Institute for Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

January 22, 2020

VIA ELECTRONIC SUBMISSION

Elijah Abinah
Director, Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Docket No.: RU-0000A-18-0284 – In the matter of possible modifications to the Arizona Corporation Commission's Energy Rules.

Re: Comments of Policy Integrity on monetizing pollution effects

Dear Mr. Abinah,

The Institute for Policy Integrity at New York University School of Law[1] (Policy Integrity) respectfully submits these comments to the Arizona Corporation Commission (Commission) pursuant to its November 23, 2020 order in the above-captioned docket. Policy Integrity is a nonpartisan think tank dedicated to improving the quality of government decisionmaking.

Policy Integrity encourages the Commission to recognize that tools are available to help it and Arizona's utilities modernize Arizona's electricity grid consistent with the revised rules.[2] In particular, the rules would permit load serving entities to consider the environmental benefits of their integrated resource plans, including the benefits of carbon dioxide emissions reductions,[3] something readily done using the tools and methodologies described in Policy Integrity's October 15, 2020 comments in docket E-00000V-19-0034 – In the Matter of Resource Planning and Procurement in 2019, 2020, and 2021, which are attached. We hereby resubmit those comments, and submit the Policy Integrity reports cited in those comments, on monetizing air pollution effects from electricity generation in integrated resource plans in this docket.

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

[2] See Ariz. Corp. Comm., Request for a New Docket – In the Matter of Possible Modificatoins to the Commission's Energy Rules (Docket No. RU-0000A-18-XXXX) (Aug. 17, 2018), https://docket.images.azcc.gov/0000191382.pdf?i=1610393010513.

[3] 26 Ariz. Admin. Reg. 3221 (Dec. 18, 2020) (proposing to add the following language to the list of items load serving entities can include as part of the integrated resource plan approval process at § R14-2-2708 (D)(15): "Providing economic benefits or reducing negative economic impacts, such as, but not limited to, benefits and impacts related to economic development, job creation or retention, customer growth or retention, location or jurisdiction of manufacture, location or jurisdiction of the source of the resource's respective parts and components, and the development of new technologies, innovations, or pilot programs.")

Policy Integrity plans to continue to engage further with the Commission as utilities implement the revised energy rules.

Thank you for your consideration.

Respectfully,

/s/ Justin Gundlach	/s/ Iliana Paul	/s/ Burcin Unel
Justin Gundlach	Iliana Paul	Burcin Unel, Ph.D.
Senior Attorney	Senior Policy Analyst	Energy Policy Director
justin.gundlach@nyu.edu	iliana.paul@nyu.edu	burcin.unel@nyu.edu

Attachments:

1. Comments of Policy Integrity on monetizing pollution quantities reported in resource plans (Oct. 15, 2020)

2. Jeffrey Shrader at al., Institute for Policy Integrity, Valuing Pollution Reductions (2018)

3. Justin Gundlach & Burcin Unel, Institute for Policy Integrity, Getting the Value of Distributed Energy Resources Right (2019)

4. Matt Butner et al., Institute for Policy Integrity, Making the Most of Distributed Energy Resources (2020)

October 15, 2020

VIA ELECTRONIC SUBMISSION

Elijah Abinah
Director, Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Docket No.: E-00000V-19-0034 – In the Matter of Resource Planning and Procurement in 2019, 2020, and 2021

Re: Comments of Policy Integrity on monetizing pollution quantities reported in resource plans

Dear Mr. Abinah,

The Institute for Policy Integrity at New York University School of Law[1] (Policy Integrity) respectfully submits these comments to the Arizona Corporation Commission (ACC or Commission) pursuant to the Commission's August 12, 2020 order modifying deadlines for filings responsive to the integrated resource plans (IRPs) filed by Tucson Electric Power (TEP), Arizona Electric Power Cooperative (AEPCO), UNS Electric (UNS), Inc., and the Arizona Public Service Company (APS) in the above-captioned docket. Policy Integrity is a nonpartisan think tank dedicated to improving the quality of government decisionmaking. Policy Integrity regularly advises on state electricity policy generally, including in California, Colorado, and Nevada,[2] and in particular on whether and how to monetize the effects of air pollutant emissions caused by electricity generation. Policy Integrity has also published a number of reports on valuing and compensating emissions reductions.

Thank you for your consideration.

Respectfully,

/s/ Justin Gundlach
Justin Gundlach
Senior Attorney
justin.gundlach@nyu.edu

/s/ Iliana Paul
Iliana Paul
Senior Policy Analyst
iliana.paul@nyu.edu

/s/ Burcin Unel
Burcin Unel, Ph.D.
Energy Policy Director
burcin.unel@nyu.edu

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

[2] See Policy Integrity's website, policyintegrity.org, for comments to states.

Comments of Policy Integrity on Arizona Integrated Resource Planning Filings

Arizona's IRP process is intended to provide the Commission, stakeholders, and the public with detailed information about how load serving entities (LSEs) plan to supply electricity to their ratepayers over the coming 15 years, and, among other things, what adverse environmental impacts are expected to result. Each IRP's presentation of several scenarios involving different resource mixes makes it possible to compare how different resource mixes would perform. All LSEs have now filed their IRPs for 2020-2035 with the Commission, which is charged to acknowledge an IRP (or explain why it does not) after determining whether that IRP complies with various requirements and is "reasonable and in the public interest."[3] Policy Integrity's comments focus narrowly on how LSEs report on the emissions of air pollutants from electricity generation. We encourage the Commission to ask that each LSE includes in its IRP not only information about the quantities of air pollutants the LSE expects to emit but also monetized estimates of the damages expected to result from those emissions. Doing so would be consistent with Arizona's requirements for IRPs, reveal important information about the nature and value of generation mixes presented in each IRP, and help the Commission to determine if each IRP is in the public interest.

I. Monetizing Emissions Impacts Is Compatible with Arizona IRP Requirements

Every other year, LSEs are required to file with the ACC plans with a 15-year time horizon that disclose environmental impacts from different resource mixes and specify how the LSE will address those impacts. Specifically, the plans must:

- Take into consideration the environmental impacts, including air pollution quantities and rates for carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur dioxide (SO_2), mercury (Hg), and particulate matter (PM), among others, for each generating unit represented in the proposed portfolios;[4]
- "[A]ddress the adverse environmental impacts of power production;"[5]
- Include "[a] plan for reducing environmental impacts related to air emissions;"[6]
- Include expected reductions in environmental impacts from demand management programs;[7]
- "[E]ffectively manage the uncertainty and risks associated with costs and environmental impacts;"[8]
- Include "[c]ost analyses and projections, including the cost of compliance with existing and expected environmental regulations."[9]

[3] § ARIZ. ADMIN. CODE § R14-2-704(B).
[4] § 703(B)(1)(p).
[5] § 703(F)(3).
[6] § 703(D)(17).
[7] § 703(D)(14)(d).
[8] § 703(F)(7).
[9] § 703(D)(1)(h).

At present, LSEs take different approaches to complying with these requirements. All Arizona LSEs typically disclose historical and projected emissions *quantities* in their plans,[10] but—even though they are all required to include information about environmental compliance costs[11]—only some LSEs report their anticipated or potential greenhouse gas regulation compliance costs in their modeling or compliance costs for other environmental regulations.[12] Similarly, some but not all LSEs "address the adverse environmental impacts of power production"[13] by identifying the expected costs of achieving different greenhouse gas emission reductions of various portfolios.[14] Currently, however, no LSE reports monetized estimates of the *damages* done by their emissions, even though all LSEs already gather and disclose much, if not all, of the information they would need to make such estimates. Notably, Arizona regulations invite LSEs to provide the ACC with analyses "pertaining to environmental impacts…which may include monetized estimates of environmental impacts that are not included as costs for compliance."[15]

LSEs should take a more comprehensive and uniform approach to reporting on costs related to emissions, one that monetizes both compliance and damage costs. This would help the ACC, stakeholders, and the public to understand the benefits and costs of LSEs' IRPs, and it would help LSEs to better "address the adverse environmental impacts of power production," as Arizona law requires. Reporting compliance but not damage costs omits key differences between proposed generation mixes and makes it harder to compare emissions impacts to revenue requirements. Monetizing damages done by emissions to the environment and public health would facilitate comparison within and across portfolios—which is much of the point of developing and presenting IRPs—of costs relevant to the decisions LSEs face when adopting one or another resource portfolio.

The Arizona Administrative Code's directive to the ACC to ensure that each LSE's IRP is "reasonable and in the public interest"[16] is also relevant here. The IRP regulations state that the ACC can make this determination by considering, among other factors, "the environmental impacts of resource choices and alternatives," "the degree to which the [LSEs] consider[] all relevant resources, risks, and uncertainties," and "the degree to which the [LSE]'s plan for future resources is in the best interest of its customers."[17] Because greenhouse gas and local air pollutant emissions pose physical and economic risks to the ratepayers of Arizona, monetizing

---

[10] *See e.g.* Ariz. Corp. Comm'n, Assessment of the 2014 Integrated Resource Plans of the Arizona Electric Utilities, at 74-75, 77-79 https://www.azcc.gov/docs/default-source/utilities-files/electric/integrated-resource-planning/2014/2014-irp-final-draft-report-for-the-azcc-13-0070-(non-redlined)-as-docketed.pdf?sfvrsn=2d221969_2 [hereinafter ACC 2014 Assessment] (providing summaries of LSE compliance with Ariz. Admin. Code requirements to disclose environmental impacts, including water consumption and contribution to coal ash).

[11] ARIZ. ADMIN. CODE § R14-2-703(D)(1)(h).

[12] *See, e.g.* Arizona Public Service Company, 2020 Integrated Resource Plan at 146 (June 2020) [hereinafter "APS 2020 IRP]; Tucson Electric Power Company, 2020 Integrated Resource Plan at 115 (June 2020); UNS Electric, Inc., 2020 Integrated Resource Plan at 71 (Aug. 2020) (all showing carbon dioxide compliance costs); *see also* ACC 2014 Assessment, *supra* note 10, at 56 & 79 (showing LSE carbon dioxide emission cost forecasts for APS, TEP and UNS and how all LSEs present other compliance costs).

[13] ARIZ. ADMIN. CODE § R14-2-703(F)(3).

[14] *See, e.g.*, APS 2020 IRP, *supra* note 12, at 16, Fig. ES-4 (showing portfolio costs as revenue requirements and carbon dioxide emission reduction levels).

[15] ARIZ. ADMIN. CODE § R14-2-703(I).

[16] § 704(B).

[17] § 704(B)(7)–(9).

these costs to facilitate their comparison to other priorities can help the ACC to judge whether a proposed portfolio is in the public interest.

II. Monetizing Emissions Impacts Would Serve Arizona Ratepayers in Several Ways

Monetizing the damages from the global pollutants, like greenhouse gases, and local pollutants, like PM or SO_2, that arise from electricity generation would serve several important purposes, in addition to facilitating compliance with Arizona's regulatory requirements for IRPs. Monetization helps LSEs, the ACC, and stakeholders compare important costs and benefits across portfolios. Monetization also reveals additional information about portfolios' environmental effects, like the significance of the public health consequences that result from exposure to air pollutant emissions. Therefore, monetization improves decisionmaking and LSEs' reporting of environmental impacts in the IRP process.

Monetization Facilitates Comparison of Important Costs and Benefits

Monetizing the emissions impacts of global and local pollutants would better inform comparisons of the costs and benefits of different generation mixes. Putting a dollar value on the damages from emissions allows LSEs to compare them directly, as costs, to other costs and benefits to which markets assign monetary value, like fuel costs. Enabling apples-to-apples comparisons could be particularly useful for LSEs looking to measure not only the performance of conventional, centralized options against renewable or distributed ones, but also for comparing renewable or distributed generation development options against one another. It could thus more accurately capture the real value of investments that comply with Arizona's Renewable Energy and Energy Efficiency Standards. Furthermore, such comparisons would also be useful for considering the impacts of local pollutants resulting from the operation of conventional resources at different times or locations.

Notably, monetization would also make the importance of emissions reductions, relative to other costs and benefits, more prominent for decisionmakers, which can help the Commission determine if an IRP is in the public interest. This is because monetary values typically have higher salience, which allows decisionmakers, stakeholders, and the public to recognize their relative importance.[18] When LSEs report only the quantity and not the monetized value of emissions, they implicitly and effectively dim the importance of emissions reductions relative to, for instance, revenue requirements. Comparing emissions with other factors in uniformly monetary terms is thus necessary to weigh them properly.

Monetization Can Reveal Important Additional Information about Costs and Benefits

Monetizing emissions impacts can reveal important details about where exactly different sorts of emissions would bear upon public health in Arizona. Policy Integrity has published several reports that describe in depth the importance of location and timing of operation to pollution-driven impacts of generation resources of different types, and also provide guidance on how to monetize those impacts:

[18] A well-documented cognitive bias known as "salience bias," as explained by Nobel laureate Daniel Kahneman, among others, causes individuals to focus more on information that is more prominent, and disregard information that is less prominent. DANIEL KAHNEMAN ET AL., JUDGMENT UNDER UNCERTAINTY: HEURISTICS AND BIASES (1982).

- *Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources* (2018);[19]
- *Getting the Value of Distributed Energy Resources Right: Using a Societal Value Stack* (2019);[20] and
- *Making the Most of Distributed Energy Resources: Subregional Estimates of the Environmental Value of Distributed Energy Resources in the United States* (2020).[21]

Although these reports focus on DERs, their basic observations are no less relevant when assessing the implications of siting centralized, large-scale generation resources in particular places or operating them more or less at particular times. Broadly, they can guide LSEs to identify how different portfolios will contribute to climate damages and affect different populations in Arizona and downwind of Arizona-based generation facilities.

The monetization methodologies suggested by these reports are more complex than the analysis presently done by most LSEs, but they would be consistent with the IRP requirement, noted above, of disclosing adverse environmental impacts.[22] Indeed, they would arguably be more consistent than merely reporting emissions volumes; just reporting those volumes does not indicate clearly the magnitude or incidence of the harmful impacts of those emissions. Revealing where and when those impacts originate and also where and how hard they hit would better discharge LSEs' duty of disclosure.

III. There Are Readily Available Tools and Techniques for Monetizing Emissions

Several available tools and techniques, described below, make monetizing emissions impacts of both global and local pollutants relatively easy. In other words, because the availability of these tools makes the cost of potentially valuable information low, investing the small amount of resources required to generate and report that information to the ACC, stakeholders, and the public is worthwhile.

A Tool to Monetize Global Emissions: The Interagency Working Group's Social Cost of Carbon

LSEs must disclose adverse environmental impacts of their electricity production; climate change is one such impact. Each unit of greenhouse gases emitted by the combustion of fossil fuels contributes to climate change and thus to the damaging effects of climate change. Although LSEs do disclose volumes of emissions,[23] emissions themselves are not environmental impacts. There is a readily available tool for valuing the emissions that cause climate change: The Social Cost of Carbon (SCC) developed by the federal government's Interagency Working Group (IWG), which indicates the monetary cost of releasing an additional ton of CO_2 into the atmosphere.[24] The IWG produced a range of estimates for the value of CO_2 emissions, as well as

---

[19] JEFFREY SHRADER AT AL. INST. FOR POL'Y INTEGRITY, VALUING POLLUTION REDUCTIONS (2018), https://policyintegrity.org/files/publications/Valuing_Pollution_Reductions.pdf [hereinafter "VALUING POLLUTION REDUCTIONS"].

