORAGE PROGRAM PLANNING DOCUMENT 7 (2011), https://perma.cc/PQ9D-RKVM. [hereinafter DOE PLANNING DOCUMENT]. "Frequency regulation" involves managing electricity flows in order to closely match supply with momentary variations in demand. "Black start" capability is the use of stored power to bring power plants on-line. *See also* AKHIL ET AL., *supra* note 35.
75. DOE DATABASE, *supra* note 4.
76. STEVE BLUME, ENERGY STORAGE COUNCIL, GLOBAL ENERGY STORAGE MARKET OVERVIEW & REGIONAL SUMMARY REPORT 2015 5 (2015).
77. LAZARD'S, *supra* note 2, at 9.
78. *See* AKHIL ET AL., *supra* note 35, at 25.
79. *See id.*
80. *See id.* at 29–30 ("CAES and pumped hydro are capable of discharge times in tens of hours, with correspondingly high sizes that reach 1000 MW.").
81. DOE DATABASE, *supra* note 4.
82. DOE PLANNING DOCUMENT, *supra* note 74, at 7.
83. DOE DATABASE, *supra* note 4.
84. *See* LAZARD'S, *supra* note 2, at 9.
85. *See* U.S. DEP'T OF ENERGY, GRID ENERGY STORAGE, *supra* note 14, at 18.

of electricity into the grid in order to reconcile electricity supply and small fluctuations in consumer demand.[86] Unlike the sizable reservoirs and extended discharge times of other mechanical storage technologies, flywheels are designed with an average capacity of 8 MW and discharge times that fall shy of one hour.[87] Flywheels constitute 2.5% of all U.S. non-pumped hydroelectric storage capacity.[88] They have a relatively high levelized cost between $276 and $989 per MWh.[89]

Electro-chemical storage refers to an array of battery-based technologies that convert the chemical energy contained in its active materials into electric energy by electrochemical reactions.[90] Like flywheels, electro-chemical batteries have lower capacity and shorter discharge times,[91] and are often used to provide small but precise amounts of electricity at a moment's notice.[92] In particular, electro-chemical systems may be paired with renewable generation sources that have variable generation outputs. By total capacity, lithium-ion batteries are the most widely deployed electro-chemical storage technology in the United States, representing roughly 22% of all non-pumped hydro storage, or 308 MW of capacity.[93] Like many battery technologies, lithium-ion systems have limited power capacities, between 0.1 and 2.0 MW, and short discharge durations, between one and two hours.[94] In addition to several grid applications, like shifting the time of generation and frequency regulation,[95] lithium-ion batteries have also emerged as a leading storage platform for plug-in hybrid electric vehicles.[96] Other electro-chemical technologies include lead-acid batteries, sodium-based batteries, and flow batteries, which account for 6%, 1.8%, and 0.37% of non-pumped hydro capacity, respectively,[97] and collectively account for only about 1.5% of domestic storage capacity.[98] As a group, electrochemical storage systems have a comparatively high levelized cost between $211 and $2291 per MWh.[99]

Thermal storage systems use reversible chemical reactions to store thermal energy in both hot and cold temperatures.[100] While some thermal units are

86. *See id.*
87. DOE Database, *supra* note 4.
88. *Id.*
89. Lazard's, *supra* note 2, at 9, 22.
90. *See* U.S. Dep't of Energy, Grid Energy Storage, *supra* note 14, at 19.
91. *See* Bovarnick, *supra* note 70, at 5.
92. *See id.*
93. DOE Database, *supra* note 4.
94. Bovarnick, *supra* note 70.
95. *See* DOE Planning Document, *supra* note 74, at 17–18.
96. *See* Akhil et al., *supra* note 35, at 96.
97. *See* Blume, *supra* note 76, at 8.
98. *Id.*
99. Lazard's, *supra* note 2, at 9.
100. *See* U.S. Dep't. of Energy, Grid Energy Storage, *supra* note 14, at 19.

relatively small, often less than 1 MW of capacity, others can reach nearly 100 MW of capacity.[101] Small systems, commonly attached to commercial or industrial buildings, "chill[ ] a storage medium during periods of low cooling demand and then use[ ] the stored cooling later to meet air-conditioning load or process cooling loads."[102] Larger units employ a process known as concentrated solar power that uses mirrors to concentrate sunlight onto a specific focal point, trapping thermal energy in molten salt that can be extracted and converted into steam later to power an electric turbine.[103] As a whole, thermal storage systems account for nearly 700 MW of storage capacity in the United States, or 3.28%.[104]

The final category of storage technologies is electrical storage systems. Unlike other storage technologies that hold electricity indirectly—that is, they hold potential energy in the form of a resource like water or compressed air that can then be converted into electrical energy—electrical technologies store electricity directly in electrostatic or magnetic fields.[105] Supercapacitors, for example, store electricity in an electrostatic field between two conductive plates.[106] A second electrical storage technology, known as superconducting magnetic energy storage systems, stores electricity in a magnetic field created by the flow of direct current in a cryogenically cooled coil.[107] Electrical storage technologies, however, are still in the very early stages of commercialization and do not contribute to domestic storage capacity.[108]

Although different types of energy storage systems can provide similar grid support functions, the efficacy of each technology in delivering each service can differ. For example, fast-ramping and geographically flexible energy storage systems are capable of providing ancillary services more quickly and precisely even though they have limited capacity, while pumped hydroelectric storage can provide higher-capacity solutions even though they require big reservoirs and hence are not easy to site.[109] The total capacity of the deployed energy storage systems, the location where they are deployed, the types of energy storage systems deployed, and their levelized costs are all important in trying to achieve

---

101. *See* Amy L. Stein, *Reconsidering Regulatory Uncertainty: Making A Case for Energy Storage*, 41 FLA. ST. U. L. REV. 697, 709 (2014); BOVARNICK, *supra* note 70, at 14.

102. Stein, *supra* note 101, at 709.

103. *See* BLUME, *supra* note 76, at 7.

104. DOE DATABASE, *supra* note 4.

105. *See* ANDERSON ET AL., *supra* note 62, at 4.

106. INT'L ENERGY AGENCY, TECHNOLOGY ROADMAP: ENERGY STORAGE 20 (2014), https://perma.cc/3JLC-A6BY.

107. *See* S. CAL. EDISON, *supra* note 30, at 33.

108. *See* SHERIDAN FEW ET AL., GRANTHAM INST., ELECTRICAL ENERGY STORAGE FOR MITIGATING CLIMATE CHANGE 6 (2016), https://perma.cc/2TUC-P7NP.

109. *See* LAZARD'S, *supra* note 2, at 5.

clean energy goals in the least costly manner. Table I provides a summary of this key information.

TABLE I: CHARACTERISTICS OF STORAGE TECHNOLOGIES

Technology	Most Common Use	Installed Capacity (MW)	Projects Announced/ Under Way	Levelized Costs ($/MWh)
Mechanical Storage				
Pumped Hydroelectric Storage	Transmission System	28,911	11	188-247
Compressed Air Energy Storage	Transmission System	739.6	5	192
Flywheels	Peaker Replacement; Frequency Regulation; Distribution Substation; Distribution Feeder; Microgrid; Island; Commercial & Industrial	86.21	2	276-989
Electro-chemical Storage				
Sodium	Transmission; Peaker Replacement; Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	0.869	1	835-1,259
Lithium-Ion	Transmission System; Peaker Replacement; Frequency Regulation; Distribution Substation; Distribution Feeder; Microgrid; Island; Commercial & Industrial; Commercial Appliance; Residential	847	79	211-1,596
Lead-Acid	Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	125	2	461-2,291
Flow Battery	Transmission System; Peaker Replacement; Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	56.5	6	290-1,657
Thermal Storage	Transmission System; Peaker Replacement	700	1	50

Note: Electrical storage technologies currently do not contribute to domestic storage capacity, and therefore are not listed in this Table. The data in this table are obtained from Lazard's, *supra* note 2.

II. POTENTIAL UNDESIRABLE CONSEQUENCES OF ENERGY STORAGE

As Part I discusses in detail, energy storage systems have the potential to provide a variety of benefits. Above all, their potential to help integrate more renewables into the grid, and, consequently, to reduce greenhouse gas emissions makes energy storage attractive to policymakers. However, when designing pol-

icy, it is important to ensure that energy storage systems reduce greenhouse gas emissions as an empirical reality, rather than a mere theoretical possibility. It is also important to inquire whether there are conditions under which greenhouse gas emissions might increase. Therefore, in this Part, we analyze the conventional assumption that energy storage only furthers the transition to renewables.

To understand the beneficial, but also the possible pernicious effects of energy storage, we first provide a simple overview of how the electricity markets operate. This inquiry is important because the consequences of energy storage depend on the types of other generators in operation, the types of resources that are used to charge the storage system, and the types of resources that are displaced when discharging from this system.

Next, we discuss the standard assumptions that are the main drivers of today's energy storage policy initiatives. Finally, we describe conditions under which these common assumptions may not hold, and explain how increased deployment of energy storage under such conditions may actually lead to undesired consequences.

A. Operation of the Electricity Markets

Until the 1990s, electricity was provided by vertically integrated utilities, which owned and operated generation, transmission, and distribution resources. Starting in 1996, FERC Orders 888, 889, and 2000 produced a transformation to a competitive market by ensuring open and non-discriminatory access to transmission lines by all generators, and led to the formation of Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs").[110] ISOs and RTOs are independent, non-profit organizations that ensure reliability while balancing demand and supply instantaneously in the wholesale market.[111] They control, monitor, and coordinate the regional grids. They assess transmission needs, provide reliability planning, and operate the region's wholesale electricity markets. Currently, approximately two-thirds of the electricity customers in the United States are served by ISOs and RTOs.[112]

One of the most important functions of ISOs and RTOs is to ensure that the demand at any given moment can be met at the lowest cost possible given

110. *See* Order No. 888, Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities, 61 Fed. Reg. 21,540, 21,540–01 (May 10, 1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888]; Order No. 889, Open Access Same-Time Information System and Standards of Conduct, 61 Fed. Reg. 21,737 (May 10, 1996) (codified at 18 C.F.R. pt. 37) [hereinafter Order No. 889]; Order No. 2000, *Regional Transmission Organizations*, 65 Fed. Reg. 809 (Jan. 6, 2000) (codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2000].

111. *See About 60% of the U.S. Electric Power Supply Is Managed by RTOs*, U.S. ENERGY INFO. ADMIN. (Apr. 4, 2011), https://perma.cc/75J6-43JX.

112. *See IRC History*, ISO/RTO COUNCIL, https://perma.cc/WZG8-CY2L.

the constraints of the grid.[113] To achieve this objective, most system operators ask each generator for bids reflecting the lowest price at which the generator is willing to supply electricity.[114] They order these bids from lowest to highest, often referred to as "merit order," and they start dispatching generators in this order until the demand is met.[115] The bid of the last generator that is needed to meet all the demand, the "marginal" generator, is paid to all of the dispatched generators.[116]

Being able to instantaneously meet the electricity demand requires plants that are continuously running to meet the minimum level of demand during the day, known as the baseload, as well as plants that can react quickly as the demand varies.[117] Some plants, such as those fueled by coal and nuclear energy, have high fixed costs of starting up and shutting down and cannot easily vary their output from hour to hour.[118] Their variable costs of generation, however, are low, and therefore, they generally bid low prices. Thus, it makes economic sense to operate these plants at a set level of output to meet the baseload demand.

These "baseload" plants are enough to meet all of the demand by themselves when the demand is low. As demand starts to increase and the baseload plants no longer provide sufficient capacity to meet the demand, intermediate plants, such as natural gas combined cycle plants, are brought online.[119] These plants have higher variable costs of generation, so their bids are higher, but they are not as costly to start up or shut down as baseload plants.

Finally, when demand is highest, peak plants, which have high variable costs of generation and thus the highest bids, are dispatched. These plants are usually less-efficient natural gas or oil-fired plants.[120] This dynamic means that electricity prices are low when baseload plants are the marginal generator, and high when this position is occupied by peak plants.

Generation costs, however, are only one factor in determining the order in which plants are dispatched. Because the electricity generated also has to be transmitted, other factors also play a role. For example, the capacity of the

113. *See* Seth Blumsack, *Regional Transmission Organizations*, PENN STATE UNIV. DEP'T. OF EARTH & MINERAL ENG'G, https://perma.cc/CF43-H43X.

114. *See Electricity Pricing*, INDEP. ELEC. SYS. OPERATOR, https://perma.cc/UB39-SRTM.

115. PHILLIP BROWN, CONG. RESEARCH SERV., R42818, U.S. RENEWABLE ELECTRICITY: HOW DOES WIND GENERATION IMPACT COMPETITIVE POWER MARKETS? 11 (2012).

116. *See* SALLY HUNT, MAKING COMPETITION IN ELECTRICITY WORK 185–86 (2002).

117. *See* NIKHIL KUMAR ET AL., NAT'L. RENEWABLE ENERGY LAB., POWER PLANT CYCLING COSTS v (2012).

118. *See* Seth Blumsack, *Basic Economics of Power Generation, Transmission and Distribution,* PENN STATE UNIV. DEP'T. OF EARTH & MINERAL ENG'G., https://perma.cc/V8VL-KMTJ.

119. *See* PUB. SERV. COMM'N. OF WIS., ELECTRIC POWER PLANTS 2–3 (2004), https://perma.cc/M7XS-6UH7.

120. *See id.*

transmission lines is central to deciding which generator will be asked to produce.[121] If the maximum capacity of a particular line has been reached, the generator at the end of that line cannot send more electricity to the grid even if it is the cheapest generator at the time and even if it is operating below capacity.[122] As a result, a more expensive generator that is at the end of another transmission line must be asked to generate instead.[123]

Other factors, such as reliability and security concerns, also affect the order of dispatch.[124] Reliability concerns arise when there is an unanticipated loss of transmission system components, or when there is a risk to the ability of the system to meet the needs of the customers at all times.[125] For example, if wind generation from a turbine is highly variable at a particular time, the risk of not being able to meet consumer demand increases. If electricity cannot be reliably transmitted from the next generator in the merit order, out-of-merit order dispatch is used.[126] Therefore, costs of generation and transmission, reliability, and security constraints jointly determine how the load at a particular location is met, and how much it costs to meet the load at that location. Because the resulting price for electricity depends on the types of generators that are running at the time as well as constraints that are location specific, it varies by time and location, creating arbitrage opportunities.

Understanding how the electricity market operates and how generators are dispatched is also important for understanding the greenhouse gas emissions from electricity generation and, as a consequence, the avoided emissions resulting from an intervention to the electricity system, such as deployment of more energy storage. Because the type of the generators running varies by time and location, the emissions from electricity generation also vary by time and location.[127] When the demand increases, the amount of emissions that result from the new electricity generation depends on the type of the last generator—the marginal generator—required to meet that new demand.[128] And, the emission

121. *See* Thomas-Olivier Nasser, *Congestion Pricing and Network Expansion* (World Bank, Policy Research Working Paper No. 1896, 1998).

122. *See id.* at 5–6.

123. *See id.*

124. *See* U.S. Dep't. of Energy, Quadrennial Energy Review 4-2 (2017), https://perma.cc/58ES-R6JX.

125. *See* N. Am. Elec. Reliability Corp., Definition of "Adequate Level of Reliability" 5 (2007), https://perma.cc/26ZM-FKMF.

126. *See* Lu Feiyu, Energy Mkt. Co., Out-of-Merit-Order Dispatch 5 (2005), https://perma.cc/Q287-GD48.

127. *See* Kyle Siler-Evans et al., *Marginal Emissions Factors for the U.S. Electricity System*, 46 Envtl. Sci. & Tech. 4742 (2012); Joshua S. Graff Zivin et al., *Spatial and Temporal Heterogeneity of Marginal Emissions: Implications for Electric Cars and Other Electricity-Shifting Policies*, 107 J. Econ. Behavior & Org. 248, 249 (2014).

128. *See* Siler-Evans et al., *supra* note 127.

intensity of this marginal generator determines the marginal emission rate.[129] When a coal plant is on the margin, the marginal emission rate is high.[130] If a generator that is less carbon intensive, such as a natural gas plant, is on the margin, the marginal emission rate is lower.[131] Because the marginal generators vary depending on the time of the day and the location, marginal emissions also vary by location and time.[132] As a result, the emissions that can be avoided by using electricity discharges from energy storage systems also depend on time and location.[133]

B. Standard Policy Arguments for Energy Storage

Solar and wind power are becoming increasingly important as many states move towards cleaner energy sources. However, both solar and wind generation are intermittent and variable.[134] If the sun is not shining, or the wind is not blowing, these resources cannot produce electricity. Certain aspects of their production profiles are fully predictable: solar generation occurs only during the daytime with an afternoon peak, while wind generally peaks at night.[135] But their output can be variable even within short spans of time due to harder-to-predict factors like sudden cloud cover. Further, the peak demand periods, which usually happen during early evening periods when most customers return home from work, do not perfectly correspond to the peak generation times of solar and wind resources.[136] Therefore, providing electricity from solar and wind energy reliably during the whole day requires smoothing out their output throughout the day.

The increased integration of renewable energy resources has led to a reexamination of the longstanding workings of the dispatch system. While all traditional power plants can be dispatched when they are needed, the same is not true for wind or solar, as they both heavily depend on weather patterns. Because of unpredictable weather events, they might not be able to deliver the dispatched amount. As a result, integrating high levels of renewable resources

129. *See id.*

130. *See id.*

131. *See id.*

132. *See id.*

133. *See id.*

134. *See* Paul L. Joskow, *Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies*, 101 Am. Econ. Rev. 238, 238 (2011).

135. *See* Phil Taylor, *Can Wind Power Be Stored?*, Sci. Am. (Sept. 28, 2009), https://perma.cc/L5WZ-NHPJ.

136. *See* Gwen Bredehoeft & Eric Krall, *Increased Solar and Wind Electricity Generation in California Are Changing Net Load Shapes*, Today in Energy (Dec. 9, 2014), https://perma.cc/4QUF-A3VW.

presents a reliability challenge.[137] In addition, it is also possible that an excess amount of energy is generated due to wind generally blowing hard at night when there is not enough demand.[138] During such times, wind generators, which generally get federal and state subsidies, can bid very low or even negative prices to ensure the electricity they generate is sold, and still make a profit.[139] Or, they may have to curtail or dump the excess generation.[140] Such low or negative prices, or wind energy being curtailed or dumped, distort the market and create efficiency costs.[141]

In this context, energy storage is often presented as a panacea to the many challenges utilities around the country face due to a desire for a higher penetration of renewable energy resources and distributed energy resources.[142] It is generally assumed that the inherent requirement of electricity markets to instantaneously balance demand and supply automatically means that energy storage is a necessity for increased penetration of intermittent and variable renewable energy resources.[143] Wind or solar energy can be stored when there is excess demand and injected into the grid later when the supply is insufficient to meet the demand. Energy storage can also help with minute-to-minute smoothing that would be necessary when a cloud passes by, as well as larger smoothing needs when a large amount of wind energy is generated during off-peak demand hours.[144]

A corollary to the assumption that energy storage is necessary for the integration of renewable resources is that it would also lead to a reduction of greenhouse gas emissions.[145] Energy storage can, of course, help reduce greenhouse gas emissions. For example, when paired with a clean generator, it can store the excess clean energy generated at times of low market demand to inject it into the grid at a later time, reducing the need for generation from the bulk system generators, which are often fossil fuel-powered. This feature is especially important for wind power, which usually peaks at night when the demand for electricity is low.[146]

---

137. *See* GEORGE CRABTREE ET AL., AM. PHYSICAL SOC'Y, INTEGRATING RENEWABLE ELECTRICITY ON THE GRID 3 (2010), https://perma.cc/FVV6-PPRY.

138. *See* Jenny Marusiak, *Being Positive About Negative Texas Wind Prices*, ENERGY CONSUMER'S BULL., (Nov. 10, 2015), https://perma.cc/D23W-PYK8.

139. *See id.*

140. *See* Lin Deng et al., *What is the Cost of Negative Bidding by Wind? A Unit Commitment Analysis of Cost and Emissions*, 30 IEEE TRANSACTIONS ON POWER SYS. 1805 (2015).

141. *See id.*

142. *See id.*

143. *See Frequently Asked Questions*, ENERGY STORAGE ASS'N, https://perma.cc/HFM5-BMWA.

144. *See* SCHMALENSEE & BULOVIC, *supra* note 21, at 61.

145. *See* Stein, *supra* note 101.

146. *See* Taylor, *supra* note 135.

It is not even necessary for energy storage to be paired with a clean energy generator to help reduce greenhouse gas emissions. As explained above, marginal emission rates vary by time and location.[147] Therefore, a stand-alone energy storage system, which is not paired with any generator, can also lower greenhouse gas emissions by charging at times when marginal emissions are low and discharging at times when marginal emissions are high. For example, energy storage can reduce emissions by charging at times when natural gas plants are on the margin and discharging when coal plants are on the margin. Essentially, energy storage can help reduce emissions by moving the generation away from the times when dirty generators are providing the marginal power, and replacing it with generation from less carbon intensive resources.

Energy storage can also reduce emissions by increasing the efficiency with which particular generators operate. For example, coal plants run most efficiently—they burn the least fuel to produce a MW of electricity—when they can run steadily at the peak power level they are designed for.[148] When they have to lower production because electricity demand goes down, they lose efficiency and start burning more fuel to produce a given amount of electricity.[149] If paired with energy storage, coal plants can continue to operate steadily at their most efficient level and store the excess energy.[150] Their efficiency would thereby increase, and hence the amount of fossil fuel needed for the same amount of electricity generation would be lower.[151]

In addition to compensating for variation in the demand, energy storage can also improve efficiency by compensating for the variation in the supply. It can help lower emissions by reducing the need for other generators to rapidly ramp up or down to compensate for the variability in the solar or wind output.[152] Natural gas turbines, which are commonly used for such purposes, use more fuel, and hence cause higher emissions, when they are quickly ramped up and down compared to when they are operated at steady power.[153] Energy storage can help reduce emissions by reducing the variability of renewable resources, and, as a consequence, the need for quick ramping.

---

147. *See* Graff Zivin et al., *supra* note 127, at 249.

148. *See* ALLAN JONES & MICHAEL GARWOOD, COAL INDUS. ADVISORY BD., INT'L ENERGY AGENCY, POWER GENERATION FROM COAL: MEASURING AND REPORTING EFFICIENCY PERFORMANCE AND CO_2 EMISSIONS 19–20 (2010); P. Bennet et al., *Impacts of Intermittent Generation*, *in* LARGE ENERGY STORAGE HANDBOOK 17 (Frank S. Barnes & Jonah G. Levine eds., 2011).

149. *See id.* at 18–21.

150. *See id.*

151. *See* STATE OF CHARGE, *supra* note 36, at 41.

152. *See* Warren Katzenstein & Jay Apt, *Air Emissions Due to Wind and Solar Power*, 43 ENVTL. SCI. & TECH. 253, 253 (2009).

153. *See id.*

C. Integrating Renewable Energy Resources Without Energy Storage

The push towards the increased deployment of energy storage has relied in large part on the implicit assumption that more storage would lead to greater use of renewable energy and lower greenhouse gas emissions. The clear complementarities between higher levels of energy storage deployment and higher levels of renewable energy resource deployment, however, must not be taken as a given. Indeed, if there is enough diversification among the renewable energy resources, energy storage may not be necessary.

A recent study suggests that even though energy storage might be necessary if the decarbonization efforts are dependent on very high shares of wind and solar energy, it is not a requisite if a diverse mix of flexible, low-carbon resources is employed.[154] If, for example, flexible nuclear generation is not an option due to public policy preferences, energy storage is needed to cost-effectively integrate high levels of variable renewable generation.[155] However, if dispatchable nuclear generation is also available as a resource in addition to other low-carbon resources, such as hydroelectric energy and demand response (which is a way of balancing the electricity demand and supply by reducing the electric usage from normal levels as a response to changes in prices or incentive payments[156]), the resulting diversity can be enough to compensate for the variability of the renewable generation.[157]

Similarly, a National Bureau of Economic Research working paper notes that diversification of renewable resources can reduce the need for storage.[158] A diverse portfolio that includes a variety of carbon-free generating resources, such as nuclear, geothermal, or hydro, could smooth out the variability of renewable generation without the need for storage.[159] Alternatively, spatially diversifying the installation of renewable resources so that the generation from different wind turbines, for example, is not highly correlated with one another could also help reduce the need for storage.[160] Other studies show that installing excess generation capacity could be a substitute for installing more energy storage capacity.[161] In some cases, overbuilding wind capacity to meet multiple times the peak demand to reduce the need for shortage, for example, might be

154. *See generally* Fernando J. de Sisternes et al., *The Value of Energy Storage in Decarbonizing the Electricity Sector*, 175 Applied Energy 368 (2016).

155. *See id.*

156. *See Reports on Demand Response and Advance Metering*, FERC, https://perma.cc/SGJ5-NDDK.

157. *See* de Sisternes et al., *supra* note 154, at 378.

158. *See* Geoffrey Heal, *Notes on the Economics of Energy Storage* 10 (Nat'l Bureau of Econ. Research, Working Paper No. 22752, 2016).

159. *See id.*

160. *See id.*

161. *See* Chang, Does Size Matter?, *supra* note 34, at 22; Paul Denholm & Robert Margolis, Nat'l Renewable Energy Lab., Energy Storage Requirements for

cheaper than providing storage capacity.[162] In this case, even though all that wind capacity would be used only a fraction of the time, the overall system costs would be lower.

These possibilities mean that all alternatives must be carefully analyzed before rolling out policies to provide incentives for increased deployment of energy storage. While energy storage can no doubt lead to a more effective use of already installed renewable capacity, there are conditions under which over-building renewable capacity, even if it leads to lower capacity utilization, is a more cost-effective solution to the intermittency problem than building a large enough energy storage system.[163]

D. Potential Negative Effects of Energy Storage on Greenhouse Gas Emissions

The prior Section argued that under some conditions, additional energy storage might not lead to the deployment of additional renewable energy, and thereby not decrease the emission of greenhouse gases. In this Section, we examine conditions under which additional storage would have pernicious effects, leading to increased emissions.

1. Effects on Existing Fossil Fuel-Fired Plants

The inherent incentive for energy arbitrage is that energy storage systems are charged when electricity prices are low and discharged when they are high. As the external costs of greenhouse gas emissions are not currently reflected in wholesale electricity prices, such arbitrage decisions will be made without considering the resulting changes in emissions. As a result, energy storage can increase emissions if the cheaper energy resources that are used in charging are dirtier than the more expensive energy resources that are displaced during discharging.

The academic literature confirms that this pattern could occur. One article, using data from Texas, demonstrates that energy arbitrage increases CO_2 and SO_2 emissions, while reducing NO_x emissions at the current low levels of renewable penetration.[164] It shows that the marginal emission rates for CO_2 and SO_2 are higher during off-peak hours when coal plants, which have the highest CO_2 and SO_2 emission intensity, are on the margin.[165] In contrast, the marginal emission rate for NO_x is higher during peak hours when high heat-rate gas

---

ACHIEVING 50% SOLAR PHOTOVOLTAIC ENERGY PENETRATION IN CALIFORNIA 30 (2016).

162. *See* Heal, *supra* note 158, at 11.

163. *See id.*

164. *See* Richard T. Carson & Kevin Novan, *The Private and Social Economics of Bulk Electricity Storage*, 66 J. ENVTL. ECON. & MGMT. 404 (2013).

165. *See id.* at 414.

units, which have the highest NO_x emission intensity, are on the margin.[166] Thus, when energy storage uses off-peak electricity to charge and displaces peak electricity, it increases CO_2 and SO_2 emissions but reduces NO_x emissions. A newer study also finds that in the short-term, energy storage can increase emissions due to energy arbitrage shifting generation from natural gas plants to coal plants.[167]

Perverse incentives may be more pronounced if the cost functions of dirtier generators have a particular shape. For example, as indicated above, the fixed costs of turning on certain generators, such as coal, are high, but the variable operational costs once the generator is turned on are low.[168] This pattern creates incentives for such a generator to continue operating once it is already on, as long as it can get sufficient revenue from the electricity it generates to cover its variable costs. Without energy storage, the amount of generation from such a generator would be limited by market demand. However, when paired with energy storage, it can continue generating and storing electricity to sell later. For example, at times of low demand, such as during the night, coal plants that normally operate below capacity will have incentives to generate more electricity than needed and store it. This means energy storage might lead to increased generation, and hence increased emissions, from coal plants. Thus, when looking at the environmental benefits of energy storage, it is critical to consider not only the decrease in emissions from the peak generator that energy storage helps avoid, but also the increase in emissions from the cheaper generator that energy storage uses to charge.

Additionally, it is costly for coal plants to vary their generation levels with changing demand.[169] Because they lose efficiency when varying generation levels, their fuel costs increase.[170] Energy storage will allow such plants to continue operating at a fixed output level. The effect of this on emissions is ambiguous. On the one hand, energy storage might increase the efficiency of electricity generation in that plant, and hence would reduce emissions from any given amount of generation. On the other hand, energy storage might help increase the total amount of generation from that particular plant, leading to an increase in emissions.

---

166. *See id.*

167. *See* JOSHUA LINN & JHIH-SHYANG SHIH, RESOURCES FOR THE FUTURE NO. RFF DP 16-37, DOES ELECTRICITY STORAGE INNOVATION REDUCE GREENHOUSE GAS EMISSIONS? 24 (2016).

168. *See* KEITH E. HOLBERT, ARIZ. STATE UNIV., ELECTRIC ENERGY ECONOMICS 1 (2011), https://perma.cc/GPS3-69H8.

169. *See* Paul Denholm & Tracey Holloway, *Improved Accounting of Emissions from Utility Energy Storage System Operation*, 30 ENVTL. SCI. & TECH. 9016, 9018 (2005) ("As it ramps up and down, the plant will operate at different efficiencies. In addition, startup and shutdown result in lost heat energy.").

170. *See id.*

Perverse effects from energy storage can also result from the way in which electricity markets function. The electricity grid is an interconnected, and capacity-constrained, network that allows electricity to be traded over long distances. The use of energy storage can reduce network congestion at certain locations, freeing up network capacity to allow flow of more energy. This newly freed up capacity may facilitate an increase in the use of dirtier sources, whose usage was previously limited by the finite capacity of transmission lines.

Energy storage can also change emissions over a longer period by affecting the profitability of fossil fuel plants. Many coal plants engage in long-term coal purchase agreements that usually have minimum purchase requirements.[171] If the purchaser does not buy a certain amount of coal, it has to pay a fine.[172] At times, coal plant owners that lack the ability to store large amounts of coal for extended periods of time may decide to burn the coal and dump the electricity into the grid at below marginal cost, to ensure that they would be dispatched, even at a loss, instead of paying a large fine for not complying with the purchase agreements.[173] Energy storage would allow such plants to buy and burn the amount of coal that they are obligated to buy without any financial consequences. This would improve the profitability of coal plants, and allow them to remain in the market longer, thereby increasing emissions.

While most of the discussion above has focused on potential emission effects of larger scale storage systems, the effects of smaller scale systems that can be installed behind-the-meter of residential customers are also ambiguous. Even though there are many such systems installed in combination with non-emitting distributed energy resources such as rooftop solar panels, energy storage can also be paired with emitting resources such as combined heat and power systems or diesel generators. Falling costs of small-scale energy storage systems may induce residential customers to start relying on their distributed energy resources more instead of relying on grid electricity. Thus, understanding the emission effects of such energy storage systems also requires a comparison of the emissions of the distributed energy resources to the emissions of the displaced generator.

2. *Effects on Efficiency Losses*

Even if there is no difference between the carbon intensity of the marginal generators during the charging and discharging periods, energy storage can still

171. *See* Steve Vied, *Burning Less Coal*, ENERGY CENT. (June 27, 2016), https://perma.cc/9KLY-TVL2.

172. *See id.*

173. *See U.S. Coal Stockpiles at Power Plants Above Average in 2012 - EIA*, REUTERS (Jan. 25, 2013), https://perma.cc/P5W8-METJ ("The high stockpiles forced some generators to burn coal instead of gas even when it was not economic to do so to avoid having to pay railroads to stop delivering the coal, energy analysts have said.").

increase emissions because of efficiency losses. Energy losses occur during charging and discharging energy storage systems, as well as during transmission and distribution.[174] As a result, the total generation needed to provide the same amount of electricity with energy storage is higher, leading to higher overall emissions. The extent of these losses is measured by "roundtrip efficiency," which is the ratio of the percentage of the energy put in to the percentage of the energy retrieved from storage. Roundtrip efficiency varies across technologies. For example, compressed air energy storage, with a roundtrip efficiency of 27–54%, has high efficiency losses, while sodium-sulfur batteries, with a roundtrip efficiency of 85–90%, are much more efficient.[175]

In addition, if these efficiency losses are sufficiently high, energy storage can lead to increased emissions even when it uses less carbon-intensive generation to displace more carbon-intensive generation. Efficiency losses cause energy storage systems to require more energy input than the amount of energy they discharge. For example, if the roundtrip efficiency of a storage system is 50%, charging it would require double the amount of energy needed during discharging. So, unless the marginal emission rate during discharging is at least twice as high as the marginal emission rate during charging, the emissions will increase.

Finally, large-scale energy storage paired with generators will change the generation mix in the market. As a result, the total distance electricity has to travel in the aggregate through transmission and distribution lines, and, therefore, the amount of losses, will change. The efficiency or emissions impacts of this effect, however, are not clear. If energy storage leads to more generation closer to customers, such as local solar farms, the electricity would travel shorter distances, reducing losses. But, if energy storage leads to generation that is further from customers, such as offshore wind, and has to be transmitted long distances, energy losses might increase. The resulting change in emissions depends on how exactly the generation mix changes, and which types of plants make up for any energy losses by increasing their generation.

3. Effects on Incentives for Future Fossil Fuel-Fired Plants

While the potential that energy storage creates for the increased integration of renewable resources is highlighted in the policy literature, generally missing from the discussion is its potential effect on other types of generation. Energy storage indeed changes investment incentives for all types of resources. For example, the potential to generate at a higher capacity factor might provide incentives for more natural gas plants. Right now, peak plants are being dis-

174. *See* Jordan Wirfs-Brock, *Lost In Transmission: How Much Electricity Disappears Between A Power Plant And Your Plug?*, INSIDE ENERGY (Nov. 6, 2015), https://perma.cc/9BKV-7477.

175. SCHMALENSEE & BULOVIC, *supra* note 21, at 293.

patched only during a limited number of hours, which means that many peak plants operate with low capacity factors.[176] Further, having to constantly ramp up and down their generation levels means that these plants do not always operate at their most efficient level.[177] Energy storage would increase both the production efficiency and capacity utilization of these plants, making them a more attractive investment option. Investments in such hybrid systems, which combine natural gas plants and energy storage systems, are already underway.[178] Additionally, investors might decide to build even bigger plants with the intention of producing and storing excess electricity.

The potential for such impact of energy storage on the incentives for future capacity investments has not been analyzed comprehensively, but the evidence suggests that under certain circumstances, storage could lead to the addition of fossil fuel capacity. One study concludes that depending on the responsiveness of renewable generation to the changes in electricity prices, overall emissions may decrease or increase.[179] Energy storage enables energy arbitrage by storing low-price electricity during off-peak periods to discharge high-price electricity during peak periods, which reduces the price difference between peak and off-peak periods.[180] This effect changes the investment incentives for each resource differently. For example, wind generators usually produce electricity during off-peak times, so an increase in off-peak electricity prices would lead to more wind investment.[181] However, a reduction in peak prices usually decreases incentives for solar investment.[182] How exactly the mix of new capacity investments changes as a result of such changes in electricity prices depends on how price sensitive each resource is. Wind generation, if highly price responsive, would go up significantly when faced with higher off-peak prices, and displace fossil fuel plants.[183] Solar generation, however, would go down significantly when faced with lower peak prices if it is highly price responsive, and would be replaced by fossil fuel generators. As a result, the overall emission impact of energy storage is highly dependent on the supply characteristics of different resources in each market.

---

176. *See* Cameron J. Thouati de Tazoult, *Capacity Factor*, ENERGYMAG.NET, https://perma.cc/EPN6-JH4L.

177. *See id.*; CHRISTIAN HULTHOLM & JAIME LOPEZ, WARTSILA ENERGY SOLS., MAXIMISING PROFITS THROUGH EFFICIENT PULSE LOAD OPERATION 4 (2015).

178. *See* Peter Maloney, *Gas Plant Makers Embrace Batteries with Hybrid Machines*, UTIL. DIVE (Jul. 25, 2017), https://perma.cc/W85U-2UQN.

179. *See* LINN & SHIH, *supra* note 167, at 4.

180. *See id.*

181. *See id.*

182. *See id.* at 4.

183. *See id.* at 25.

4. Interactions with Existing Policy, Regulatory, and Market Structures

Market structure also plays an important role in determining the overall effects of energy storage. How competitive the wholesale electricity is and how much market power generators have affect the bids submitted by the generators, and hence the dispatch order and the marginal emissions. If a generator has market power, it can submit a bid over its marginal cost and withhold capacity to increase market prices, and, hence its profits. For example, consider a setting where coal-fired generators have market power and can withhold capacity from the market to keep market prices high. In this case, energy arbitrage is more likely to be between more efficient combined cycle natural gas plants, which would be on the margin during off-peak time periods when there is not enough coal capacity, and less efficient simple cycle natural gas plants, which would be on the margin during peak time periods.[184] Because now, the arbitrage is among natural gas plants, instead of being between coal-fired and natural gas plants, the potential emission benefits of standalone energy storage, as well as of energy storage paired with renewable resources, are lower compared to the benefits that could accrue in a competitive wholesale market.[185]

Interactions with other policies and regulations can also create perverse incentives. Ironically, existing clean air regulations may exacerbate the perverse incentives to use coal-fired plants to charge energy storage instead of building new generators. The Clean Air Act, for example, may lead to coupling of energy storage with existing coal-fired plants without having to meet many of the more stringent standards required for new generators, leading to higher emissions.[186] Under the Clean Air Act, new construction, major upgrades, or changes in the method of operation would trigger a new source review, and more stringent standards.[187] However, an increase in the hours of operation is not considered a change that would trigger a new source review.[188] This regulatory regime might create incentives to store and use electricity generation from existing coal plants, which would cause an increase in the plant's hours of operation but not trigger a new source review, instead of meeting the peak demand

184. *See* Ramteen Sioshansi, *Emissions Impacts of Wind and Energy Storage in a Market Environment*, 45 ENVTL. SCI. & TECH. 10,728, 10,731 (2011).

185. *See id.*

186. *See* Denholm & Holloway, *supra* note 169, at 9021. Adding utility-scale storage systems onto existing average coal-fired power plants, in an effort to capture excess energy produced, increases SO_2 and NO_x emissions more than building a new load-following plant that meets the Clean Air Act standards.

187. *See* 42 U.S.C. § 7411(a)(2), (a)(4), (f) (2012).

188. *See* Prevention of Significant Deterioration of Air Quality Rule, 40 C.F.R. § 51.166(b)(2)(iii)(f). Major exemptions to the change rule include: (1) routine maintenance, repair, and replacement; (2) an increase in production rate, if unaccompanied by capital expenditure; (3) an increase in the hours of operation; (4) use of alternate fuels; and (5) installation of new pollution control equipment. *Id.*

by building a new plant, which would be subject to more stringent standards.[189] Under this scenario, emissions would increase as a result of the availability of storage.[190]

All of these scenarios underscore the importance of seriously examining the effects of increased energy storage. While energy storage definitely has a great deal of potential to help us move closer to a clean energy future in a cost-effective manner, it is crucial to ensure that policy initiatives are based on sound economic analysis, taking all possible effects of energy storage into account. Otherwise, the outcome may indeed be the exact opposite of the policy goals.

III. Inadequacy of the Current Regulatory and Policy Landscape

Regulatory and policy structures play an important role in creating incentives for energy storage. While both federal and state policies have helped increase the deployment of energy storage, most current policies indiscriminately seek to promote more energy storage without any regard for the potential of energy storage to cause an increase in greenhouse gas emissions.

As described in Part II, there are conditions under which energy storage can have a detrimental effect on greenhouse gas emissions. The existence of such scenarios underscores the need for a policy framework than can distinguish between socially beneficial and harmful energy storage systems, and encourage only those deployments that would be socially beneficial.

Some policies encourage energy storage systems only if they are paired with renewable energy resources. While these policies help prevent some of the undesirable consequences of indiscriminate incentives, they still fall short of providing efficient incentives for socially desirable outcomes. In particular, they lack the ability to reward the full range of benefits that energy storage systems can bring, as described in Part I.

Furthermore, some regulations prevent energy storage systems from providing, and, hence, receiving compensation for all the services they are able to supply. This resulting inadequacy in compensation hinders the investment incentives for energy storage systems. Therefore, the current regulatory and policy structure is not only insufficient to differentiate between beneficial and harmful energy storage, but is also insufficient to induce an efficient level of deployment of any type of energy storage.

In this Part, we describe the current regulatory and policy settings and highlight how they fail to provide the appropriate incentives for energy storage. First, we discuss how most of the federal and state direct investment incentives just encourage more energy storage deployment without considering their impact on the environment, and how they fail to value all the different benefits

189. *See* Denholm & Holloway, *supra* note 169, at 9021.

190. *See id.*

energy storage systems can bring to the grid. Then, we describe how federal and state policies that indirectly encourage more energy storage through price signals similarly fail to provide the appropriate incentives.

A. Inadequacy of Direct Investment Incentives

Any potential increase in greenhouse gas emissions due to energy storage systems can be prevented if policymakers recognize this possibility, and put in place policies that can differentiate between systems that are socially beneficial and ones that are potentially harmful. However, current policies lack the ability to do so. Most current policies are aimed at simply increasing the level of energy storage deployment. Furthermore, even more targeted policies fall short of achieving socially efficient outcomes because they fail to recognize all the potential benefits of energy storage.

1. Distinguishing Between Beneficial and Harmful Energy Storage

Federal and state policymakers have channeled several billion dollars towards energy storage research, development, and pilot projects, and established procurement mandates for energy storage, providing direct investment incentives for energy storage. These policies are intended to encourage the deployment of energy storage systems indiscriminately, without regard to whether their use might be harmful.

At the federal level, under a provision of the Energy Independence and Security Act of 2007, Congress allocated about $2.95 billion towards research, development, and pilot projects for storage systems related to "electric drive vehicles, stationary applications, and electricity transmission and distribution."[191] The American Recovery and Reinvestment Act of 2009 made $185 million available in matching funds for pilot projects and established a 30% investment tax credit for eligible domestic manufacturers.[192] While the future of project support through the Department of Energy under President Trump is

191. 42 U.S.C. § 17231(p) (2012). The program is intended to promote "energy storage systems for electric drive vehicles, stationary applications, and electricity transmission and distribution." *See id.* § 17231(c).

192. American Recovery and Reinvestment Act of 2009, Pub. L. No. 115-5, 123 Stat. 115, 138–139 (2009); U.S. DEP'T OF ENERGY, A GLIMPSE OF THE FUTURE GRID THROUGH RECOVERY ACT FUNDING (2015), https://perma.cc/EE6V-B3YK. For a list of ARRA (American Recovery and Re-investment Act) storage projects, see DOE PLANNING DOCUMENT, *supra* note 74, at 23–27. *See also* 26 U.S.C. §§ 48, 48C (2012). The tax credit applied to manufacturers of several advanced energy systems. *Id.* Approximately $30.4 million has been allocated to storage manufactures and $600,000 to electric vehicle battery storage. *See* TOM STANTON, NAT'L REGULATORY RESEARCH INST., REPORT NO. 14-08, ENVISIONING STATE REGULATORY ROLES 24 (2014).

unclear,[193] the list of priority infrastructure projects of the new administration includes an energy storage project to help expedite local energy storage procurement in California.[194]

States have also played a significant role in advancing energy storage through policy measures. Many state-level initiatives, such as research and development grants or tax credits, essentially mirror federal actions. Other measures, like procurement mandates, exist only at the state level. At least six states sponsor research and development projects; ten states have offered tax credits; and six have indicated that in-state utilities must include storage in long-term resource planning.[195] California and Puerto Rico have issued storage-specific procurement mandates, while another seven states include storage within their renewable portfolio standards.[196] Most recently, New York passed a bill to adopt an energy storage mandate.[197] Moreover, some renewable portfolio standards count storage towards the overall procurement mandates, but do not actually require the adoption of storage resources.[198] Unsurprisingly, over half of all storage capacity is found in states with at least one policy favoring storage.[199]

Among procurement mandates, California's 2013 policy is the most aggressive, requiring the state's largest utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric—to collectively procure 1325 MW of energy storage by 2020.[200] As a result, in February 2017, San Diego Gas & Electric deployed what was at the time the world's largest lithium-ion battery, which can store up to 120 MWh of electricity.[201] In June 2015, Oregon adopted a mandate requiring that every state utility procure at least 5 MWh of storage by 2020.[202] Most recently, New York directed its investor-owned utilities to install at least two energy storage systems by 2018.[203] The order requires utilities to deploy energy storage systems that can provide at least two different services to the grid.[204]

---

193. *See* Bade, *supra* note 11.
194. *See* Bade, *supra* note 10.
195. *See* STANTON, *supra* note 192, at 27–28.
196. *See id.* at ii.
197. *See* Peter Maloney, *New York Energy Storage Target Official after Gov. Cuomo Signs Bill*, UTIL. DIVE (Dec. 1, 2017), https://perma.cc/TPE7-THPF.
198. *See* STANTON, *supra* note 192.
199. *See id.* at 29.
200. Press Release, Cal. Pub. Utils. Comm'n., CPUC Sets Energy Storage Goals for Utilities (Oct. 17, 2013) (on file with author).
201. City News Service, *SDG&E to Unveil World's Largest Lithium Ion Battery Energy Storage Facility*, FOX5 SAN DIEGO (Feb. 24, 2017, 6:18 AM), https://perma.cc/52AX-9S46.
202. H.B. 2193, 78th Or. Leg. Assemb. (Or. 2015).
203. Robert Walton, *New York PSC Directs Utilities to Deploy 2 or More Grid-Scale Storage Projects*, UTIL. DIVE (Mar. 10, 2017), https://perma.cc/QX8M-NYNS.
204. Order on Distributed System Implementation Plan Filings, Case No. 14-M-0101 and Case No. 16-M-0411, PUB. SERV. (N.Y. Mar. 9, 2017).

Electric vehicles have also been receiving attention in energy storage policies. PJM, which is an RTO that serves over 61 million individuals across 13 states, includes electric vehicles among energy storage resources like electrochemical batteries and flywheels.[205] Electric vehicles, which can provide frequency regulation services with their installed batteries while connected to the grid, are compensated according to how quickly and accurately they can supply frequency regulation in the PJM ancillary service market.[206] This PJM scheme provides an estimated value of $1800 per electric vehicle per year.[207]

All of these policies aim to encourage more energy storage deployment, whether by funding energy storage research and development, creating procurement targets, or directly compensating for a service provided. However, they do not provide any safeguards against the deployment of potentially harmful energy storage systems. Furthermore, even when there is direct evidence of actual negative emissions impacts of energy storage systems as in the case of electric vehicles, which lead to an increase in emissions when they are charged at night when marginal emissions are high,[208] these policies are not revised or corrected.

2. *Quest for Efficiency*

Some direct investment policies are more targeted, seeking to create incentives for energy storage systems only if they are paired with renewable generators. While such targeted policies can reduce any potential negative emissions consequences of energy storage systems, they do not go far enough to provide efficient incentives for all other types of beneficial energy storage systems.

For example, Puerto Rico's storage mandate, adopted in 2013, requires that all future renewable generators include some minimum quantity of storage capacity.[209] The standard requires each new renewable generator to have enough storage capacity to provide 45% of the plant's maximum generation capacity over the course of one minute—a measure intended to help smooth changes in the intermittent output due to changes in sunlight or wind.[210] In addition, the Puerto Rico mandate further requires that all new renewable generators have

205. PJM Interconnection, Ancillary Services Fact Sheet (2017), https://perma.cc/QN2A-HPP3 [hereinafter Ancillary Fact Sheet]. PJM Interconnection, or "Pennsylvania-New Jersey-Maryland" Interconnection, coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. *See Who We Are*, PJM, https://perma.cc/8GQZ-42YE.

206. Ancillary Fact Sheet, *supra* note 205.

207. Penelope Crossley, *Defining the Greatest Legal and Policy Obstacle to 'Energy Storage'*, 2013 Renewable Energy L. & Pol'y Rev. 268, 271–72 (2014).

208. *See* Graff Zivin et al., *supra* note 127, at 249.

209. *See* Jeff St. John, *Puerto Rico Mandates Energy Storage in Green Power Mix*, Greentech Media (Dec. 27, 2013), https://perma.cc/Z8A7-JAT7.

210. *See id.*

enough storage capacity to meet 30% of its generation capacity for approximately 10 minutes to be able to provide other services necessary to balance the varying output such as frequency regulation.[211]

Even though such a targeted policy can help limit emissions from the electricity generated to charge energy storage systems, it is not sufficient to achieve efficient incentives for all types of energy storage systems. Because such policies encourage only the deployment of paired energy storage and renewable generator systems, they tip the balance towards investment in such systems. As a result, there is a decrease in the relative amount of investment for other types of energy storage systems, such as flywheels or pumped hydroelectric storage, which can provide other benefits while also reducing greenhouse gas emissions, even when they are not paired with a renewable generator. So, these more targeted policies, even if inadvertently, effectively discriminate against beneficial energy storage systems that are not paired with renewable generators.

B. Inadequacy of Indirect Price Incentives

Achieving economic efficiency requires accurate prices that signal the true value of energy storage systems and therefore can guide efficient investment. To ensure proper investment signals, energy storage systems must be able to participate in all the markets in which they can provide services, and they must receive compensation for all these services. However, current regulations, which were designed with more traditional resources in mind, create a barrier to establishing such a framework.

At the federal level, FERC did not address energy storage directly until 2007. Under Orders 890 and 719, issued in 2007 and 2008 respectively, FERC amended regulations regarding ancillary services, such as frequency regulation, to require that ISOs and RTOs permit non-generation resources, like storage systems, to provide and get compensated for these services.[212] And, even though the FERC orders generally favored storage by expanding opportunities for market participation and ensuring fair and adequate compensation for storage projects, they have fallen short of eliminating all the entry barriers and providing sufficient incentives for efficient deployment of energy storage.

---

211. *See id.*

212. RTOs and ISOs serve two-thirds of electricity customers in the United States. *See The Role of ISOs and RTOs*, IRC RTO/ISO COUNCIL, https://perma.cc/8LMD-2M84. The seven RTOs are: CAISO, ERCOT, SPP, MISO, PJM, NYISO, and ISO-NE. *See Regional Transmission Organizations ("RTO")/Independent System Operators ("ISO")*, FERC, https://perma.cc/PNB9-VFEY; *see also The Role of ISOs and RTOs*, IRC RTO/ISO COUNCIL, https://perma.cc/SFX4-DBNY; Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 118 FERC ¶ 61,119 (Feb. 16, 2007) [hereinafter FERC Order No. 890]; Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, 125 FERC ¶ 61,071 (Oct. 17, 2008) [hereinafter FERC Order No. 719].

Under a 2011 ruling known as Order 755, FERC required that all ISO/RTO jurisdictions adopt "pay for performance" market rules that tie compensation for frequency regulation to the performance and accuracy of the system offering the regulation.[213] In its order, FERC observed that then-existing "compensation methods . . . fail[ed] to acknowledge the inherently greater amount of frequency regulation service provided by" fast-ramping resources, like storage technologies, as compared to traditional frequency regulation providers like fossil fuel-fired plants and gas-fired turbines.[214] A study cited in Order 755, for example, demonstrated that flywheel and battery storage systems could be seventeen times more effective than conventional regulation resources because of how quickly and accurately the storage technologies could respond to system imbalances.[215] As noted earlier, fast-ramping storage systems have faster response times, offer more precise regulation, and accommodate a greater range of fluctuations in grid load.[216] Prior to Order 755, resources that conferred inherently different levels of frequency control were compensated at identical rates based exclusively on the capacity devoted to frequency control.[217]

Order 755 sought to address market pricing in ISO and RTO jurisdictions by imposing a two-part rate structure for frequency service: one payment for the absolute amount of frequency control a resource provided, and a second "performance" payment that reflected how accurately a system responded to frequency imbalance.[218] FERC, however, stopped short of prescribing a particular metric for valuing the "accuracy" of a system, leaving ISOs and RTOs latitude to establish the payment.[219] Significantly, Order 755 expressly stated that it was likely that flywheels and batteries were undervalued by existing compensation schemes because these schemes did not take account of the fast-ramping properties of these technologies.[220] A report by PJM determined that the "price for frequency regulation resources nearly tripled after Order 755 authorized increased pay for fast responding frequency control."[221]

---

213. Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (Oct. 20, 2011) [hereinafter Order No. 755].

214. *Id.*

215. *See id.* at ¶ 35.

216. *See* Meyer, *supra* note 63, at 513–14.

217. *See* Stein, *supra* note 101, at 742.

218. Order No. 755, *supra* note 213, at ¶ 131.

219. *Id.* Moreover, because energy storage systems can provide frequency control either by supplying electricity or by absorbing excess electricity, these systems offer unique control flexibility: a 10 MW battery actually holds 20 MW of frequency control capacity. However, many ISO/RTOs lack a mechanism for compensating this performance because market rules were designed for traditional generators that may only control frequency by supplying electricity. *See* Meyer, *supra* note 63, at 515.

220. *See* Order 755, *supra* note 213, at ¶ 22.

221. *See* John Jung, *Energy Storage: The Utility's Best Friend*, PUB. UTIL. FORT. 40 (Mar. 2015).

Order 755, however, applied only to electricity markets managed by regional ISOs and RTOs. In all other markets—which account for approximately one-third of U.S. electricity consumption[222]—the utilities that bought power from generation resources and delivered it to consumers procured ancillary services by contracting directly with the supplying generators or with third-party providers.[223] In theory at least, storage systems could contract with utilities as third-party providers to provide ancillary services. In practice however, that option was foreclosed by a 1999 FERC ruling known as the *Avista* Order.[224] Under this order, third parties looking to provide ancillary service were required to demonstrate a lack of market power for the particular ancillary service in the particular geographic market before contracting with utilities.[225] Noting that "certain information needed to perform such a market power study [was] not currently available," FERC eventually concluded that "the effect of the *Avista* policy is to categorically prohibit sales of [third-party] ancillary services to public utility transmission providers outside of the RTO and ISO markets."[226]

FERC responded to the *Avista* policy in a 2013 ruling known as Order 784.[227] The order lifted the obligation on third-party ancillary service providers to demonstrate a lack of market power, which *Avista* had required, and mandated that transmission utilities consider the "speed and accuracy" of frequency control resources when contracting—two criteria that favored storage systems.[228]

Even though Orders 755 and 784 eliminated some of the barriers for energy storage, they created an advantage for only certain types of energy storage systems. The certainty of a cash flow from one type of service, such as frequency regulation, incentivizes the deployment of only the types of energy storage

222. *See The Role of ISOs and RTOs*, *supra* note 212.

223. *See* Meyer, *supra* note 63, at 517.

224. *See* Avista Corp., 87 FERC ¶ 61,223 (1999), *order on reh'g*, 89 FERC ¶ 61,136 (1999).

225. *See* Meyer, *supra* note 63, at 518. The purpose of the study was to mitigate concerns that a third-party ancillary service provider might charge unjust or unreasonable rates—where if a third-party provider lacked market power, unreasonable rates would inevitably lead transmission utilities to return to purchasing ancillary service directly from the public utility. *See id.* at 518, n.189.

226. Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies, 139 FERC ¶ 61,245 at para. 11 (proposed June 22, 2012) (to be codified at 18 C.F.R. pts. 35, 101, 141).

227. *See* Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies, 144 FERC ¶ 61,056, para. 1–5 (2013). Order 784 also supplied FERC's now-standard definition of energy storage assets as "property that is interconnected to the electrical grid and is designed to receive electrical energy, to store such electrical energy as another energy form, and to convert such energy back to electricity and deliver such electricity for sale, or to use such energy to provide reliability or economic benefits to the grid." *Id.* at para. 172.

228. Marcia A. Stanford, *Energy Insight: FERC Order 784—Accommodating the Battery; Supporting Electricity Storage*, LEXOLOGY (Aug. 29, 2013), https://perma.cc/Y8KF-UGB8.

technologies that can easily provide that service even if it comes at the expense of other, potentially more beneficial, types of energy storage systems. For example, these orders encourage more investment in low-capacity flywheels or lithium-ion batteries that can provide frequency regulation very effectively even though a particular jurisdiction might benefit more from a large capacity system such as a pumped hydro system that could help avoid costly capacity investments.[229]

Even as these orders lifted the barriers for energy storage systems to be compensated for one of the services they provide, the barriers for other services such as capacity remain. For example, the Midcontinent Independent System Operator ("MISO") explicitly limited the services that "storage energy resources" can provide to regulation services because they were designing the rules with only flywheels in mind.[230] Flywheels can provide regulation services very effectively but are limited in size and discharge duration. Therefore, MISO's definition of the services that storage energy resources provided did not include energy ramping, or capacity.[231]

In addition, the way certain regulations are currently designed creates a disadvantage for energy storage systems. For example, PJM and ISO New England ("ISO-NE") penalize resources that are not available during the entire period of an emergency action or a shortage event, which often does not have a pre-determined time limit when initially announced.[232] The 2014 Polar Vortex, for example, led PJM to call for an almost thirteen hour-long emergency event.[233] However, an energy storage system, because it has to recharge at some point, can provide services only for a limited duration, possibly for a shorter time than the whole duration of the emergency event. For example, as we discussed in detail in Part I.C, flywheels and lithium-ion batteries both have discharge durations of less than two hours. Therefore, an energy storage system would have to pay a significant penalty for not performing during the entire shortage period if it wanted to provide capacity services even when it could reliably provide capacity for a certain, but shorter period of time than the entire emergency event.[234] When energy capacity needs were being met with generators that could run indefinitely such as coal, nuclear, and natural gas, specifying a maximum time frame for such performance expectations was not necessary,

229. *See* Jung, *supra* note 221.

230. Peter Maloney, *How IPL Wants FERC to Transform MISO Energy Storage Tariffs*, UTIL. DIVE (Nov. 8, 2016), https://perma.cc/5NRZ-87KG.

231. *See id.*

232. *See* Tesla Motors, Inc., Electric Storage Participation in Regions with Organized Wholesale Electric Markets, Docket No. AD16-20-000 (Jun. 6, 2016) [hereinafter Tesla Comments]; *see also* Fickling, *supra* note 3; Hamilton, *supra* note 3; Ivanova, *supra* note 3.

233. PJM Performance Assessment Hours for 2011–2014 (Mar. 25, 2015), https://perma.cc/JZ9E-H29T.

234. *See* Tesla Comments, *supra* note 232, at 3–4.

and the lack of such a limitation did not hinder the market efficiency.[235] However, the lack of such a limitation currently creates a disincentive for energy storage systems, tipping the balance in favor of more traditional assets.

Some rules can even create a disadvantage for certain types of energy storage systems over others. For example, MISO protocols for frequency regulation, which were designed with flywheel storage systems in mind, prevent lithium-ion batteries from being used efficiently.[236] If lithium-ion batteries are forced by MISO to provide one hour of injections and one hour of withdrawals, just like flywheel systems, the cell life of the systems will be reduced to three years instead of the ten years if cycled properly.[237] In February 2017, responding to a complaint, FERC ordered MISO to revise its tariff to allow all types of energy storage systems to participate in all MISO markets that "they are technically capable of participating in, taking into account their unique physical and operational characteristics."[238]

In another attempt to remove a different disincentive for energy storage, in November 2016, FERC issued a proposed rule with the goal of removing barriers currently hindering electric storage resources and distributed energy resource aggregations from participating in the organized wholesale electric markets.[239] These aggregations are numerous small-scale resources combined and controlled by third party software that can provide large-scale grid services.[240] The 2016 proposed rule would require ISOs and RTOs to revise their tariffs to accommodate the participation of these resources.

In the 2016 proposed rule, FERC recognized the variety of benefits that expanded energy storage participation could bring to the wholesale markets.[241] The proposed rule, however, made clear that FERC struggles to identify rules that would allow energy storage systems to be compensated fully for all the services they can provide. For example, FERC requested input on how to accommodate the ability of energy storage systems to provide ancillary services if they are not already online and providing energy services.[242] Unlike traditional generators, which have to be already generating electricity to be able to provide spinning resources, energy storage resources have the ability to ramp up and down immediately even if they were not already online, and therefore, they can

235. *See id.* at 4.

236. *See* Maloney, *supra* note 230.

237. *See id.*

238. Indianapolis Power & Light Co., 158 FERC ¶ 61,107, para. 2 (2017).

239. *See* Electric Storage Participants in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121 (proposed Nov. 17, 2016) (to be codified at 18 C.F.R. pt. 35). This policy will be discussed in more detail in Part IV.

240. *See id.*

241. *See id.* at 15–17.

242. *See id.* at 46.

provide ancillary services regardless of their dispatch status.[243] However, because the current rules are designed for traditional resources, they prevent energy storage systems from earning revenue on these services even though they are technically capable of providing them.[244] Unless all such regulations that are designed for traditional services can be updated to allow the participation of any resource that has the technical ability to reliably provide a service, federal regulations will fall short of providing efficient incentives for energy storage deployment.

At the state level, there are also policies that incentivize energy storage deployment through price signals. For example, Hawaii's 2015 decision to replace retail rate net metering for rooftop solar systems with new tariffs is a policy that encourages customers with solar panels to adopt more energy storage.[245] Under the new tariffs, customers can choose either the "self-supply" option and not export to the grid, or the "grid-supply" option and get paid at a rate much lower than the retail rates that the customers pay for grid electricity.[246] While these tariff options reduced the incentives for installing solar panels by themselves, they created incentives for customers with solar panels to install energy storage systems as well, to better manage their electricity usage by storing the excess generation during the day for later use, and, hence, to reduce the need for expensive grid electricity at night.[247]

However, just like price incentives at the federal level, state level price incentives are not sufficient to ensure efficiency in energy storage deployments. The compensation that customers get in these cases depends on the retail electricity rates. Because retail electricity rates are regulated, and are generally based on the average cost of providing electricity in a particular service territory, they are not precise enough to achieve economic efficiency.