[20] JUSTIN GUNDLACH & BURCIN UNEL, INST. FOR POL'Y INTEGRITY, GETTING THE VALUE OF DISTRIBUTED ENERGY RESOURCES RIGHT (2019), https://policyintegrity.org/files/publications/Getting_the_Value_of_Distributed_Energy_Resources_Right.pdf.

[21] MATT BUTNER ET AL., INST. FOR POL'Y INTEGRITY, MAKING THE MOST OF DISTRIBUTED ENERGY RESOURCES (2020), https://policyintegrity.org/files/publications/Making_the_Most_of_Distributed_Energy_Resources.pdf.

[22] *See* ARIZ. ADMIN. CODE § R14-2-703(B)(1)(p).

[23] *See, e.g.*, APS 2020 IRP, *supra* note 12, at 180–181, Tbl. D-14(1)-(3) (quantifying avoided carbon dioxide and other emissions attributed to renewable energy resources for different portfolios).

[24] *See* INTERAGENCY WORKING GROUP ON THE SOCIAL COST OF CARBON, TECHNICAL SUPPORT DOCUMENT: SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866 at 23 (2010).

estimates for methane and nitrous oxide emissions. These estimates are based on three widely-cited integrated assessment models (IAMs) that combine physical climate effects with economic damages. The IWG began developing the SCC in 2009 and continued to refine it through 2016, before the group was disbanded. Despite the fact that the SCC and other social costs of greenhouse gases are not currently being updated by the federal government, the estimates released in 2016 remain the best available estimates of the marginal damages caused by greenhouse gases.[25]

LSEs can use the IWG SCC to convert the greenhouse gas emissions quantities already reported in their IRPs to monetary values.[26] For instance, if APS were to use the IWG SCC to monetize the emissions avoided by its Bridge Portfolio and Accelerate Portfolio for years 2020 through 2035, it would find that those portfolios would avoid climate damages worth $4.49 billion and $5.55 billion respectively.[27] These values represent a significant fraction of those portfolios' revenue requirements—$26.59 billion for the Bridge Portfolio and $28.44 billion for the Accelerate Portfolio.[28]

Tools to Monetize Local Emissions: Existing Public Health Models

A number of models exist that monetize the damages from local air pollutants. It is important to note that these damages depend not only on what pollutant is emitted, but also where they go and the timing—both time of day and season—of their emission. IRPs often contain some but not all of this information. This subsection provides an overview of how to approximate these damages.

Arizona LSEs already quantify aggregate historical and projected annual emissions of a number of local pollutants in their IRPs.[29] These IRPs also disclose details about specific generating units.[30] It would involve only a small further step for LSEs to determine what local pollutants are emitted from particular generators, and when those emissions occur. However, the 2020 IRPs from the state's LSEs do not disclose information about when different generators are dispatched.

Armed with these details, LSEs can approximate the damages caused by their emission of local pollutants using any one of several existing models, including: Estimating Air Pollution Social Impact Using Regression (EASIUR), BenMap, Air Pollution Emission Experiments and Policy Analysis Model, and Co-Benefits Risk Assessment (COBRA). Details on model characteristics and required inputs can be found in our report, *Valuing Pollution Reductions*.[31]

---

[25] Richard L. Revesz et al. *Best Cost Estimate of Greenhouse Gases*, 357 SCI. 655 (2017), https://policyintegrity.org/documents/Science_Revesz_et_al_081718.pdf.

[26] The IWG SCC should be considered an underestimate of the cost of global pollutant emissions that results from electricity production because it omits several important categories of climate damages and so fails to capture the costs of those damages. NATIONAL ACADEMIES OF SCIENCES, ENGINEERING, AND MEDICINE, VALUING CLIMATE DAMAGES: UPDATING ESTIMATION OF THE SOCIAL COST OF CARBON DIOXIDE (2017) (citing PETER HOWARD, INST. FOR POL'Y INTEGRITY, OMITTED DAMAGES: WHAT'S MISSING FROM THE SOCIAL COST OF CARBON (2014)). Because the IWG SCC increases over time, *see* IWG 2010, *supra* note 24, LSEs should be sure to use the IWG SCC for the appropriate year of emissions for each of the 15 years included in their IRPs.

[27] *See* APS 2020 IRP, *supra* note 12, at 180–181, Tbl. D-14(1) and (3). Reported in 2019 dollars, calculations made using the IWG SCC of $42 (2007 dollars) per metric ton of CO_2 for year 2020 emissions through $55 (2007 dollars) per metric ton for year 2035 emissions, converting 2007 dollars to 2019 dollars using a rate of inflation of 1.23.

[28] *Id*. at 376–78.

[29] These pollutants include CO_2, NO_X, SO_2, Hg, and PM. *See supra* notes 4 and 10.

[30] *See, e.g.* APS 2020 IRP, *supra* note 12, at 50.

[31] VALUING POLLUTION REDUCTIONS, *supra* note 19, at 22-24.

Even if applying this technique to an IRP yields a somewhat rough estimate of the monetary costs of pollution-related damages, that information is important for the Commission, LSEs, and other stakeholders to have when comparing IRP portfolios. Local pollution can impose tremendous costs to public health, and if two otherwise identical options would result in grossly disparate public health impacts, that feature should inform how those options weigh.

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

Copyright © 2018 by the Institute for Policy Integrity.
All rights reserved.

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.

This report does not necessarily reflect the views of NYU School of Law, if any.

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

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.

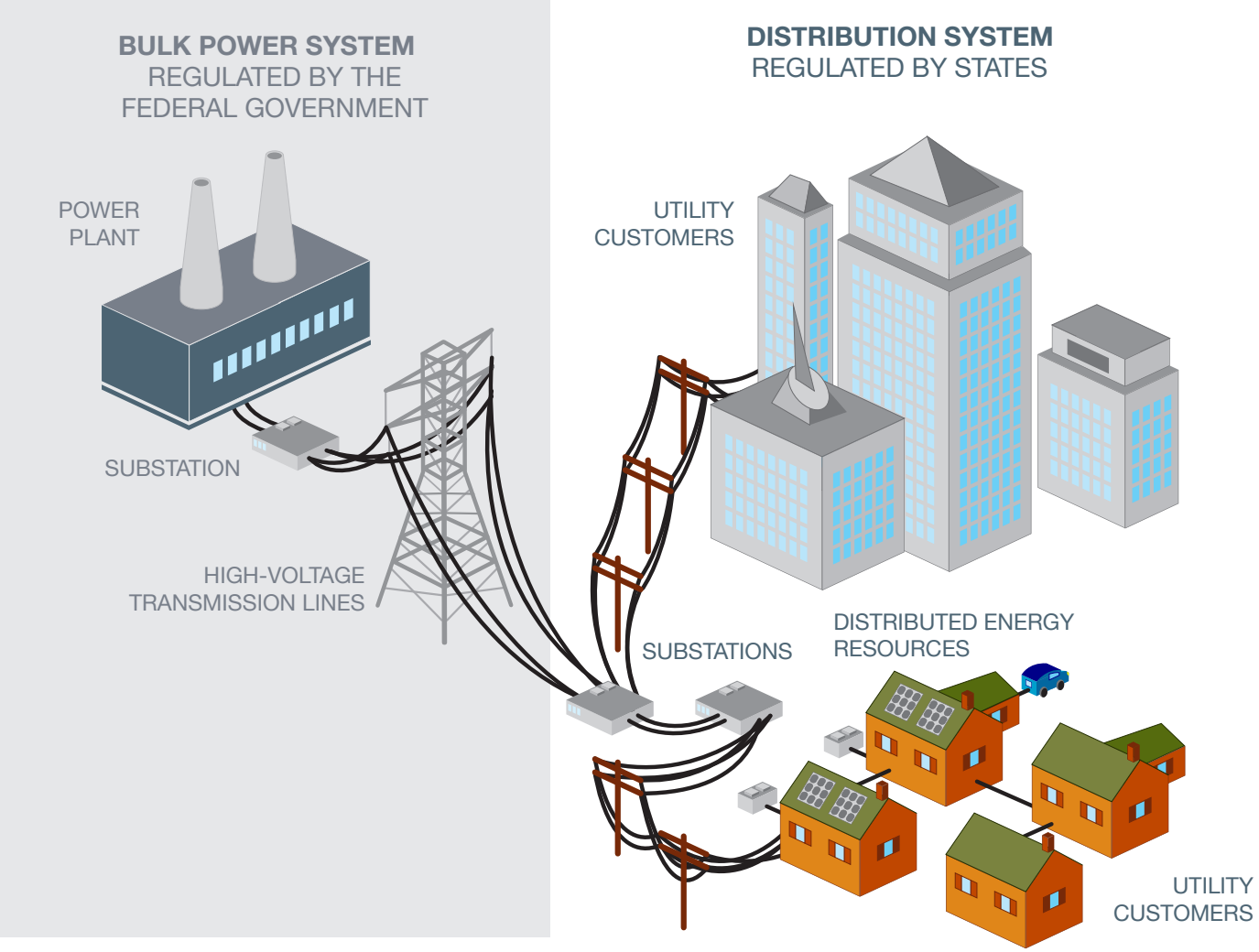
A brief overview of distributed resources, utility regulators, and grid operators

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.

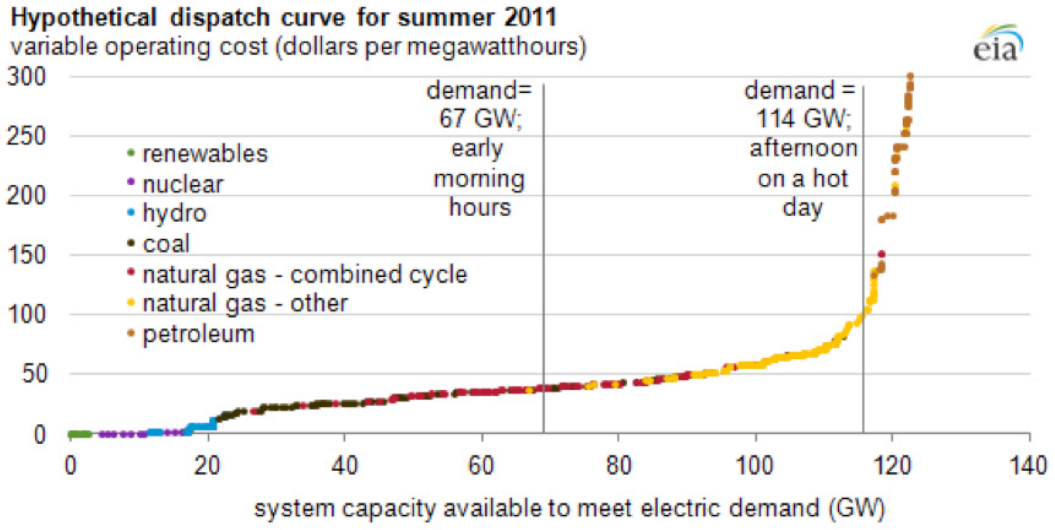
Counterfactual dispatch scenarios could be run as often as the grid operator reruns its dispatch algorithm. However, this approach is also flexible and can be updated less frequently if the administrative costs of frequently identifying counterfactual dispatch outweigh the benefits. For example, if there 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]

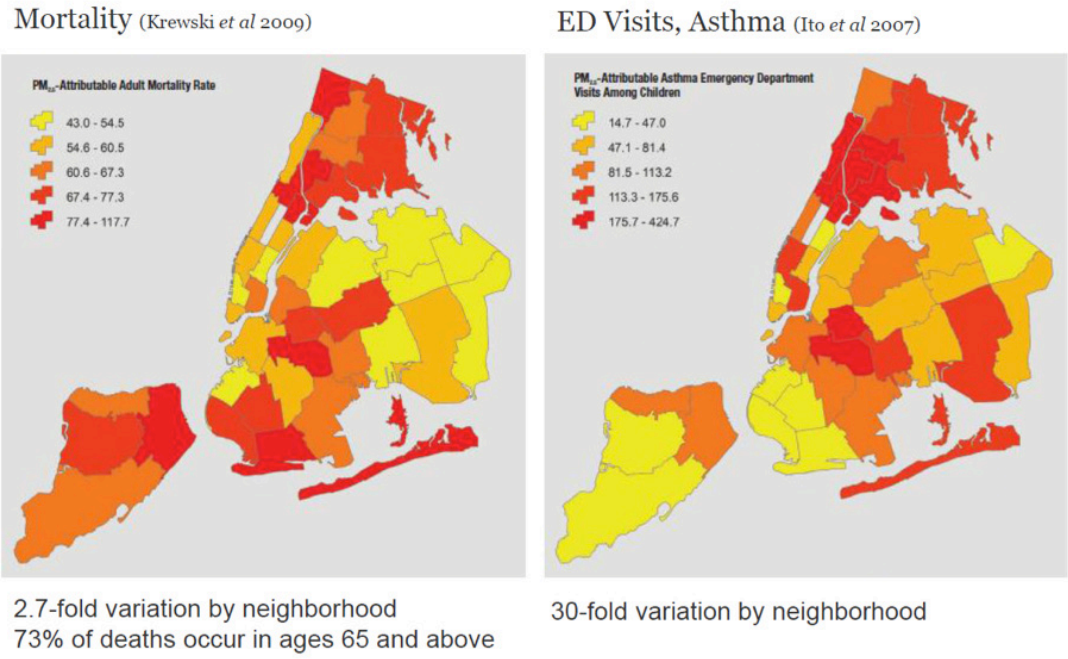
Exposed Population

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.

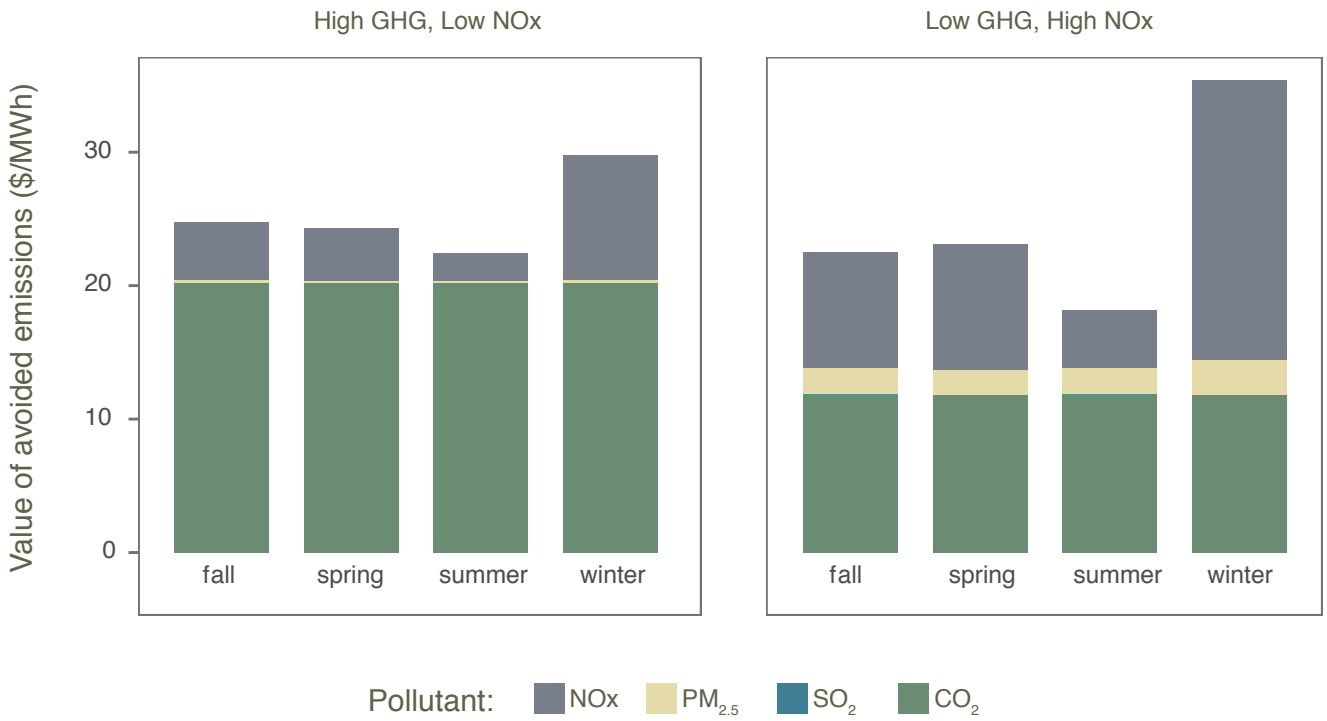
Table 5: Damage Per Unit of Emissions in Two Regions of New York[109]

$PM_{2.5}$ ($/kg)				
Population	Winter	Spring	Summer	Fall
High	355	872	712	316
Low	107	48	50	80
NOx ($/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.

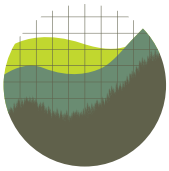
107 Emissions rates are calculated based on data from eGrid (2016), *supra* note 15, and NEI (2014), *supra* note 31.

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.

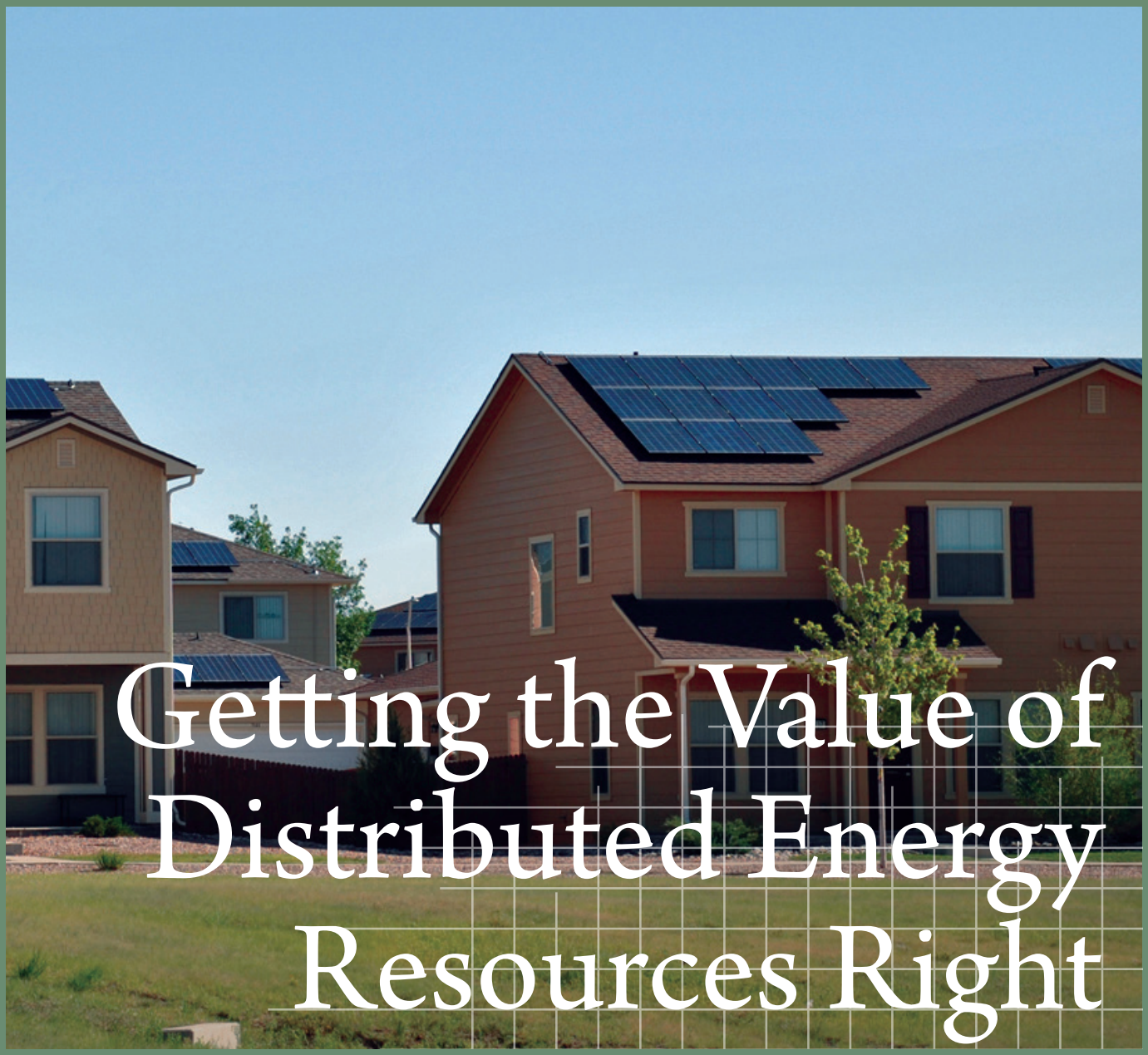


Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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

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

ELECTRICITY POLICY INSIGHTS



© U.S. Air Force photo/Carole Chiles Fuller

Getting the Value of Distributed Energy Resources Right

Using a Societal Value Stack

December 2019
Justin Gundlach
Burcin Unel, Ph.D.

Copyright © 2019 by the Institute for Policy Integrity.
All rights reserved.

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

Justin Gundlach is an Attorney at the Institute for Policy Integrity at NYU School of Law, where Burcin Unel is Energy Policy Director. The authors wish to thank Dina Abdulhadi for her research and assistance with earlier versions of this report, as well as Christine Pries, Richard L. Revesz, Brandon Smithwood, Tom Stanton, Derek Sylvan, Ferit Ucar, and Christopher Villarreal for their helpful comments and suggestions.

This report does not necessarily reflect the views of NYU School of Law.

Table of Contents

Executive Summary

Distributed energy resources (DERs) are small assets that can reduce or supply some or all onsite demand for electricity. Some DERs, such as solar photovoltaic (PV) systems and combined heat and power (CHP) facilities, generate electricity. Others, such as energy storage and demand response resources, do not generate electricity themselves but can modify or reduce customers' electricity demand. DERs' presence has grown over the past decade, and their proliferation is sure to continue.

DERs' growing prevalence increases the pressure on state legislatures and public utility commissions to resolve disputes over how DERs should be compensated for providing services valued by utilities and their customers. The most contentious of these disputes relates to compensating DERs like solar PV and energy storage for the electricity that they export to the grid. Currently, 40 states use net energy metering (NEM) programs to compensate electricity exports from DERs. NEM credits DER owners for their exported excess generation against their consumption of electricity from centralized resources, based on the underlying retail rate. That rate is usually time-invariant and uniform across a utility's service territory. As a result, NEM-based compensation does not capture differences in the value of DERs across time or location. Diverse concerns over how NEM allocates the benefits and costs of DERs have led many states to examine their NEM programs, and in some cases to revise or abandon them.

This report analyzes a promising alternative to NEM, "value stacking." It describes the sources of value added by DERs and recommends adopting an approach to DER compensation that is inclusive of those values. Once DERs' presence in a given utility service territory has become significant, value stacking is preferable to other alternatives, because it:

- Compensates all DERs for the services they provide, using uniform criteria and based on measured performance;
- Reflects differences across times (e.g., "peak" versus "off-peak" demand) and locations (e.g., where congestion is absent versus where it makes it relatively expensive to deliver electricity services from the centralized grid);
- Recognizes the costs of emitting greenhouse gases and local pollutants and compensates DERs for avoiding them;
- Relies on a uniform, accurate compensation scheme to inform where DERs are installed and operated (instead of prescribing volumes or locations of DER capacity); and
- Is neutral with respect to technology and scale.

In addition to explaining the benefits of this value stacking methodology, the report also provides suggestions for how to implement this approach.

Introduction

Distributed energy resources (DERs) are small physical assets that can reduce or supply some or all onsite electricity demand ("load"). They tend to be located "behind the meter," meaning that they are owned and operated by electricity customers rather than utilities.[1] Some, but not all, types of DERs generate electricity; those that can do so, such as solar photovoltaic (PV) systems and combined heat and power (CHP) facilities, are called distributed generation (DG). Other types of DERs, such as energy storage and demand response resources, can modify or reduce customers' electricity demand, even though they do not generate electricity themselves. DERs' presence in the United States has been growing, and there is little reason to doubt that DERs will eventually become a standard feature of electricity systems nationwide.[2]

DERs can provide many services to the grid. For example, PV systems can reduce customers' need for electricity from the grid as well as inject electricity into the grid. Energy storage systems can modify customers' electricity demand throughout the day, reduce their peak demand, and help with system balancing. Currently, different types of DERs receive compensation through a variety of programs and mechanisms, some market-based, others regulatory. Demand response resources, for instance, can participate in wholesale or retail electricity markets in most states, individually or in aggregations.[3] Solar PV owners most often receive bill credits for the electricity they generate and export to the electricity grid. And the purchase and installation of energy-efficient assets can often be financed through utility- or third-party vendor-sponsored programs and property-assessed clean energy or "PACE" programs.

Today, as DERs are becoming more common, state legislatures and public utility commissions are wrestling with the question of how best to compensate them for providing these electricity services.[4] At present, the most contentious policy debates focus on how to compensate DERs that are capable of exporting electricity to the centralized grid, such as DG and some forms of energy storage.

Net energy metering (NEM) has been the predominant approach to compensating owners of DG. As of April 2019, 40 states, plus DC and four territories, use some form of mandatory NEM to assign a value to electricity that DERs inject into the grid.[5] Under NEM, generation in excess of what customers consume onsite is exported to the electricity grid

---

[1] In a 2016 report, the National Association of Regulatory Utility Commissioners (NARUC) collected definitions used by several states and other authorities before suggesting the following definition:

> A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load.

NARUC, Distributed Energy Resources Rate Design and Compensation 43-44 (2016), https://perma.cc/37A5-D5S6.

[2] *See generally* Ignacio J. Perez-Arriaga et al., Utility of the Future: An MIT Energy Initiative Response to an Industry in Transition 36 (2016), https://perma.cc/56VC-H8EN.

[3] "Aggregation" involves the coordination of multiple, dispersed DERs, and is usually conducted by an entity that also acts as a liaison between the DER owners and a buyer of the aggregated service they provide. DERs can interact with the bulk power system through an aggregator, usually a distribution utility or a third-party who bids the aggregated service offering into a wholesale market. *See* Scott Burger et al., *A review of the value of aggregators in electricity systems*, 77 Renewable & Sustainable Energy Revs. 395 (2017) (describing role and functions of aggregators).

[4] North Carolina Clean Energy Technology Center, The 50 States of Solar: Q1 2019 Quarterly Report Executive Summary (2019), https://perma.cc/PCR7-RC7P (cataloguing regulatory proceedings related to distributed solar in 43 states, DC, and Puerto Rico); *see also* Tom Stanton, Nat'l Reg'y Research Inst., Review of State Net Energy Metering and Successor Rate Designs (2019), https://perma.cc/2XCF-TQX8 (surveying recent and ongoing efforts).

[5] DSIRE/NC Clean Energy Ctr., Net Metering—April 2019 (2019), https://perma.cc/GLM4-9F87.

where it is distributed to other retail electricity consumers. DER owners are generally credited for this excess generation against their consumption for each billing period.[6] That is, under NEM, both excess generation and retail electricity service are valued at the same rate, based on the underlying retail rate that the customer faces.

States initially adopted NEM in large part because it was a simple mechanism that allowed customers to install and own DERs capable of injecting excess generation into the grid. It required no upgrades to electric meters, few if any changes to how utilities conducted billing, and no change to the legal status of DER owners even though they exported electricity to the grid. As a result, NEM allowed for DER integration without disrupting the rules or relationships that governed electricity service. NEM programs fostered growth in DERs, especially distributed solar PV.[7] As participation has grown, however, problems with NEM have become increasingly evident. First and foremost among those problems is that, because NEM is based on retail rates, whenever retail rates fail to reflect the costs of electricity service accurately, NEM likewise inaccurately values DERs.[8] This means, for instance, that NEM often *undercompensates* DERs for avoiding emissions of greenhouse gases and local pollutants.[9] And, in general, NEM does a poor job of guiding developers and would-be DER owners to put the right sort of DER in the right place, resulting in economically inefficient patterns of development.

A second, related problem is how NEM allocates the costs and benefits of DER owners' participation in the electricity grid. Specifically, utilities and others have argued that, under NEM, DER owners pay too little towards the cost providing access to reliable grid electricity when they get bill credits. The costs of DER owners' access are thus—so the argument goes—borne by other electricity consumers, who pay more to help make up the difference,[10] and by utilities that absorb the rest of the shortfall. Casting these cost allocations as misallocations leads to the conclusion that NEM runs afoul of core regulatory principles like cost causation.[11]

Concerns about NEM and responses to those concerns vary markedly across states. Reform efforts in California, Hawaii, and New York, for instance, aim to support DERs' further proliferation but ensure that it is cost-effective. Meanwhile, in Indiana, Kentucky, and Louisiana, reforms aim primarily to curb DERs' impacts on utility cost recovery. And in New Hampshire, Nevada, and Vermont, reforms aim to strike a balance between encouraging continued DER adoption while also curbing DERs' effects on utility cost recovery.

This report recommends that state policymakers, as they grapple with how to integrate DERs effectively, make two changes to their regulatory approaches to DER integration. First, any approach to DER compensation should be centered

---

[6] Some states' programs now require customers to pay a "non-bypassable" charge or "minimum bill" that cannot be offset by credits for excess generation. *See* Stanton, note 4, at 23. Many programs also include provisions that allow customers to carry over excess credits across billing periods. *See, e.g.*, NV Energy, https://www.nvenergy.com/account-services/energy-pricing-plans/net-metering/net-metering-faqs (accessed Nov. 15, 2019).