First, generation, transmission, and distribution costs are usually bundled and averaged into a single price.[248] Therefore, policies based on these single bundled electricity prices cannot provide differential signals for the value that

---

243. *See* Audun Botterud, Apurba Sakti, and Francis O'Sullivan, Comment Letter on Proposed Rule on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators 4 (Feb. 13, 2017) [hereinafter MIT Comments].

244. *See* 157 FERC ¶ 61,121, *supra* note 1, at 46.

245. *See* Herman K. Trabish, *What Comes after Net Metering: Hawaii's Latest Postcard from the Future*, UTIL. DIVE (Oct. 22, 2015), https://perma.cc/93PR-FUQR.

246. *See* Proposed Decision and Order, Instituting a Proceeding to Investigate Distributed Energy Resource Policies, Order No. 33258, HAW. PUB. UTIL. COMM'N. (Oct. 13, 2015).

247. *See* Travis Hoium, *Hawaii May Have Just Given Energy Storage a Huge Boost*, THE MOTLEY FOOL (Oct. 22, 2015), https://perma.cc/PG7M-ZP3D; Mark Dyson & Jesse Morris, *Hawaii Just Ended Net Metering for Solar: Now What?*, ROCKY MOUNTAIN INST. BLOG (Oct. 16, 2015), https://perma.cc/5C62-TXCH.

248. DEVI GLICK ET AL., ROCKY MOUNTAIN INST., RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE 12 (2014).

energy storage can provide to different levels of the grid.[249] Second, retail electricity prices generally do not vary based on time or location.[250] Therefore, they lack the ability to provide accurate price signals about many of the services that energy storage can provide such as energy arbitrage or congestion relief. When investors cannot see precise signals about what kind of energy storage would be most valuable or where energy storage would be most valuable, the outcome will not be economically efficient.

Overall, while there are both state and federal level policies that allow for some types of energy storage systems to be compensated for some of the benefits they provide to the grid, as discussed above, they are not sufficient to ensure efficiency. Currently, not all types of energy storage systems can be compensated for all of the benefits they provide to the grid. Entry barriers must be lifted so that all types of energy storage systems can participate in markets for any service they have the technical ability to provide. Compensation rules must be clarified so that energy storage systems can earn value streams for each service they provide, especially when these services are provided at different levels of the electricity grid.

More importantly, the greenhouse gas emissions–consequences of energy storage systems should be taken into account to ensure that energy storage systems can indeed help to achieve clean energy and climate policy goals. Even if new FERC regulations eliminate barriers to entry and to earning multiple value streams, and even if state policymakers can reform retail rates to provide more precise price signals, the resulting framework would still not be able to sufficiently differentiate between those energy storage systems that can reduce greenhouse gas emissions and those that can increase greenhouse gas emissions. To guarantee that a policy framework would reduce greenhouse gas emissions requires emitting generators to fully pay for the external damages they cause.

IV. Policies Needed to Achieve Efficient Incentives

Fighting climate change is one of today's most important public policy issues. However, as explained in Part II, widespread deployment of cheaper storage is not guaranteed to help achieve climate policy goals. As energy storage has the potential to be a vital component of the modern grid, ensuring efficiency in energy storage deployment and providing well-designed incentives for the deployment of the energy storage systems that are most beneficial to society is essential to both federal and state decarbonization policies. As discussed in Part III, however, the current regulatory and policy framework is insufficient to provide incentives for developing economically efficient energy storage deployment. Achieving such efficiency requires putting in place a regulatory and pol-

249. *Id.* at 15.
250. *Id.* at 21.

icy framework that takes emissions into account, eliminating any uncertainties and barriers, and ensuring that energy storage systems can be compensated for all the benefits they provide to the grid.

In this Part, we outline the requirements of an energy storage policy that can help ensure the most efficient use of energy storage systems as part of the modern grid. First, we explain the reforms that are needed to provide efficient deployment of energy storage systems. Then, we discuss the jurisdictional roles in implementing these much-needed policies.

A. Achieving Efficiency

In perfectly competitive markets, the price of a good reflects the true value of that good to the society. This market price serves as a signal to drive investments in a manner that efficiently allocates society's resources towards the type of energy storage that would bring the most value to the society. But, if the price signal that investors receive is not accurate, for whatever reason, then the market cannot lead to the most socially desirable outcome.

In the case of energy storage, there are three main reasons why current price signals do not accurately reflect the true societal value of energy storage systems. First, because electricity prices do not take into account the external costs associated with electricity provision such as the damages from greenhouse gas emissions, any energy storage investment based on electricity arbitrage revenues would not lead to socially efficient deployment of energy storage. Second, because the current regulatory framework creates barriers to entry, energy storage systems cannot fully participate in all the markets for which they could provide value. Third, because the current framework prevents energy storage systems from earning multiple revenue streams for various benefits they provide at different levels of the grid, their earnings do not accurately reflect their true value and therefore cannot drive efficient levels of energy storage deployment. Achieving efficiency requires solving all three of these problems.

1. Internalizing Externalities

As we explained in Part II, if the greenhouse gas emissions effects of energy storage systems are not taken into account in policymaking, the resulting outcomes might indeed be detrimental to climate policy goals. When externalities such as greenhouse gas emissions are present, markets left to their own devices do not produce socially desirable results.[251] Achieving economic efficiency in these circumstances requires that externalities be fully "internalized"—by requiring parties to the market transaction to bear these external costs and benefits.[252]

---

251. *See, e.g.*, PAUL KRUGMAN & ROBIN WELLS, MICROECONOMICS 250–52 (2008).
252. *Id.* at 251.

If fossil fuel generators are not forced to pay for the external costs of their carbon emissions, they can submit bids to the wholesale market that are lower than the true social cost of producing electricity, and get dispatched based on this inefficiently low bid. As a result, generators with low fuel costs, such as coal plants, are dispatched even at times of low demand, leading to low off-peak electricity prices. Because energy storage systems can maximize their arbitrage revenue by charging when electricity prices are low, and discharging when they are high, market dynamics incentivize energy storage systems to charge using cheap dirty generation without taking emissions into account.

If, on the other hand, the dirty generators had to internalize the external costs of their emissions, they would need to submit higher bids to the market to ensure that they could cover the higher costs of producing electricity, which would lead to higher electricity prices when dirty generators are on the margin, incentivizing energy storage systems to use cheaper clean resources to charge. As a result, energy storage systems would use cleaner resources to displace dirtier resources, and, indeed, reduce greenhouse gas emissions.

The most economically efficient way of internalizing an externality is to impose an economy-wide tax on greenhouse gas emissions.[253] This first-best policy, however, requires congressional action, and, therefore is not feasible to adopt and implement in today's political climate. Therefore, alternative ways to distinguish between socially beneficial and potentially harmful energy storage systems are required. A cost-benefit analysis can serve as an interim tool to assess the greenhouse gas emissions of energy storage systems.

a. Reflecting Marginal External Damage of Greenhouse Gas Emissions in the Wholesale Markets

In the absence of an economy-wide carbon tax, the next best policy to make sure that the outcome in electricity markets is socially desirable is to ensure that the costs of the externalities are reflected in wholesale electricity markets. Carbon emissions in the electricity sector can be internalized by a policy that makes dirty generators pay for each ton of carbon they emit, either in the form of an adder or an allowance price in a cap-and-trade policy. Such carbon pricing would make it costlier for emitting resources to generate electricity, forcing them to bid higher prices in the wholesale market and creating an advantage for clean resources. This advantage would in turn ensure that wholesale electricity prices are lower when only clean energy resources are producing, and are higher when dirtier energy resources are also being dispatched, reversing the dispatch order described in Part II.

This reversal in the dispatch order of dirty and clean generators eliminates any potential concerns about energy arbitrage leading to higher generation from

253. *See id.*

dirty sources. On the contrary, in this case, energy storage systems would charge at times when cleaner, and thus cheaper, resources are on the margin, and discharge when more carbon intensive, and thus more expensive, resources are on the margin. They would essentially use cleaner generation to displace dirty generation, lowering greenhouse gas emissions and truly helping achieve climate policy goals.

Internalizing carbon emissions would also help alleviate the other concerns explained in Part II. When dirty generators such as coal plants have to pay for their emissions, they will no longer be among the lowest-cost resources, and therefore, they will no longer run as cheap baseload plants. They will be dispatched less often and earn less revenue. If a fossil-fueled plant is no longer guaranteed to eventually sell all the electricity it generates, it will have lower incentives to run longer than necessary and store the excess electricity. Further, pricing emissions increases the cost of efficiency losses when batteries are charged and discharged with fossil-fueled resources. Finally, as revenue opportunities decrease, investment incentives for new emitting plants will decrease as well, moving the market towards cleaner energy resources in the long run.

Consequently, if externalities can be internalized at the wholesale levels, the basic market forces will automatically discriminate against potentially harmful energy storage systems. Implementation of such a policy, however, requires more than the approval of state regulators. It requires coordination with ISOs and RTOs as well as FERC's approval. Hence, it is not a solution that can be implemented quickly unless ISOs and RTOs, state policymakers, and federal regulators all share the same goal. And, given the Trump administration's views on regulation, different policy priorities of different states, and the composition of FERC with the newly appointed Republican-majority Commissioners, it is not realistic to assume that the wholesale market can be redesigned to internalize the externalities in the short term.

The discussions in a recent FERC technical conference on the future of the wholesale energy and capacity markets indeed showed the disparity of opinions related to a possible carbon adder among different stakeholders and among different jurisdictions.[254] While many energy experts and generators supported

254. *See* FERC, State Policies and Wholesale Market Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, LLC Technical Conference Transcript (May 1, 2017) [hereinafter Technical Conference Transcript]; *see also id.* at 57–59 (discussion by Jeffrey Bentz, Director of Analysis for the New England States Committee on Electricity, arguing that carbon pricing might not be useful in New England states); *id.* at 116–18 (discussion by David Patton, the President of Potomac Economics, which serves as the independent market monitor for several ISOs/RTOS, arguing that carbon price cannot "be high enough to make a lot renewables economic"); *id.* at 170–71, 182–83 (discussion by Mark Kresowik, Eastern Region Deputy Director for Sierra Club, supporting carbon pricing through RGGI but not through market operators); *id.* at 60–63 (discussion by Robert Scott, Commissioner at the New Hampshire Public Service Commission, arguing that RGGI is the preferred alternative); *id.* at 158 (discussion by Brad Jones,

the idea of a carbon price in the wholesale markets, some state regulators strongly opposed it.[255] Even in jurisdictions where state policymakers agree on the desirability of a carbon adder, like New York, the process is expected to take a minimum of three years.[256] Therefore, short-term solutions, however imperfect, are needed as a stopgap measure.

b. Using Cost-Benefit Analysis in Procurement

As more states are looking into integrating energy storage systems into the grid immediately, an interim policy tool is needed to ensure socially beneficial energy storage deployment in the near-term. A societal cost-benefit analysis can help state regulators incorporate greenhouse gas emission impacts of energy storage systems into decision-making, and thus serve as a second-best policy tool until a more comprehensive policy can be enacted in the long term. Using a cost-benefit analysis to evaluate utility investments that require regulatory approval would help eliminate some of the socially undesirable investments.

The purpose of a cost-benefit analysis is to understand whether a specific investment is desirable.[257] The net benefits of each alternative resource, whether it is a distributed energy resource or a traditional generator resource, can be represented using a common metric of dollars. Thus, as long as all the cost and benefit categories, including the external costs and benefits, are consistently calculated for each resource, comparing the net benefits of each alternative and choosing the one that yields the highest net benefit to society will ensure that only socially beneficial energy storage systems are installed.

Using cost-benefit analysis for energy storage systems would require a comprehensive analysis of all the benefits discussed in Part I, as well as a careful study of the potential effects on emissions discussed in Part II. The arbitrage and other revenue opportunities for energy storage systems would help forecast an expected charging and discharging profile, which can then be used to quantify the potential benefits and costs of this system. The cost-benefit analysis would monetize these expected benefits and costs of a particular energy storage system given the specific network characteristics of the area of the planned investment.

---

the President and the CEO of NYISO, explaining the steps they have taken to start incorporating carbon pricing into New York's wholesale markets); *id.* at 126–28 (discussion by Scott Weiner, Deputy of Markets and Innovation at the New York Department of Public Service, explaining that they will start working with NYISO to agree on first principles).

255. *See* Gavin Bade, *The Carbon Consensus: Generators, Analysts Back CO_2 Price at FERC Technical Conference*, UTIL. DIVE (May 3, 2017), https://perma.cc/AQX4-TKCY.

256. *See* Technical Conference Transcript, *supra* note 254, at 188 (quoting Brad Jones, the President and the CEO of NYISO, as saying that the entire process would take a minimum of three years).

257. *See generally* RICHARD L. REVESZ & MICHAEL A. LIVERMORE, RETAKING RATIONALITY (2008).

The emissions impact of energy arbitrage can similarly be calculated based on the emission rates during charging and discharging times of the expected profile. If the emissions from the electricity generation that is used to charge the energy storage system are less than the emissions from the electricity that would have had to be generated in the absence of the energy storage system during the discharge period, then energy arbitrage would lead to a decrease in emissions. If the opposite is true, energy arbitrage would increase emissions. Quantifying and monetizing these external costs in the cost-benefit analysis would indicate negative net benefits if a particular energy storage system would provide little benefits at the expense of a large increase in greenhouse gas emissions. Therefore, such an analysis can prevent investments in energy storage systems that would use high carbon intensive generation to displace low carbon intensive generation.

An added advantage of cost-benefit analysis is that it can take into account emissions related to the construction and the operation of the storage systems.[258] A comparative study of different energy storage systems finds that life-cycle emissions differ not only due to the type of the paired generator but also due to the type of the energy storage system itself.[259] Therefore, a cost-benefit analysis that analyzes the total emissions during an energy storage system's entire lifespan is desirable.

While such use of a cost-benefit analysis can be a solution in the short term, it is not sufficient in the long term. First, as explained above, it can be applied only to investments over which state regulators have jurisdiction. Therefore, it cannot prevent an unregulated energy company from investing in energy storage systems that might have detrimental emissions consequences. Second, carrying out a comprehensive analysis for every single investment opportunity might be burdensome given the expected increase in energy storage projects over the next decade, and may delay construction. Therefore, while policymakers can rely on cost-benefit analysis in the short term, long-term policy priorities must focus on whether the market price signals are accurate, and whether externalities are internalized in the market.

2. *Eliminating Barriers to Entry*

Currently, different ISOs and RTOs integrate energy storage systems into their organized wholesale markets differently. Certain energy storage technologies already are allowed to provide energy and ancillary services in some of the

258. *See* Denholm & Kulcinski, *supra* note 18.

259. *See id.* Of the storage technologies considered, the PSB BES demonstrates the highest greenhouse gas emission coupled with fossil sources, while CAES demonstrates the least. Coupled with nuclear or renewable sources, PHS has the lowest greenhouse gas emissions, with BES having slightly higher emissions. CAES emissions are significantly higher, although lower than any existing fossil generation source.

organized markets by using existing participation rules. However, as discussed in Part III, because these rules were designed with traditional generators in mind, they lack the flexibility to recognize unique characteristics of energy storage systems.[260] Furthermore, certain aspects of markets designed to provide better incentives for traditional generators such as performance penalties are creating disincentives for energy storage systems.

Redesigning market rules to ensure that energy storage systems participate to the full extent of their unique technical capabilities would increase the efficiency of the electricity markets. As discussed in Part III, FERC has already shown some progress towards this goal by aiming to remove some of the barriers currently hindering electric storage resources in its 2016 Proposed Rule.[261]

The 2016 proposed rule would promote technology neutrality in revised tariffs in order to facilitate the participation in wholesale markets of distributed energy resources. FERC notes that greater competition, and thereby improving the efficiency of the wholesale electric market and expanding the participation of electric storage resources, would "reduce[ ] the burden on the transmission system" by allowing more efficient operation of large thermal generators, better integration of variable resources, and greater overall reliability in the wholesale markets.[262]

In the proposed rule, FERC recognizes that energy storage systems have the ability to provide a variety of services such as energy, capacity, and regulation, yet are restricted by rules that were designed for other resources.[263] Therefore, FERC seeks to require ISOs and RTOs to revise their tariffs to accommodate the participation of energy storage resources based only on their physical and operational characteristics, and their capability to provide energy, capacity, and ancillary services.[264] For example, FERC proposes new bidding parameters such as charge and discharge time and rate, which can give ISOs and RTOs information about the characteristics of energy storage systems, and hence the services they can provide.[265]

However, these proposed changes, while a big step towards increasing efficiency, are still limited in scope. Performance requirements, which penalize energy storage systems for not being able to provide certain services while

260. *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121, para. 13 (proposed Nov. 17, 2016) (to be codified at 18 C.F.R. pt. 35).

261. *See id.* at 14.

262. *Id.* at 17.

263. *See id.* at 13–14.

264. *See id.* at 56–57.

265. *See id.* at 58–59.

charging, still remain.[266] Finally, market rules and technological requirements vary from one market to another, making it more difficult to enter into more than one market with the same energy storage technology.[267] If, instead, market rules and eligibility requirements in all jurisdictions were uniformly based on the technical attributes that are required for a particular service, the existing barriers for energy storage systems, as well as barriers for any other new energy technology that may be viable in the future, would be eliminated.

3. Eliminating Barriers to Earning Multiple Value Streams

In a perfectly competitive market, market forces allocate resources to the most socially desirable products based on market prices that reflect the true societal value of those products, and products that are not valued sufficiently exit the market as a result. Thus, the market decides which products can best satisfy society's needs. Even when externalities are present, as long as they are internalized in the market, it is most economically efficient to let the market forces determine the outcome. But, this efficiency depends on the existence of accurate price signals that show the full value these products provide. A price signal below the full value would lead to inefficiently low investment. For energy storage systems, ensuring accurate price signals requires eliminating the barriers for earning compensation for multiple value streams. Creating a framework that can allow energy storage systems to be compensated for all the services they have the technical ability to provide, and then letting the market decide on what technologies are desirable, should be the goal of policy reforms. Achieving such accurate prices would not only lead to an efficient composition of energy resources but also an efficient level of energy storage deployment.

An accurate price signal depends on unbundling the different services that energy storage systems can provide and ensuring that they get compensated for each service. As discussed in Part III, the current regulatory framework makes it difficult, or impossible, for an energy storage system to participate in the market for every service that it has the technical ability to provide. Therefore, current price signals do not reflect the full value of energy storage systems. This inability of storage systems to participate in the markets for services they have the technical ability to provide, and therefore to be compensated for all these services, leads both to an under-utilization of existing storage systems and to an under-investment in new storage systems. Therefore, an efficient policy must

266. *See* Advanced Energy Economy, Comment Letter on Proposed Rule on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators 41 (Feb. 13, 2017) [hereinafter AEE February Comments].

267. *See* Advanced Energy Economy, Comment Letter on Proposed Rule on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators 10 n.15 (Jun. 5, 2016) [hereinafter AEE June Comments].

recognize the differential benefits that each storage system provides, and allow energy storage systems to be compensated for all these benefits.

Until recently, however, the regulators and the stakeholders in the electricity markets were more concerned about the opposite issue. Efficiency requires full compensation for all the services provided, but not double compensation from different sources for the same service. In January 2017, FERC issued a Policy Statement that provided guidance on how electric storage resources seeking to receive cost-based rate recovery for certain services (such as transmission or grid support services) while also receiving market-based revenues (for providing separate market-based rate services) could address these concerns related to double recovery by resources.[268] "Cost-based" rates are fixed, pre-determined rates that guarantee a minimum return. "Market-based" rates, on the other hand, are driven by market forces in a competitive marketplace. Accordingly, a system that generates and sells electricity in a competitive wholesale market will receive whatever the market-driven "market-rate" is for each kWh sold. By contrast, a system that provides an ancillary service like frequency regulation is entitled to receive a fixed "cost-based" rate that guarantees a minimum return and which is based on that system's cost of providing the service (e.g., frequency regulation).[269]

Storage resources can perform ancillary services that are entitled to cost-based compensation and can also sell power in wholesale markets at a market-based rate, even switching between the two almost instantaneously.[270] In its Policy Statement, FERC addressed the concerns about storage systems receiving both cost-based and market-based compensation. The first concern was the potential for combined cost-based and market-based rate recovery to result in double recovery of costs by the electric storage resource owners, to the detriment of cost-based ratepayers. The second concern was the potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in the wholesale electric markets, to the detriment of competitors that do not

268. *See* FERC, Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, Policy Statement, 158 FERC ¶ 61,051 (Jan. 19, 2017) [hereinafter Policy Statement].

269. For a general discussion regarding difficulties classifying energy storage, see ANITA LUONG, AM. INST. OF CHEM. ENGINEERS, GRID-SCALE ENERGY STORAGE, 14–16 (2011), and Stein, *supra* note 101, at 717–30.

270. *See* Policy Statement, *supra* note 268, at 1. Storage resources can inject small amounts of power into grid transmission lines, or absorb excess power that isn't immediately consumed, to maintain grid frequency—an ancillary service that entitles the storage resource to cost-based rate recovery. In addition, recall that most storage technologies don't literally "store" electricity—as a silo literally stores grain—but rather hold the kinetic, potential, mechanical, or thermal energy that is converted into electricity upon request. Accordingly, a storage system can generate electricity this way and sell its output in wholesale markets at the competitive market-based rate. *See* Stein, *supra* note 101, at 718–19.

receive cost-based rate recovery.[271] The Policy Statement detailed possible approaches to deal with the former concern, while dismissing the latter concern as insignificant.[272]

First, FERC acknowledged the possibility that storage systems might recover their costs of operation through market-based sales while also receiving cost-based rates specifically designed to cover operation expenses. Thus, storage systems might be receiving a windfall in the cost-based rates at the expense of ratepayers. However, FERC also noted that instances of double recovery could be addressed by crediting a storage system's market-based revenues back to ratepayers.[273]

Second, FERC largely dismissed fears that the ability of storage systems to receive two streams of revenue would adversely affect wholesale markets by enabling storage owners to sell electricity in wholesale markets at low prices that would consequently suppress market rates.[274] Here, FERC noted that other market participants also receive some form of cost-based rate recovery. For example, "vertically integrated utilities" receive cost-based compensation for electricity sold within a defined area while also engaging in market-based sales of electricity outside that area.[275]

FERC's proposed rule also discussed another mechanism for potential double compensation. It requested input on whether it is possible to determine the end use of the energy used to charge behind-the-meter energy storage systems, and whether one can distinguish between charging to sell in wholesale markets, which would get paid the wholesale rate, and charging to sell in retail markets, which would get paid the retail rate.[276] This question highlights FERC's struggle to identify the exact boundaries between the services an energy storage system can provide in the wholesale market, and the services an energy storage system can provide in the retail market.

To deal with the double compensation issue, FERC proposed that distributed energy resources that participate in one or more retail compensation programs, such as net metering, not be eligible to participate in the wholesale markets as part of a distributed energy resource aggregation.[277] This proposed rule highlights the difficulty of formulating a framework to compensate energy storage systems, which have the ability to provide benefits to every part of the electric grid, for all of the value they provide to the grid. Preventing a distribution level energy storage system from providing services at the generation or transmission level would prevent that system from being compensated for all of

271. *See* Policy Statement, *supra* note 268, at 1, 11.
272. *See id.* at 11–16.
273. *See id.*
274. *See id.* at para. 20–23.
275. *Id.*
276. *See* 157 FERC ¶ 61,121, *supra* note 1, at para. 96–102.
277. *See id.* at para. 102.

the value it provides, which leads to inefficient price signals and hurts energy storage deployment.

While prohibiting duplicate compensation for the same service is, of course, necessary for economic efficiency, ensuring that distributed energy resources can be fully compensated for the unique benefits they can provide at every level—generation, transmission, and distribution—is also necessary, and perhaps more important, for economic efficiency in energy storage deployment. As recently as June 2016, three regional operators—MISO, ISO-NE, and New York Independent System Operator—explicitly affirmed the eligibility of storage systems to provide frequency regulation, but their rules prevent energy storage resources that provide frequency regulation from providing other services such as reserves.[278] In addition, a framework for compensating unbundled ancillary services, which energy storage systems can provide even when they are not already online, is lacking.[279]

Because the revenue potential based on only one category of benefits does not justify the current high upfront investment that is needed, one value stream is not enough to give sufficient incentives for large scale deployment.[280] Thus, unless such restrictions that prevent multiple revenue streams are eliminated, energy storage deployment will be below the socially efficient level. Therefore, a new framework that allows compensation for different value streams should be considered, even if those value streams are based on benefits that accrue to different parts of the market and, thus, have to rely on different compensation mechanisms.

Setting up a framework for accurate valuation is especially critical as behind-the-meter energy storage systems are likely to become more prevalent in the next future.[281] As discussed in Part I, behind-the-meter systems can provide benefits to both the distribution system and the wholesale market and thus have the potential to confer large benefits on the grid. Therefore, limiting the source of compensation of these systems to only one of these levels, as the current regulatory framework does, hinders efficiency.

One solution to these dual problems would be for FERC and state regulators to coordinate and explicitly lay out the categories of benefits of energy storage systems and how to compensate for each benefit. While this task is not easy, the current state-level initiatives to understand and value the benefits of all

---

278. *See* Comments of the Energy Storage Association on Electric Storage Participation in Regions with Organized Wholesale Electric Markets, 157 FERC ¶ 61,121, at 6, n.9 (Feb. 13, 2017) [hereinafter ESA Comments].

279. *See* AEE February Comments, *supra* note 266, at 52; Tesla Comments, *supra* note 232, at 2–6.

280. *See* CHANG, DOES SIZE MATTER?, *supra* note 34; CHANG, DISTRIBUTED ENERGY STORAGE IN TEXAS, *supra* note 34, at 2.

281. *See* Peter Maloney, *How Behind-the-Meter Storage Could Make Up 50% of the U.S. Market by 2021*, UTIL. DRIVE (Jan. 31, 2017), https://perma.cc/AF89-J9WC.

distributed energy storage systems, including energy storage systems, can provide a useful foundation for this route.

For example, New York State currently is in the process of establishing a methodology to value all distributed energy resources.[282] The New York State Public Service Commission recently issued an order in this proceeding to outline a framework that is generally described as a "value stack" approach.[283] In this approach, distributed energy resources, including energy storage systems, are compensated for their energy value, capacity value, and environmental value of their net exports. In addition, the systems that can reduce demand during the ten highest usage hours of a utility's territory are paid a demand reduction value, and the systems located at "high value" grid locations are paid a locational system relief value.[284]

The New York State Public Service Commission's initial order, which is only an interim order until a more complete methodology can be established in the second phase, restricts this value stack compensation to resources that can provide net exports to the grid. Therefore, energy storage systems that are not paired with a generating resource are not currently eligible for this compensation.[285] However, the second phase of the proceeding is expected to broaden the scope of the value stack approach to all other energy storage systems, which provide to the system by modifying or shifting the customer demand even if they do not provide net exports to the grid, as well.[286] This second phase will also improve and modify the initial value stack to include more benefits categories, at more granular levels. Further, it will improve the methodology for calculating some of the value categories that do not already have an established methodology, such as the locational system relief value or the demand reduction value.

This value stack framework has the potential to provide compensation for the value that distributed energy resources provide at all levels, even if the system itself is located behind the meter. Furthermore, if all states start using such an unbundled approach to compensate energy storage systems, rules can be crafted to determine which actor would compensate an energy storage system for each value component, based on where the benefits accrue. For example, an energy storage system can be compensated for the energy value in the wholesale electricity market while being compensated for the locational system relief value

282. *See* N.Y. PUB. SERV. COMM'N., SUPPLEMENTAL STAFF WHITE PAPER ON DER OVERSIGHT (2017).

283. Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, Case Nos. 15-E-0751 & 15-E-0082, N.Y. PUB. SERV. COMM'N. (2017).

284. *Id.* at 10.

285. *See id.* at 38–39.

286. *See* Notice of Phase Two Organizational Conference, Case No. 15-E-0751, N.Y. PUB. SERV. COMM'N. (2017).

by the distribution utilities. The environmental value that energy storage systems provide by avoiding emissions, if it exists, can be paid by the state itself, because it would be reflective of a state policy.

Preventing double compensation is also easier under this approach. For example, if a system is being compensated for its energy value already by this framework or by the wholesale markets, the same system would not be compensated for its energy value by any other retail program, but would be allowed to be paid for its distribution level benefits by a retail program. Similarly, if a system is already being paid for the environmental value through this value stack approach, it would not be allowed to participate in additional programs such as renewable energy credit markets. Such a categorization would allow energy storage systems to be compensated for the full benefit they provide, while alleviating double recovery concerns.

Therefore, coordination among ISOs and RTOs, which determine the eligibility rules and tariffs; federal regulators, which approve these rules and tariffs; state regulators, which regulate utilities; and utilities, which serve the customers, is essential to efficient energy storage deployment. Such coordination is especially important for behind-the-meter distributed energy storage systems, which have the ability to provide services to all the levels of the grid, to ensure that they can get compensated for the value they provide to the entire electric system, not just to their owners, and thus to incentivize deployment at locations that are most useful to the society as a whole. Unless this fundamental coordination problem can be resolved, neither the level of energy storage deployment, nor the composition of the types of energy storage systems that are deployed, will be efficient.

B. Jurisdictional Roles

As with other grid-connected technologies, energy storage resources may fall within the regulatory jurisdiction of federal or state entities. In general, federal and state governments share the task of regulating grid operation as well as any interconnected systems, like generation and transmission resources. Understanding this jurisdictional divide and establishing the roles each regulator can play in implementing the policies outlined in Part III.A is crucial to the success of energy storage policies.

While establishing clear jurisdictional boundaries between state and federal regulators has been increasingly difficult as new types of energy resources such as demand response come into play,[287] this challenge is especially complicated for energy storage systems. Because energy storage systems can provide

287. *See* FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 775–82 (2016) (holding that FERC's Order No. 745 was a valid exercise of FERC's authority over wholesale demand response).

benefits at different levels of the electricity grid regardless of where they are physically located, jurisdictional boundaries for regulating energy storage systems are particularly uncertain.

First, it remains unclear whether sales of power into, and out of, an energy storage facility constitute sale of wholesale or retail power. While the Federal Power Act assigns to FERC jurisdiction over wholesale transactions, it reserves authority over retail transactions to state utility commissions.[288] The way in which assets are compensated differs based on whether an asset is subject to FERC or state jurisdiction. This lack of clarity creates significant financial uncertainty for developers, hindering the pace of energy storage deployment.