[7] Stephen Comello & Stefan Reichelstein, *Cost Competitiveness of Residential Solar PV: The Impact of Net Metering Restrictions*, 75 Renewable & Sustainable Energy Revs. 46, 46, 54 (2017).

[8] *See* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 44 Harv. Envtl. L. Rev. 43, 71-77 (2017), https://policyintegrity.org/files/publications/Managing_the_Future_of_the_Electricity_Grid.pdf.

[9] Steven Sexton et al., *Heterogeneous Environmental and Grid Benefits from Rooftop Solar and the Costs of Inefficient Siting Decisions* 19 (Nat'l Bureau of Econ. Research, Working Paper No. 25241, 2018), https://perma.cc/TK7G-YPQ2 ("...more than 25 percent of states provide subsidies that are at least $0.05 per kWh less than avoided damages.").

[10] The term "cost shift" describes when costs incurred to serve one group of customers are paid, in part or in full, by another. Cost shift represents a departure from the regulatory principle of "cost causation," which holds that a customer should pay the costs incurred to provide that customer with benefits.

[11] *See, e.g.*, Sanem Sergici et al., *Quantifying Net Energy Metering Subsidies*, 32 Electricity J. 106632 (2019), https://doi.org/10.1016/j.tej.2019.106632 ("… NEM policies create a subsidy issue from non-DG customers to DG customers."); Willis Geffert & Kurt Strunk, *Beyond Net Metering: A Model for Pricing Services Provided by and to Distributed Generation Owners*, 30 Electricity J. 36, 37 (2017).

on a "value stack" framework that reflects diverse, time- and location-specific value categories. Second, the scope of these value categories should be consistent with the perspective of society as a whole, not just a utility or its ratepayers.

It is important to note, however, that these recommendations still represent a second-best alternative to rate design reforms that cause electricity prices to more accurately reflect the costs of providing electricity services. In particular, if rates reflected accurate costs—including those related to emissions—based on time and location, consumers could respond by changing their patterns of consumption and DER adoption and use in a socially efficient manner.[12]

Before fully explaining these recommendations, part I of this report offers some background about the electricity grid and its regulation to provide context, and part II describes the benefits of DER deployment. Part III begins by describing the origins and effects of NEM and the problems that result from using it to compensate DERs. It then explains how a value stack framework can translate multiple, time-and-location-specific inputs into a rate of DER compensation, with inputs reflecting DERs' full value to society rather than merely the perspective of a utility or electricity consumers. The last part offers some conclusions.

[12] *See generally* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Modernizing Rate Design*, 44 Harv. Envtl. L. Rev. (forthcoming 2020), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3373163.

I. Background

To comprehend the value provided by DERs, one must understand the components of the centralized electricity grid as well as what DERs are and what they can do.

The electricity grid's main components

The centralized electricity grid is made up of several parts. (See Figure 1.) The bulk power system encompasses large-scale generators and transmission facilities. Large generators are usually located some distance away from those who ultimately consume electricity. Transmission lines carry electricity at high voltage across most of that distance. Distribution lines carry it the rest of the way at lower voltage. The bulk power and distribution segments of the grid interact, but they are managed mostly independently of one another, such that the real-time balance of electricity generation and consumption effectively happens at two levels. Grid managers at each level have limited access to detailed, real-time information about operations on the other level.

Figure 1. Segments of the electricity grid and where DERs can interconnect to it.

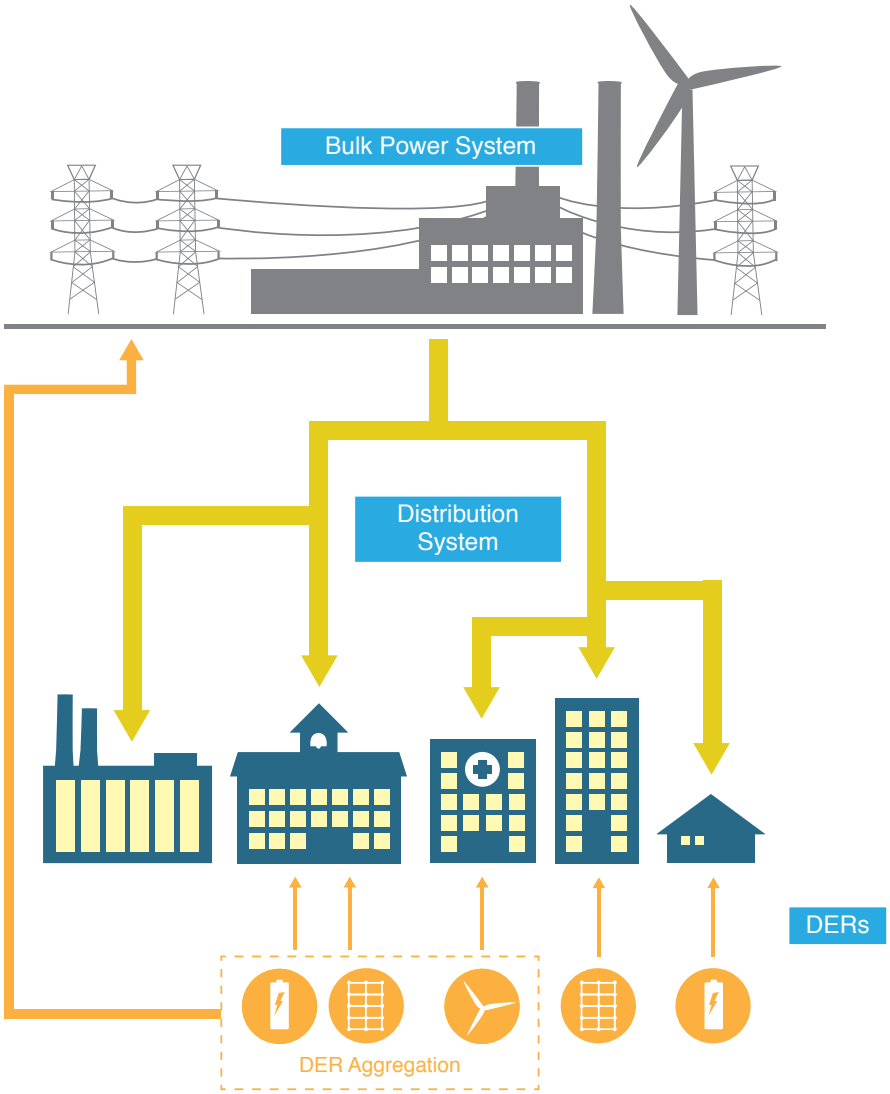


Figure 1 shows a simplified rendering of the electricity grid. Most generation and all transmission occurs in the bulk power system (above the line); electricity flows from there through the distribution system to customers (below the line). DERs generally interconnect to the distribution segment of the system, but can also participate in the bulk power system in aggregations. Where distribution grids have integrated both DERs and "smart" components, two-way flows of electricity and information have converted a once-centralized grid into a partly decentralized one.[13]

Distributed energy resources: a brief taxonomy

There are several subcategories of DERs, which are each comprised of a variety of physical devices and techniques (sometimes enabled by software and communications technology). Table 1 illustrates this point.

Table 1. DER subcategories and examples.[14]

Subcategory	Examples
Distributed generation	• solar PV • small-scale wind • CHP • fuel cell • microturbine • small reciprocating engine
Energy storage	• chemical batteries (lithium-ion, nickel-cadmium, flow, others) • battery-powered electric vehicles • chilled water heating/cooling systems
Demand response	• curtailable residential water heaters and pool pumps • appliances and programmable thermostats that respond to signals from the grid • building energy management systems
Energy efficiency	• LED lighting • improved building envelope insulation • improved seals on doors and windows • high-efficiency equipment and appliances

Although Table 1 lists particular assets or techniques separately, several of them can be deployed in combination.[15] Solar PV plus battery storage, for instance, is an increasingly popular combination. The combination ensures that the storage component is charged using a renewable primary energy source and that the owner will have access to electricity generated by the solar PV system even at times when the sun is not shining.

---

[13] *See* Jeffrey J. Cook et al. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States (2018), https://perma.cc/3FCP-3XYH (describing efforts by 23 utilities to coordinate the operation of DER in their service territories so that they can perform ancillary services and enhance reliability).

[14] The assets and techniques listed are not exhaustive. For a more complete list, see Lisa Schwartz et al., Lawrence Berkeley Nat'l Lab., Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline: Distributed Energy Resources, ch. 1 (2017), https://perma.cc/9LJY-L2VY. Table 1 also does not list all DER examples for each subcategory, and it omits large-scale energy storage and demand response assets, which tend to either be owned by commercial and industrial facilities or to be located in front of the meter, where they serve the bulk power system.

[15] *See generally* John Shenot et al., Capturing More Value from Combinations of PV and Other Distributed Energy Resources (2019), https://perma.cc/P63S-TGQR.

DERs differ in their ability to perform different services that are required for electricity system operation.[16] For example, solar PV can export electricity to the grid, while demand response can only reduce net load or modify load shapes. However, distributed solar PV cannot provide "black start" capability to restore service after an outage, but CHP and storage can.[17] DER profiles also vary with respect to how, how much, and for how long, they can perform some of those functions.[18]

Table 2. Potential functions of DERs.

Function	Type of DER					
	Solar PV*	Solar PV + Storage	Standalone Storage	CHP	Demand Response	Energy Efficiency
Generation	Yes, limited	Yes, limited	No	Yes	No	No
Generation capacity	Yes, limited	Yes, limited	No	Yes	Yes	Yes, limited
Voltage control	No	Yes	Yes	Yes	No	No**
Frequency regulation	No	Yes	Yes	Yes	Yes, limited	No
Spinning reserves	No	Yes	Yes	Yes	Yes, limited	No
Nonspinning reserves	No	Yes	Yes	Yes	No	No***
Flexibility to support renewables integration	No	Yes	Yes	Yes	Yes	No
Line loss reduction	Yes	Yes	Yes, limited	Yes	Yes	No**
Black start capability	No	No	Yes	Yes	No	No

** Newer inverters enable solar PV modules to perform a wider range of functions than those deployed even a few years ago. As new modules' prevalence grows, some of the "No" entries in this column—such as "Flexibility to support renewables integration"—will switch to "Yes."*
*** Conservation voltage reduction (CVR) is an exceptional form of energy efficiency that can provide voltage control and reduce line losses.*
**** A small subset of energy efficiency resources can bid to provide services in wholesale capacity markets.*

It is important to note that while Table 2 indicates various DERs' inherent abilities, DERs' ability to perform functions cost-effectively—or at all—also depends in part on the location and design of supporting infrastructure.[19]

---

[16] The Smart Electric Power Alliance recently assembled a bibliography of reports that discuss the functions DER can perform. It indicates which reports focus on which categories of electricity service. Tanuj Deora et al., Smart Elec. Power Alliance, Beyond the Meter: Recommended Reading for a Modern Grid 12 tbl.4 (2017).

[17] John Larsen & Whitney Herndon, Rhodium Grp. (prepared for U.S. Dep't of Energy), What Is It Worth? The State of the Art in Valuing Distributed Energy Resources 11 (2017), https://perma.cc/KQ96-3C9U.

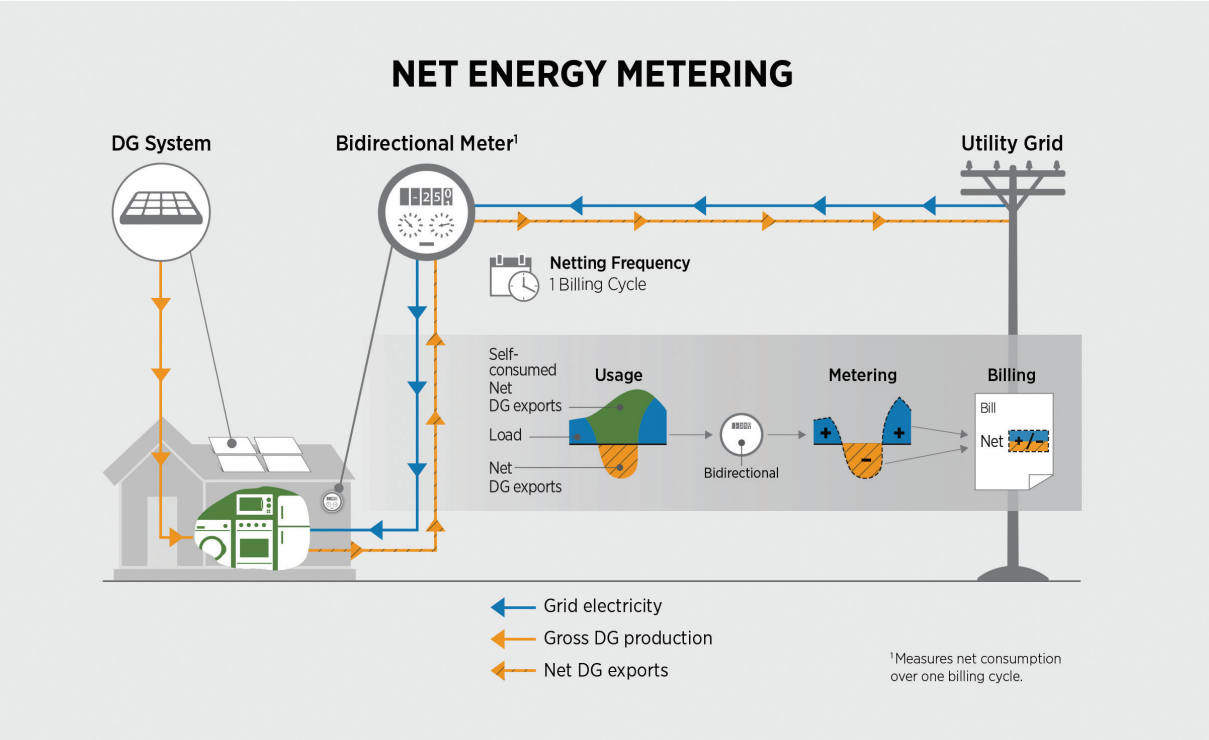
[18] Ryan Edge et al., Smart Elec. Power Alliance, Distributed Energy Resources Capabilities Guide 6 (2016).

[19] *See* San Diego Gas & Elec. Co., Distribution Resources Plan; Demonstration Project A: Enhanced Integration Capacity Analysis 30 fig.16 (2016), https://perma.cc/HJ44-UBJ8 (describing differences in solar PV, battery, and electric vehicle profiles under different circumstances).

Net energy metering

NEM programs vary in their particulars,[20] but the generic version of NEM is broadly representative. It involves a utility customer that has (1) an onsite DER capable of generating electricity, and (2) a single electricity meter. Essentially, when customers draw electricity from the grid, the meter runs forward, and when customers generate more than they consume, the excess flows to the grid and the meter runs backward.[21] Utilities charge customers at the retail rate, a volumetric, or per kilowatt-hour (kWh) charge, for their net consumption of electricity. This arrangement credits customers through their electricity bill for their excess generation. Notably, if electricity generated by DERs only reduces customers' net consumption from the grid without any excess flows, the arrangement resembles the adoption of energy efficiency measures that reduce electricity demand. The National Renewable Energy Laboratory developed Figure 2 to summarize NEM visually.

Figure 2. National Renewable Energy Laboratory's schematic of NEM, showing physical and financial interaction between DER owner and utility.[22]



[20] For a survey of current NEM programs, see the "Programs" webpage of NC Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency, https://programs.dsireusa.org/system/program.

[21] Older, analog meters literally spin in reverse; newer metering technology, called advanced metering infrastructure or AMI, is digital and can track flows in both directions. *See* Qie Sun et al., *A Comprehensive Review of Smart Energy Meters in Intelligent Energy Networks*, 3 IEEE Internet of Things J. 464, 465-67 (2016). By 2018, 53% of electricity customers had AMI installed. U.S. Energy Info. Admin., Form EIA-861 (2018), Spreadsheet labeled "Advanced_Meters_2018," https://www.eia.gov/electricity/data/eia861/zip/f8612018.zip. This was up from 4.7% in 2008 and 37.6% in 2013. Fed. Energy Reg'y Comm'n, 2018 Assessment of Demand Response and Advanced Metering—Staff Report 3 tbl.2.1 (2018).

[22] Owen Zinaman et al., Nat'l Renewable Energy Lab., Grid-Connected Distributed Generation: Compensation Mechanism Basics 3 (2017), https://perma.cc/L9CB-Z8TL.

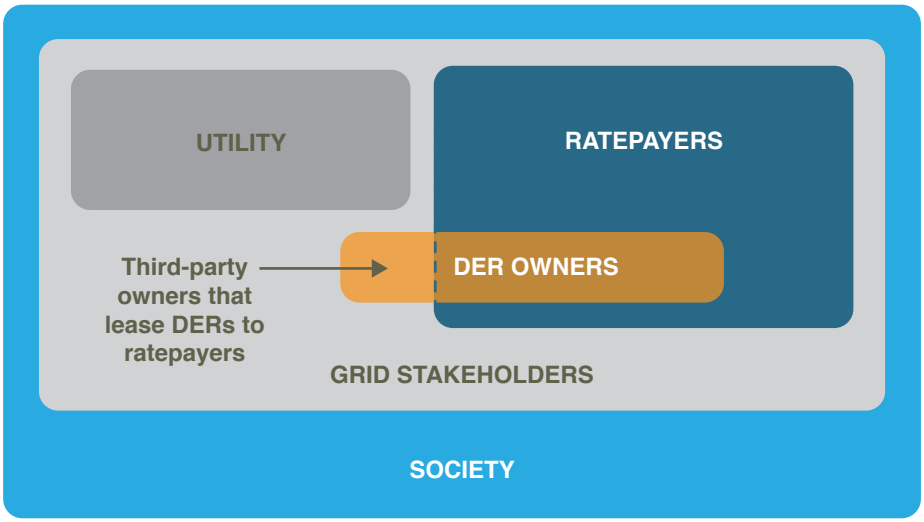
II. The value of distributed energy resources

Whether by reducing a customer's need to buy electricity from the grid, exporting excess electricity from that customer to the grid, or performing some other function listed in Table 2 above, DERs can reduce the need for operation of one or more components of the centralized grid. Assessing the value of DERs requires identifying these benefits and costs, then measuring those benefits and costs in comparison to the benefits and costs of the centralized resources that DERs would displace. As explained below, the first of these steps involves adopting one or more analytical perspectives. And the subsequent steps involve specifying where, when, and how the DERs being analyzed would operate, as well as a baseline scenario to which their operations can be compared.

Adopting the right perspective(s)

The state agencies charged with regulating electric utilities require estimates of a given investment's costs and benefits before authorizing utilities to pay for it using ratepayers' money. But because the economic value of the assets and systems that contribute to electricity service provision accrues differently to different stakeholders, deriving an estimate of that value requires adopting the perspective of one or more stakeholders. Figure 3 shows the overlapping perspectives of stakeholders affected by decisions to install and operate electricity resources, whether distributed or centralized. The perspective chosen determines three key aspects of valuation: (1) the scope of effects to be counted in the analysis, (2) whether to count them as benefits or costs, and (3) to whom and how much those benefits and costs accrue.

Figure 3. Overlapping perspectives on electricity-related benefits and costs.



Public utility regulatory commissions recognize the importance of perspective in at least some contexts—most often in relation to energy efficiency programs—and require utilities to employ one or more tests that embody prescribed perspectives when proposing to recover particular costs.[23] The five tests that were initially developed by California's Energy

[23] *See* Nat'l Efficiency Screening Project, Database of State Efficiency Screening Practices, https://nationalefficiencyscreening.org/state-database-dsesp/ (accessed Oct. 20, 2019) (indicating tests prescribed in 46 states and the District of Columbia).

Commission and Public Utilities Commission in 1983,[24] and later adopted elsewhere, are summarized in Table 3 below. The entries in the "perspective" column indicate the scope of benefits and costs to be considered when implementing the corresponding test. The Participant Cost Test provides the perspective with the narrowest scope and the Societal Cost Test the broadest, with the others arrayed in between. Crucially, of those listed in table 3, only the societal perspective takes the costs of emissions—and the benefits of avoiding emissions—into account.

Table 3. Perspectives associated with tests of DER benefits and costs.

Perspective	Test
Society as a whole	Societal Cost
Utility system + customers participating in one or more sanctioned programs	Total Resource Cost
Utility system	Utility Cost
Impact on rates paid by all electricity customers	Rate Impact Measure
Customers who participate in a given program, e.g., NEM	Participant Cost

Many states direct utilities to use at least two of these perspectives when analyzing the value of energy efficiency investments,[25] in order to discern both the magnitude and distribution of those investments' benefits and costs. California and New York direct their utilities also to do so for DER compensation. Specifically, California's Public Utilities Commission recently updated its directive to utilities regarding cost-effectiveness analyses, instructing them to make the Societal Cost Test the primary analytic screen and also to apply, secondarily, the Total Resource Cost Test and Ratepayer Impact Measure to all DERs and supply-side resources.[26] And in New York, a 2016 Public Service Commission Order directs utilities to employ a standard benefit cost test, complete with societal, utility, and ratepayer perspectives, to assess the value of proposed DER procurements and energy efficiency projects. [27]

---

[24] *See generally* Cal. Pub. Utils. Comm'n, Standard Practice for Cost-benefit Analysis of Conservation and Load Management Programs: Joint Staff Report (1983).

[25] *See* Nat'l Efficiency Screening Project Database, *supra* note 23 (listing analytic perspectives prescribed for use by utilities in numerous states, including California, Minnesota, and New York). The National Energy Efficiency Screening Project, recognizing that jurisdictions vary in their policy objectives and treatment of particular costs and benefits as relevant, has developed a framework that regulators can use to develop a jurisdictionally specific Resource Value Test for identifying and estimating benefits and costs of investments in energy efficiency. Nat'l Efficiency Screening Project, The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening (2014), https://perma.cc/TQG6-9KBP. They plan to publish a manual in June 2020 on how to apply that framework to DERs. Nat'l Efficiency Screening Project, National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs)—Overview 3 (2019), https://perma.cc/ZG3A-CQ9E.

[26] Decision adopting cost-effectiveness analysis framework policies for all distributed energy resources, Cal. Pub. Utils. Comm'n, RM 14-10-003, at 2, 65-67 (May 21, 2019), https://perma.cc/L73F-KPNX.

[27] Order Establishing the Benefit Cost Analysis Framework, N.Y. Pub. Serv. Comm'n, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision 1-2 (Jan. 21, 2016), https://perma.cc/9UQD-3PQA.

Distributed energy resources' benefits and costs

Numerous reports already identify and categorize benefits and costs of DERs.[28] Tables 4 and 5 organize a conventional list of those benefits and costs using the perspectives described above. Note that these tables contain illustrative lists—not comprehensive or definitive ones[29]—of potential benefits and costs.

Table 4. Potential Benefits of DERs.

Perspective	Category	Benefit
Electricity system stakeholders (i.e., utilities and their customers, including DER owners)	Bulk power system	Avoided energy costs
		Avoided generation capacity costs
		Avoided reserves and ancillary services costs
		Avoided transmission capital costs and line loss
		Avoided financial risk of primary energy source price volatility
		Avoided environmental compliance costs
	Distribution system	Avoided distribution capital costs and line losses
Society	Public health and safety	Improved resilience to disruptive hazards and stressors
		Public health benefits of avoided local pollution
	Environmental	Environmental benefits of avoided local pollution
		Avoided greenhouse gas emissions

As Table 4 shows, by avoiding the need to incur various costs, DERs can yield diverse benefits to centralized electricity system stakeholders. And, by avoiding emissions and improving electricity system resilience, they can also benefit society as a whole. Compared with these benefits, the costs of DERs, listed in Table 5 below, tend to be easier to measure. Capital and maintenance costs for a DER owner and interconnection costs for the local utility, for instance, which are available from accounting records, do not require estimation.

[28] *See, e.g.*, Shay Bahramirad, *Intro to Value of DER*, Presentation to NextGrid Working Group 1 (Feb. 28, 2018), https://perma.cc/Z44Q-XRSL; Galen Barbose, Lawrence Berkeley Nat'l Lab., Putting the Potential Impacts of Distributed Solar into Context 12 tbl.2 (2017), https://perma.cc/WLP3-2J2P; Susan F. Tierney, The Analysis Grp., The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability (2016), https://perma.cc/36ND-XDR9.

[29] Other potential benefits not listed here include, for instance, lower bills for low-income electricity consumers and reduced adverse emissions impacts for environmental justice communities. Gridworks et al., The Role of Distributed Energy Resources in New Jersey's Clean Energy Transition 4, 9 (2019), https://perma.cc/7MMU-7Y6Z; Tim Woolf et al., Synapse Energy Econ. (prepared for Advanced Energy Econ. Inst.), Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits 30-31 (2014), https://perma.cc/5LQ3-Q437.

Table 5. Costs of DERs.

Perspective	Category	Costs
Utilities + ratepayers who do not own DERs	Program costs	Measure costs (to utility)
		Financial incentives
		Program and administrative costs
		Evaluation, measurement, and verification
	Integration	Interconnection costs (in excess of utility's own costs of interconnection)
	Capital costs (if any)	Distribution grid segment upgrades prompted by DER additions*
DER owners	Costs of DER adoption and operation	Measure costs (to participants)
		Interconnection fees
		Annual operations and maintenance costs
		Resource consumption by participant
		Transaction costs to participant

** At least some of this category of costs is often paid by DER developers*

As the descriptions below make clear, estimating DERs' benefits tends to require several more analytical steps than estimating their costs. Importantly, however, the relative ease of measuring costs is not a reason to ignore benefits and should be recognized as a source of potential over-weighting of costs and under-weighting of benefits in DER valuations.

> **Non-Wires Alternatives (NWAs)**
>
> NWAs generally combine a variety of DER types, ranging from energy-efficient lighting to battery storage. They deserve special mention because their development is generally led by utilities, which undertake them in lieu of distribution system upgrades that would be more expensive. Several states either direct or authorize retail utilities to recover the costs of NWAs through rates, so long as the suite of DERs performs as needed over the relevant timeframe.[30]

Bulk power system

Installing and operating DERs can avoid some of the costs to various stakeholders—and society as a whole—of operating the bulk power system. Those bulk power system costs that could be avoided include the generation of electricity (usually called "energy"), the capacity to generate electricity, ancillary services (i.e., measures that maintain voltage, frequency, and other features of the quality of delivered electricity), and additional costs, which arise indirectly from bulk power system operations, including hedges against changes in primary fuel prices and environmental compliance costs. The following brief descriptions summarize what gives rise to each of these costs and how DERs can potentially avoid them.

Energy costs. These costs reflect multiple factors, including the cost of the primary fuels used to generate electricity, availability of generation, congestion in the transmission system, and line losses. Because each of these constituent factors is sensitive to time and location, energy costs vary based on time and location.

Generation capacity and ancillary services. Retail utilities purchasing services from the bulk power system not only pay for electricity (akin to water flowing through a pipe), but also for (1) generators to invest in adequate capacity (i.e., a big enough pipe) to meet load under both ideal and adverse conditions in future years; and (2) the ancillary services

[30] *See* Brenda Chew et al., Non-Wires Alternatives: Case Studies from Leading U.S. Projects (2018).

required for electricity to maintain its voltage and frequency (akin to water that flows steadily and without turbulence or sloshing from side to side) required for smooth consumption. As with energy, regular auctions conducted by regional wholesale market managers assign prices to capacity and ancillary services.

DERs can help avoid the costs of energy, generation capacity, and ancillary services by reducing the need to deliver electricity to a particular location at a given time. Specifically, DERs can reduce the volume of bulk power system generation needed, avoid the need to turn on the most expensive generators in the fleet, and reduce both congestion and line losses in the short run. Over longer timeframes, DERs can obviate the need to build or maintain expensive generators altogether and can contribute to plans to reduce or eliminate congestion.

Other bulk power system costs. DERs can avoid several other costs, such as the financial risk arising from primary fuel price volatility, which results from changes in the supply of and demand for coal, natural gas, and uranium. These costs accrue in different ways, some of them easier to measure and relate to DER usage than others.

Distribution system

Location and timing of electricity consumption are as important to the costs of operating the distribution system as the bulk power system. Capital expenditure to replace, upgrade, or build new distribution system facilities is the largest component of distribution system costs.[31] Other significant costs include line losses between the bulk power system and customers, the fine balancing required to maintain power quality, and averting or dealing with reliability failures.[32] All of these costs can vary significantly across even small geographies and distribution system segments.[33]

DERs can help avoid some of these costs, depending on where DERs are located and when and how they operate.[34] For instance, if load in a particular location peaks when solar PV is most productive, then simple rooftop solar installations could offset growth in local demand for electricity and thereby help to avoid or defer the costs of upgrading local distribution facilities to handle that growth. However, if load peaks in the early evening, after the sun has set, then solar PV combined with storage could offset local load growth but a standalone rooftop solar PV installation could not. Another important factor affecting DERs' ability to avoid costs in a particular location is the availability of supporting infrastructure and assets, such as AMI. If the local distribution system is unable to make full use of DERs as compared to centralized resources, it could impede a local DER's performance and cost-effectiveness.[35]

Distribution system capacity can also be a *limiting* factor in relation to DER deployment. If the DER to be deployed is DG, then local distribution facilities must be able to absorb the excess generation it is expected to export to the grid—otherwise that DER would threaten reliability by sometimes overloading those facilities. This constraint is called "host-

---

[31] *See* Tierney, *supra* note 28, at 17 ("the opportunity for greatest economic value rests with the ability . . . to avoid specific distribution-system upgrades"); Melissa Whited et al., Synapse Energy Econ. (prepared for Consumers Union), Caught in a Fix: the Problem with Fixed Charges for Electricity 26 (2016), https://perma.cc/RJ33-B8X7.

[32] *See* Paul De Martini & Lorenzo Kristov, Lawrence Berkeley Nat'l Lab., Distribution Systems in a High Distributed Energy Resource Future 21 (2015), https://perma.cc/PM66-D2LN.

[33] Bahramirad, *supra* note 28, at 6 (describing that system costs and thus potential DER value "varies not only by each of the approximately 5,500 feeders on the ComEd system [in and around Chicago], but potentially within a given feeder.").