Second, as discussed in Part I, energy storage systems can bring benefits to generation, transmission, and distribution systems simultaneously, and therefore they cannot and should not be classified as assets in only one of these traditional categories.[289] But, because energy storage can perform all three of these functions, regulators and developers are unsure about how to design rate schemes, allocate cost recovery, and prevent double-counting of various energy storage services, while also ensuring that storage providers are compensated fully for all the functions storage performs.[290]

1. Roles for FERC

Under the Federal Power Act of 1935, FERC holds plenary jurisdiction over wholesale interstate markets, while state officials exercise authority over their respective in-state markets and utilities.[291] Since 1935, however, courts have construed federal jurisdiction broadly, and by 2010, the scope of federal authority included several retail and intrastate transactions.[292] Consequently, a sizeable amount of all electricity that flows into or out of the grid will pass

288. *See* Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1292 (2016).

289. *See* Stein, *supra* note 101, at 717.

290. *See id.* at 718.

291. Since the Federal Power Act of 1935, federal regulators have exercised regulatory jurisdiction over "matters relating to . . . the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," so long as such matters "are not subject to regulation by the States." 16 U.S.C. §§ 824–824w (2012). The Act, for example, expressly reserves to states oversight of facilities either "used for the generation of electric energy," "in local distribution," or "for the transmission of electric energy in intrastate commerce." 16 U.S.C. § 824(b)(1) (2012).

292. *See, e.g.*, Fed. Power Comm'n v. Fla. Power & Light Co., 404 U.S. 453, 458 (1972) (noting that it is sufficient to show that power from intrastate transaction "commingled" with power from interstate transaction); Jersey Cent. Power & Light Co. v. Fed. Power Comm'n, 319 U.S. 61 (1943) (noting that it is sufficient to show that part in intrastate transaction was "no more than a funnel" to out-of-state party); New York v. FERC, 535 U.S. 1, 17 (2002) (holding that federal regulators may regulate unbundled retail sales).

under federal jurisdiction, giving federal officials considerable influence over the rate, terms, and conditions of nearly all grid-related transactions.[293]

Because an energy storage system can be used for several purposes, it might not be exclusively wholesale or retail. There is uncertainty, for example, about which transactions constitute a sale for resale, and therefore are subject to FERC jurisdiction, and which transactions constitute a sale for consumption, and therefore are subject to state jurisdiction.[294] Thus, energy storage can be subject to both federal and state regulation.

FERC has treated electricity pumped into and out of hydroelectric storage and compressed air energy storage facilities as wholesale transactions.[295] It remains unclear whether and to what extent this posture extends to other energy storage systems.[296] Further, it is not clear whether the energy drawn for efficiency losses or the essential operation of the battery should be considered a wholesale transaction.[297] This ambiguity is exacerbated for certain systems like behind-the-meter energy storage systems, which can withdraw electricity from the grid for both personal consumption and resale. Therefore, clarifying this distinction is perhaps the most important, and the most urgent, role for FERC.

However, it is important that this FERC clarification not be based on generic classifications of state programs. For example, a ruling that an energy storage system that participates in state net metering policies cannot provide other services, as FERC suggested in the proposed rule, would not only be vague, but also lead to inefficient outcomes. State net metering policies vary significantly.[298] Therefore, depending on the details of a state policy, energy storage systems participating in such state programs may be compensated based on retail rates, avoided costs rates, or a combination. Furthermore, given that even retail rates are designed and calculated differently from one state to another, using generic classifications of such programs to determine which systems can participate in wholesale markets would lead to economically unjustified differences in compensation for similar systems in different states. Likewise, preventing systems from providing wholesale services in addition to

293. For a discussion of the evolution of this broadening authority, and a discussion of the functionalist approach to FERC authority under the FPA, see Matthew R. Christiansen, *FERC v. EPSA: Functionalism and the Electricity Industry of the Future*, 68 STAN. L. REV. 100 (2016).

294. *See* Stein, *supra* note 101, at 716–18.

295. PJM Interconnection, L.L.C., 132 FERC ¶ 61,203, (2010); *see* Stein, *supra* note 101, at 717.

296. *See* Comments of the ISO-RTO Council on Notice of Proposed Rulemaking Regarding Electric Storage Resources and Distributed Energy Resource Aggregations in Organized Wholesale Electric Markets, 157 FERC ¶ 61,121, at 3 (Feb. 13, 2017).

297. *See id.*

298. *See supra* Part I.

retail services, when they are capable of doing so, would impede economic efficiency.

Instead of using criteria based on participation in state programs as it suggested in the proposed rule,[299] FERC should determine the rules based on the nature of the end usage of the electricity withdrawn from the grid. An energy storage system can withdraw energy from the grid for many reasons such as for consumption, for the operation of the battery, or for resale in the wholesale markets. Instead of ruling that every transaction of an energy storage system should be subject to state jurisdiction just because that system participates in a state program, FERC should attempt to distinguish among different end-uses of the stored energy. For example, the portion of the energy withdrawn that is sold back to the wholesale markets should be classified as sale for resale, a wholesale transaction, and the energy withdrawn that is used for personal consumption should be classified as not for resale, a retail transaction.

Additionally, FERC should work with state regulators to define and categorize the benefits energy storage systems can provide, and then provide guidelines for effective coordination between states, ISOs, and RTOs on which benefit is going to be compensated at what level to ensure full, but not double compensation. Defining and categorizing transaction types and benefits is a crucial step towards ensuring that energy storage systems can be deployed efficiently.

Determining these rules based on the nature of the end service provided by energy storage, and the technical requirements that are necessary for those services, would also help eliminate entry barriers. When rules do not depend on the type of resource, but instead depend on the ability to reliably provide a certain service, any type of energy storage system that has the technical ability to do so would be able to participate in the market and improve market efficiency.

FERC also plays an important role in achieving efficient price signals in the wholesale markets. The Federal Power Act directs FERC to ensure that rates and rules are "just and reasonable," and are not unduly discriminatory or preferential.[300] Therefore, ensuring that the ISO and RTO tariffs, relevant price formation mechanisms, and other payment mechanisms such as performance payments do not hinder the efficiency of the markets by insufficiently compensating an energy resource, or by preventing it from being compensated at all, is FERC's responsibility under the Federal Power Act.[301]

---

299. *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121 (proposed Nov. 17, 2016) (to be codified at 18 C.F.R. pt. 35).

300. 16 U.S.C. §§ 824d–824e (2012).

301. *See id.*

Finally, FERC has to determine its jurisdictional boundaries in helping states achieve their state policy goals in the most efficient ways when externalities are present. As discussed in Part II, unless the impacts of greenhouse gas emissions associated with energy storage systems can be taken into account, the market outcome will not be efficient. And, as discussed in Part III, the best way to achieve efficiency is for greenhouse gas emissions to be accounted for in the wholesale market. Whether FERC has the authority to impose a carbon adder, or to approve ISO and RTO tariffs with a carbon adder remains a crucial, yet an open, question.[302]

2. *Roles for States*

While reducing much of the uncertainty about the role of the energy storage systems and eliminating inefficient market rules and barriers rest on FERC's shoulders, states also have the responsibility to implement policies for efficient deployment of energy storage systems.

If the wholesale markets fail to fully internalize greenhouse gas emissions, then the responsibility of ensuring that the energy storage systems that are deployed are indeed socially beneficial rests with the states. State regulators should direct their utilities to conduct a cost- benefit analysis to consider the potential impact of energy storage systems on greenhouse gas emission before deploying them. When wholesale markets fail to internalize emissions, using a cost-benefit analysis would help prevent the installation of energy storage systems that would largely increase greenhouse gas emissions.

States also have an important role to play in achieving accurate price signals. While FERC is responsible for ensuring efficient price signals for the transactions in wholesale markets, states bear the same responsibility in retail markets.[303] Creating a framework for energy storage systems to be compensated based on all the values they bring—even when installed locally behind-the-meter, with the proper locational and temporal granularity—is crucial to efficiency.

It is, of course, challenging to quickly move to an approach that unbundles payments based on different value stacks for each category of benefit an energy

---

302. *See* Christopher J. Bateman & James T.B. Tripp, *Toward Greener FERC Regulation of the Power Industry*, 38 HARV. ENVTL. L. REV. 276, 301 (2014); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U.C. DAVIS L. REV. 1783, 1840 (2016); STEVEN WEISSMAN & ROMANY WEBB, CTR. FOR LAW, ENERGY, & THE ENV'T, ADDRESSING CLIMATE CHANGE WITHOUT LEGISLATION 4 (2014); *see also* Bade, *supra* note 255; Rich Heidorn Jr., *ISO-NE Two-Tier Auction Proposal Gets FERC Airing*, RTO INSIDER (May 8, 2017), https://perma.cc/4N24-BY4B.

303. *See generally* Frank A. Wolak, *Regulating Competition in Wholesale Electricity Supply*, *in* NAT'L BUREAU OF ECON. RESEARCH, ECONOMIC REGULATION AND ITS REFORM: WHAT HAVE WE LEARNED? 195, 210 (Nancy L. Rose ed., 2014) (discussing the role played by state regulators in price signaling on the retail markets).

storage system can bring, and then calculate the remuneration for each of these stacks in a temporally and locationally granular fashion. State regulators have to determine the value categories, the granularity of each category, and the compensation formula for each category. However, as discussed throughout this Article, there are multiple benefits energy storage systems can provide, and the magnitude of these benefits depends on where and when they are operated. Therefore, unless the price signals that the investors receive vary based on these benefits, neither the level of energy storage deployment nor the composition of the deployed energy storage systems will be socially optimal.

Conclusion

Energy storage systems hold the key to decarbonization of the electric grid, and thus a clean energy future. However, contrary to the common assumptions relied on by policymakers to promote policies that indiscriminately encourage more energy storage deployment, there are circumstances under which energy storage systems can increase greenhouse gas emissions. In this Article, we describe these circumstances in detail, filling an important void in the current debate. Additionally, we discuss the shortcomings of the current regulatory and policy framework to provide sufficient incentives for socially beneficial energy storage deployment.

Finally, we outline the reforms that are necessary to realize the clean energy future promised by increased energy storage deployment. To ensure that energy storage systems can indeed help achieve climate policy goals, externalities related to greenhouse gas emissions should be internalized, entry barriers should be eliminated, and market rules should be modified to guarantee accurate price signals that can value all the benefits energy storage systems have the technical ability to provide. Unless these reforms can be enacted, both the level and the composition of energy storage deployment will remain far from efficient.

Exhibit E

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

ELECTRICITY POLICY INSIGHTS

Managing the Future of Energy Storage

Implications for Greenhouse Gas Emissions

April 2018
Madison Condon
Richard L. Revesz
Burcin Unel, Ph.D.

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Richard Revesz is the Lawrence King Professor of Law and Dean Emeritus at NYU School of Law, and Director of the Institute for Policy Integrity. Burcin Unel is the Energy Policy Director at the Institute for Policy Integrity. Madison Condon is a Legal Fellow at the Institute for Policy Integrity.

Executive Summary

With rapidly advancing technology and declining manufacturing costs, energy storage systems are becoming a central element in many energy policy debates. Policymakers see storage as a potential solution to the challenges that stem from the intermittency of certain renewable resources, such as solar and wind. Storage systems are therefore considered key to hastening the clean energy revolution, and are at the nexus of energy and climate change policy. Reductions in greenhouse gas emissions are often a stated goal of policymakers encouraging energy storage installation.

Energy storage systems, undoubtedly, will be a key part of the future of the electric grid. They have the potential to provide many benefits to the grid, such as lowering the price of electricity at peak demand times, and deferring or avoiding new capacity investments. However, contrary to the prevailing wisdom, energy storage is not guaranteed to reduce emissions, and may, in fact, increase emissions if policies are not designed carefully. Further, while this oft-cited (but not guaranteed) benefit of storage dominates headlines in policy discussions around the country, many other types of benefits that energy storage systems can provide are not well recognized in policymaking.

This report seeks to be a resource to policymakers interested in maximizing the benefits of energy storage. It highlights the underappreciated benefits of energy storage and discusses the ways in which current policies are failing to encourage socially optimal deployment of storage technology. As policymakers start to rely more heavily on energy storage systems to achieve clean energy goals and other improvements to the grid, it is helpful to first understand the ways that the current regulatory and policy landscape fails to reward storage systems for the variety of benefits they provide to the grid, including ancillary benefits such as frequency regulation. Further, policymakers must keep in mind that the greenhouse gas impact of energy storage depends primarily upon whether the type of generation used to charge the storage is cleaner than the type of generation avoided when the storage is used; otherwise, storage could produce pernicious results.

Policy reforms that account for the range of benefits provided by storage, including reduced air pollution, are required at both state and federal levels. This report recommends that policymakers focus on:

- Accurately pricing externalities caused by greenhouse gases;
- Eliminating entry barriers for energy storage systems; and
- Eliminating barriers to multiple value streams.

This report outlines what is needed to realize each of these three goals and provides an overview of state and federal actions currently under way.

Table of Contents

Executive Summary i

Introduction 1

Overview of the Electric Grid 2

Benefits of Energy Storage 4

- Demand Smoothing and Energy Arbitrage 4
- Ancillary Services 4
- Complementing Renewables and Reducing Emissions 5
- Types of Energy Storage Technology 7

Potential Negative Effects of Energy Storage on Greenhouse Gas Emissions 8

- Marginal Emissions 8
- Efficiency Losses 10

Policies Needed to Maximize the Benefits of Energy Storage Deployment 11

- Internalizing Externalities 11
  - Short-Term Strategy: Cost-Benefit Analysis in Procurement 12
- Eliminating Barriers to Entry 13
- Eliminating Barriers to Earning Multiple Value Streams 14
  - Challenges Related to Behind-The-Meter Energy Storage 16
  - Market-Based and Cost-Based Rates: Concerns Over Double Compensation 16

Regulatory Roles and Challenges 19

- Tasks for FERC 19
- Tasks for State Regulators 20

Conclusion 21

Introduction

There are 25.2 gigawatts ("GW") of operational energy storage in the United States, with an additional 7.2 GW announced, contracted, or under construction.[1] The current total corresponds to about 2.7 percent of the current U.S. generation capacity.[2] It is expected that annual new deployment of energy storage will exceed 1.9 GW in 2019 and 2.7 GW in 2020.[3] By comparison, annual capacity additions of all other technologies are expected to be 11.1 GW in 2019 and 14.8 GW in 2020, making energy storage an increasingly important component of the electricity grid in the near future.[4]

This report seeks to be a resource to policymakers interested in maximizing the benefits of energy storage. It highlights the underappreciated benefits of energy storage and discusses the ways in which current policies are failing to encourage socially optimal deployment of storage technology. As policymakers start to rely more heavily on energy storage systems to achieve clean energy goals and other improvements to the grid, it is helpful to first understand the ways that the current regulatory and policy landscape fails to reward storage systems for the variety of benefits they provide to the grid, including ancillary benefits such as frequency regulation. Further, policymakers must keep in mind that the greenhouse gas impact of energy storage depends primarily upon whether the type of generation used to charge the storage is cleaner than the type of generation avoided when the storage is used; otherwise, storage could produce pernicious results.

In February 2018 the Federal Energy Regulatory Commission (FERC) issued its Final Rule on Electric Storage Participation in Regional Markets, Order 841 (Storage Rule).[5] This Storage Rule is a crucial step toward removing regulatory barriers that have prevented the efficient deployment of energy storage resources around the country. This report considers how FERC's Storage Rule provides for the removal of certain regulatory barriers and highlights the questions that remain for energy storage system developers.

This report serves as a guide to policymakers at multiple jurisdictional levels and highlights the need for: (1) accurately pricing externalities caused by greenhouse gases; (2) eliminating entry barriers for energy storage systems; and (3) eliminating barriers to compensation from multiple value streams.[*]

[*] This report is based on the recent article, Richard L. Revesz & Burcin Unel, *Managing The Future Of The Electricity Grid: Energy Storage And Greenhouse Gas Emissions*, 42 Harv. Envtl. L. Rev. 139 (2018).

Overview of the Electric Grid

The electric grid contains three components: generation, transmission, and distribution. Electricity is produced by large generators, transmitted by high-voltage transmission lines closer to the end-users, and finally distributed by low-voltage distribution lines to energy consumers. Ensuring the stability of the grid requires that the supply of electricity at all times be equal to the demand of electricity, which changes throughout the day. In addition to the need for energy resources that can generate enough electricity and vary generation based on the demand, this balancing act requires a variety of "ancillary" services, such as frequency regulation, to ensure stability.

Key Terms

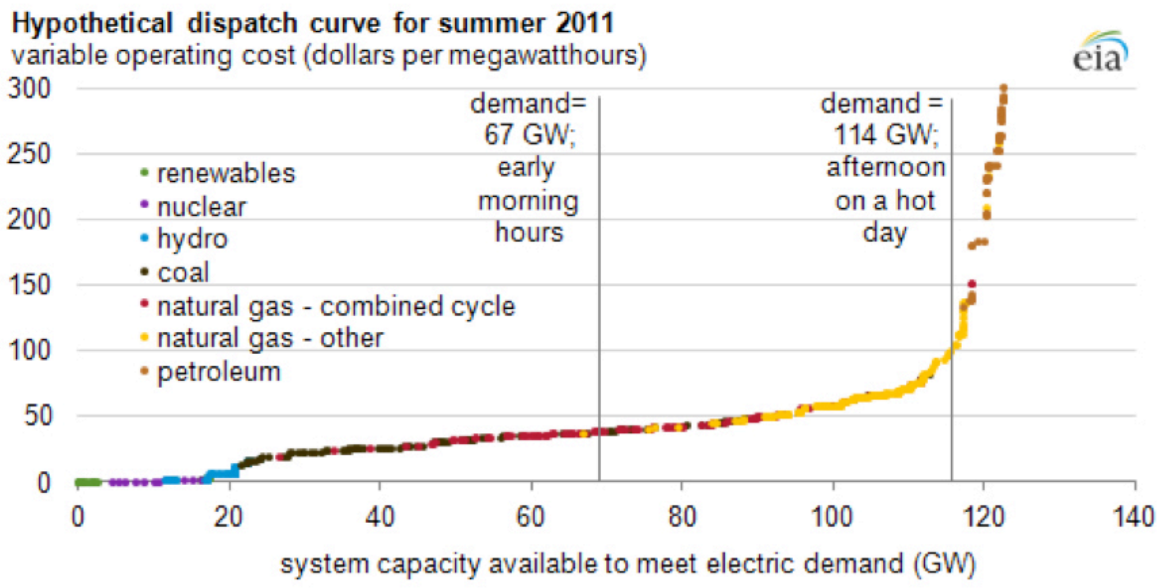
Baseload: The baseload is the minimum level of demand on an electrical grid over a span of time. Baseload demand is satisfied by generators that can continuously meet this minimum demand at a comparatively low cost. It is important to note that the term 'baseload' is not technology specific and does not refer to certain types of of resources that have historically been used to meet the minimum demand, such as nuclear or coal plants. 'Baseload resources' is technology neutral and refers to low-cost resources that would be most often called upon to meet the around-the-clock minimum level of demand, and therefore can be any low-cost resource that can help reliably meet the minimum level of demand.

Energy system operators are tasked with achieving this balancing act at the lowest possible cost. They ensure that the electricity demand at any given moment is met with the cheapest supply possible given the operational constraints of the grid. In simplified terms, most operators ask each generator for bids reflecting the lowest price at which the generator is willing to supply electricity. These bids are ordered from lowest to highest, often referred to as "merit order," and generators are dispatched in this order and taking the operational constraints of the grid until the demand is met. The bid of the last generator that is needed to meet all the demand, the "marginal" generator, is paid to each of the dispatched generators.

Instantaneously meeting electricity demand, which varies during the day, requires plants that are continuously running to meet the minimum level of demand during the day, known as the "baseload." It also requires additional plants that can react quickly as demand varies. Some plants, such as those fueled by coal and nuclear energy, have high fixed costs of starting up and shutting down and cannot easily vary their output from hour to hour. Their variable costs of generation, however, are low, and they therefore generally bid low prices. Thus, it often makes economic sense to continually operate these plants at a set level of output to meet the baseload demand.

These "baseload" plants are enough to meet all of the demand by themselves when the demand is low, typically at night. As demand starts to increase and the baseload plants no longer provide sufficient capacity to meet the demand, intermediate plants, such as natural gas combined cycle plants, are brought online. These plants have higher variable costs of generation, so their bids are higher, but they are not as costly to start up or shut down as baseload plants. When demand is highest, peak plants, which have high variable costs of generation and thus the highest bids, are dispatched. These plants are usually less-efficient natural gas or oil-fired plants. This dynamic means that electricity prices are low when baseload plants are on the margin, and high when peak plants are on the margin.

Figure 1: Illustrative Market Supply Curve[6]



Source: U.S. Energy Information Administration (2012)

Reliably transmitting electricity from generators to consumers further requires meeting a variety of other operational constraints. The amount of electricity that flows through the transmission and distribution networks must not be higher than the capacity of these networks, for example. And the electricity's cycle frequency and voltage level must be maintained throughout the grid. If these constraints are not met, the system may become unstable, blackouts may occur, or the grid may sustain damage.

Benefits of Energy Storage

Energy storage can provide numerous benefits to the grid at each of its three levels, as well as to end-users directly. The benefits of energy storage can be broken down into three main categories: (1) demand smoothing and energy arbitrage; (2) ancillary services; (3) assisting renewables and reducing emissions.

Demand Smoothing and Energy Arbitrage

Energy storage facilitates arbitrage—the purchasing of wholesale electricity when the price is low in order to sell later when the price is high. Arbitrage can help lower the total cost of meeting the electricity demand by reducing the need to generate electricity when it is costly to do so. Energy storage can help meet resource adequacy requirements that are needed to ensure system reliability during system peaks by charging during off-peak times and discharging during peak times. This arbitrage ability reduces the need for generation, transmission, and distribution capacity expansions, and enables higher levels of use of existing cheaper generation resources. Therefore, by engaging in energy arbitrage, energy storage systems can help defer or reduce the need for capacity investment in more traditional resources, such as new natural gas combustion turbines, to meet peak demand and reduce costs significantly.[7]

Further, the ability of energy storage to smooth demand throughout the day enables generators to run at their optimal capacity over longer periods of time, increasing overall grid efficiency. It is costly for certain generators to ramp up and down their power supply in order to meet daily fluctuations in demand.[8] By partnering with storage resources, these generators can produce a continual level of output at a low cost, storing the unwanted power until demand increases later in the day.

Ancillary Services

Energy storage systems can help grid operators meet a variety of operational constraints of the grid's transmission and distribution systems. Frequency and voltage must be maintained throughout the grid, and the energy supplied must not exceed the capacity of each of the grid's components. Grid operators use ancillary services, such as frequency regulation and voltage control, to help stabilize the grid and assist it in responding to changing demand. Electric storage resources, for example, are capable of faster start-up times and high ramp rates than other resources typically used for these services.[9] Therefore, energy storage

Key Terms

Ancillary Services:

- *Frequency regulation* is used to reduce the minute-to-minute, or shorter, fluctuations caused by differences in electricity supply and demand.
- *Ramping resources* are needed to manage longer-duration fluctuations in the supply due to factors that affect generation such as changes in wind speed or cloud cover.
- *Voltage support* helps maintain voltage levels throughout the system.
- *Reserve capacity* is the extra capacity needed that can respond quickly to ensure system stability in the case of unexpected changes in customer demand.
- *Spinning reserves* are already online and can respond in less than ten minutes, while non-spinning reserves are offline but can come online and respond in less than ten minutes.

has the potential to supply ancillary services at a lower cost than the resources that have been traditionally used, like gas turbines. This can reduce overall system costs, or avoid the need for constructing new capacity from traditional resources.

Complementing Renewables and Reducing Emissions

Many policymakers see energy storage as a necessary complement to the broader use of clean renewable energy resources, such as solar and wind power, that are intermittent and variable. If the sun is not shining, or the wind is not blowing, these resources cannot produce electricity. Further, peak demand periods may not perfectly correspond to the peak generation times of solar and wind resources.[10] Therefore, providing electricity from solar and wind energy reliably during the whole day requires smoothing out their output throughout the day.

Energy storage is often presented as a solution to the challenges utilities around the country face due to a desire for a higher penetration of renewable energy resources. Wind or solar energy can be stored when there is excess demand and injected to the grid later when the supply is insufficient to meet the demand. Energy storage can also help with minute-to-minute smoothing that would be necessary when a cloud passes by, as well as larger smoothing needs when a large amount of wind energy is generated during off-peak demand hours.

Solar panels connected to a battery storage system.

Table 1: Benefits of Energy Storage at Each Level of the Grid

At the generation level:	
Energy arbitrage	Purchasing wholesale electricity when the price is low and selling it when the price is high can help lower the total cost of meeting the electricity demand by reducing the need to generate electricity when it is costly to do so.
Resource adequacy	Charging during off-peak times and discharging during peak times can help meet resource adequacy requirements needed to ensure system reliability during system peaks, reducing the need for capacity investment.
Variable resource integration	Energy storage can help "firm" the variable output from a renewable generator by charging when there is not enough demand for the generator's output and discharging when there is need.
Management of must-take resources	Resources such as hydro, nuclear, and wind must be taken by the buyers regardless of market prices due to regulatory or operational constraints so storage can avoid them having to dump excess energy at low demand.
Frequency regulation	Grid instability is prevented by ensuring that generation is matched with consumer demand at every moment.
Ramping	Ramping counteracts the effects of varying renewable generation.
Spinning/non-spinning reserves	Reserves can provide extra generating capacity in the event of an unexpected energy shortfall.
Voltage support	Voltage must be maintained within an acceptable range to match demand.
Black start	Storage can be used to restore power station operation in the event of a grid outage.
At the transmission level:	
Congestion relief	Storage can reduce the bottlenecks caused at certain locations of the transmission system during high-demand times by discharging at those locations during those periods.
Transmission system upgrade deferral	Shifting the electricity demand to less congested times prevents system overload and reduces the need, the size, or the urgency of new investment in the transmission systems.
Improved performance	Voltage maintenance and increased capacity improve the overall functioning of grid transmission.
At the distribution level:	
Congestion relief	Reducing congestion during peak demand times avoids the need for costly upgrades.
Mitigate outages	Storage can discharge in the event of an unexpected power outage.
Consumers (behind the meter):	
Manage consumption	Lower bills by displacing consumption from peak to off-peak rates, if consumers face time-varying rates.
Storage	Store energy from behind-the-meter generation, such as rooftop solar.
Back-up power	Provides emergency power in the event of grid failure.

Types of Energy Storage Technology

Energy storage can be provided by a broad range of technologies, each with varying characteristics that make them better or less suited to providing certain storage services. For example, mechanical flywheels' fast-ramping capability and geographic flexibility mean that they are typically used to inject small and precise amounts of electricity into the grid for frequency regulation, despite their limited capacity. By contrast, pumped hydroelectric storage can provide higher-capacity, but require large reservoirs that are challenging to site.

An energy storage system's rated power capacity, duration of discharge, levelized cost, and barriers to installation, are all factors that determine what service the storage system is best suited to provide.

Key Terms

Rated power capacity: storage unit's total output, expressed in kW or MW.

Duration of discharge: the time a given system can output electricity at its rated power capacity.

Levelized cost: unit cost of providing electricity over the lifetime of a resource, expressed in dollars per MWh.

Table 2: Characteristics of Storage Technologies[11]

Technology	Most Common Use	Installed Capacity (MW)	Projects Announced/ Under Way	Levelized Costs ($/MWh)*
Mechanical Storage				
Pumped Hydroelectric Storage	Transmission System	22,610	11	152-198
Compressed Air Energy Storage	Transmission System	114	5	116-140
Flywheels	Peaker Replacement; Frequency Regulation; Distribution Substation; Distribution Feeder; Microgrid; Island; Commercial & Industrial	58	3	332-1,251
Electro-chemical Storage				
Sodium	Transmission; Peaker Replacement; Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	26	1	301-1,837
Lithium-Ion	Transmission System; Peaker Replacement; Frequency Regulation; Distribution Substation; Distribution Feeder; Microgrid; Island; Commercial & Industrial; Commercial Appliance; Residential	635	113	190-1,274
Lead-Acid	Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	51	2	425-1,710
Flow Battery	Transmission System; Peaker Replacement; Distribution Substation; Distribution Feeder; Island; Commercial & Industrial; Commercial Appliance; Residential	5	5	184-413
Thermal Storage	Transmission System; Peaker Replacement	669	2	227-862

* These levelized cost estimations vary depending on the end-use of the energy discharged from the storage system.

Potential Negative Effects of Energy Storage on Greenhouse Gas Emissions

Energy storage is often presented as a solution to the challenges utilities face in trying to promote clean energy resources in the fight against climate change. Storage can indeed encourage the penetration of intermittent and variable renewable energy resources.[12] A corollary to the assumption that storage is necessary for the integration of clean energy resources, is that storage would also lead to a reduction of greenhouse gas emissions.[13] Storage can certainly serve this goal. When paired with a clean generator, for example, it can store the excess energy generated at times of low market demand and inject it to the grid at a later time, reducing the need for generation from fossil-fuel powered bulk system generators.

However, contrary to common belief, the relationship between increased deployment of energy storage and reduced carbon emissions is not guaranteed in today's energy markets. In fact, several studies have shown that under certain conditions, additional storage can lead to increased emissions. The emissions impact of increased storage capacity depends on several effects, primarily: (1) whether the type of generation used to charge the storage is cleaner than the type of generation avoided when the storage is used; and (2) the amount of additional energy needed to make up for the efficiency losses from storage.[†]

- If storage is charged during off-peak times by dirty generators, and then discharged during peak times as a competitor to more expensive, and cleaner, energy sources, the net effect will be an increase in emissions.
- Energy storage demands more total energy generation to compensate for energy lost during charging and discharging, leading to greater emissions, if charged with emitting resources.

Marginal Emissions

Understanding how generators are dispatched is important for understanding the greenhouse gas emissions from electricity generation and, as a consequence, the avoided emissions resulting from an intervention to the electricity system, such as deployment of more energy storage. Because the combination of the types of generators running varies by time and location, the emissions from electricity generation also vary by time and location.[14] When demand increases, the magnitude of the change in emissions that results from the new electricity generation depends on the type of generator, i.e., the marginal generator, dispatched to meet that new demand. The emission intensity of these marginal generators determine the marginal emission rate. When a coal plant is "on the margin," the marginal emission rate is high. If a generator that is less carbon intensive, such as a natural gas plant, is on the margin, the marginal emission rate is lower. Because marginal generators vary depending on the time of day and the location, the emissions that can be avoided by using electricity discharges from energy storage systems also vary.