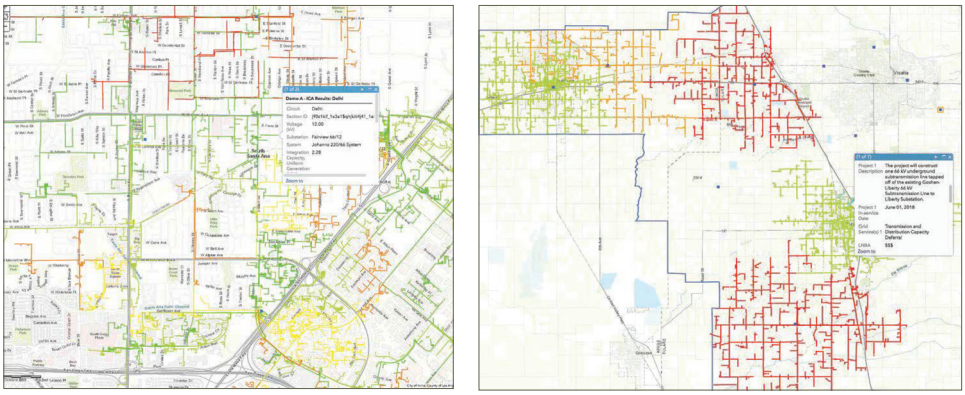
[34] Scott Burger et al., *Why Distributed?: A Critical Review of the Tradeoffs Between Centralized and Decentralized Resources*, 17 IEEE Power & Energy Mag. 16, 19 (2019) ("To capture locational value due to network constraints, DERs must be able to operate both where and when constraints are binding."); *see also* Revesz & Unel, *supra* note 8, at 74-75.

[35] Burger et al., *supra* note 34, at 19 (emphasizing relevance of binding performance constraints to valuation); Tierney, *supra* note 28, at 19 (similar).

ing capacity," and like the distribution system costs that DERs can avoid, it varies significantly across different locations. Upgrading distribution facilities specifically to increasing DER hosting capacity is a cost *caused* (rather than avoided) by DER. Notably, different types of DERs have different hosting capacity needs: whereas storage might require capacity to draw more electricity from the grid to charge at particular times, and solar-plus-storage or CHP might require capacity to export excess generation to the grid, some rooftop solar might be expected to simply reduce local loads and so can itself open up more local capacity.

Locational analyses done in California show how sensitive costs are to even small locational variations. The maps shown in Figure 4 below were developed by Southern California Edison.

Figure 4. Maps showing integration capacity (left) and locational net benefits (right).[36]



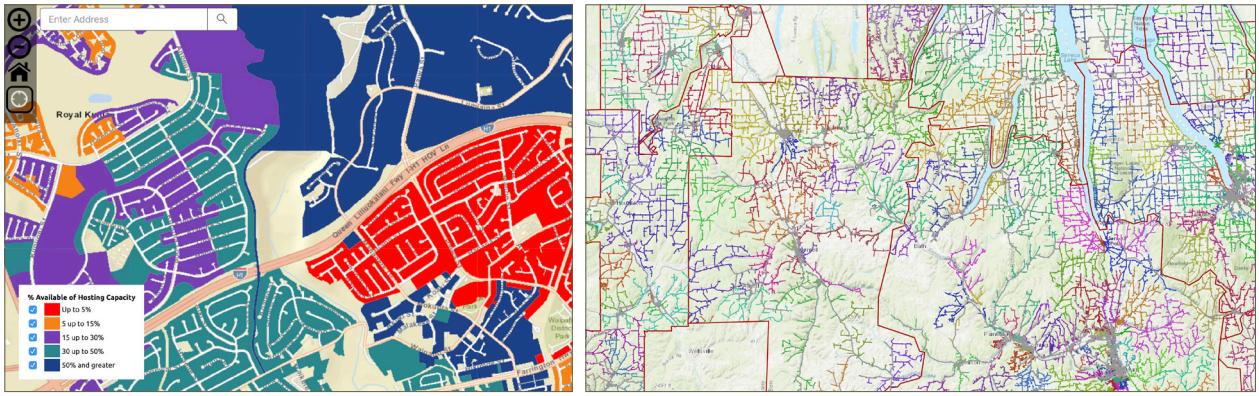
On the left panel, green indicates distribution line segments that can easily host additional DER capacity; red indicates little or no hosting capacity; yellow and orange are in between. On the right panel, green indicates line segments with higher expected value for DER due to an opportunity for deferral of distribution capacity upgrades; red indicates little or no value; yellow and orange are, again, in between.[37]

[36] Tim McDuffie, *Distributed Energy Resource Optimization*, SolarPro, July/Aug. 2018, at 39-40 figs.2, 3 & 4 https://www.solarprofessional.com/.

[37] Note that these maps reflect expected load growth as adjusted by the expected installation of DERs. The maps do not reflect the counterfactual scenario of distribution system costs with *no* DERs, which would reveal where and how much the installation of DERs could add value by avoiding those costs. In September 2017, California's Public Utilities Commission ordered the state's electric utilities to develop long-term forecasts of load growth and related distribution system costs, unadjusted by assumed DER installation, to facilitate clearer analyses of DERs' value. Decision on Track 1 Demonstration Projects A (Integration Capacity Analysis) and B (Locational Net Benefits Analysis), Cal. Pub. Utils. Comm'n Decision 17-09-026, Rulemaking 14-08-013, at 45-48 (Sept. 28, 2017), https://perma.cc/2Q4Q-NHSG. In June 2019, the Commission issued a white paper further specifying how utilities should comply. *See* Administrative Law Judge's Amended Ruling Requesting Comments on the Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values, Cal. Pub. Utils. Comm'n Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (June 13, 2019), https://perma.cc/R62G-BBZV.

As Figure 5 shows, Hawaii and New York State's utilities make similar "heat maps" and accompanying data available to DER developers.[38]

Figure 5. Oahu hosting capacity and locational value map (left); Hornell, NY hosting capacity map (right).



Maps like these show developers both where there is adequate capacity to accommodate DERs, and whether the addition of DERs would be likely to avoid costs to the distribution system. Recently updated (but still a work in progress)[39] Marginal Cost of Service Studies for New York distribution utilities provide a detailed description of the multiple components that underlie maps like these. For instance, the study conducted for Orange & Rockland examines the marginal cost of increasing existing capacity to serve prospective load growth for each of the utility's 50 feeders, and breaks that cost down into five "cost centers" for each feeder.[40] Placed on a map, that cost information would resemble the right panel of Figure 4 above. By examining load shapes on feeders with above-average costs, the Orange & Rockland study also highlights where DERs could avoid costs and the sort of load DERs would need to serve in order to do so.[41]

Effects beyond the electricity system

As indicated in Table 4, above, the activities involved in providing electricity services have numerous effects that are felt beyond the operation of the electricity grid. For instance, centralized, fossil-fueled electricity generators emit both greenhouse gases, which contribute to anthropogenic climate change, and local air pollution, which results in direct harms to public health and the environment. Centralized electricity generation also consumes water resources and results in water pollution (thermal and toxic), among other impacts. Installing and operating DERs can avoid these detrimental effects. DERs can also improve electricity system resilience to disruptions, such as from storms and wildfires that are expected to

---

[38] Hawaiian Electric, Oahu Locational Value Map (LVM), https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps/oahu-locational-value-map-(lvm) (accessed Nov. 21, 2019); New York State Electric & Gas and Rochester Gas & Electric, Distributed Interconnection Guide Map, https://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56 (accessed Nov. 21, 2019).

[39] *See, e.g.,* Synapse Energy Econ. (prepared for Clean Energy Parties), Appendix B: Information Requests Round #2 Regarding NY Utilities' MCOS Studies, N.Y. Pub. Serv. Comm'n Case 19-E-0283, Proceeding on Motion of the Commission to Examine the Utilities' Marginal Cost of Service Studies (Sept. 16, 2019), https://perma.cc/JT4L-3S7R; City of New York's First Set of Information Requests to Consolidated Edison Company of New York, Inc. Regarding Its Marginal Cost of Service Study, N.Y Pub. Serv. Comm'n Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies (July 15, 2019), https://perma.cc/2QD7-92CT.

[40] Philip Q. Hanser et al., The Brattle Grp. (prepared for Orange & Rockland), Marginal Cost of Service Study, 16 tbl.8 (2019). The "[Marginal Cost] Map" in the study itself appears on page 27.

[41] *Id.* at 20, 22.

increase in frequency and severity as the climate changes.[42] And DERs can help provide predictable and secure electricity access for low-income individuals and communities.[43]

Quantifying and monetizing some of these effects, like reduced water usage, is straightforward because the necessary data inputs and valuations are generally already available from prices assigned by markets or regulators.[44] Monetizing others, like the global and local costs of emissions, requires data to be gathered and analyzed, but, as explained below, can be made a routine step in electricity-related cost accounting.[45] Monetizing still others, such as improved resilience to disruption, often requires more significant and project-specific analysis.[46]

Finally, DERs can affect local economic activity, either by promoting local spending and causing job creation or undermining economic activity that relies on the operation of centralized resources.[47] These effects can be monetized but are rightly considered benefits or costs to *local* communities only—to society as a whole they might not represent a benefit or cost per se but a mere transfer of resources.

Specifying a baseline for scenario analysis

Estimating the value that a DER provides to society requires two scenarios—the baseline or "business as usual" scenario in which grid-based assets and existing DERs provide service, and the alternative scenario in which new DERs account for some or all of the relevant service provision. If a baseline is not updated with appropriate frequency, then it provides an inaccurate set of parameters for comparison to the new DER deployment scenario. It is, therefore, necessary to establish and maintain data sources for deriving accurate baseline values, and to correctly specify intervals for updating data inputs.

Calculating the value of distributed energy resources

Assigning monetary value to the operation of a DER at a particular time and place builds upon the data requirements and analytical decisions described above, namely identifying benefits and costs, deciding which are relevant, and specifying key features of the DER project and the baseline scenario to which it is an alternative. Valuing the effects of a specific DER's operation in comparison to a baseline scenario involves five component steps:

(1) identifying the resource(s) whose operation will be modified or displaced by operation of the DER;

(2) characterizing the timing and degree of that modification or displacement by comparing DER operation/output to that of the displaced resource(s);

---

[42] Resilience is distinct from reliability, the costs of which are already internalized in the rates paid for electricity service. Nat'l Acad. Scis., Eng. & Med., Enhancing the Resilience of the Nation's Electricity System 9 (2017), https://doi.org/10.17226/24836. [hereinafter "NAS, Enhancing Resilience"].

[43] Gridworks et al., *supra* note 29, at 4, 9.

[44] *See, e.g.*, Indep. Evaluation Monitor, Arkansas Technical Reference Manual, Protocol L, Version 7.0, at 88-90 (Aug. 2016), https://perma.cc/2ZXC-BWTN (describing derivation of value of avoided water use from retail water rates).

[45] *See generally* Jeffrey Shrader et al., Inst. for Pol'y Integrity, Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources (2018), https://policyintegrity.org/publications/detail/valuing-pollution-reductions.

[46] For an example of this sort of analysis, *see* San Francisco's analysis of the resilience value of adding solar + storage facilities to shelters and public libraries throughout the city. Abigail Rolon et al., Arup (for San Francisco Dep't of the Env't), Solar and Energy Storage for Resiliency (2018), https://perma.cc/9FFU-MV9R. For a general methodology for monetizing resilience value, see Burcin Unel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System (2018), https://policyintegrity.org/publications/detail/toward-resilience.

[47] *See* Woolf et al., *supra* note 29, at 4, 17 n.8, 33.

(3) estimating the costs avoided as a result of this displacement (including the costs of infrastructure development and pollution);

(4) comparing those avoided costs to the costs of installing and operating the DER; and

(5) determining the appropriate frequency of and process for updates.[48]

The rest of this subpart describes how these steps apply to different categories of benefits DERs could provide.

Avoided bulk power system costs

Wholesale electricity markets already do much of the analysis required to assign a monetary value to a DER's avoidance of bulk power system costs. The following short descriptions build on those above. Implementing what is described here requires access to models of the relevant bulk power system region and detailed knowledge of the profile of the DER to be deployed.

Generation. The locational marginal price (LMP) is the marginal cost of providing electricity to a specific location (either a zone or node) in the bulk power system at a specific time.[49] More specifically, it reflects three costs: generation, congestion (i.e., costs incurred to deal with transmission capacity limits), and transmission system line losses.[50]

Calculating the value of avoided generation relies heavily on LMP, which is specified at the level of a wholesale market zone,[51] as shown on the map of real-time wholesale zonal prices in figure 6, below, or a transmission system node.

---

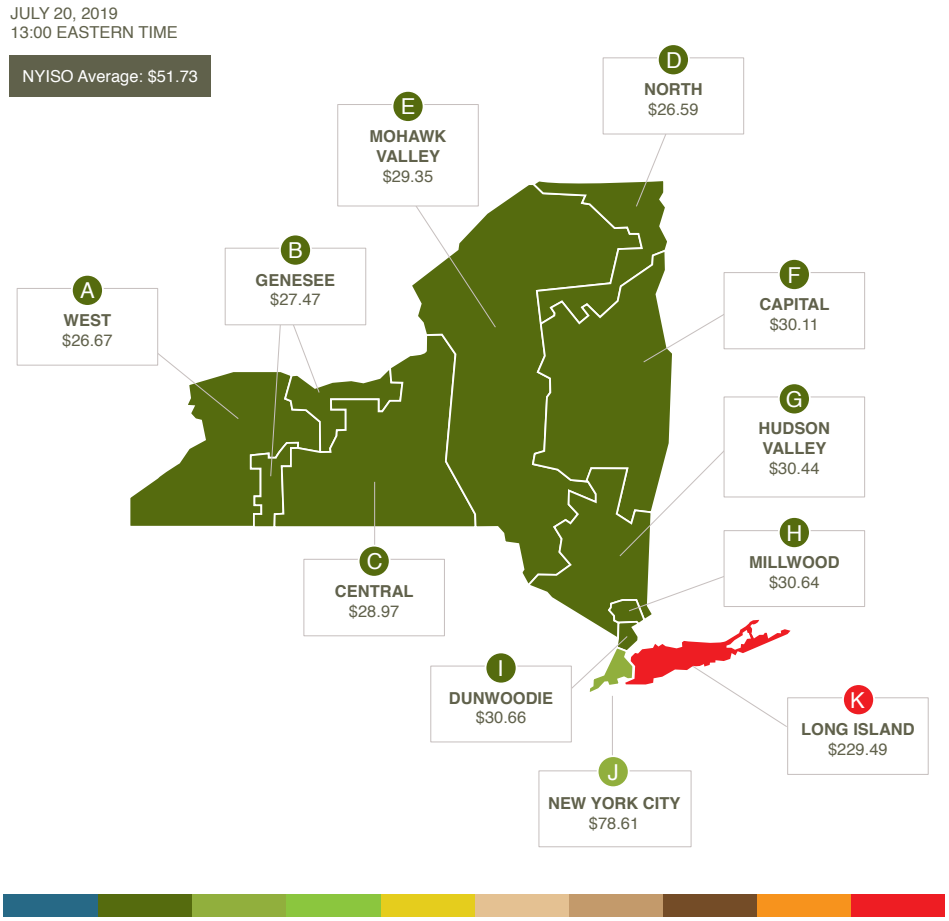
[48] *Cf.* Natalie Mims Frick et al., Lawrence Berkeley Nat'l Lab., A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States 7-8 (2018), https://perma.cc/CNG2-N6KC (listing "minimum data requirements" for DER valuation).

[49] Fed. Energy Reg. Comm'n, Energy Primer: A Handbook of Energy Market Basics 60-61 (2015), https://perma.cc/AAU7-JZYN.

[50] This calculation can use the systemwide annual average rate of line losses, but it is more accurate to use the marginal loss rate for the relevant zone or node over different time periods, e.g., seasonal and daily. This granularity is important because loss rates tend to be higher at peak times and increase over greater distances. NYISO, for example, uses a marginal rate. New York Independent System Operator, Market Services Tariff § 17.2.2.1 (Aug. 16, 2019) ("Marginal Losses Component LBMP").

[51] In locations where electricity system ownership is vertically integrated and no wholesale market operates, estimates of marginal energy costs can be derived from "system lambda," an engineering statistic used to estimate the shadow cost of a one-unit change in production. *See* Severin Borenstein & James Bushnell, Energy Inst. at Haas, *Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency* 11 (Nat'l Bureau of Econ. Research, Working Paper No. 24756, 2019), https://perma.cc/FJ9D-KQ6Y.

Figure 6. Real-time energy prices (LMP) across New York Independent System Operator (NYISO) Zones A through K at 1pm on July 20, 2019.[52]



Zonal prices sometimes diverge significantly, for instance when extreme weather occurs in combination with congested transmission capacity. Figure 6 shows the zonal prices at 1pm on July 20, 2019, the hottest day of 2019 in New York State. From 11:00am to 10:00pm on that day LMP for Zone K (Long Island) ranged from just over twice the NYISO average to almost six times the average.[53] That ratio was highest at 2:15pm, when the LMP in Zone K was over $360/MWh and the average of all 11 NYISO zones was just under $62/MWh.[54] The limited capacity of congested transmission facilities to carry more electricity to Long Island accounted for most of the difference at that hour.[55]

Generation capacity. In regions with competitive wholesale markets, auctions between generators and wholesale electricity purchasers (chiefly retail utilities, but also competitive retail providers in states with retail choice) establish the

[52] For the sake of simplicity and clarity, this report draws heavily on the example of the New York State electricity grid, where the ISO and wholesale market's boundary matches that of the state. Other ISO/RTO regions operate in a broadly similar fashion—deriving prices for energy, capacity, and ancillary services from regular auctions—but contain multiple states (e.g., ISO-NE, PJM, SPP, and MISO) or portions of individual states (e.g., ERCOT and CAISO).

[53] Data retrieved from NYISO's Open Access Same-Time Information System, Real-Time Market LBMP, Zonal, Archived File "07-2019", http://mis.nyiso.com/public/P-24Alist.htm.

[54] *Id.*

[55] *Id.*

prices for future generation capacity. These vary across regions and from year to year, but generally amount to a fraction of the total price paid for bulk power system services.[56]

Calculating the value of avoided generation capacity requires three sets of data points:

- the effective capacity of the DER across specified time periods, such as daily peak loads in a given zone or node for all four seasons;
- expected system capacity needs over the same time periods; and
- the expected *value* of future capacity, based on the prices assigned by the wholesale market for the relevant timeframe.

Armed with these data, it is possible to estimate how much the contribution of the DER in a given location will reduce local capacity needs and thereby lower capacity prices.

Transmission. In addition to transmission congestion and line losses, which are short term costs reflected in LMP, DERs can also potentially avoid the longer-term costs of transmission capacity additions. Those longer-term costs are substantially reflected in generation capacity prices and the congestion component of LMP, which captures what wholesale electricity purchasers are willing to pay over the short-term to overcome the transmission constraints in a particular location by buying electricity from accessible resources and routing it around the constraints. But relying on LMP can risk ignoring DERs' potential to avoid significant long-term costs.[57] A more focused calculation of the avoided cost of additional transmission can be done either by estimating the relationship between planned transmission capacity additions and their associated revenue requirements,[58] or by a more intensive modeling exercise that estimates the sensitivity of transmission capacity needs to incremental changes in load of the sort affected by the installation and operation of DERs.[59]

Ancillary services and other bulk power system costs. Even though the remaining bulk power system costs identified in Table 4 above tend to be small relative to generation and generation capacity, DERs' ability to avoid such costs can be valuable. In addition to being relatively small, however, these avoided costs are generally harder to calculate precisely—and extremely difficult to calculate for particular times and locations. This is why the tool that California utilities have been directed to use as the basis for the Locational Net Benefits Analysis of DERs simply calculates ancillary services as 0.9% of the value of generation.[60] Calculating the value of avoided fuel price volatility requires several analytical steps to translate from an estimated cost to a unit of marginal value made available by installing and operating a DER.[61]

---

[56] David B. Patton et al., Potomac Econ., 2018 State of the Market Report for the New York ISO Markets 3 fig.1 (2019), https://perma.cc/V73H-3N2T.

[57] Clean Energy Parties, Proposal for Distribution and Transmission Value for Distributed Energy Resources (DERs) and DRV/LSRV Modifications, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack 22-23 (June 7, 2018) https://perma.cc/BUA7-Z2GN.

[58] For an example of a regression analysis developed to estimate this value, see Reuben Behlihomji et al., Southern California Edison, Co., Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals, Application No. A.17-06-030, Ex. SCE-02A, at 36-39 (Nov. 1, 2017), https://perma.cc/5RDP-N5L3.

[59] *See* Clean Energy Parties filing, *supra* note 57, at 23 (describing version of NYISO Reliability Needs Assessment that would detect the value of such incremental changes).

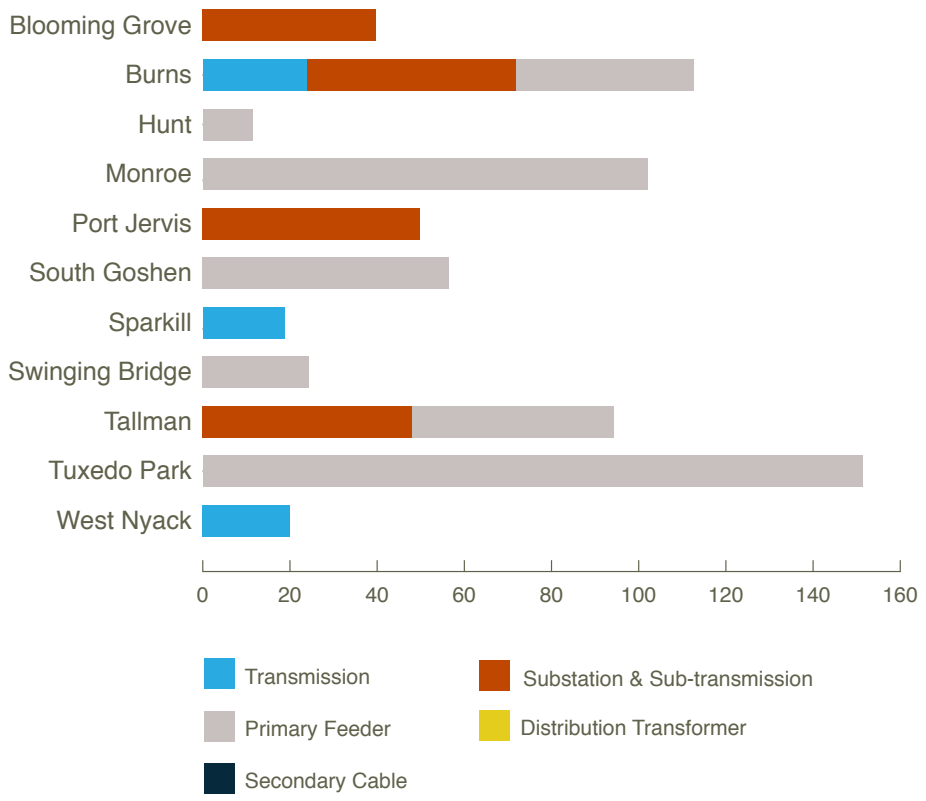
[60] Cal. Pub. Utils. Comm'n, Cost-effectiveness: 2019 Avoided Cost Calculator, ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/ACC_2019_v1b.xlsb ("General Inputs" tab) (accessed Aug. 25, 2019). That calculation also excludes the value of regulation "up" or "down" from its estimate. *Id.*

[61] For a description of one approach, *see* Daymark Energy Advisors (for Maryland Pub. Serv. Comm'n), Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland 115-120 (2018), https://perma.cc/J3P9-UMU2.

Avoided distribution system costs

From a policymaker's perspective, determining the benefits of DERs to the distribution system only requires understanding the costs that DERs could avoid, like line losses and the marginal cost of adding distribution capacity. The Marginal Cost of Service Study commissioned by Orange & Rockland, a utility that serves the counties just northwest of New York City, describes the marginal costs of investments required to match expected load growth for each of the utility's 50 feeders.[62] The study breaks those marginal costs down into five "cost centers" or categories of infrastructure for each feeder. As shown in Figure 7, which depicts a characteristic sample of those 50 feeders, there is significant locational variation between services areas, and no costs are expected for two of those cost centers.

Figure 7. Marginal costs of planned capacity additions ($/kW) in sample of feeder areas in Orange & Rockland's service territory.[63]



According to its 2019 Marginal Cost of Service Study, Orange & Rockland does not plan to incur any capital costs for 28 of its 50 feeders over the coming decade. Nor does any feeder require upgrades or replacement of distribution transformer or secondary cable facilities in that time. But, as shown by Figure 7, maintaining service at the Burns location will require investments in transmission, substation, and primary feeder facilities; and at Tuxedo Park a very large investment in the primary feeder is necessary.

---

[62] Hanser et al., *supra* note 40, at 16 tbl.8.
[63] *Id.*

Although line losses represent a small portion of the distribution costs that DERs can potentially avoid, they are still substantial.[64] Importantly, because line losses can vary significantly across a given utility's service territory and at different times,[65] using an average rate of line losses will likely distort any estimate of how much of that cost a DER could potentially avoid.[66]

Private decisions of DER developers and would-be owners about whether to install new DERs must also take into account available hosting capacity[67] and the compatibility of DER profiles with local "load shapes"—that is, the level and timing of local aggregate demand to understand whether it makes economic sense for them to install DERs. Compensating DERs for helping to avoid these sorts of costs sends a clear signal to DER developers and would-be owners about where to locate new DERs and what sorts of DERs to install there. In locations where a given DER's excess generation would help avoid distribution system costs by serving peaks in local load, a value stack will compensate that DER for providing a more cost-effective alternative to centralized system upgrades.

* * *

Taking the analytical steps described above results in an estimation of the value of particular DERs in a particular location. However, actually developing those DERs requires a degree of certainty about the compensation that will stem from that estimation. Due to the routine nature of wholesale market price patterns, many of the relevant avoided costs are predictable (including the value of avoiding wholesale generation, generation capacity, transmission, and other bulk power system costs). But local distribution system costs, as Orange & Rockland's Marginal Cost of Service Study shows, do not change on a uniform schedule and respond to changes in load, which are less predictable than the changes that inform bulk power system prices. This variability can undermine the usefulness of information provided by utilities to DER developers, if the DER compensation scheme employs a time horizon that is shorter than the amortization period used by the local utility for distribution infrastructure. Part III discusses options for balancing different stakeholders' interests and needs for accurate and predictable information about distribution system costs.

Avoided emissions of greenhouse gases and local pollutants

Potential benefits of DERs include avoiding emissions from centralized electricity generation. As with other benefits described above, the benefits of avoided emissions vary with time and place. With respect to greenhouse gas emissions—pollutants with global rather than local effects—that variation results from the different marginal emissions rates of whatever resources the DER's operation displaces. With respect to local air pollution, that variation owes to the marginal emissions rate of the displaced resource, location of populations near or downwind of that resource, and prevailing weather patterns.

---

[64] *See, e.g.*, Xcel Energy Servs., Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System—Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223, at v & 31-34 (May 23, 2013), https://perma.cc/9F54-5RXB.

[65] Borenstein & Bushnell, *supra* note 51, at 12-14.

[66] Some states direct utilities to calculate and report line losses on a marginal basis. *See* Testimony of Chris Neme on behalf of the N. Carolina Justice Ctr. et al., N.C. Utils. Comm'n Docket No. E-2, SUB 1174, In the Matter of Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69, at 7, 30 (Sept. 4, 2018), https://perma.cc/7J6Y-NV6J. In states that allow utilities to report average rates, this small piece of a value stack is likely to be inaccurate. *See* Jim Lazar & Xavier Baldwin, Reg'y Assistance Project, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements 3-5 (2011), https://perma.cc/TX57-GA6D (describing how averages understate line losses).

[67] Utilities generally charge DER developers the cost of expanding hosting capacity to accommodate a new DER installation.

Calculating the volume of emissions avoided requires detailed information about the type of pollution and marginal emissions rates of regional generation resources over the smallest possible intervals of time. Calculating the value of avoiding those emissions requires estimating the damage they would have done. For greenhouse gases, the best available tool for estimating the monetary value of damages from each increment of emissions is the Social Cost of Carbon, which was developed by the Interagency Working Group in 2010, and then updated in 2013 and 2016.[68] For local pollutants, several tools exist for estimating the monetary value of damage done, including BenMAP, EASIUR, AP2, and COBRA.[69]

Policy Integrity has previously described a five-step method for developing monetary estimates of emissions reductions attributable to DERs in *Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources*.[70] That report includes methodologies, data sources, and analytical tools for each of the following steps:

1. Determine what generation resource(s) will be displaced by a DER's installation/operation;
2. Quantify marginal emissions rates of the displaced generation;
3. Calculate in monetary terms the damages of relevant emissions generally, with attention to types of pollutants, their destinations, and the timing (seasonal and daily) of their emission;
4. Monetize the value of emissions avoided by displacing generation using the marginal emissions rates established by Step 2 and the per unit damages established by Step 3 (taking care to consider emissions priced fully or partly by existing policies and to adjust as needed to avoid double-counting);
5. Subtract from the result of Step 4 the value of any emissions directly attributable to operation of the DER.

Notably, Steps 3 and 4 are significantly easier to complete for greenhouse gas emissions than for ambient air pollution.

Improved resilience

Electricity system resilience is distinct from reliability.[71] Reliability focuses on high-probability, low-impact events, like downed tree limbs, and is concerned with preventing outages that might result. By contrast, resilience focuses on low-probability, high-impact events, like hurricanes or large-scale cyberattacks, and is concerned with resisting, absorbing, and recovering from the disruption they cause.[72] In addition, unlike with reliability, there is no single metric or set of metrics that indicate resilience to all types of hazard.[73] Instead, resilience is specific to a type of hazard, such that a system designed to be resilient to cyberattack *might* but will not necessarily also be resilient to hurricanes or wildfires. These features make it harder, but certainly not impossible, to calculate the resilience value of a DER.