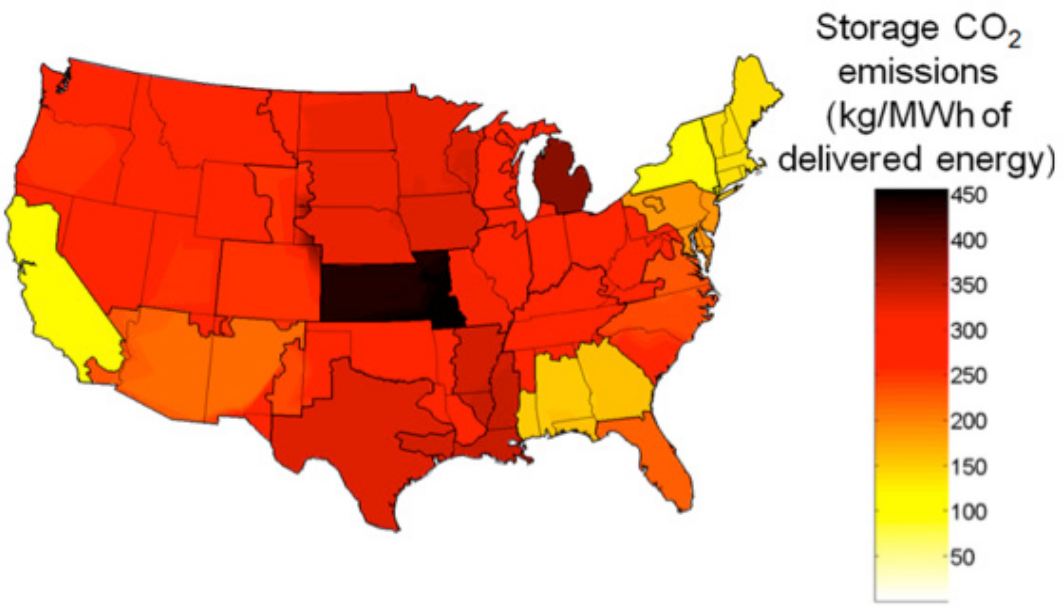
[†] In addition to these two drivers of storage-induced increases in emissions, there are secondary effects of storage that can increase emissions. Manipulation of market power by large generators, as well as pre-existing regulations, can play an important, and sometimes distortionary, role on the end-effect of storage on net emissions. See Revesz & Unel, *supra*.

The inherent incentive for energy arbitrage is that energy storage systems are charged when electricity prices are low and discharged when they are high. As the external costs of greenhouse gas emissions are not currently reflected in wholesale electricity prices, such arbitrage decisions will be made without considering the resulting changes in emissions. As a result, energy storage can increase emissions if the cheaper energy resources that are used in charging are dirtier than the more expensive energy resources that are displaced during discharging. Thus, when considering the environmental benefits of energy storage, it is critical to consider not only the decrease in emissions from the generator that energy storage avoids, but also the increase in emissions from the cheaper generator used for charging.

The academic literature confirms that this pattern could occur:

- Carson and Novan (2012) model energy arbitrage in Texas and show that with low penetration of renewables into the market, CO_2 and SO_2 emissions increase while NOx emissions decrease. Storage charges during off-peak times, when coal plants are on the margin. The storage discharges during peak hours, displacing high heat-rate gas generators, which compared to coal, have lower CO_2 and SO_2 emissions and higher NOx emissions.[15]
- Hittinger and Azevedo (2015) model the deployment of bulk storage in 20 locations across the United States find that net CO_2 emissions increased between 104 and 407 kg/MWh of delivered energy, owing to the fact that the marginal electricity provider at night is often a coal plant while the marginal provider at peak demand is a natural gas plant.[16]
- Hittinger and Azevedo (2017) calculate how much wind and solar would be required to offset the increase in emissions due to energy storage deployment. They find that, depending on location, between 0.03 MW and 4 MW of wind, and between 0.25 MW and 17 MW of solar, would be needed to offset the average increase in emissions from the installation of a 25 MW/100 MWh storage device.[17]

Figure 2: Potential CO_2 Emissions Impacts of Energy Storage



Source: CO_2 emissions resulting from the addition of bulk energy storage across the continental U.S. when there are no constraints on generation (Hittinger and Azevedo, 2017).

Perverse incentives may be more pronounced if the cost functions of dirtier generators have a particular shape. For example, the fixed costs of turning on certain generators, such as those powered by coal, are high, but the variable operational costs once the generator is turned on are low.[18] This pattern creates incentives for such a generator to continue operating once it is already on, as long as it can get sufficient revenue from the electricity it generates to cover its variable costs. Without energy storage, the amount of generation from such a generator would be limited by market demand. However, when paired with energy storage, this generator can produce additional electricity and store it to sell later. In this case, energy storage leads to increased generation from an emissions-intensive source. A coal plant, for example, that would normally operate below capacity at times of low demand (i.e., nighttime, or during spring and fall), can operate continuously at full capacity with the use of storage technology. In this case, the coal plant's use of storage to sell excess energy at times of higher demand, leads to an overall increase in emissions.

Additionally, it is costly for coal plants to vary their generation levels with changing demand.[19] Because they lose efficiency when varying generation, their fuel costs increase. Energy storage will allow such plants to continue operating at a fixed output level, and possibly at a higher capacity factor, that they find most efficient. The effect of this on emissions is ambiguous. On the one hand, energy storage might increase the efficiency of electricity generation in that plant, and hence would reduce emissions from any given amount of generation, all else equal. On the other hand, energy storage might help increase the total amount of generation from that particular plant, leading to an increase in emissions.

Efficiency Losses

Even if there is no difference between the carbon intensity of the marginal generators during the charging and discharging periods, energy storage can nevertheless increase emissions because of efficiency losses. Energy losses occur during charging and discharging energy storage systems, as well as during transmission and distribution.[20] As a result, a greater amount of total generation is needed to provide a given amount of electricity using storage, which leads to higher overall emissions. The extent of these losses is measured by "roundtrip efficiency," which is the ratio of the percentage of the energy put in to the energy retrieved from storage. Roundtrip efficiency varies across technologies. For example, compressed air energy storage, with a roundtrip efficiency of 27–54%, has high efficiency losses, while sodium-sulfur batteries, with a roundtrip efficiency of 85–90%, are much more efficient.[21]

If these efficiency losses are significantly high, energy storage can lead to increased emissions even when it uses less carbon-intensive generation to displace more carbon-intensive generation. Efficiency losses cause energy storage systems to require more energy input than the amount of energy they discharge. For example, if the roundtrip efficiency of a storage system is 50%, charging it would require double the amount of energy needed during discharging. So, unless the marginal emission rate during discharging is at least twice as high as the marginal emission rate during charging, the emissions will increase.

Policies Needed to Maximize the Benefits of Energy Storage Deployment

The current regulatory and policy framework provides insufficient incentives for developing economically efficient energy storage deployment, where and when it can bring the most benefits to the grid. Procurement mandates and direct investment incentives encourage the deployment of storage indiscriminately, without considering potential negative emissions effects, or which type of energy storage could bring the most benefit to which level of the grid. Some policies are targeted to provide incentives for energy storage only when paired with renewable generators. While this type of targeted incentive reduces the potential negative emissions consequences, they fail to provide incentives for the many other types of services storage systems can provide.

There are three main reasons why the current landscape lacks the proper signals for maximizing the benefits of energy storage systems. First, because prices do not take into account the external costs of electricity provision, such as the damages from greenhouse gas emissions, energy storage investment based on electricity arbitrage revenues does not lead to socially efficient deployment of energy storage. Second, barriers to entry prevent energy storage systems from fully participating in all the markets in which they could provide value. And, finally, energy storage systems cannot earn multiple revenue streams for various benefits they provide at different levels of the grid, so their current earnings do not accurately reflect their true value.

Achieving efficiency requires solving all three of these shortcomings. Therefore, policymakers should:

1. Put in place a regulatory and policy framework that takes emissions into account;
2. Eliminate any uncertainties and barriers to entry; and
3. Ensure that energy storage systems can be compensated for all the benefits they provide to the grid.

Internalizing Externalities

The most economically efficient way of internalizing an externality is to impose an economy-wide tax on greenhouse gas emissions. This first-best policy, however, requires congressional action, and in today's political climate is infeasible in the near term. Therefore, alternative ways to distinguish between socially beneficial and potentially harmful energy storage systems are required.

Carbon dioxide emissions in the electricity sector can be internalized by a "carbon pricing" policy in the wholesale electricity markets that makes generators pay for each ton of carbon dioxide they emit. Such carbon pricing would make it costlier for emitting resources to generate electricity, forcing them to bid higher prices in the wholesale market and creating an advantage for clean resources. Therefore, it aligns the inherent incentives in energy arbitrage with the clean energy goals of society.

Implementation of such a policy, however, requires more than the approval of state regulators. It requires coordination with grid operators, called "independent system operators" ("ISOs") or "regional transmission organizations ("RTOs"),

as well as approval from FERC. Even though there are efforts under way in some jurisdictions, like New York, to achieve this goal, redesigning the wholesale market to internalize externalities will take time.[22] Short-term strategies, at smaller scales, are necessary to hasten and smooth the transition to a cleaner grid.

Short-Term Strategy: Cost-Benefit Analysis in Procurement

As more states are looking into integrating energy storage systems into the grid immediately, an interim policy tool is needed to ensure socially beneficial energy storage deployment in the near term. A societal cost-benefit analysis can help state regulators incorporate greenhouse gas emission impacts of energy storage systems into decision-making, and thus can serve as that interim policy tool until a more comprehensive policy can be enacted in the long term.

The purpose of a cost-benefit analysis is to understand whether a specific investment is desirable. The net benefits of each alternative resource, whether it is a distributed energy resource or a traditional generator resource, can be represented using a common metric of dollars. Thus, as long as all the cost and benefit categories, including the external costs and benefits, are consistently calculated for each resource, comparing the net benefits of each alternative and choosing the one that yields highest net benefit to society will ensure that only socially beneficial energy storage systems are installed. Using cost-benefit analysis for energy storage systems would require a comprehensive analysis of all the benefits, as well as a careful study of the potential effects on emissions discussed. The arbitrage and other revenue opportunities for energy storage systems would help forecast an expected charging and discharging profile, which can then be used to quantify the potential benefits and costs of this system. The cost-benefit analysis would monetize these expected benefits and costs of a particular energy storage system given the specific network characteristics of the area of the planned investment.

The emissions impact of energy arbitrage can similarly be calculated based on the marginal emission rates during charging and discharging times of the expected profile. If the emissions from the generation of the electricity that is used to charge the energy storage system are less than the emissions from the electricity that would have had to be generated in the absence of the energy storage system during the discharge period, then energy arbitrage would lead to a decrease in emissions. If the opposite is true, energy arbitrage would lead to an increase in emissions. Quantifying and monetizing these external costs in the cost-benefit analysis would indicate negative net benefits if a particular energy storage system would provide little benefits at the expense of a large increase in greenhouse gas emissions. Therefore, such a well-done cost-benefit analysis can prevent investments in energy storage systems that would use high carbon intensive generation to displace low carbon intensive generation.

An added advantage of cost-benefit analysis is that it can take into account emissions related to the construction and the operation of the storage systems. A comparative study of different energy storage systems finds that lifecycle emissions differ, not only due to the type of the paired generator, but also due to the type of the energy storage system itself.[23] Therefore, a cost-benefit analysis that analyzes the total emissions during an energy storage system's entire lifespan is desirable.

While such use of a cost-benefit analysis can be a solution in the short term, it is not sufficient in the long term. First, it can be applied only to investments over which state regulators have jurisdiction. Therefore, it cannot prevent an unregulated energy company from investing in energy storage systems that might have detrimental emissions consequences. Second, carrying out a comprehensive analysis for every single investment opportunity might turn out to be burdensome given the expected increase in energy storage projects over the next decade, and may lead to delays in construction. Therefore,

while policymakers can rely on cost-benefit analysis in the short term, long-term policy priorities must focus on that the market price signals are accurate, and that externalities are internalized in the market.

Eliminating Barriers to Entry

At present, ISOs and RTOs integrate energy storage systems into their organized wholesale markets in different ways. Some markets already allow certain storage technologies to provide ancillary services. However, these rules were designed with traditional generators in mind and lack the flexibility to recognize unique characteristics of energy storage systems.[24] Some aspects of these market rules, such as performance penalties that penalize storage systems for not providing certain services while charging, create disincentives for energy storage systems.

Redesigning market rules to ensure participation of energy storage systems fully in the market to the extent of their unique technical capabilities will increase the efficiency of the electricity markets. With the Storage Rule, released in February 2018, FERC has made progress towards this goal by aiming to remove some of the barriers currently hindering electric storage resources.[25]

In the Storage Rule, FERC recognized that energy storage systems have the ability to provide a variety of services such as energy, capacity, and regulation, yet are restricted by compensation schemes that were designed for other resources.[26] Therefore, FERC asked ISOs and RTOs to revise their tariffs to accommodate the participation of energy storage resources based on their physical and operational characteristics, and their capability to provide energy, capacity, and ancillary services. For example, FERC proposed new bidding parameters such as charge and discharge time and rate, which can give ISOs and RTOs information about the characteristics about energy storage systems, and hence the services they can provide.

However, some questions regarding the implementation of the Storage Rule still remain, and how they are resolved will affect the incentives for the development of energy storage resources. Performance requirements, such as minimum run-times, are allowed to remain in ISOs and RTOs market rules. Some commenters on the proposed version of FERC's Storage Rule argued that these limitations, as well as other requirements like "must-offer" rules, can limit the ability of some storage systems to provide value to the grid that they are technically capable of providing.[27] While FERC acknowledged this possibility, it further explained that while it was not "appropriate to establish one standard" regarding performance requirements' accommodation of energy storage, it was expecting ISOs and RTOs to demonstrate compliance with the mandate of the overall rule and show that their "market rules provide a means for electric storage resources to provide capacity."[28]

Further, FERC has not ordered ISOs and RTOs to remove any requirements that resources providing ancillary services must also have an energy schedule, meaning all resources must be online and running at the time they are called upon to provide ancillary services.[29] Some commenters pointed out that this requirement excludes electric storage resources that are able to start and ramp-up more quickly than traditional resources, and are therefore technically capable of providing ancillary services despite not already being online.[30] FERC acknowledged that this rule may limit the participation of certain resources, but ultimately concluded that ordering ISOs and RTOs to allow storage resources without an energy schedule to participate in the market for ancillary services could complicate, and render inefficient, the dispatch process. Nevertheless, FERC encouraged ISOs and RTOs to consider how to allow storage resources to provide ancillary services without participating in the energy market.[31]

Ensuring that energy storage resources are able to receive compensation for all the values they are technically able to provide to the grid is essential for efficient resource deployment. Therefore, beyond these FERC mandates, ISOs and RTOs have the responsibility to reshape market mechanisms in order to maximize storage benefits. In order to encourage storage resource participation, ISOs and RTOs need to examine their existing participation models, which are designed for traditional resources, and eliminate or redesign any rules that inadvertently create disincentives for energy storage resources.

Eliminating Barriers to Earning Multiple Value Streams

Accurate price signals show the true value of a good or service to the society, and therefore lead to economically efficient investment signals. Therefore, maximizing the benefits of energy storage requires investors to be able to receive compensation for the wide range of services that energy storage can provide to every level of the energy grid.

Because the revenue potential based on only one category of benefits does not justify the current high upfront investment that is needed, one value stream is not enough to give enough incentives for large scale storage deployment.[32] A new framework that allows compensation for different value streams should be developed, even if those value streams are based on benefits that accrue to different parts of the market and, thus, have to rely on different compensation mechanisms. Ensuring accurate price signals requires unbundling the different services that energy storage systems can provide and ensuring that they are able to be compensated for each service.

Further, because energy storage can provide benefits to both wholesale markets, which are under FERC jurisdiction, and retail markets, which are under state jurisdiction, coordination between the federal authorities and state regulators is needed. FERC and state regulators must coordinate to explicitly lay out the categories of benefits of energy storage systems and how to compensate for each benefit. In its Storage Rule, FERC clarified one narrow issue: that storage should be allowed to provide value to the wholesale markets. FERC did not directly address complications that may arise from a storage resource's simultaneously participation in both the wholesale and retail markets. Future coordination between regulators at both the state and federal level will be needed to resolve these complications.

Under FERC's Storage Rule, ISOs and RTOs must create a participation model that allows energy storage resources to receive compensation based on their physical and operational characteristics, including: state of charge, minimum state of charge, maximum state of charge, minimum charge limit, maximum charge limit, minimum discharge limit, discharge ramp rate, and charge ramp rate.[33] FERC declined to require ISOs and RTOs to make each of these characteristics an individual bidding parameter, but explained that they must demonstrate how their market rules account for each of these characteristics.[34]

Some current state-level initiatives provide a blueprint for the accurate valuation of the benefits of energy storage. New York's "value stack" approach is a regulation scheme in which storage systems can be compensated based on specific categories of benefits they provide.

Table 3: New York State's Proposed Value Stack Compensates for Five Different Values

Value	Service	Provided to
Energy value	Provides energy	Generation and partially transmission
Installed capacity value	Reduces the need for generation capacity expansion	Generation
Environmental value	Reduces emissions	Society at large
Demand reduction value	Reduces the need for distribution-level infrastructure investment	Distribution
Locational system relief value	Reduces distribution-level congestion	Distribution

New York's "Value Stack" Approach

New York State is currently in the process of establishing a methodology to value all distributed energy resources.[35] The New York State Public Service Commission recently issued an order in this proceeding outlining a framework that is generally described as a "value stack" approach.[36] In this approach, distributed energy resources, including energy storage systems, are compensated for their energy value, capacity value, and environmental value of their net exports. In addition, to account for the distribution system value of DERs, the systems that can reduce demand during the ten highest usage hours of a utility's territory are paid a demand reduction value, and the systems located at "high value" grid locations are paid a locational system relief value.

The New York State Public Service Commission's initial order, which is only an interim order until a more complete methodology can be established in the second phase, restricts this value stack compensation to resources that can provide net exports to the grid. Therefore, energy storage systems that are not paired with a generating resource are not currently eligible for this compensation. However, the second phase of the proceeding is expected to broaden the scope of the value stack approach to include other energy storage systems that provide value to the system by modifying or shifting the customer demand even if they do not provide net exports to the grid.[37] This second phase will also improve and modify the initial value stack to include more benefits categories, at more granular levels. Further, it will improve the methodology for calculating some of the value categories that do not already have an established methodology, such as the locational system relief value, or the demand reduction value.

In an unbundled compensation approach, each value component can receive compensation from multiple grid actors based on where the benefits accrue. For example, an energy storage system can be compensated for the energy value in the wholesale electricity market, while simultaneously receiving compensation for its locational system relief value at the distribution level. The environmental value that energy storage systems provide by avoiding any (uninternalized) emissions, if it exists, can be paid by the ratepayers as a whole. FERC's Storage Rule neither specifically endorses nor prohibits this model, but does leave open some questions that must be resolved moving forward, namely how to address concerns around accounting for behind-the-meter storage and avoiding double-compensation.

Challenges Related to Behind-The-Meter Energy Storage

Storage resources located behind the meter pose a challenge to regulators depending on how they are used: these resources may charge using energy from the grid, and then later discharge either to satisfy behind–the-meter energy demand of the consumer, or back to the grid. FERC has determined that energy purchased from the grid for the purpose of later resale back the grid to provide capacity, energy, and ancillary services constitutes a "sale for resale" and therefore should be charged the wholesale rate. Energy consumed behind the meter, however, should be charged the retail rate. Therefore, in order for ISOs and RTOs to accurately charge storage resources the correct rates for all energy withdrawn, they must be able to determine the end use of that energy. The Storage Rule requires ISOs and RTOs to developing metering and accounting practices that would enable this determination.[38] It remains to be seen exactly what methodologies will be proposed by each ISO and RTO and whether FERC will find that the proposed method meets the requirements of the Final Rule.

The second challenge for properly valuing behind-the-meter energy storage resources is related to the retail rates. Because current retail rates are flat, bundled volumetric rates that are set by state utility regulators and roughly correspond to average cost of providing electricity to the end-users, they lack the necessary granularity to provide efficient price signals for behind-the-meter energy storage systems.[39] Setting up a framework for accurate valuation is especially critical as behind-the-meter energy storage systems are likely to become more prevalent in the recent future.[40] Behind-the-meter systems can provide benefits to both the distribution system and the wholesale market and thus have the potential for conferring large benefits on the grid. Therefore, retail rate reforms by states are necessary to complement FERC action in order to incentivize the right type of energy storage system at where and when it is needed, both in front of- and behind-the-meter.

Market-Based and Cost-Based Rates: Concerns Over Double Compensation

In recent debate, the concerns of regulators that energy storage systems not receive "double compensation" for their services has impeded the development of policy allowing for compensation through multiple value streams. While preventing duplicate compensation for the same service is, of course, necessary for economic efficiency, ensuring that distributed energy resources can be fully compensated for the unique benefits they can provide at every level—generation, transmission, and distribution—is also necessary for economic efficiency in energy storage deployment.

A framework that enables energy storage systems to be compensated for the many services they are able to provide must account for multiple value streams, not only paid for by different grid entities, but also compensated at different rates, using different methods of rate calculation. Electric storage resources providing value to the energy grid through transmission or grid support services are generally compensated through "cost-based" rates, which are pre-determined and fixed to guarantee a minimum return. These rates are based on the system's cost of providing a given service. Energy supply, however, is compensated according to "market-based" rates, which are determined through supply and demand. A system that generates and sells electricity in a competitive wholesale market will receive whatever the market-driven "market-rate" is for each kWh sold.[41]

Key Terms

Cost-based rates: fixed, pre-determined rates that guarantee a minimum return, based on a storage system's cost of providing the service.

Market-based rates: set by supply and demand in a competitive market.

Storage resources can perform ancillary services entitled to cost-based compensation while also selling power in wholesale markets at a market-based rate, even switching between the two almost instantaneously.[42] In January 2017, FERC issued a Policy Statement that provided guidance on how electric storage resources could receive both cost-based rate recovery and market-based revenues without receiving double compensation.[43] FERC acknowledged the possibility that storage systems might recover their costs of operation through market-based sales while also receiving cost-based rates specifically designed to cover operation expenses, thereby receiving a windfall at the expense of ratepayers. FERC noted, however, that instances of double recovery could be addressed by crediting a storage system's market-based revenues back to ratepayers.

Further, FERC largely dismissed fears that the ability of storage systems to receive two streams of revenue would enable storage owners to sell electricity at prices low enough to suppress wholesale market rates. Here, FERC noted that other market participants currently receive some form of cost-based rate recovery while simultaneously supplying to the market. For example, "vertically-integrated utilities," which own generation as well as transmission and distribution, receive cost-based compensation for electricity sold within a defined area, while also engaging in market-based sales of electricity outside that area. FERC concluded that the compensation mechanisms for storage, including the setting of "just and reasonable" cost-base rates, could be designed in such a way as to avoid anti-competitive effects in the market.

FERC's 2018 Storage Rule did not address commenters' concerns about cost-based recovery and multiple value streams, explaining that the issue was outside the scope of the storage rule.[44] However, the order does require that RTOs and ISOs provide compensation to storage systems for services that are not typically procured through a market mechanism, such as black start services that help restore power to a generator without the need for withdrawals from the grid, primary frequency response, and reactive power services.

Under the value stack approach described above, preventing double compensation is straightforward. If, for example, a system is already being compensated for its energy value by the wholesale markets, the same system would not be allowed to get compensated for its energy value by any other retail program, but would be allowed to be paid for its distribution level benefits by a retail program. Similarly, if a system is already being paid for the environmental value directly, it would not be allowed to participate in additional programs such as renewable energy credit markets. Such a categorization would allow energy storage systems to be compensated for the full benefit they provide, while alleviating double compensation concerns.

Implementing such an approach will require coordination among ISOs and RTOs, which determine the eligibility rules and tariffs; federal regulators, which approve these rules and tariffs; state regulators, which regulate utilities; and utilities, which serve the customers. Such coordination is especially important for behind-the-meter distributed energy storage systems, so they can be compensated for the value they provide to the entire electric system, not just the value they provide to their owners. Unless this fundamental coordination problem can be resolved, neither the level of energy storage deployment, nor the composition of the types of energy storage systems that are deployed will be efficient.

Maximizing Benefits from Energy Storage: A Road Map

1. Internalizing Externalities

- In the absence of economy-wide carbon pricing, policymakers should implement a carbon pricing policy in the wholesale electricity markets.
- In the shorter-term, policymakers should employ cost-benefit analyses that price the societal costs of climate change into specific regulatory and procurement decisions.

2. Eliminating Barriers to Entry

- ISOs and RTOs must revise tariffs to accommodate energy storage systems for the range of services they have the technical ability to provide, allowing storage systems to be precisely compensated for the value they provide to the grid.
- Rules that currently provide disincentives because they are designed for traditional resources should be redesigned.

3. Eliminating Barriers to Earning Multiple Value Streams

- Federal and state policymakers should coordinate to explicitly lay out the categories of benefits of energy storage systems and how to compensate for each benefit.
- A framework should be developed that allows for services to be paid for by different grid actors, at different rates, using different methods of rate calculation.
- Policies should avoid double compensation without preventing storage systems from receiving compensation for all services provided.

Regulatory Roles and Challenges

As with other grid-connected technologies, energy storage resources fall within the regulatory jurisdiction of both federal and state entities. Under the Federal Power Act (FPA), FERC holds plenary jurisdiction over wholesale interstate markets, while state officials exercise authority over their respective in-state markets and utilities.[45] In general, federal and state governments share the task of regulating grid operation as well as any interconnected systems, like generation and transmission resources. Understanding this jurisdictional divide and establishing the roles each regulator can play in implementing emissions-reduction policies is crucial to the success of energy storage policies.

Regulatory Roles

There are two main regulatory actors that each have their own role to play in the formation of a regulatory and policy framework that encourages the efficient allocation of storage resources: FERC and state governments.

- The Federal Power Commission was established by Congress in 1920, and renamed the Federal Energy Regulatory Commission (FERC) in 1977. FERC is an independent agency tasked with overseeing the transmission and wholesale sales of natural gas, oil, and electricity in interstate commerce.
- State governments have the authority to regulate utilities within their borders and to implement state-wide policies, such as storage infrastructure requirements and net-metering programs, which can influence the incentives for energy storage deployment.

While establishing clear jurisdictional boundaries between state and federal regulators has been increasingly difficult as new types of energy resources such as demand response come into play,[46] this challenge is especially complicated for energy storage systems. Because energy storage systems can provide benefits at different levels of the electricity grid regardless of where they are physically located, jurisdictional boundaries for regulating energy storage systems are particularly uncertain.

Tasks for FERC

FERC has an important role in achieving efficient price signals in the wholesale markets. The FPA directs FERC to ensure that rates and rules are "just and reasonable," and are not unduly discriminatory or preferential.[47] Therefore, ensuring that the ISO and RTO tariffs, relevant price formation mechanisms, and other payment mechanisms such as performance payments provide accurate compensation, and that these tariffs do not hinder the efficiency of the markets by insufficiently compensating an energy resource, or by preventing it from being compensated at all, is FERC's main responsibility.

In the Storage Rule, FERC clarified that sales of power into energy storage facilities for the purpose of later resale to the grid, including in the form of provision of ancillary services, constitutes a sale of wholesale power.[48] Power sold to storage resources that is later used by retail consumers for their own purposes, however, is a retail sale within the jurisdiction of state entities. Because how assets are compensated differs based on whether an asset is subject to a FERC or state jurisdiction, this clarification provides much needed financial certainty for energy storage developers.

Energy storage systems can bring benefits to generation, transmission, and distribution systems at the same time, and therefore they cannot, and should not, be classified as assets in only one of these traditional categories. But, because energy storage can perform all three of these functions, regulators and developers are unsure about how to design rate schemes, allocate cost recovery, and prevent double-counting of various energy storage services, while also ensuring that storage providers are compensated fully for all the functions storage performs.

The Storage Rule went a long way in establishing more clarity, by requiring RTOs and ISOs to establish participation models for energy storage systems that recognize their physical and operational characteristics and allow them to the compensated for all the services—energy, capacity, and ancillary—that they are technically capable of providing. In order to effectively implement this model, ISOs and RTOs must define and categorize the benefits energy storage systems can provide, and determine which benefit is going to be compensated at what level to ensure full, but not double compensation.

While FERC identified a list of technical characteristics that must be taken into account when developing a pricing scheme for energy storage services, it did not mandate that RTOs and ISOs use specific bidding parameters. Neither did it order ISOs and RTOs to remove run-time and must-offer requirements that could potentially limit the full integration of energy storage resources into the compensation model. Instead, FERC explained that it was choosing to allow ISOs and RTOs flexibility in designing their participation models. However, it remains FERC's responsibility to ensure that the specific ISO/RTO participation models are truly eliminating barriers to entry and hence ensuring just and reasonable rates.

Tasks for State Regulators

While the task of eliminating inefficient wholesale market rules and barriers primarily rests on FERC's shoulders, states also have the responsibility to implement policies for efficient deployment of energy storage systems.

If the wholesale markets fail to fully internalize greenhouse gas emissions, then the responsibility of ensuring that energy storage systems are indeed socially beneficial rests with the states. State regulators should direct their utilities to conduct a cost-benefit analysis to consider the potential impact of energy storage systems on greenhouse gas emission before deploying them. When wholesale markets fail to internalize emissions, using a cost-benefit analysis would help ensure that the installation of energy storage systems would not increase greenhouse gas emissions.

States also have an important role in creating accurate price signals. While FERC is responsible for ensuring efficient price signals for the transactions in the wholesale markets, states bear the same responsibility in the retail markets.[49] Creating a framework for energy storage systems to be compensated based on all the values they bring—even when installed locally behind-the-meter—is crucial to efficiency. Relatedly, it is up to state regulatory mechanism to coordinate with ISOs and RTOs to ensure that energy storage system are not receiving inefficient double compensation from both the retail and wholesale markets for provision of the same service.

It is, of course, challenging to quickly move to an approach that both unbundles payments based on different value stacks for each category of benefit, and also calculates the remuneration for each of these stacks in a temporally and locationally granular fashion. State regulators have their work cut out for them in determining the value categories, the granularity of each category, and the compensation formula for each category.

Conclusion

To ensure that energy storage systems can help achieve climate policy goals, externalities related to greenhouse gas emissions should be internalized, entry barriers should be eliminated, and market rules should be modified to guarantee accurate price signals that can value all the benefits energy storage systems have the technical ability to provide. Unless these reforms can be enacted, both the level and the composition of energy storage deployment will remain far from efficient.

Endnotes

1 Dep't of Energy Global Energy Storage Database, https://perma.cc/6S2W-3V3T.

2 Energy Info. Admin., Electric Power Annual 2015 70 (2016).

3 Energy Storage Association, 35x25: A Vision for Energy Storage, 1, November 2017.

4 Energy Info. Admin., Annual Energy Outlook 2017 71 (2017), https://perma.cc/4BBB-SLBK.

5 *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 83 Fed. Reg. 9580, 9582 (March 6, 2018), 162 FERC ¶ 61,127 (to be codified at 18 C.F.R. pt. 35) [hereinafter "Storage Rule"].

6 U.S. Energy Information Administration, *Electric generator dispatch depends on system demand and the relative cost of operation*, Today in Energy, August 17, 2012.

7 Garrett Fitzgerald et al., Rocky Mountain Inst., The Economics of Battery Energy Storage 16 (2015), https://perma.cc/A6PY-V66E.

8 *See* P. Bennet et al., *Impacts of Intermittent Generation*, in Large Energy Storage Handbook 17 (Frank S. Barnes & Jonah G. Levine eds., 2011).

9 *See* Andrew H. Meyer, *Federal Regulatory Barriers to Grid-Deployed Energy Storage*, 39 Colum. J. Envtl. L. 479, 513-14 (2014).

10 *See* Gwen Bredehoeft & Eric Krall, *Increased Solar and Wind Electricity Generation in California Are Changing Net Load Shapes*, Today in Energy (Dec. 9, 2014), https://perma.cc/4QUF-A3VW.

11 Table reproduced from Richard L. Revesz & Burcin Unel, *Managing The Future Of The Electricity Grid: Energy Storage And Greenhouse Gas Emissions*, 42 Harv. Envtl. L. Rev. 139, 155 (2018) using data from Lazard, Lazard's Levelized Cost of Storage Analysis—Version 3.0, (2017) and Version 2.0, (2016).

12 *See Frequently Asked Questions*, Energy Storage Ass'n, https://perma.cc/HFM5-BMWA.

13 *See* Amy L. Stein, *Reconsidering Regulatory Uncertainty: Making A Case for Energy Storage*, 41 Fla. St. U. L. Rev. 697, 709 (2014).

14 *See* Kyle Siler-Evans *et al.*, *Marginal Emissions Factors for the U.S. Electricity System*, 46 Envtl. Sci. & Tech. 4742 (2012); Joshua S. Graff Zivin *et al.*, *Spatial and Temporal Heterogeneity of Marginal Emissions: Implications for Electric Cars and Other Electricity-Shifting Policies*, 107 J. Econ. Behavior & Org. 248, 249 (2014).

15 *See* Richard T. Carson & Kevin Novan, *The Private and Social Economics of Bulk Electricity Storage*, 66 J. Envtl. Econ. & Mgmt. 404 (2013).

16 Eric Hittinger & Ines Azevedo, *Bulk Energy Storage Increases United States Electricity System Emissions*, 49 Environ. Sci. Technol., 3203, 3208 (2015).

17 Eric Hittinger & Ines Azevedo, *Estimating the Quantity of Wind and Solar Required To Displace Storage-Induced Emissions*, 51 Environ. Sci. Technol. 12988, 12990 (2017).

18 *See* Keith E. Holbert, Ariz. State Univ., Electric Energy Economics 1 (2011), https://perma.cc/GPS3-69H8.

19 *See* Paul Denholm & Tracey Holloway, *Improved Accounting of Emissions from Utility Energy Storage System Operation*, 30 Envtl. Sci. & Tech. 9016, 9018 (2005) ("As it ramps up and down, the plant will operate at different efficiencies. In addition, startup and shutdown result in lost heat energy.").

20 Richard Schmalensee & Vladimir Bulovic, Mass. Inst. of Tech. Energy Inst., The Future of Solar Energy 154, 285 (2015), https://perma.cc/S478-9CNH.

21 *Id.* at 293.

22 See, e.g., Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, Case Nos. 15-E-0751 & 15-E-0082, N.Y. Pub. Serv. Comm'n. (2017).

23 *See* Paul Denholm & Gerald L. Kulcinski, *Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems*, 45 Energy Conversion & Mgmt. 2153 (2004).

24 Storage Rule at 9582.

25 *See id.*

26 *See id.*

27 *See* Advanced Energy Economy, Comments on FERC's Proposed Storage Rule (proposed Nov. 17, 2016), Docket No. RM16-23-000, at 14–15; GridWise Comments on FERC's Proposed Storage Rule (proposed Nov. 17, 2016), Docket No. RM16-23-000, at 3.

28 Storage Rule at 9595.

29 *Id.* at 9598.

30 *See id* at 9596 (summarizing comments).

31 *Id.* at 9598.

32 *See* Judy Chang et al., The Brattle Grp., Renewables and Storage: Does Size Matter? (2010), https://perma.cc/VC2U-3GCE; Judy Chang et al., The Brattle Grp., The Value of Distributed Electricity Storage in Texas (2014), https://perma.cc/D37X-DFTM.

33 Storage Rule at 9613.

34 *Id.* at 9609.

35 *See* N.Y. Pub. Serv. Comm'n., Supplemental Staff White Paper on DER Oversight (2017).

36 Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, Case Nos. 15-E-0751 & 15-E-0082, N.Y. Pub. Serv. Comm'n. (2017).

37 *See* Notice of Phase Two Organizational Conference, Case No. 15-E-0751, N.Y. Pub. Serv. Comm'n. (2017).

38 Storage Rule at 9625.

39 *See* Richard Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 44 Harv. Envtl. L. Rev. 43, 94 (2017); *see also* Dave Gahl et al., *Getting More Granular: How Value of Location and Time May Change Compensation for Distributed Energy Resources*, Solar Energy Industry Association, 7, January 2018.

40 *See* Peter Maloney, *How Behind-the-Meter Storage Could Make Up 50% of the U.S. Market by 2021*, Util. Dive (Jan. 31, 2017), https://perma.cc/AF89-J9WC.

41 For a general discussion regarding difficulties classifying energy storage, *see* Anita Luong, Am. Inst. of Chem. Engineers, Grid-Scale Energy Storage, 14–16 (2011), and Stein, *supra* note 9 at 717–30.

42 Storage resources can inject small amounts of power into grid transmission lines, or absorb excess power that isn't immediately consumed, to maintain grid frequency – an ancillary service that entitles the storage resource to cost-based rate recovery. In addition, recall that most storage technologies don't literally "store" electricity – as a silo literally stores grain – but rather hold the kinetic, potential, mechanical, or thermal energy that is converted into electricity upon request. Accordingly, a storage system can generate electricity this way and sells its output in wholesale markets at the competitive market-based rate. *See* Stein, *supra* note 9 at 718–19.

43 *See* FERC, Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, Policy Statement, 158 FERC ¶ 61,051 (Jan. 19, 2017).

44 Storage Rule at 9626.

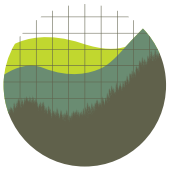
45 Since the Federal Power Act of 1935, federal regulators have exercised regulatory jurisdiction over "matters relating to . . . the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," so long as such matters "are not subject to regulation by the States." 16 U.S.C. §§ 824–824w (2017). The Act, for example, expressly reserves to states oversight of facilities either "used for the generation of electric energy", "in local distribution", or "for the transmission of electric energy in intrastate commerce." 16 U.S.C. § 824(b)(1) (2012).

46 *See* FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 775–782 (2016) (holding that FERC's Order No. 745 was a valid exercise of FERC's authority over wholesale demand response).

47 16 U.S.C. §§ 824d–824e (2012).

48 Storage Rule at 9601.

49 *See generally*, Frank A. Wolak, *Regulating Competition in Wholesale Electricity Supply, in* Nat'l Bureau of Econ. Research, Economic Regulation and its Reform: What Have We Learned? 195, 210 (Nancy L. Rose ed., 2014) (discussing the role played by state regulators in price signaling on the retail markets).



Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org

Exhibit F

The Social Cost of Greenhouse Gases and State Policy

A Frequently Asked Questions Guide

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

October 2017

Iliana Paul
Peter Howard, Ph.D.
Jason A. Schwartz

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Peter Howard is the Economics Director at the Institute for Policy Integrity at NYU School of Law. Iliana Paul is a Policy Associate at the Institute for Policy Integrity at NYU School of Law. Jason A. Schwartz is the Legal Director at the Institute for Policy Integrity at NYU School of Law. The authors wish to thank Denise Grab, Richard Revesz, Derek Sylvan, and Burcin Unel for their contributions to this report.

Table of Contents

Executive Summary 1

What is the SCC? 2
- What is the best estimate of the SCC for states to use? 2
- What's included in the SCC number? What isn't? 3
- Is there a state-specific SCC we can use? 4
- Why should our state use a global number? 4

How and why states should use the SCC? 7
- Why should my state use the SCC? 7
- What are the possible applications of the SCC in state policymaking? 8
- The emissions from my state/this leasing decision/this regulation/this project are so small, does the SCC still apply? 8
- Which states are already using the SCC, and how? 9
  - California 9
  - Colorado 9
  - Illinois 9
  - Minnesota 10
  - Maine 10
  - New York 11
  - Washington 11
- My state already has a climate policy or a renewable energy policy in place, so why should we still use the SCC? 12

Are the federal IWG numbers still the best? 12
- How were the IWG numbers developed? 13
- How have the IWG numbers been used to date? 14
- Who has endorsed the IWG numbers? 15
- Did a recent Trump Executive Order delegitimize the IWG numbers? 15
- If the Trump administration comes out with a new number, should we use it? 15
- How will the numbers be updated? 15
- Are there other estimates of the SCC? 16

What methodological choices went into the IWG numbers? 16
- Which models? 16
- Why did the IWG select a 3% discount rate as a "central" estimate? 17
  - First, what is a discount rate? 17
  - Why is the discount rate important? 17
  - Why is the IWG correct to exclude a 7% discount rate? 18
  - What is a declining discount rate? 18
  - Why should the central IWG estimate be interpreted as a lower bound? 19
- Why did the IWG select a 300-year time horizon? 19
- Why did the IWG recommend a global rather than domestic estimate? 20

Why did the IWG develop separate numbers for methane and nitrous oxide, rather than just adjusting by their global warming potential? 20

Common (but misguided) critiques of the SCC 22

Aren't there benefits of carbon dioxide emissions? 22

If we adapt to climate change or develop new technologies, then won't the value of avoiding emissions be zero? 22

Isn't there too much uncertainty around the SCC to use it? 22

Didn't the noted economist Robert Pindyck say the SCC numbers were flawed? 23

Technical guidance: how do we apply the SCC in our analyses? 24

What should we choose as our central estimate? 24

Can we just calculate damages from a single year of emissions? 25

How does discounting work? 25

What about inflation? 25

So once we multiply emissions by the SCC and discount back, are we done? 26

And what are all of the steps put together? 26

How is the SCC used in an analysis with other discount rates? 27

What other resources exist? 27

Executive Summary

Scientists predict that climate change will have, and in some cases has already had, severe consequences for society, like the spread of disease, decreased food security, and coastal destruction. These damages from emitting greenhouse gases are not reflected in the price of fossil fuels, creating what economists call "externalities." **The social cost of carbon (SCC) is a metric designed to quantify and monetize climate damages, representing the net economic cost of carbon dioxide emissions.** Simply, the SCC is a monetary estimate of the damage done by each ton of carbon dioxide that is released into the air. The SCC can be used to evaluate policies and guide decisions that affect greenhouse gas emissions.

At the federal level, the SCC has been used by numerous agencies for regulatory impact analysis and in environmental impact statements; however, the SCC can also be used across a range of other areas, including electricity ratemaking, resource management policy and royalty setting, setting emissions caps, and establishing a carbon price. States should use the SCC in a number of different contexts to aid in making rational policy decisions in a transparent manner. Many states are already using the SCC in their decisionmaking.

The best estimates of the SCC for states to draw from are currently the 2016 estimates from the federal government's Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), despite the fact that this group was recently disbanded. The 2016 IWG estimates are based on the most up-to-date science and economics and were arrived at through an academically rigorous, transparent, and peer-reviewed process. The National Academies of Science, Engineering and Medicine (NAS) conducted a thorough review of the IWG estimates in 2016, and a group of scholars at the nongovernmental organization Resources for the Future has begun a project to update the SCC based on the NAS recommendations.

State decisionmakers can benefit from an understanding of several issues related to the SCC, including discount rates, time horizons, and the global nature of the IWG estimate. States should also know that the IWG calculated additional estimates specifically for the social cost of methane and the social cost of nitrous oxide, which are more precise quantifications of the social costs of emissions of those greenhouse gases than simply multiplying the SCC by the global warming potential of those gases, and can be used in all of the scenarios where the SCC can be used.

There are many misguided critiques of the SCC made by those who would prefer less regulation of greenhouse gases, but this should not deter decisionmakers from using the SCC. In fact, there are a wide range of resources that decisionmakers can use while exploring how and why to use the SCC.

What Is the SCC?

Scientists predict that climate change will have, and in some cases has already had, severe adverse consequences for society, like the spread of disease, decreased food security, and coastal destruction. These damages from emitting greenhouse gases are not reflected in the price of fossil fuels, creating what economists call "externalities." **The social cost of carbon (SCC) is a metric designed to quantify and monetize climate damages, representing the net economic cost of carbon dioxide emissions.** Simply, the SCC is a monetary estimate of the damage done by each ton of carbon dioxide[1] that is released into the air.

The SCC can be used to evaluate policies and guide decisions that affect greenhouse gas emissions.

What is the best estimate of the SCC for states to use?

The federal government's Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), which operated from 2009-2017, remains the best source for SCC estimates. Its methodology, and why its estimates are the best available values for the SCC, are discussed below. Values for the social cost of other greenhouse gases are also discussed in a later section.

Table 1 is from the Interagency Working Group's 2016 Technical Support Document and shows the SCC estimates, in 2017 dollars, at five-year intervals. In all of the IWG technical support documents, their figures are given in 2007 dollars, but the values presented here in Table 1 are inflated to current (2017) dollars for ease of reference.

Table 1: Social Cost of CO_2 (in 2017 dollars per metric ton of CO_2)[2]

Year of Emission	Average estimate at 5% discount rate	Average estimate at 3% discount rate—IWG's Central Estimate	Average estimate at 2.5% discount rate	High Impact Estimate (95th percentile estimate at 3% discount rate)
2020	$14	**$50**	$74	$148
2025	$17	**$55**	$82	$166
2030	$19	**$60**	$88	$182
2035	$22	**$66**	$94	$202
2040	$25	**$72**	$101	$220
2045	$28	**$77**	$107	$236
2050	$31	**$83**	$114	$254

[1] Note that a metric ton (2,204 pounds, also known as the tonne) is slightly different from both a short ton (2,000 pounds) and a long ton (2,240 pounds). There are many ways to conceptualize a metric ton (2,204 pounds) of carbon dioxide. A metric ton of carbon dioxide is how much a typical car emits after 2,397 miles or about 15% of a typical home's emissions from electricity use for a year (*see* EPA Greenhouse Gas Equivalencies Calculator at https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator). An important distinction is that, because carbon dioxide consists of carbon and oxygen, 3.67 metric tons of carbon dioxide is equivalent to 1 metric ton of carbon.

[2] Interagency Working Grp. on Soc. Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12,866 (2016) [hereinafter TSD 2016], at 4, *available at* https://www.obamawhitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf.

Note that the value of the SCC increases over time. This is because the further in the future greenhouse gases are emitted, the greater the damages they will cause, due to the effects of accumulation. Therefore, it is important to calculate the full stream of climate effects, i.e., to take into consideration the emissions from every year of a policy, so that these increasing damages are reflected. The importance of calculating a full stream of future effects, rather than choosing only one year for analysis, is discussed in a later section.

What's included in the SCC number? What isn't?

The numbers in Table 1 reflect climate damages as estimated by combining three "Integrated Assessment Models"—specifically, DICE, FUND, and PAGE. These models translate carbon dioxide emissions into changes in atmospheric greenhouse concentrations, atmospheric concentrations into changes in temperature, and temperature changes into economic damages.[3]

DICE calculates the effect of temperature on the global economy using a global damage function that is not disaggregated by impacts to specific sectors.[4] Alternately, PAGE, looks at economic, noneconomic, and catastrophic damages. Finally, FUND considers a number of specific market and nonmarket sectors, including: agriculture, forestry, water, energy use, sea level rise, ecosystems, human health, and extreme weather.[5]

Quantified impacts represented in the models include: changes in energy demand (via cooling and heating); changes in agricultural output and forestry due to alterations in average temperature, precipitation levels, and CO_2 fertilization; property lost to sea level rise; increased coastal storm damage; changes in heat-related illnesses; some changes in disease vectors (e.g. malaria and dengue fever); changes in fresh water availability; and some general measures of catastrophic and ecosystem impacts.

It is important to note, however, that these models omit or poorly quantify some highly significant damage categories, and therefore, the SCC values in Table 1 should be considered lower-bound estimates of the actual costs of marginal carbon emissions. In fact, many experts believe the IWG SCC values are severe underestimates (even while endorsing their continued use for the time being as the best currently available estimates).

Damages that are poorly quantified or omitted from the IAMs are listed in Table 2.

---

[3] Interagency Working Grp. on Soc. Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12,866 (2010) [hereinafter TSD 2010], at 5, *available at* https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.

[4] TSD 2010, *supra* note 3, at 6.

[5] TSD 2010, *supra* note 3, at 7.

Table 2: Damages Omitted from the SCC[6]

Category	Specific Impacts Missing from the SCC*
Health	Respiratory illness from increased ozone pollution, pollen, and wildfire smoke
	Lyme disease
	Death, injuries, and illness from omitted natural disasters and mass migration
	Water, food, sanitation, and shelter
Agriculture	Weeds, pests, and pathogens
	Food price spikes
	Heat and precipitation extremes
Oceans	Acidification, temperature, and extreme weather impacts on fisheries, species extinction and migration, and coral reefs
	Storm surge interaction with sea level rise
Forests	Ecosystem changes such as pest infestations and pathogens, species invasion and migration, flooding and soil erosion
	Wildfire, including acreage burned, public health impacts from smoke pollution, property losses, and fire management costs (including injuries and deaths)
Ecosystems	Biodiversity***, habitat**, and species extinction**
	Outdoor recreation** and tourism
	Ecosystem services**
	Rising value of ecosystems due to increased scarcity
	Accelerated decline due to mass migration
Productivity and economic growth	Impacts on labor productivity and supply from extreme heat and weather, and multiple public health impacts across different damage categories
	Impacts on infrastructure, capital productivity, and supply from extreme weather events, and diversion of financial resources toward climate adaptation
	Impact on research and development from diversion of financial resources toward climate adaptation
Water	Availability and competing needs for energy production, sanitation, and other uses
	Flooding
Transportation	Changes in land and ocean transportation
Energy	Energy supply distributions
Catastrophic impacts and tipping points	Rapid sea level rise**
	Methane releases from permafrost**
	Damages at very high temperatures***
	Unknown catastrophic events

[6] Peter Howard, Cost of Carbon Project. Omitted Damages: What's Missing From the Social Cost of Carbon (2014), *available at* http://costofcarbon.org/reports/entry/omitted-damages-whats-missing-from-the-social-cost-of-carbon [hereinafter "Omitted Damages"].

Category	Specific Impacts Missing from the SCC*
Inter- and intra-regional conflict	National security
	Increased violent conflicts from refugee migration from extreme weather, and food, water, and land scarcity

* Climate impacts that have been largely unquantified in the economics literature and are therefore omitted from SCC models.

** These impacts are represented in a limited way in one or more of the SCC models: 1) they may be included in some models, and not others; 2) they may be included only partially (e.g., only one or several impacts of many in the category are estimated); 3) they may be estimated using only general terms not specific to any one damage—in these instances, estimated damages are usually very small relative to their potential magnitude, and relative to the impacts explicitly estimated in the models. See complete report for details.

*** While technically represented in SCC models through extrapolations from small temperature changes, there are no available climate damage estimates for large temperature changes, and these may be catastrophic.

Is there a state-specific SCC we can use?

No, there is no SCC estimate that only reflects climate damages to individual states. No models can accurately calculate a domestic-only, let alone a state-only SCC (see more below). Furthermore, as detailed in the next section, it is in your state's best interest to use an estimate of the global damages of a ton of CO_2. Your state benefits tremendously from actions of other states and other countries to mitigate climate change, and for numerous reasons discussed below, the use of a global SCC helps encourage reciprocal policy choices. Your state's citizens and businesses also have financial and other interests that extend far beyond your physical borders. If all states or countries used jurisdiction-specific numbers, the result would be significant underregulation.

Why should our state use a global number?

Not only is it best economic practice to estimate the global damages of U.S. greenhouse gas emissions in regulatory analyses and environmental impact statements, but no existing methodology for estimating a "domestic-only" value is reliable or complete. If a state agency is required to provide a domestic-only estimate, the existing, deficient methodologies must be supplemented to reflect international spillovers to the United States, U.S. benefits from foreign reciprocal actions, and the extraterritorial interests of U.S. citizens including financial interests and altruism. The same applies to any attempt to use a state-specific SCC value.

From 2010 through 2016, federal agencies based their regulatory decision and National Environmental Policy Act (NEPA) reviews on global estimates of the social cost of greenhouse gases. Though agencies often also disclosed a "highly speculative" range that tried to capture exclusively U.S. climate costs, emphasis on a global value was recognized as more accurate given the science and economics of climate change, economic practices, and consistency with U.S. strategic goals.[7]

To avoid a global "tragedy of the commons" that could irreparably damage all countries, including the United States, every government worldwide should ideally set policy according to the global social cost of greenhouse gases.[8] Because greenhouse pollution does not stay within geographic borders but rather mixes in the atmosphere and affects the climate

[7] *See generally* Peter Howard & Jason Schwartz, *Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon*, 42 Columbia J. Envtl. L. 203 (2017) [hereinafter "Howard & Schwartz 2017"].

[8] *See* Garrett Hardin, *The Tragedy of the Commons*, 162 Science 1243 (1968) ("[E]ach pursuing [only its] own best interest . . . in a commons brings ruin to all."), 1244.

worldwide, each ton emitted by the United States or a particular U.S. state not only creates domestic harms, but also imposes large externalities on the rest of the world. Conversely, each ton of greenhouse gases abated in another country benefits the United States along with the rest of the world. A Policy Integrity report, "Foreign Action, Domestic Windfall," calculates that global actions on climate change—particularly by Europe, and including efforts of the United States and other countries—already benefited the United States by over $200 billion as of 2015. Furthermore, the report finds that, as of 2015, climate policies worldwide—including efforts by Europe, Canada, and many other countries, as well as U.S. policies from the time—could generate upwards of $2 trillion in direct benefits to the United States by 2030.[9]

If all countries set their greenhouse emission levels based on only domestic costs and benefits, ignoring the large global externalities, the aggregate result would be substantially sub-optimal climate protections and significantly increased risks of severe harms to all nations, including the United States. The same concept would apply to state policies where global externalities are not taken into account. Thus, basic economic principles demonstrate that the United States stands to benefit greatly if all countries apply global social cost of greenhouse gas values in their regulatory decisions and project reviews. Indeed, the United States stands to gain hundreds of billions or even trillions of dollars in direct benefits from efficient foreign action on climate change.[10]

Therefore, a rational tactical option in the effort to secure an economically efficient outcome is for the United States and individual states to continue using global social cost of greenhouse gas values.[11] The United States is engaged in a repeated strategic dynamic with several significant players—including the United Kingdom, Germany, Sweden, and others—that have already adopted a global framework for valuing the social cost of greenhouse gases.[12] For example, Canada and Mexico have explicitly borrowed the U.S. estimates of a global SCC to set their own fuel efficiency standards.[13] States have also entered into this international dynamic, with California coordinating with Canada on its cap-and-trade program and with a coalition of states and cities agreeing to uphold the pledges from the Paris Agreement. For the United States or any individual state to now depart from this collaborative dynamic by selecting to a domestic-only estimate could undermine the country's long-term interests and could jeopardize emissions reductions underway in other countries, which are already benefiting all 50 U.S. states and territories.

There are significant, indirect costs to trade, human health, and security likely to "spill over" to the United States as other regions experience climate change damages.[14] Due to its unique place among countries—both as the largest economy with trade- and investment-dependent links throughout the world, and as a military superpower—the United States is particularly vulnerable to effects that will spill over from other regions of the world. Spillover scenarios could entail a

---

[9] Peter Howard & Jason Schwartz, Inst. for Pol'y Integrity, Foreign Action, Domestic Windfall: The U.S. Economy Stands to Gain Trillions from Foreign Climate Action (2015), at 2, *available at* http://policyintegrity.org/files/publications/ForeignAction-DomesticWindfall.pdf.

[10] *Id.*

[11] *See* Robert Axelrod, The Evolution of Cooperation 10-11 (1984) (on repeated prisoner's dilemma games).

[12] *See* Howard & Schwartz 2017, *supra* note 7, at 260.

[13] *See* Heavy-Duty Vehicle and Engine Greenhouse Gas Emission Regulations, SOR/2013-24, 147 Can. Gazette pt. II, 450, 544 (Can.), *available at* http://canadagazette.gc.ca/rp-pr/p2/2013/2013-03-13/html/sor-dors24-eng.html ("The values used by Environment Canada are based on the extensive work of the U.S. Interagency Working Group on the Social Cost of Carbon."); Jason Furman & Brian Deese, *The Economic Benefits of a 50 Percent Target for Clean Energy Generation by 2025*, White House Blog (June 29, 2016) (summarizing the North American Leader's Summit announcement that U.S., Canada, and Mexico would "align" their SCC estimates).

[14] Indeed, the integrated assessment models used to develop the global SCC estimates largely ignore inter-regional costs entirely, *see* Omitted Damages, *supra* note 6; though some positive spillover effects are also possible, such as technology spillovers that reduce the cost of mitigation or adaptation, *see* S. Rao et al., *Importance of Technological Change and Spillovers in Long-Term Climate Policy*, 27 Energy J. 123, 123–39 (2006); overall spillovers likely mean that the U.S. share of the global SCC is underestimated, *see* Jody Freeman & Andrew Guzman, *Climate Change and U.S. Interests*, 109 Columbia L. Rev. 1531 (2009).

variety of serious costs to the United States as unchecked climate change devastates other countries. Correspondingly, mitigation or adaptation efforts that avoid climate damages to foreign countries will radiate benefits back to the United States as well.[15]

For more details on the justification for a global value of the social cost of greenhouse gases, see Peter Howard & Jason Schwartz, *Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon*.[16] Another strong defense of the global valuation as consistent with best economic practices appears in a letter published in the March 2017 issue of *The Review of Environmental Economics and Policy*, co-authored by Nobel laureate Kenneth Arrow.[17]

How and why states should use the SCC?

Why should my state use the SCC?

As noted above, the SCC is a tool for internalizing externalities; specifically, it provides a monetary value for the cost of carbon emissions that will result from a particular decision. Without having this value on hand, a decisionmaker is faced with imperfect, incomplete information and may struggle to make a policy choice that maximizes net social welfare. The economic literature supports monetizing climate effects to achieve these goals because monetization helps put the impact of climate damages in context.

If an analysis only qualitatively discusses the effects of global climate change, decisionmakers and the public will tend to overly discount that specific action's potential contribution. Without context, it is difficult for decisionmakers and the public to assess the magnitude and climate consequences of a proposed action. Quantification of these emissions and the monetization of their effects makes it easier to compare costs and benefits.

Monetization provides much-needed context for otherwise abstract consequences of climate change. It allows decision-makers and the public to weigh all costs and benefits of an action—and to compare alternatives—using the common metric of money. Monetizing climate costs, therefore, better informs the public and helps "brings those effects to bear on [an agency's] decisions."[18] The tendency to ignore non-monetized effects is the result of common but irrational mental heuristics like probability neglect. For example, the phenomenon of probability neglect causes people to reduce small probabilities entirely down to zero, resulting in these probabilities playing no role in the decision-making process.[19] This heuristic applies even to events with long-term certainty or with lower-probability but catastrophic consequences, so long as their effects are unlikely to manifest in the immediate future. Weighing the real risks that, decades or centuries from now, climate change will fundamentally and irreversibly disrupt the global economy, destabilize earth's ecosystems, or compromise the planet's ability to sustain human life is challenging; without a tool to contextualize such risks, it is far easier to ignore them. Monetization tools like the social cost of carbon (and the social cost of other greenhouse gases) are designed to solve this problem: by translating long-term costs into present values, concretizing the harms of climate change, and giving due weight to the potential of lower-probability but catastrophic harms.

---

[15] *See* Freeman & Guzman, *supra* note 14, at 1563-93.

[16] Howard & Schwartz 2017, *supra* note 7.

[17] Richard Revesz, Kenneth Arrow et al., *The Social Cost of Carbon: A Global Imperative*, 11 Review of Environmental Economics and Policy 172 (2017).

[18] *See* Baltimore G. & E. Co. v. NRDC, 462 U.S. 87 (U.S. 1983) at 96.

[19] Cass R. Sunstein, *Probability Neglect: Emotions, Worst Cases, and Law* (John M. Olin Law & Economics, Working Paper No. 138, 2001), *available at* http://ssrn.com/abstract=292149.

Finally, the SCC enables regulators and policymakers to take into account the effect of their decisions on society as a whole, as climate change is a global problem. This consideration can encourage reciprocal actions from other actors, including other U.S. states and other countries. We discuss more above why the "global" SCC estimates are the best ones.

What are the possible applications of the SCC in state policymaking?

Even though the IWG estimates were developed for use in regulatory analysis, there is wide support for use of the SCC in other contexts. The SCC is useful for evaluating nearly all energy regulations and environmental rules and actions. In general, using the SCC allows us to compare the costs of limiting carbon dioxide pollution to the costs of climate change. The SCC should be used in all appropriate instances, including but not limited to rulemaking that addresses greenhouse gas emissions, electricity ratemaking and regulation, natural resource valuation and royalty setting, regulatory cost-benefit analysis for climate actions, environmental impact statements, and setting carbon emissions caps or taxes.

In market-based emissions reduction schemes, the SCC should be fully internalized to allow the environmental attributes of clean energy resources to be more accurately valued and to ensure carbon-free resources are not under-valued. For states that are members of the Regional Greenhouse Gas Initiative (RGGI), for example, a state-level effort to price carbon should take into account the SCC minus the RGGI price of carbon. Note that if the RGGI carbon price were as high as the SCC, then this additional step would not be necessary.

The SCC can also allow state policymakers to compare the costs and benefits of a proposal or set the stringency of a regulation. If a state wants to set a greenhouse gas emissions cap, for example, legislators can use the SCC to determine what the cap should be. Overall, using the SCC gives states information on which measures will ultimately improve societal well-being vis-à-vis climate change.

Finally, using the SCC to gauge the climate impacts of coal and natural gas leases can help determine new royalty rates, helping the states to improve their leasing programs. Using the SCC can help ensure that taxpayers get a fair deal out of the use of their state's lands, rather than having a disproportionate amount of benefits fall to privates companies while costs fall to the public.

The emissions from my state/this leasing decision/this regulation/this project are so small, does the SCC still apply?

The SCC absolutely still applies. The argument that individual projects are too small to monetize misunderstands the tools available for valuing climate effects. The social cost of greenhouse gases protocols were developed to assess the cost of actions with "marginal" impacts on cumulative global emissions, and the metrics estimate the dollar figure of damages for one extra ton of greenhouse gas emissions.[20] The integrated assessment models used to derive the estimates work by first running a climate-economic-damage calculation for a baseline scenario, and then adding a single additional unit of greenhouse gas emissions to the model and rerunning the calculation. The approach assumes that the marginal damages from increased emissions will remain constant for small emissions increases relative to gross global emissions.[21] In other words, the monetization tools are in fact perfectly suited to measuring the marginal effects—that is, the effects of one additional unit—of emissions from smaller-scale decisions, as well as from nationwide policies.

---

[20] TSD 2010, *supra* note 3, at 1.

[21] *Id.* at 2.

Which states are already using the SCC, and how?

It may be helpful for state decisionmakers to understand how other states have begun to use the SCC to date. States including—but not limited to—California, Colorado, Illinois, Minnesota, Maine, New York, and Washington have all begun using the federal SCC in energy-related analysis, recognizing that the SCC is the best available estimate of the marginal economic impact of carbon emission reductions. Several states and municipalities have used the SCC in the context of renewable energy decisionmaking, and Illinois and New York State have used the SCC to assess the value of the avoided carbon emissions from using nuclear generation rather than fossil fuel generation.

California

California uses the SCC in the Air Resources Board's scoping plan for the state's updated climate change policy. In the January 2017 draft of the scoping plan, the economic analysis uses the IWG SCC with a range of discount rates (2.5-percent to 5-percent).[22] Two companion bills were passed in the California legislature in the summer of 2016 to renew the policy, one of which mandates the Air Resources Board to consider the "social costs of greenhouse gases" in the analysis that underlies the new policy's accompanying regulations.[23] The Board is still finalizing the scoping plan as of October 2017.

The use of the SCC is also being discussed in a proceeding on the value of integrated distributed energy resources at the California's Public Utilities Commission.[24]

Colorado

In March 2017, the Colorado Public Utilities Commission ordered that the Public Service Company of Colorado, also knowns as Xcel Energy, take into account the IWG's social cost of carbon in its Energy Resource Plan (ERP).[25] ERPs include information on costs associated with generation resources, as well as alternatives. Advocates for the use of the "federally developed" SCC noted that the Colorado PUC had considered externalities, like public health effects, in other ERP proceedings. The PUC has authority under §40-2-123(1)(b), C.R.S to include such considerations in resource planning. One SCC advocate, Western Resource Advocates (WRA), argued that §40-2-123(1)(b) should be read to permit the Colorado PUC to "consider two distinct categories: (1) the likelihood of new environmental regulation; and (2) the risk of higher future costs associated with the emission of greenhouse gas pollution." The Colorado PUC ultimately agreed with WRA's reading and cited it as support for their decision.[26]

Illinois

Illinois has recently used the SCC in its "zero emissions credit" (ZEC) policy. In late 2016, the state legislature passed a comprehensive energy bill, which included provisions for valuing the social benefits of energy from zero-emissions

---

[22] Cal. Air Res. Bd., The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target (Jan. 20, 2017).

[23] Cal. Health & Safety Code §§ 38562.5 & 38562.7.

[24] Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources ("IDER") (Rulemaking No. 14-10-003).

[25] Colorado PUC, Decision No. C17-0316, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2016 Electric Rersource Plan, Proceeding No. 16A-0396E, *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=863402.

[26] *Id.* at 84.

facilities. This bill uses the SCC to make this calculation, using an SCC value of $16.50/MWh, based on the IWG SCC estimates.[27]

Maine [28]

Maine enacted the Act to Support Solar Energy Development in Maine during its 2014 legislative session.[29] Section 1 of the Act states that it is "in the public interest to develop renewable energy resources, including solar energy, in a manner that protects and improves the health and well-being of the citizens and natural environment of the State while also providing economic benefits to communities, ratepayers and the overall economy of the State."[30] Section 2 of the Act instructs the Public Utilities Commission to determine the value of distributed solar energy generation in the State, evaluate implementation options, and deliver a report to the Legislature. Maine has a statute that calls for calculating "the societal value of the reduced environmental impacts of the energy."[31] Maine uses the federal SCC, as well as other monetized costs and benefits, to make this calculation. Because carbon costs are already partially embedded in existing energy valuation as a result of carbon emissions caps under RGGI, the net SCC is calculated by subtracting the embedded carbon allowance costs from the total SCC. The Maine Public Utilities Commission uses the federal SCC, with a "central" 3-percent discount rate estimate.

Maine's statute requires the PUC to assess how to maximize social welfare in its policy options. Maine addresses this requirement by weighing market costs and benefits with the monetized values of societal benefits in a cost-benefit analysis.[32]

Minnesota

The Minnesota Public Utilities Commission is statutorily mandated to consider externalities for all proceedings.[33] Between 1993, when this provision was enacted, and 2014, Minnesota used its own methodology to determine the costs of $PM_{2.5}$, SO_2, NO_x, and CO_2.[34] In 2014, after environmental advocacy groups filed a motion requesting that the Minnesota Public Utility Commission update these figures, the commission referred the issue to the Office of Administrative Hearings to assess how to value externalities, including whether the state should use the federal SCC.[35]

---

[27] 20 I.L.C.S. 3855 §§ 1-75(d-5)(1)(B). ("(i) Social Cost of Carbon: The Social Cost of Carbon is $16.50 per megawatthour, which is based on the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update using a 3% discount rate, adjusted for inflation for each year of the program. Beginning with the delivery year commencing June 1, 2023, the price per megawatthour shall increase by $1 per megawatthour, and continue to increase by an additional $1 per megawatthour each delivery year thereafter.")

[28] For more details, *see* Maine Public Utilities Commission, Maine Distributed Solar Valuation Study (2015) [hereinafter "MPUC Distributed Solar Valuation Study"], *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf .

[29] Maine P.L ch. 562 (Apr. 24, 2014) (codified at 35-A M.R.S.A. §§ 3471-3474).

[30] *Id.* at § 3472(1).

[31] *Id.* at § 2(1).

[32] MPUC Distributed Solar Valuation Study, *supra* note 28, at 4.

[33] ("The [Public Utilities] commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.") 2016 Minnesota Stat. § 216B.2422 subd. 3.

[34] State of Minnesota, Office of Administrative Hearings, In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3, Docket No. OAH 80-2500-31888, MPUC E-999/CI-14-643, Findings of Fact, Conclusions, and Recommendations: Carbon Dioxide Values, 2-3 (Apr. 15, 2016) [hereinafter "Minnesota Opinion"].

[35] *Id.* at 4.

The Administrative Judge who reviewed the matter[36] recommended that "the Commission adopt the Federal Social Cost of Carbon as reasonable and the best available measure to determine the environmental cost of CO_2, establishing a range of values including the 2.5 percent, 3.0 percent, and 5 percent discount rates . . . ."[37]

The decision to use the federal SCC, with some adjustments, was recently upheld, and the Minnesota PUC will use a range of $9.05 to $43.06 per short ton by 2020. Notably, Minnesota has decided to adjust the federal SCC estimates by using a range between the IWG's "central" 3-percent estimate and a lower bound that uses a 5-percent discount rate and a shortened timeline of only 100 years. As discussed below, uncertainty does not support the argument for shortening the time horizon for the SCC.

New York

The New York Public Service Commission first used the SCC in January 2016 in the benefit-cost analysis order for the Reforming the Energy Vision proceeding. The PSC chose the SCC, as opposed to other methods suggested by commenters, as the tool to monetize marginal climate damage costs in the benefit-cost analysis of a resource portfolio. New York's Clean Energy Standard and accompanying Zero Emissions Credit ("ZEC") take into account the SCC in calculating the value of using emission-free nuclear power, rather than carbon-emitting fossil fuel power.[38] The New York Public Service Commission's program is designed to compensate nuclear plants based directly on the value of the carbon-free attributes of their generation.[39]

The commission recognized that the federal SCC is the "best available estimate of the marginal external damage of carbon emissions."[40] It then designed the ZEC based upon the difference between the average April 2017 through March 2019 projected SCC, as published by the IWG in July 2015 and a fixed baseline portion of the cost that is already captured in the market revenues received by the eligible nuclear facilities under RGGI.[41] The New York Public Service Commission uses the federal SCC, with a "central" 3-percent discount rate estimate.[42] This approach was upheld in June 2017 by the United States District Court for the Southern District of New York.[43]

Washington

In April 2014, Governor Jay Inslee issued an executive order on climate change. Executive Order 14-04 on Washington Carbon Pollution Reduction and Clear Energy Action requires the state's agencies to "[e]nsure the cost-benefit tests for energy-efficiency improvements include full accounting for the external cost of greenhouse gas emissions."[44] With these requirements in mind, the Washington State Energy Office, in consultation with the Washington State Department of Ecology, recommended that all state agencies use the federal SCC estimates.

---

[36] The Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3.

[37] Minnesota Opinion, *supra* note 34, at 123.

[38] *See* Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, New York Public Service Comm'n Case No. 15-E-0302, Order Establishing a Clean Energy Standard 131 (Aug. 1, 2016) [hereinafter "CES Order"].

[39] Denise Grab & Burcin Unel, "New York's Clean Energy Standard Is a Key Step Toward Pricing Carbon Pollution Fairly," Utility Dive (Aug.18, 2016), *available at* http://www.utilitydive.com/news/new-yorks-clean-energy-standard-is-a-key-step-toward-pricing-carbon-pollut/424741/.

[40] CES Order, *supra* note 38, at 134.

[41] *Id.* at 129.

[42] New York State Department of Public Service's Staff White Paper on Benefit-Cost Analysis in the Case No. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

[43] Coalition For Competitive Electricity et al v. Zibelman et al. (S.D.N.Y., Jul. 27, 2017).

[44] State of Washington, Exec. Order 14-04 at 6, *available at* http://www.governor.wa.gov/sites/default/files/exe_order/eo_14-04.pdf.

The Energy Office noted that the federal SCC estimates do not capture the total cost of emitting carbon dioxide into the atmosphere (total future climate damages), and because of omitted damages and uncertainty about the full scope of the consequences of climate change, the Office recommended using the lower 2.5-percent discount rate.[45]

The Energy Office supports using the 2.5-percent discount rate for a number of reasons.[46] First, the 2.5-percent discount most closely matches with the existing Office of Financial Management real discount rate of 0.9 percent. Second, the IWG models focus only on the damages of climate change that can be easily monetized and since the trend seems to be that additional impacts are monetized with each federal SCC update, Washington can stay ahead of this trend by choosing the lowest IWG discount rate. Third, because the discount rate applied to greenhouse gas emissions is an "intergenerational" discount rate applied to society as a whole, the discount rate used in this context should be substantially lower than private sector discount rates. Fourth, there is a higher risk associated with underestimating the SCC than with overestimating it. Fifth, Washington State wants to lead on climate issues, so it makes sense for the Energy Office to put forth the higher associated SCC.

Washington state agencies have begun following the recommendation of the state's energy office and using a 2.5-percent discount rate for their economic analyses involving greenhouse gas emissions. The Department of Ecology uses the 2010 IWG estimates, with a value of $78 per metric ton for 2020 emissions.[47]

My state already has a climate policy or a renewable energy policy in place, so why should we still use the SCC?

There is nothing that should prevent a state from using the SCC, even if there is already a climate or renewable energy policy, like a renewable portfolio standard (RPS) or clean energy standard (CES). In fact, states can use the SCC in setting RPSs or CESs or other renewable resource mandates. RPSs and CESs alone can be economically problematic, as such policies effectively "'pick winners" in electricity markets. The first-best public policy tool to promote clean energy resources and achieve greenhouse gas reductions is to use a carbon price that would lead the power generators that use dirtier energy resources to internalize the externalities caused by greenhouse gas emissions fully. Using a carbon price to achieve greenhouse gas reductions would be the least-cost way of achieving carbon emission reductions compared to other alternatives.[48] However, using the SCC to set the standard can make RPSs or CESs more efficient. When state agencies are determining standards, the SCC and other externalities, including other societal costs and benefits, should be incorporated into the analysis. We elaborate on this process below.

---

[45] Washington State Department of Commerce, Social Cost of Carbon: Washington State Energy Office Recommendation for Standardizing the Social Cost of Carbon When Used for Public Decision-Making Processes, at 3 (2014).

[46] *Id.* at 3-5.

[47] *See, e.g.*, State of Washington, Department of Ecology, Preliminary Cost-Benefit and Least-Burdensome Alternative Analysis: Chapter 173-442 WAC Clean Air Rule & Chapter 173-441 WAC Reporting of Emissions of Greenhouse Gases (2016), at 38, *available at* https://fortress.wa.gov/ecy/publications/documents/1602008.pdf; inflated from 2007 dollars to 2017 dollars.

[48] Erik Paul Johnson, *The Cost Of Carbon Dioxide Abatement From State Renewable Portfolio Standards*, 36 Res. Energy Econ. 332, 349–50 (2014); Karen Palmer & Dallas Burtraw, *Cost-Effectiveness Of Renewable Electricity Policies*, 27 Energy Econ. 873, 893 (2005); Carolyn Fischer, Richard G. Newell, Environmental And Technology Policies For Climate Migration, 55 J. of Envtl. Econ. Mgmt. 142, 160 (2008) (finding that lowest cost emissions reductions come from a combination of an emissions price with a small "learning subsidy").

Are the federal IWG numbers still the best?

The "central" SCC estimate of around $50 per ton of CO_2[49] is the best currently available estimate for the external cost of carbon dioxide emitted in the year 2020. Of course, there is uncertainty over the science and economics of climate change. This uncertainty is due to the complexity of the climate system, the difficulty of placing a monetary value on environmental services, the long time horizon over which climate change occurs, and the unprecedented amount of carbon emissions that have entered the atmosphere since the industrial revolution. As science and economics improve and progress, this uncertainty will decline, but uncertainty can never be fully eliminated from future predictions. The fact that there is uncertainty does not mean that there is no social cost of carbon dioxide emissions. If anything, this uncertainty implies that we should take stronger action, as discussed in the below section on uncertainty.[50]

We discuss at length below why the IWG estimates still represent the best methodology and are based on the best available science and economics. Recent executive orders do not change this fact.

How were the IWG numbers developed?

A federal court ruling spurred the development of the SCC. A 2008 ruling by the U.S. Court of Appeals for the Ninth Circuit required the federal government to account for the economic effects of climate change in a regulatory impact analysis of fuel efficiency standards.[51] As a result, President Obama convened the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) in 2009 to develop an SCC value for use in federal regulatory analysis.

The SCC was developed through an academically rigorous, regularly-updated, and peer-reviewed process. The SCC values were developed using the three most widely cited climate economic impact models that link physical impacts to the economic damages of carbon dioxide emissions. All of these IAMs—DICE, FUND, and PAGE[52]—have been extensively peer reviewed in the economic literature.[53] The newest versions of the models were also published in peer-reviewed literature.[54] The IWG gives each model equal weight in developing the SCC values.[55] The IWG also used peer-reviewed inputs to run these models.[56] The IWG conducted an "extensive review of the literature . . . to select three sets of input parameters for these models: climate sensitivity, socio-economic and emissions trajectories, and discount rates."[57] For each parameter, the IWG documented the inputs it used, all of which are based on peer-reviewed literature.[58]

---

[49] For 2020 emissions in 2017 dollars, from TSD 2016, Table 2, inflated with the Bureau of Labor Statistics Inflation Calculator, *available at* https://data.bls.gov/cgi-bin/cpicalc.pl.

[50] William D. Nordhaus, *Projections and Uncertainties about Climate Change in an Era of Minimal Climate Policies*. National Bureau of Economic Research (2016), *available at*: http://www.nber.org/papers/w22933.pdf.

[51] Ctr. for Biological Diversity v. Nat'l Highway Traffic and Safety Admin., 538 F.3d 1172 (9th Cir. 2008).

[52] More specifically: DICE (Dynamic Integrated Climate and Economy), developed by William D. Nordhaus (more information *available at* http://www.econ.yale.edu/~nordhaus/); PAGE (Policy Analysis of the Greenhouse Effect), developed by Chris Hope; and FUND (Climate Framework for Uncertainty, Negotiation, and Distribution), developed by Richard Tol (more information *available at* http://www.fund-model.org/). *See* TSD 2010, *supra* note 3, at 5.

[53] *See* TSD 2010, *supra* note 3, at 4-5.

[54] *See* TSD 2016, *supra* note 2, at 6; *see also* William Nordhaus, *Estimates of the Social Cost of Carbon: Concepts and Results from the DICE-2013R Model and Alternative Approaches*, 1 J. Ass'n Envtl. & Resource Economists 273 (2014).

[55] TSD 2016, *supra* note 2, at 5.

[56] *Id.* at 5-29.

[57] *Id.* at 6.

[58] *See* TSD 2010, *supra* note 3, at 12-23.

The analytical methods that the IWG applied to its inputs were also peer-reviewed, and the IWG's methods have been extensively discussed in academic journals.[59]

The IWG's analytical process in developing the SCC was transparent and open, designed to solicit public comment and incorporate the most recent scientific analysis. Beginning in 2009, the Office of Management and Budget and the Council of Economic Advisers established the IWG, composed of scientific and economic experts from the White House, Environmental Protection Agency, and Departments of Agriculture, Commerce, Energy, Transportation, and Treasury, to develop a rigorous method of valuing carbon dioxide reductions resulting from regulations.[60] In February 2010, the IWG released estimated SCC values, and an accompanying Technical Support Document that discussed the IAMs, their inputs, and the assumptions used in generating the SCC estimates.[61] In May 2013, after all three IAMs had been updated and used in peer-reviewed literature, the IWG released revised SCC values, with another Technical Support Document.[62] The U.S. Government Accountability Office examined the IWG's 2010 and 2013 processes, and found that these processes were consensus-based, relied on academic literature and modeling, disclosed relevant limitations, and incorporated new information via public comments and updated research.[63]

To further enhance the academic rigor of the process, the IWG requested that the NAS undertake a review of the latest research on modeling the economic aspects of climate change to help the IWG assess the technical merits and challenges of potential approaches for future updates to the SCC.[64] In mid-2016, the NAS issued an interim report to the IWG that recommended against conducting an update to the SCC estimates in the near term, but that included recommendations about enhancing the presentation and discussion of uncertainty regarding particular estimates.[65] The IWG responded to these recommendations in its most recent Technical Support Document from 2016,[66] which included an addendum on the social cost of methane and the social cost of nitrous oxide.[67] The NAS issued a report in January 2017 that contained a roadmap for how SCC estimates should be updated.[68] In the 2017 report, the NAS recommended future improvements to the IWG three-model methodology, but in the meantime, the NAS supported the continued near-term use of the existing social cost of greenhouse gas estimates based on the DICE, FUND, and PAGE models, as used by federal agencies to

---

[59] *See, e.g.*, Michael Greenstone *et al.*, *Developing a Social Cost of Carbon for U.S. Regulatory Analysis: A Methodology and Interpretation*, 7 Rev. Envtl. Econ. & Pol'y 23 (2013); Frank Ackerman & Elizabeth Stanton, *Climate Risks and Carbon Prices: Revising the Social Cost of Carbon*, Econ.: The Open-Access, Open-Assessment E-Journal (Apr. 2012), at 6 (reviewing the IWG's methods and stating, "[T]he Working Group analysis is impressively thorough.")

[60] TSD 2010, *supra* note 3, at 2-3.

[61] *See generally* TSD 2010, *supra* note 3.

[62] *See* Interagency Working Group on the Social Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2013) [hereinafter TSD 2013].

[63] Gov't Accountability Office, Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates (2014) [hereinafter Gov't Accountability Office].

[64] *See* TSD 2016, *supra* note 2, at 2.

[65] National Academies of Sciences, Engineering and Medicine, Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update (2016) [hereinafter NAS First Report].

[66] TSD 2016, *supra* note 2.

[67] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (2016) [hereinafter "TSD 2016 Addendum"], *available at* https://www.obamawhitehouse.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf.

[68] The National Academy of Sciences accepted public comment during its review process. Policy Integrity submitted comments during that process. Institute for Policy Integrity, Recommendations for Changes to the Final Phase 1 Report on the Social Cost of Carbon, and Recommendations in Anticipation of the Phase 2 Report on the Social Cost of Carbon (Apr. 29, 2016) [hereinafter "Policy Integrity NAS comments"] *available at* http://policyintegrity.org/documents/Comments_to_NAS_on_SCC.pdf.

date.[69] The SCC estimates will need to be updated over time to reflect the best-available science and changing economic conditions, and, as we discuss below, a nongovernmental organization Resources for the Future plans to undertake this project based on the NAS 2016 and 2017 recommendations.

How have the IWG numbers been used to date?

The IWG numbers have been used extensively in federal regulatory analysis, on more than one hundred occasions since the first estimates were published in 2010.[70] In fact, the mandate for federal agencies to use the IWG SCC values was ended only recently, on March 28, 2017, with Executive Order 13,783. The SCC has, in fact, been used in a range of contexts aside from federal regulatory impact analysis, which we discuss above.

Who has endorsed the IWG numbers?

The IWG SCC numbers have been endorsed or otherwise supported by the NAS, the Government Accountability Office, and the federal courts. The NAS has supported the continued near-term use of the existing social cost of greenhouse gas estimates based on the DICE, FUND, and PAGE models, as federal agencies have done to date.[71] Additionally, the Government Accountability Office found in 2014 that the estimates derived from these models and used by federal agencies are consensus-based, rely on peer-reviewed academic literature, disclose relevant limitations, and are designed to incorporate new information via public comments and updated research.[72] In fact, the social cost of greenhouse gas estimates used in federal regulatory proposals and EISs have been subject to approximately 100 distinct public comment periods.[73] The economics literature confirms that estimates based on these three IAMs remain the best available estimates.[74] Finally, in 2016, the U.S. Court of Appeals for the Seventh Circuit held the estimates used to date by agencies are "reasonable," and other courts have supported agencies' use of these values.[75]

Did a recent Trump Executive Order delegitimize the IWG numbers?

Absolutely not. While the IWG was disbanded and its guidance was withdrawn, which is unfortunate, the IWG still used the best data, the best models, and the best methodologies that are currently available. Accordingly, the IWG estimates are still the best numbers for states to use and still the only numbers endorsed by the NAS.

---

[69] Specifically, NAS concluded that a near-term update was not necessary or appropriate and the current estimates should continue to be used while future improvements are developed over time. NAS First Report, *supra* note 66.

[70] Howard & Schwartz 2017, Appendix A; Jane A. Leggett. *Federal Citations to the Social Cost of Greenhouse Gases*, Congressional Research Service (Mar 21, 2017), *available at* https://fas.org/sgp/crs/misc/R44657.pdf.

[71] Specifically, NAS concluded that a near-term update was not necessary or appropriate and the current estimates should continue to be used while future improvements are developed over time. NAS First Report, *supra* note 66.

[72] Gov't Accountability Office, *supra* note 63.

[73] Howard & Schwartz 2017, *supra* note 7, at Appendix A.

[74] E.g., Richard G. Newell *et al.*, *Carbon Market Lessons and Global Policy Outlook*, 343 Science 1316 (2014); Bonnie L. Keeler *et al.*, *The Social Costs of Nitrogen*, 2 Science Advances e1600219 (2016); Richard L. Revesz *et al.*, *Global Warming: Improve Economic Models of Climate Change*, 508 Nature 173 (2014) (co-authored with Nobel Laureate Kenneth Arrow, among others).

[75] *See e.g.* Zero Zone v. Dept. of Energy, No. 14-2147 (7th Cir., Aug. 8, 2016), at 44 (finding that the agency "acted reasonably" in using global estimates of the social cost of carbon, and that the estimates chosen were not arbitrary or capricious); High Country Conservation Advocates v. U.S. Forest Service (D. Colo., June 27, 2014); Western Organization of Resource Councils v. U.S. Bureau of Land Management (D. Mont., Jan. 25, 2017).

If the Trump administration comes out with a new number, should we use it?

Only if the number is consistent with best practices and reflects the best available literature and the recommendations of the NAS panel. If a new number uses a discount rate higher than 5-percent, selects only one of the three IAMs used by the IWG or an IAM that does not take into account nonmarket damages, if it only uses a domestic number, or if it dramatically shortens the time horizon, for example, that would be inconsistent with best practices and should not be followed by the states.

How will the numbers be updated?

In May 2017, the environmental economics think tank, Resources for the Future (RFF), launched a program to update the SCC based on the recommendations made by the NAS.[76] The new initiative contains several key elements. RFF will create a new integrated framework for the estimation process and revise some of the socioeconomic projections to better reflect uncertainty. RFF will also convene domestic and international actors and conduct educational outreach on how to use the SCC. States should consider looking to RFF for new SCC estimates in the coming years.

Are there other estimates of the SCC?

While states should be careful not to cherry-pick a single estimate from the literature, it is noteworthy that various estimates in the literature are consistent with the numbers derived from a weighted average of DICE, FUND, and PAGE—namely, with a central estimate of about $50 per ton of carbon dioxide, and a high-percentile estimate of about $148, for year 2020 emissions (in 2017 dollars, at a 3-percent discount rate). The latest central estimate from DICE's developers is $104 (at a 3-percent discount rate);[77] from FUND's developers, $14;[78] and from PAGE's developers, $148, with a high-percentile estimate of $386.[79]

Similarly, a comparison of international estimates of the social cost of greenhouse gases suggests that a central estimate of $50 per ton of carbon dioxide is a very conservative value. Sweden places the long-term valuation of carbon dioxide at $168 per ton; Germany calculates a "climate cost" of $171 per ton of carbon dioxide in the year 2030; the United Kingdom's "shadow price of carbon" has a central value of $118 by 2030; Norway's social cost of carbon is valued at $106 per ton for year 2030 emissions; and various corporations have adopted internal shadow prices as high as $82 per ton of carbon dioxide.[80]

All of this—not to mention the omitted damages that are not included in the SCC—suggests, again, that the IWG estimates, while still the most reliable and most endorsed numbers for federal and state-level U.S. policymaking, should be treated as a lower bound.

---

[76] Resources for the Future, "Updating and Improving the Social Cost of Carbon," *available at* http://www.rff.org/research/collection/updating-and-improving-social-cost-carbon; Nat'l Acad. Sci., Eng. & Medicine, Valuing Climate Damages: Updating Estimates of the Social Cost of Carbon Dioxide 3 (2017) [hereinafter "NAS Second Report"].

[77] William Nordhaus, *Revisiting the Social Cost of Carbon*, Proc. Nat'l Acad. Sci. (2017) (estimate a range of $21 to $141).

[78] D. Anthoff & R. Tol, *The Uncertainty about the Social Cost of Carbon: A Decomposition Analysis Using FUND*, 177 Climatic Change 515 (2013).

[79] C. Hope, *The social cost of CO_2 from the PAGE09 model*, 39 Economics (2011); C. Hope, *Critical issues for the calculation of the social cost of CO_2*, 117 Climatic Change, 531 (2013). Values inflated to 2017 dollars.

[80] *See* Howard & Schwartz 2017, *supra* note 7, at Appendix B. All figures in 2017 USD.

What methodological choices went into the IWG numbers?

Which models?

Economists estimate the SCC by linking together a global climate model and a global economic model. The resulting models are called Integrated Assessment Models, or IAMs. This integration helps economists take a unit of carbon emissions and translate that into an estimate of the cost of the impact that emissions have on our health, well-being, and quality of life in terms of dollars. The models are based on the best available science and economics from peer-reviewed publications.

The IWG uses the three most–cited models, which are William Nordhaus' DICE model (Yale University), Richard Tol's FUND model (Sussex University), and Chris Hope's PAGE model (Cambridge University).

Why did the IWG select a 3% discount rate as a "central" estimate?

The IWG produced four different SCC estimates by using different discount rates. According to the IWG's 2010 Technical Support Document, the 3-percent discount rate estimate is considered the central estimate because it uses the central (i.e., middle) discount rate and is based on an average or mean, rather than worse-than-expected, climate outcome. The use of this "central" discount rate is supported by surveys of experts.[81] The IWG further argues that the 3% is consistent with OMB's Circular A-4 guidance, corresponds to the correct discounting concept (i.e., the consumption rate of interest) when damages are measured in consumption-equivalent units, and roughly corresponds to the after-tax riskless interest rate.

The central estimate is an "average" or mean estimate in the sense that the IWG ran its models thousands of times using slightly varying assumptions to reflect uncertainty, and equally weighted the results to produce a mean average. It is important to note that the SCC is an average estimate of marginal damages, and not an average estimate of average damages. In other words, the SCC is the average estimate of the marginal impacts caused by an additional unit of greenhouse gases. It is not appropriate to interpret the SCC as an estimate of the average damages of all greenhouse gases ever emitted. It is how much the next unit of emissions will cost us.

First, what is a discount rate?

It is easiest to explain the idea of discount rates with a simple example: If offered $1 now or $1 in a year, almost everyone would choose to receive the $1 now. Most individuals would only wait until next year if they were offered more money in the future. The discount rate is how much more you would have to receive to wait until next year. Similarly, if individuals were asked to pay $1 now or $1 next year, most individuals would choose to pay $1 later. Most individuals would only pay now if they were asked to pay more money in the future. The discount rate is how much more you would have to pay in the future to be willing to pay $1 in the present.

---

[81] Peter Howard & Derek Sylvan, *Expert Consensus on the Economics of Climate Change, Institute for Policy Integrity Report* (Dec. 2015); M.A. Drupp, *et al.*, *Discounting Disentangled: An Expert Survey on the Determinants of the Long-Term Social Discount Rate* (London School of Economics and Political Science Working Paper, May 2015) (finding consensus on social discount rates between 1-3%).

Why is the discount rate important?

The discount rate is one of the most important inputs in models of climate damages, with plausible assumptions easily leading to differences of an order of magnitude in the SCC. The climate impacts of present emissions will unfold over hundreds of years. When used over very long periods of time, discounting penalizes future generations heavily due to compounding effects. For example, at a rate of 1 percent, $1 million 300 years hence equals over $50,000 today; at 5 percent it equals less than 50 cents.[82] The discount rate changed by a factor of five, whereas the discounted value changed by more than five orders of magnitude. Depending on the link between climate risk and economic growth risk, even a rate of 1 percent may be too high.[83] Uncertainty around the correct discount rate pushes the rate lower still.[84]

Why is the IWG correct to exclude a 7% discount rate?

The IWG correctly excluded a 7-percent discount rate, a typical private sector rate of return on capital, for several reasons. First, typical financial decisions, such as how much to save in a bank account or invest in stocks, focus on private decisions and use private rates of return. However, here we are concerned with social discount rates because emissions mitigation is a public good, where individual emissions choices affect public well-being broadly. Rather than evaluating an optimal outcome from the narrow perspective of investors alone, economic theory would require that we make the optimal choices based on societal preferences (and social discount rates). Second, climate change is expected to affect primarily consumption, not traditional capital investments.[85] Guidelines of the federal Office of Management and Budget note that in this circumstance, consumption discount rates are appropriate.[86] Third, 7 percent is considered much too high for reasons of discount rate uncertainty and intergenerational concerns (further discussed below). Fourth, interest rates are at historic lows, with no indication of increasing, so traditional rates of return used to guide discount rate selection are too high at the present time.[87]

---

[82] Dallas Burtraw & Thomas Sterner, *Climate Change Abatement: Not "Stern" Enough?* (Resources for the Future Policy Commentary Series, Apr. 4, 2009), *available at* http://www.rff.org/Publications/WPC/Pages/09_04_06_Climate_Change_Abatement.aspx.

[83] "If climate risk dominates economic growth risk because there are enough potential scenarios with catastrophic damages, then the appropriate discount rate for emissions investments is lower tha[n] the risk-free rate and the current price of carbon dioxide emissions should be higher. In those scenarios, the "beta" of climate risk is a large negative value and emissions mitigation investments provide insurance benefits. If, on the other hand, growth risk is always dominant because catastrophic damages are essentially impossible and minor climate damages are more likely to occur when growth is strong, times are good, and marginal utility is low, then the "beta" of climate risk is positive, the discount rate should be higher than the risk-free rate, and the price of carbon dioxide emissions should be lower." Robert B. Litterman, *What Is the Right Price for Carbon Emissions?*, Regulation, Summer (2013) 38-43, at 41 *available at* http://www.cato.org/sites/cato.org/files/serials/files/regulation/2013/6/regulation-v36n2-1-1.pdf.

[84] *See* "Isn't there too much uncertainty around the SCC to use it?" on page 23.

[85] "There are two rationales for discounting future benefits—one based on consumption and the other on investment. The consumption rate of discount reflects the rate at which society is willing to trade consumption in the future for consumption today. Basically, we discount the consumption of future generations because we assume future generations will be wealthier than we are and that the utility people receive from consumption declines as their level of consumption increases . . . . The investment approach says that, as long as the rate of return to investment is positive, we need to invest less than a dollar today to obtain a dollar of benefits in the future. Under the investment approach, the discount rate is the rate of return on investment. If there were no distortions or inefficiencies in markets, the consumption rate of discount would equal the rate of return on investment. There are, however, many reasons why the two may differ. As a result, using a consumption rather than investment approach will often lead to very different discount rates." Maureen Cropper, *How Should Benefits and Costs Be Discounted in an Intergenerational Context?*, 183 Resources 30, at 33.

[86] *See* Office of Mgmt. & Budget, *Circular A-4*, Nat'l Archives (Sept. 17, 2003), *available at* https://georgewbush-whitehouse.archives.gov/omb/circulars/a004/a-4.html [https://perma.cc/GSV8-TAUR], at 33.

[87] Council of Econ. Advisers, Discounting for Public Policy: Theory and Recent Evidence on the Merits of Updating the Discount Rate at 1 (CEA Issue Brief, 2017) [hereinafter "CEA Brief"], *available at* https://obamawhitehouse.archives.gov/sites/default/files/ page/files/201701_cea_discounting_issue_brief.pdf.

What is a declining discount rate?

The IWG chose as one of its discount rates an estimate based upon declining discount rates. The 2.5-percent discount rate was included by IWG as a constant-rate approximation of a declining discount rate.[88] Since the IWG undertook its initial analysis, a consensus has emerged among leading climate economists that a declining discount rate should be used for climate damages to reflect long-term uncertainty in interest rates.[89] Arrow *et al* (2013) presents several arguments that strongly support the use of declining discount rates for long-term benefit-cost analysis.

But perhaps the best reason is the simple fact that there is considerable uncertainty around which interest rate to use: uncertainty in the rate points directly to the need to use a declining rate, as the impact of the uncertainty grows exponentially over time.[90] The uncertainty about future discount rates could stem from a number of reasons particularly salient to climate damages, including uncertainties in future economic growth, consumption, and the interest rate used by consumers.

Why should the central IWG estimate be interpreted as a lower bound?

A number of factors might result in using a SCC value that is higher than the estimate based on a 3-percent discount rate. Recent research has shown that the appropriate discount rate for intergenerational analysis may be even lower than that reflected in the SCC analysis, which would result in a higher SCC.[91] A jurisdiction might decide that the uncertainty associated with climate damages warrants using a discount rate that declines over time, leading to a higher SCC.[92] A consensus has emerged among leading climate economists that a declining discount rate should be used for climate damages to reflect long-term uncertainty in interest rates, and the NAS January 2017 recommendations to the IWG support this approach.[93] Furthermore, a number of types of damage from climate change are missing or poorly quantified in the federal SCC estimates, meaning that **the federal SCC estimate associated with a 3-percent discount rate should be interpreted as a lower bound on the central estimate**.[94]

---

[88] TSD 2010, *supra* note 3, at 23 ("The low value, 2.5 percent, is included to incorporate the concern that interest rates are highly uncertain over time. It represents the average certainty-equivalent rate using the mean-reverting and random walk approaches from Newell and Pizer (2003) starting at a discount rate of 3 percent. Using this approach, the certainty equivalent is about 2.2 percent using the random walk model and 2.8 percent using the mean reverting approach. Without giving preference to a particular model, the average of the two rates is 2.5 percent. Further, a rate below the riskless rate would be justified if climate investments are negatively correlated with the overall market rate of return. Use of this lower value also responds to certain judgments using the prescriptive or normative approach and to ethical objections that have been raised about rates of 3 percent or higher.")

[89] The arguments here are primarily based on: Kenneth J. Arrow *et al.*, *Determining Benefits and Costs for Future Generations*, 341 Science 349 (2013); Kenneth J. Arrow *et al.*, *Should Governments Use a Declining Discount Rate in Project Analysis?*, Rev Environ Econ Policy 8 (2014); Richard G. Newell & William A. Pizer, *Discounting the Distant Future: How Much Do Uncertain Rates Increase Valuations?*, 46 J. Envtl. Econ. & Mgmt. 52 (2003); Maureen L. Cropper *et al.*, *Declining Discount Rates*, American Economic Review: Papers and Proceedings (2014); S.K. Rose, D. Turner, G. Blanford, J. Bistline, F. de la Chesnaye, and T. Wilson. *Understanding the Social Cost of Carbon: A Technical Assessment*. EPRI Report #3002004657 (2014).

[90] Martin L. Weitzman, *Gamma Discounting*, 91 Am. Econ. Rev. 260, 270 (2001) [hereinafter "Weitzman 2001"].

[91] CES Order, *supra* note 38; CEA Brief, *supra* note 87.

[92] *See* Weitzman 2001, *supra* note 90. Kenneth J. Arrow *et al.*, *Determining Benefits and Costs for Future Generations*, 341 Science 349 (2013); Kenneth J. Arrow *et al.*, *Should Governments Use a Declining Discount Rate in Project Analysis?*, 8 Rev Environ Econ Policy 1 (2014); Maureen L. Cropper *et al.*, *Declining Discount Rates*, 104 Am. Econ. Rev. 538 (2014); Christian Gollier & Martin L. Weitzman, *How Should the Distant Future Be Discounted When Discount Rates Are Uncertain?* 107 Economics Letters 3 (2010). Policy Integrity further explores the use of declining discount rates in its recent comments to the National Academies of Sciences. Policy Integrity NAS comments, *supra* note 68.

[93] NAS Second Report, *supra* note 76.

[94] *See* Omitted Damages, *supra* note 6; Revesz *et al.* 2014, *supra* note 74.

As we discussed above, Washington State agencies have begun following the recommendation of the state's energy office and using a 2.5-percent discount rate for their economic analyses involving greenhouse gas emissions, for a number of reasons, including that the damages omitted from the IWG estimates and the uncertainty surrounding climate consequences warrant more dramatic action.[95]

Why did the IWG select a 300-year time horizon?

In 2017, NAS issued a report stressing the importance of a longer time horizon for calculating the social cost of greenhouse gases, the rationale for which is also included in the 2016 IWG Technical Support Document. The report states that, "[in the context of the socioeconomic damage, and discounting assumptions, the time horizon needs to be long enough to capture the vast majority of the present value of damages."[96] The report goes on to note that the length of the time horizon is dependent "on the rate at which undiscounted damages grow over time and on the rate at which they are discounted. Longer time horizons allow for representation and evaluation of longer-run geophysical system dynamics, such as sea level change and the carbon cycle."[97] In other words, after selecting the appropriate discount rate based on theory and data (in this case, 3 percent or below), analysts should determine the time horizon necessary to capture all costs and benefits that will have important net present values at the discount rate. Therefore, a 3 percent or lower discount rate for climate change implies the need for a 300-year horizon to capture all significant values. NAS reviewed the best available, peer-reviewed scientific literature and concluded that the effects of greenhouse gas emissions over a 300-year period are sufficiently well established and reliable as to merit consideration in estimates of the social cost of greenhouse gases.[98]

The best available science and economics thus supports a 300-year time horizon for climate effects. We note that, so far one state, Minnesota, has chosen a different time horizon. For the reasons above, this should not be considered a best practice.[99]

Why did the IWG recommend a global rather than domestic estimate?

As we discussed above, the IWG recommends using a global estimate for a number of reasons. Generally, a global number is appropriate because climate change is a global phenomenon and emissions that occur in one part of the world affect other parts of the world. The same is true for avoided emissions. Simply, if all countries set their greenhouse emission levels based on only domestic costs and benefits, ignoring the large global externalities, the aggregate result would be substantially sub-optimal climate protections and economically inefficient policies.

Why did the IWG develop separate numbers for methane and nitrous oxide, rather than just adjusting by their global warming potential?

The IWG has also developed robust federal estimates of the **social cost of methane (SCM)** and **social cost of nitrous oxide (SCN_2O)**. Methane and nitrous oxide are two important, and potent, greenhouse gases. Prior to the IWG's work

---

[95] *See*, e.g., State of Washington, Department of Ecology, Preliminary Cost-Benefit and Least-Burdensome Alternative Analysis: Chapter 173-442 WAC Clean Air Rule & Chapter 173-441 WAC Reporting of Emissions of Greenhouse Gases 38 (2016), *available at* https://fortress.wa.gov/ecy/publications/documents/1602008.pdf.

[96] NAS Second Report, *supra* note 76, at 77.

[97] *Id.*

[98] NAS First Report, *supra* note 66, at 32.

[99] See for more information, "Isn't there too much uncertainty around the SCC to use it?" on page 23.

on social costs for the emission of these pollutants, the SCC was multiplied by the Global Warming Potential (GWP) of each gas.[100] But, according to the IWG:

> "While GWPs allow for some useful comparisons across gases on a physical basis, using the [SCC]…to value the damages associated with changes in CO_2-equivalent emissions is not optimal…because non-CO_2 GHGs differ not just in their potential to absorb infrared radiation over a given time frame, but also in the temporal pathway of their impact on radiative forcing, which is relevant for estimating their social cost but not reflected in the GWP."[101]

In other words, because the GWP of each GHG changes over the lifetime of the gas, multiplying the SCC by the GWP in any particular year is inaccurate. The SCM and SCN_2O methodologies build directly on the IWG's SCC methodology, and replace the less accurate methodology of multiplying the SCC by these gases' relative global warming potential. The same rigorous, consensus-based, transparent process used for the federal SCC has shaped the federal SCM and federal SCN_2O estimates. Just as the federal SCC likely underestimates the true social cost of carbon, the federal SCM and SCN_2O are **likely to underestimate the true social cost of these other greenhouse gases** due to omitted damages and uncertainties regarding the scope of the effects in the underlying models.[102] Nonetheless, **the 2016 IWG SCM and SCN_2O are the best available estimates of the social costs associated with the emission of those greenhouse gases**.

Table 3: Social Cost of Methane Estimates (in 2017 dollars per metric ton)[103]

Year of Emission	Average estimate at 5% discount rate	Average estimate at 3% discountrate—IWG's Central Estimate	Average estimate at 2.5% discount rate	95th percentile estimate at 3% discount rate
2020	$648	**$1440**	$1920	$3839
2025	$780	**$1680**	$2159	$4439
2030	$912	**$1920**	$2399	$5039
2035	$1080	**$2159**	$2759	$5879
2040	$1200	**$2399**	$3119	$6598
2045	$1440	**$2759**	$3359	$7318
2050	$1560	**$2999**	$3719	$8038

[100] TSD 2016 Addendum, *supra* note 67, at 2 ("The potential of these gases to change the Earth's climate relative to CO_2 is commonly represented by their 100-year global warming potential (GWP). GWPs measure the contribution to warming of the Earth's atmosphere resulting from emissions of a given gas (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. As such, GWPs are often used to convert emissions of non-CO_2 GHGs to CO_2-equivalents to facilitate comparison of policies and inventories involving different GHGs.")

[101] TSD 2016 Addendum, *supra* note 67, at 2.

[102] Alex L. Marten et al, *Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates*. 15 Climate Policy 272 (2015). 15(2): 272-298 (2015, published online, 2014) [hereinafter "Marten et al."]; Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, and Union of Concerned Scientists Comments on EERE-2015-BT-STD-0016, Energy Conservation Standards for WICF Refrigeration System and EERE-2014-BT-STD-0031, Energy Conservation Standards for Residential Furnaces (Nov. 7, 2016).

[103] TSD 2016 Addendum, *supra* note 67, at 7.

Table 4: Social Cost of Nitrous Oxide Estimates (in 2017 dollars per metric ton)[104]

Year of Emission	Average estimate at 5% discount rate	Average estimate at 3% discountrate—IWG's Central Estimate	Average estimate at 2.5% discount rate	95th percentile estimate at 3% discount rate
2020	$5639	**$17,996**	$26,393	$46,788
2025	$6598	**$20,395**	$28,793	$52,787
2030	$7558	**$22,794**	$32,392	$58,785
2035	$8878	**$25,194**	$34,791	$65,984
2040	$10,078	**$27,593**	$38,390	$71,982
2045	$11,397	**$29,993**	$40,790	$79,180
2050	$13,197	**$32,392**	$44,389	$86,379

The SCM and SCN_2O were developed more recently, so have a shorter history of being used by federal—or state—agencies, but the figures were approved by the IWG and appear in an addendum to the group's 2016 Technical Support Document. They were also peer-reviewed by the EPA and by academic journals.[105] For other greenhouse gases beyond methane and nitrous oxide, adjusting the SCC with the gases global warming potential is fine. In fact, for now, it is the best option for state decisionmakers.

Common (but misguided) critiques of the SCC

Aren't there benefits of carbon dioxide emissions?

There are benefits to carbon dioxide, and some of these benefits, such as potential increases in agricultural yields, are captured in the SCC estimate. These benefits reduce the magnitude of the SCC. Other benefits that are the result of climate change are omitted, including the lower cost of supplying renewable energy from wind and wave sources, the increased availability of oil due to higher temperatures in the Arctic, and fewer transportation delays from snow and ice. However, omitted negative impacts almost certainly overwhelm omitted benefits.[106] As a consequence, $50 should be interpreted as a lower-bound central estimate.

The other benefits from the use of carbon fuels that are unrelated to climate change (such as economic output) are omitted from the SCC, but they are always included in any analysis in which the SCC is used. In a benefit-cost analysis, the cost of regulations, such as the potential loss of output, is always balanced against the benefits of carbon reductions as partially measured by the SCC.

If we adapt to climate change or develop new technologies, then won't the value of avoiding emissions be zero?

No. Adaptation and technological change are included in the IAMs already, explicitly or implicitly. In fact, DICE and FUND may overestimate the potential for adaptation by assuming high levels of costless adaptation. Additional research

[104] *Id.*
[105] Marten et al., *supra* note 102.
[106] Revesz *et al.* 2014, *supra* note 74; Omitted Damages, *supra* note 6.

on adaptation—particularly the ability of technological change and climate impacts to lower and raise, respectively, the cost of adaptation—is necessary. According to the 2010 IWG Technical Support Document,[107] future research may lead to an increase or decrease in future damages. But even under the overly optimistic assumptions about adaptation made by some models, in none of the IAMs is adaptation effective enough to significantly eliminate climate damages.

Isn't there too much uncertainty around the SCC to use it?

Absolutely not. Decisionmakers should not throw up their hands because of uncertainty. As the Ninth Circuit has held: "[W]hile the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[108] On the whole, uncertainty suggests an even higher SCC than estimated.

Uncertainty around climate change generally warrants more stringent climate policy and raises the SCC. Current integrated assessment models (IAMs) used to calculate the SCC show that the net effect of uncertainty about economic damage resulting from climate change, costs of mitigation, future economic development, and many other parameters raises the SCC compared to the case where models simply use our current best guesses of these parameters.[109] Even so, IAMs still underestimate the impact of uncertainty on the SCC by ignoring fundamental features of the climate problem: the irreversibility of climate change, society's aversion to risk and other social preferences, and many catastrophic impacts.[110] The next generation of numerical models designed to capture these features of the climate problem currently focus on the optimal tax (i.e., the SCC on the optimal emissions path) and require key simplifying assumptions, though existing results indicate that uncertainty leads to an increase in the optimal tax under uncertainty for realistic parameter values. Rather than being a reason not to take action, if anything, uncertainty increases the SCC and should lead to more stringent policies to address climate change.

While the 2016 IWG estimate is the best available SCC figure, it likely represents a lower bound for the costs of climate change because the models that are used to get the estimates leave out several categories of climate damages, which we discussed earlier. Again, damages currently omitted from the models include, but are not limited to, the effects of climate change on fisheries; the effects of increased pest, disease, and fire pressures on agriculture and forests; and the effects of climate-induced migration. Additionally, these models omit the effects of climate change on economic growth and the rise in the future value of environmental services due to increased scarcity.[111]

Uncertainty is also no reason to shorten the SCC time horizon. In 2017, NAS issued a report stressing the importance of a longer time horizon for calculating the social cost of greenhouse gases. The report states that, "[i]n the context of the socioeconomic, damage, and discounting assumptions, the time horizon needs to be long enough to capture the vast majority of the present value of damages." The report goes on to note that the length of the time horizon is dependent "on the rate at which undiscounted damages grow over time and on the rate at which they are discounted. Longer time

---

[107] TSD 2010, *supra* note 3, at 30. *Also see*, Omitted Damages, *supra* note 6, at 42-43.

[108] *Ctr. for Biological Diversity* 548 F.3d, *supra* note 51, at 1200.

[109] Richard S. Tol, *Safe policies in an uncertain climate: an application of FUND*, Global Environmental Change, 9(3), 221-232 (1999); Peterson, S. (2006). Uncertainty and economic analysis of climate change: A survey of approaches and findings. Environmental Modeling & Assessment, 11(1), 1-17; TSD 2016, *supra* note 2.

[110] Robert S. Pindyck, *Uncertainty in environmental economics*, Review of Environmental Economics and Policy (2007), 1(1), 45-65; A. Golub *et al.* Uncertainty in integrated assessment models of climate change: Alternative analytical approaches. Environmental Modeling & Assessment (2014), 19(2), 99-109; D. Lemoine, & I. Rudik. Managing Climate Change Under Uncertainty: Recursive Integrated Assessment at an Inflection Point. Annual Review of Resource Economics(2017) 9:18.1-18.26.

[111] *See* Omitted Damages, *supra* note 6, for a more complete list.

horizons allow for representation and evaluation of longer-run geophysical system dynamics, such as sea level change and the carbon cycle." In other words, after selecting the appropriate discount rate based on theory and data (in this case, 3% or below), analysts should determine the time horizon necessary to capture all costs and benefits that will have important net present values at the discount rate. Therefore, a 3% or lower discount rate for climate change implies the need for a 300-year horizon to capture all significant values. NAS reviewed the best available, peer-reviewed scientific literature and concluded that the effects of greenhouse gas emissions over a 300-year period are sufficiently well established and reliable as to merit consideration in estimates of the social cost of greenhouse gases.[112]

Didn't the noted economist Robert Pindyck say the SCC numbers were flawed?

Not really, because he actually wants higher numbers. Robert Pindyck wrote a brief article[113] and released a working paper[114] shortly after the 2013 update to the IWG's SCC estimates, in which he criticizes the SCC. However, Pindyck actually advocates for an even higher SCC. He says: "My criticism of IAMs should not be taken to imply that because we know so little, nothing should be done about climate change right now, and instead we should wait until we learn more. Quite the contrary." He goes on to explain that being proactive will benefit society in the longterm. "One can think of a GHG abatement policy as a form of insurance: society would be paying for a guarantee that a low-probability catastrophe will not occur (or is less likely)."[115] Pindyck actually enforces the idea we discussed above, namely that the uncertainty underlying the SCC is no reason to not use the IWG estimates, but rather that decisionmakers who are interested in taking into account the climate effects of particular options should use the SCC as a starting point. In fact, Pindyck's own best estimate of the SCC is between $80 to $100, and goes up to $200.[116] Many groups cite Pindyck when criticizing the SCC, but fail to mention that his conclusion actually supports a robust accounting of climate damage externalities in decisionmaking.

Technical guidance: how do we apply the SCC in our analyses?

What should we choose as our central estimate?

The IWG SCC estimates are not a single number, but instead a range of four estimates, based on three discount rates, plus a 95th percentile estimate that represents catastrophic, low-probability outcomes.[117] Discount rates allow economists to measure the value of money over time—the tradeoff between what a dollar is worth today and what a dollar would be worth in the future.[118] Higher discount rates result in a lower SCC; if future climate damages are discounted at a high rate,

---

[112] NAS Second Report, *supra* note 76.

[113] Robert S. Pindyck, *Pricing Carbon When We Don't Know the Right Price*, Regulation (Summer 2013). *Available at* https://object.cato.org/sites/cato.org/files/serials/files/cato-video/2013/6/regulation-v36n2-1-2.pdf.

[114] Robert Pindyck, "Climate Change Policy: What do the Models Tell Us?" Working Paper 19244. National Bureau of Economic Research (July 2013), *available at* http://www.nber.org/papers/w19244.pdf.

[115] *Id.* at 16.

[116] *Id.*

[117] TSD 2010, *supra* note 3; TSD 2013, *supra* note 62; Interagency Working Group on the Social Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2015); TSD 2016, *supra* note 2.

[118] If offered $1 now or $1 in a year, almost everyone would choose to receive the $1 now. Most individuals would only wait until next year if they were offered more money in the future. The discount rate is how much more you would have to receive to wait until next year.

we would be placing less value on avoiding those damages today. The IWG uses discount rates of 5, 3, and 2.5 percent.[119] The fourth value is taken from the 95th percentile of the SCC estimates corresponding to the 3-percent discount rate, which represents catastrophic but unlikely situations.[120] Note that application of the 95th percentile value was not part of an effort to show the probability distribution around the 3-percent discount rate; rather, the 95th percentile value serves as a methodological shortcut to approximate the uncertainties around low-probability but high-damage, catastrophic, or irreversible outcomes that are currently omitted or undercounted in the economic models.

Frequently, agencies will conduct their economic analyses using a range of SCC values.[121] Often, other analyses focus on a "central" estimate of the SCC.[122] The IWG recommends using a 3% discount rate. However, Washington State, for example, selected the 2.5% discount rate as its "central" estimate, for reasons discussed above.

Choosing the most appropriate discount rate is crucial to obtaining the best SCC estimate. A policymaker might decide that the uncertainty associated with climate damages warrants using a discount rate that declines over time, leading to a higher SCC. A consensus has emerged among leading climate economists that a declining discount rate should be used for climate damages, to reflect long-term uncertainty in interest rates.[123] The National Academy of Sciences January 2017 recommendations to the IWG support this approach.[124] Furthermore, as noted above, **the federal SCC estimate associated with a 3-percent discount rate should be interpreted as a lower bound**.[125]

Can we just calculate damages from a single year of emissions?

No. The values of the SCC in the IWG analysis are calculated by adding up the streams of future effects from a ton of emissions in the year of anticipated release, with discount rates reflecting the passage of time between the anticipated release and the future effects. It is necessary to include in the analysis emissions for each year that a plan, action or project is in place, because the SCC increases over time.

How does discounting work?

The IWG's SCC values represent the damages associated with each additional ton of carbon dioxide emissions released *from the perspective of the year of emission*. It is necessary when conducting a policy analysis *at the present time* about policies that affect greenhouse gas releases *in the future* to make sure that the SCC values are translated into the *perspective*

---

[119] The IWG correctly excluded a 7% discount rate, a standard private sector rate of return on capital, in its SCC calculations for two main reasons. First, typical financial decisions, such as how much to save in a bank account, focus on private decisions and use private rates of return. However, in the context of climate change, analysts are concerned with social discount rates because emissions mitigation is a public good, where individual emissions choices affect public well-being broadly. Second, climate change is expected to primarily affect consumption, not traditional capital investments.

[120] *See* Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, and Union of Concerned Scientists. Comments on Proposed Exception to the Colorado Roadless Rule (RIN 0596-AD26) and Supplemental Draft Environmental Impact Statement (November 2015) to Forest Service; Council on Environmental Quality; Office of Information and Regulatory Affairs to describe importance of 95th percentile value.

[121] *See, e.g.*, Energy Conservation Program: Energy Conservation Standards for Miscellaneous Refrigeration Products, 81 Fed. Reg. 75,194 (Oct. 26, 2016); Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 Fed. Reg. 74,504 (Oct. 26, 2016).

[122] *See, e.g.*, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, New York Public Service Comm'n Case No. 14-M-0101 (Jan. 21, 2016) ["BCA Order"].

[123] *See* Weitzman 2001, *supra* note 90; Kenneth J. Arrow *et al.* 2013, *supra* note 92; Kenneth J. Arrow *et al.*, 2014, *supra* note 92; Maureen L. Cropper *et al.* 2014, *supra* note 92; Christian Gollier & Martin L. Weitzman 2010, *supra* note 92. Policy Integrity comments to NAS, *supra* note 68.

[124] NAS Second Report, *supra* note 76.

[125] *See* Omitted Damages, *supra* note 6; Richard L. Revesz *et al.* 2014, *supra* note 74.

of the year of the policy decision. The proper way to accomplish this translation is by using the discount rate to convert the effects of emissions from the year of release into the present value.

Imagine a policy has costs today and would decrease emissions in the year 2025. The IWG estimates for 2025 are how much those reductions are worth to people in year 2025, looking at cumulative effects over a 300-year period and discounting back to the year 2025. But because we prefer present consumption over future consumption, how we'd value that today isn't the same as how people in year 2025 would value it. Still, we need to discount from year 2025 back to today.

What about inflation?

Separate from the discounting considerations, which reflect the resource tradeoffs facing the actors in the relevant year of action, currency tends to inflate over time. The IWG's calculations for the SCC are based upon 2007 dollars, but the purchasing power of the dollar has gone down since then, meaning that $1 in 2007 is worth $1.20 in 2017.[126] It is important to ensure that the analysis is consistent across time frames and makes sense to decisionmakers. Thus, before any calculations are done, the analysts should account for inflation by converting all of the SCC values from 2007 dollars into dollars for the year the analysis is taking place (currently, 2017).

So once we multiply emissions by the SCC and discount back, are we done?

Not quite. It is still best to include a qualitative description of omitted damages. Best practices for regulatory analysis require including all costs and benefits, even the hard-to-monetize ones. Include a qualitative description to emphasize that the SCC is a lower bound on damages.

And what are all of the steps put together?

To make the calculation, the SCC figure should be multiplied by the projected avoided emissions to provide a figure for the monetized benefits of an action's or project's avoided greenhouse gas emissions. Specifically, you should:

1. Convert the SCC values from 2007 dollars to the year of analysis, using a consumer price index inflation calculator[127] (if the values have not yet been converted);
2. Determine the avoided emissions for each Year X between the effective date and the end date of 2030;
3. Multiply the quantity of avoided emissions in Year X by the corresponding SCC in Year X,[128] to calculate the monetary value of damages avoided by avoiding emissions in Year X;[129]
4. Apply the same discount rate used to calculate the SCC to calculate the present value of future effects of emissions from Year X;[130]

---

[126] *See* CPI Inflation Calculator, http://data.bls.gov/cgi-bin/cpicalc.pl?cost1=1&year1=2007&year2=2017.

[127] *See* CPI Inflation Calculator, http://data.bls.gov/cgi-bin/cpicalc.pl.

[128] In general, the SCC goes up over time because greenhouse gases accumulate, exacerbating the effects of climate change—and therefore the harm from each additional unit of emissions—over time. TSD 2010, *supra* note 3, at 28.

[129] The SCC for a given year encompasses the effects that a ton of carbon dioxide, once emitted in that year, will have stretching into the future over a 300-year time frame. TSD 2010, *supra* note 3, at 25.

[130] Using a consistent discount rate for both the SCC (assessed from the perspective of the actors in the year of emission) and the net present value calculation (assessed from the perspective of the decisionmaker) is important to ensure that the decisionmaker is treating emissions in each time frame similarly. The decisionmaker should not be overvaluing or undervaluing emissions in the present as compared to emissions in the future. NAS First Report, *supra* note 66.

5. Sum these values for all relevant years between the effective date and the end date to arrive at the total monetized climate benefits of the plan's avoided emissions;[131] and
6. Qualitatively describe in the final discussion of the climate benefits all of the other damages that have been omitted from the SCC.

State agencies could conduct these calculations with a single, central discount rate for the SCC, or the agency could conduct the analysis several times, using a range of discount rates for the SCC, being sure to use the selected discount rate in step 4 for each different iteration.

Because the SCC has been used in a number of federal regulatory impact analyses and environmental impact statements, there are a number of examples from which states can learn how to conduct their own SCC analysis.[132]

How is the SCC used in an analysis with other discount rates?

In its Phase 1 report, NAS recommended that the SCC be used with a "consistent" discount rate in cost-benefit analysis.[133] "Consistent" should be interpreted to mean "compatible" and based on the same theoretically-sound methodology (i.e., theoretically consistent): for example, applying a higher discount rate (say 3%) to other costs and benefits may be "consistent" with a lower discount rate (say 2.5%) for the SCC, to account for the greater uncertainty with respect to climate change relative to more short-run benefits and costs. This approach is appropriate when climate uncertainty exceeds the short-run uncertainty captured by most benefit-cost analysis in which the SCC is applied.

What other resources exist?

- Omitted Damages: What's Missing from the Social Cost of Carbon (2014) by Peter Howard
- Think Global, International Reciprocity as Justification for a Global Social Cost of Carbon (2016) by Jason Schwartz and Peter Howard
- Best cost estimates of greenhouse gases (2017) by Richard Revesz, Michael Greenstone, Michael Hanemann, Thomas Sterner, Peter Howard, Jason Schwartz
- Global Warming: Improve Economic Models of Climate Change (2014) by Richard L. Revesz, Kenneth Arrow *et al.*
- The Social Cost of Carbon: A Global Imperative (2017) by Richard L. Revesz, Jason A. Schwartz, Peter H. Howard, Kenneth Arrow, Michael A. Livermore, Michael Oppenheimer, and Thomas Sterner
- Flammable Planet: Wildfires and the Social Cost of Carbon (2014), by Peter Howard
- Recent comments by Policy Integrity, EDF, NRDC, and Union of Concerned Scientists on the SCC
- Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update (2016), National Academies of Sciences

---

[131] Steps 4 and 5 combined are equivalent to calculating the present value of the stream of future monetary values using the same discount rate as the SCC discount rate.

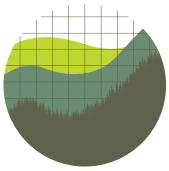
[132] *See, e.g.*, Energy Conservation Program: Energy Conservation Standards for Commercial Refrigeration Equipment 79 Fed. Reg. 17,726, at 17,728, 17,773, 17,779, 17,811 (Mar. 28, 2014); U.S. Department of Energy, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment 12-22, 13-4 to 13-5, 14-2 (2014).

[133] NAS First Report, *supra* note 66, at 49.

- Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide (2017), National Academies of Sciences
- Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2010), Interagency Working Group on the Social Cost of Greenhouse Gases
- Revised: Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2013), Interagency Working Group on the Social Cost of Greenhouse Gases
- Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (2016), Interagency Working Group on the Social Cost of Greenhouse Gases Under Executive Order 12866 Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (2016), Interagency Working Group on the Social Cost of Greenhouse Gases

For more information, contact one of Policy Integrity's experts on the social cost of carbon in decisionmaking:

- Denise A. Grab, Western Regional Director, denise.grab@nyu.edu
- Peter H. Howard, Ph.D., Economics Director, peter.howard@nyu.edu
- Jason A. Schwartz, Legal Director, jason.schwartz@nyu.edu
- Burcin Unel, Ph.D., Energy Policy Director, burcin.unel@nyu.edu



Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org