---

[68] Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis (2016), https://perma.cc/UYX6-2W8M.

[69] For a summary description of each of these models and references to fuller descriptions, *see* Jeffrey Shrader et al., *supra* note 50.

[70] *Id.*

[71] NAS, Enhancing Resilience, *supra* note 42, at 9.

[72] *Id.* at 10 ("Resilience is not just about being able to lessen the likelihood that outages will occur, but also about managing 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."); *see also* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012 P 22 (2018) (citing National Infrastructure Advisory Council's Critical Infrastructure Resilience Final Report and Recommendations 8 (Sept. 2009)).

[73] Standard reliability metrics include the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Distribution Index (SAIDI), which measure different aspects of system performance and show no differences in sensitivity to different sources of disruption.

Over the past decade, resilience has become a greater priority for policymakers with responsibility for different segments of the electricity grid,[74] owing to increasingly frequent and severe climate-driven weather events, and recognition of the electricity grid's susceptibility to cyberattack.[75] However, determining the value of avoiding disruption, and, further, of particular investments that could achieve such avoidance, has proved challenging.[76] Policy Integrity's 2018 report, *Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System*,[77] offers guidance on this issue. Drawing on the academic literature, it proposes calculating the resilience value of any investment or intervention using the following five analytical steps:

1. Characterize potential sources of disruption;
2. Specify metrics for resilience; each metric should—
    - Be 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); and
    - Use data from computation models that incorporate historical experience or expert evaluation.
3. Quantify system resilience in a baseline scenario;
4. Characterize how the investment or intervention would modify system resilience; and
5. Compare the benefits and costs of the resulting resilience improvement.[78]

These steps are broadly consistent with approaches developed by other researchers to estimate the resilience value of DERs.[79]

This approach can also be supplemented by valuing community resilience.[80] This distinction is noteworthy because state-level policies adopted to promote resilience often aim at the communities and individuals that rely on public health and safety services, many of which rely on electricity.[81]

---

[74] *See, e.g.*, Arthur Maniaci, NYISO, *2019 Climate Study – Draft Outline of Statement of Work for RFP* (Nov. 9, 2018), https://bit.ly/2HrKCJm; Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, N.Y. Pub. Serv. Comm'n Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service (Feb. 21, 2014), https://perma.cc/6WAP-ATHM (directing ConEd to undertake a Climate Change Vulnerability Study and implement responses to its findings).

[75] NAS, Enhancing Resilience, *supra* note 42, at 10-12.

[76] Wilson Rickerson et al., Converge Strategies (prepared for NARUC), The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices (2019), https://perma.cc/P7YZ-STEY.

[77] Unel & Zevin, *supra* note 46.

[78] As noted in Policy Integrity's report, these steps are a streamlined version of the steps and data requirements developed by Sandia National Laboratory as part of the DOE Metrics Analysis for Grid Modernization Project. *See* Eric Vugrin et al., Sandia Nat'l Labs., Resilience Metrics for the Electric Power System: A Performance-Based Approach (2017), https://perma.cc/CK3F-SF5A.

[79] *See* Rickerson et al., *supra* note 76.

[80] For the definitions of these two types of resilience, compare NAS, Enhancing Resilience, *supra* note 42, at vii, *with* Nat'l Acad. of Sci., Eng'g & Med, Building and Measuring Community Resilience: Actions for Communities and the Gulf Research Program 12-13 (2019), and Nat'l Inst. Sci. & Tech, Community Resilience Planning Guide for Buildings and Infrastructure Systems, vol. 1, at 13 (2016), https://perma.cc/68TB- 5B98.

[81] For a discussion of the challenges arising from improving not only the resilience of electricity services but also community resilience, *see* Justin Gundlach, *Microgrids and Resilience to Climate-Driven Impacts on Public Health*, 18 Houston J. Health Pol'y & L. 77 (2018); *see also* Rolon et al., *supra* note 46 (estimating resilience value to the city and county of San Francisco of adding solar plus storage installations to local shelters and libraries).

III. Reasons to move beyond net energy metering

NEM programs in many states, though not all, have enabled a significant amount of private investment in DERs—particularly solar PV. However, because NEM programs' compensation of DERs generally ignores temporal and locational value, NEM is at odds with this report's recommended approach to valuing DERs over the long-term, once a critical mass of DERs has been installed in a given utility service territory.

As explained below, the crux of the problem with NEM lies in its reliance on retail rates. Small retail electricity customers generally pay for electricity service through a monthly, two-part tariff. One part of that rate is fixed, meaning that it does not vary with the customer's electricity usage. The other part is volumetric, meaning that customers pay for the kWh of electricity they consumed during each billing period. The price multiplied by the customer's monthly kWh is "flat" across all the hours of the month. The vast majority of ratepayers are charged a bundled, flat rate for consuming electricity. The rates paid by larger commercial and industrial customers often also include a "demand charge" that reflects their peak demand during each billing period.

The shortcomings of net energy metering

Because NEM compensates DERs based on the net consumption of the customer, it relies on the underlying retail rates.[82] If these retail rates are bundled rates (and for most consumers they are), NEM does a poor job of capturing the benefits and costs of DERs in a granular way.

Reliance on partial and distorted price information

NEM's reliance on retail rates causes three types of problems: it distorts economic signals about efficient DER deployment and operation, it ignores important benefits and costs, and it shunts non-DG DER into a different set of compensation and planning processes, which also distorts economic efficiency.

Distorted economic signals. Nearly all retail utilities charge their customers based on the average cost of electricity service in the utility's territory over each billing period. As a result, most utilities charge a flat price of electricity service for that period, even though the *costs* of providing that service vary significantly across both time (minute, hour, day, season) and location (distribution system line and feeder, and bulk power system node and zone). This discrepancy between price and cost leads customers to not see accurate price signals about the underlying costs when they consume electricity, leading to economically inefficient consumption. Furthermore, because every customer pays the same retail rate regardless of where and when they consume electricity, those who use electricity during cheaper off-peak times cross-subsidize those who use electricity during more expensive peak times. Similarly, those who use electricity at less congested locations, cross-subsidize those who use electricity at congested locations.[83]

---

[82] *See* Revesz & Unel (2017), *supra* note 8, at 60 (noting that 34 jurisdictions credited NEM participants at the retail rate in 2017).

[83] Distribution facilities experience increased wear and tear at near-peak times. Thus, flat pricing at near-peak times results in indifference to the capital costs of distribution system upkeep—costs that utilities generally seek to recover through charges that capture the coincidence of customers' maximum level of demand with maximum local demand on the distribution system ("coincident peak demand").

By basing compensation to DER owners on the flat retail rate, NEM creates for DER owners the same distortions that lead electricity customers to consume inefficiently. That is, DER owners receive an average price for their electricity even at times when its value to the centralized grid far exceeds (or falls below) the monthly average, and even in places where it alleviates (or creates) costs. As academic researchers and the New York State Energy Research and Development Authority (NYSERDA) found in one study, causing DERs to be deployed and operated at the wrong times and in the wrong places can lead NEM's costs to exceed its benefits.[84]

Ignored benefits and costs. Because it is based on retail rates, NEM only reflects the benefits and costs included in a utility's perspective on value. It ignores other benefits and costs, like public health benefits of avoided emissions, treating them as externalities to which electricity prices should be indifferent. Ignoring externalities like these causes decisions about electricity consumption and electricity system design—and DER installation and operation—to be needlessly net-costly to society. Notably, these benefits and costs also—like the system costs highlighted in the previous paragraph—generally depend on time and place.[85]

Fragmentary compensation for DER subcategories. The rules that currently govern compensation for DG and different types of non-DG DERs generally *prevent* direct competition among them by causing compensation to flow to different technologies through distinct channels at different rates. As a consequence, different resource types that provide comparable services often do not compete in a direct and meaningful fashion. As shown in table 6, there is little overlap among compensation mechanisms for different types of DER.

---

[84] Sexton et al., *supra* note 9, at 3-4, 29-31; Kush Patel et al., Energy+Environmental Economics (prepared for N.Y. State Energy Research & Dev. Auth. and N.Y. State Dep't of Pub. Serv.), The Benefits and Costs of Net Metering in New York 51-62 (2015), https://perma.cc/3L5C-K73K.

[85] *See* Shrader et al., *supra* note 50, at 4.

Table 6. Compensation mechanisms for different DER categories.

Type of DER	Main compensation, cost recovery, and subsidy mechanisms
DG	NEM,[86] and numerous grant, rebate, tax credit, and other programs to reduce the costs of installation.[87]
Standalone BTM energy storage	Energy storage deployed by customers "behind the meter" is generally valued by its owners because it can help avoid consumption of grid-based electricity (along with associated demand charges for commercial and industrial customers), or provide backup power during an outage.[88] Subsidies for deploying energy storage vary by state. Some are grants that reduce the cost of deployment.[89] Others seek to encourage storage to reduce peak usage and to displace high-emitting generation resources, by compensating storage that charges at times when the marginal emissions rate of grid-based electricity generation is low and to discharge when it is highest.[90]
Demand response	Wholesale demand response programs compensate demand response resources like generation capacity and delivered generation, based on bids that clear in wholesale capacity and energy market auctions. Retail demand response programs compensate different demand response providers differently: residential customers subject to time-of-use rates save when they avoid higher-priced periods; residential customers subject to flat rates generally receive bill credits; and participating commercial and industrial customers might receive capacity or performance payments (similar to wholesale "capacity" and "energy") as either bill credits or monetary compensation.
Energy efficiency	Customers who invest in EE can recover their costs through reduced energy consumption. Utilities subject to legislative and regulatory mandates can often also recover the costs of making or subsidizing qualifying EE investments through rates and other regulatory mechanisms.[91] In addition, commercial consumers in at least 20 states (and residential consumers in three states and multiple localities) can access low-cost financing for EE investments through PACE programs[92] and recover payments through each participant's property tax bill.
Non-wires alternatives (NWAs)	As noted above, some states direct or authorize retail utilities to recover the costs of NWAs through rates, so long as the suite of DERs perform as needed over the relevant timeframe.[93]

Net energy metering and "fairness"

As explained above, NEM's earliest defining feature was that it enabled DER compensation without disrupting other aspects of providing centralized electricity services, such as metering, billing, and regulatory and tax treatment of flows of electricity and money. How NEM allocates benefits and costs, both between NEM program participants and other ratepayers, and between NEM program participants and utilities, has always been incidental to that more basic priority.

---

[86] For a survey that provides summary descriptions of DG compensation schemes for all 50 states as of September 2018, see Memorandum from Juliet Homer & Alice Orrell, Pacific Nw. Nat'l Lab., to Stacey Donohue, Idaho Pub. Util. Comm'n, Distributed Generation Cost-Benefit and Ratemaking Considerations for Idaho 8 (Jan. 25, 2019), https://perma.cc/JK4K-4B4E.

[87] For a comprehensive list of state and federal level programs, see the "Programs" webpage of NC Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency, *supra* note 29, (accessed Aug. 27, 2019).

[88] Garrett Fitzgerald et al., Rocky Mtn. Inst., The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid 4 (2015), https://perma.cc/7MHL-2A8G.

[89] *See, e.g.*, Julian Spector, *New York's Energy Storage Incentive Could Spur Deployment of 1.8GWh*, GreenTech Media, Apr. 29, 2019, https://perma.cc/E9U4-CZ7Y; Sarah Shemkus, *Massachusetts Grants Help Get Energy Storage Projects off the Ground*, Energy News Network, Nov. 8, 2018, https://perma.cc/5G5R-9L4P.

[90] *See, e.g.*, Decision Approving GHG Emission Reduction Requirements for the Self Generation Incentive Program Storage Budget, Cal. Pub. Utils. Comm'n Rulemaking 12-11-005, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues (Aug. 9, 2019), Mass. Dep't of Energy Resources, The Clean Peak Energy Standard: Draft Regulation Summary (Aug. 7 & 9, 2019), https://perma.cc/2ZT8-YDNZ.

[91] *See* Am. Council for an Energy Efficient Economy, Energy Efficiency Resource Standard, https://perma.cc/6YUQ-8XVC (accessed Oct. 22, 2019) (listing policies of various states).

[92] PACENation, *PACE Programs Near You*, https://pacenation.us/pace-programs/ (accessed Aug. 27, 2019).

[93] Brenda Chew et al., Non-Wires Alternatives: Case Studies from Leading U.S. Projects (2018).

And yet, even though fairness was never the main priority of the design of NEM programs, their "fairness" has received a great deal of attention by commentators and public service commissions in recent years.[94] Some discussions of NEM's fairness focus on whether NEM results in a "cross-subsidy" or "cost shift," whereby DER owners' patterns of electricity consumption and compensation for excess generation leads them to contribute disproportionately less to the revenues utilities rely on to cover the costs of providing centralized electricity services. As a result, so goes the argument, customers with no DER end up paying a disproportionately greater share of utility costs.[95] Other discussions of fairness focus on whether NEM is "fair" to utilities, which receive less in bill payments from NEM participants yet must maintain the infrastructure that supports those participants' continued access to centralized resources.[96]

This report does not attempt to define fairness or to articulate whether or how NEM could be made fair. Instead, it argues that the question of NEM's "fairness" arises from misplaced reliance on retail rates, which are necessarily based on an unduly narrow perspective on benefits and costs. The question of fairness can be best dealt with by adopting a broader perspective and allocating the benefits and costs encompassed by *that* perspective in accordance with principles of economic efficiency and cost causation—steps embodied in the value stacking mechanism described below. Taking these steps recognizes the value contributed by DERs and compensates those contributions for that value, but not more. Unfortunately, resolution of this sort is seldom if ever considered in arguments over whether NEM is unfair and in need of correction. Instead, demands for so-called fairness have given rise to tight caps on NEM eligibility and non-coincident demand charges for NEM program participants,[97] measures that establish more stable revenue streams for utilities[98] but do not cause DERs to be compensated more accurately in light of their benefits and costs to society.

* * *

NEM has enabled the initial deployment of renewable DERs in many jurisdictions,[99] but as those deployments have grown, state authorities have begun to re-examine NEM.[100] Indeed, many if not all states that allow DERs to interconnect and compete with centralized grid resources are either exploring or implementing changes to their original NEM programs (see callout box).[101] For the reasons presented above—some of them valid, others debatable—states want to move beyond NEM. Some also want to move to an approach centered on value stacking.

---

[94] *See, e.g.*, Geffert & Strunk, *supra* note 11, at 37 (examining whether NEM is unfair to non-participants and utilities and concluding that it is unfair to both).

[95] *But see* Memo from Homer & Orrell, *supra* note 86, at 8. ("cost shifts can go both ways"); *see also* Barbose, *supra* note 28, at 30-31 (concluding that NEM often leads to cost shift but in de minimis amounts that do not materially affect ratepayers).

[96] *See, e.g.*, Lindsey Hallock & Rob Sargent, Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society 15-16, tbl.2 & fig.1 (2015), https://perma.cc/2Y5P-E9PC (showing that sponsorship and methodology of 11 "value of solar" studies generally predicts conclusions about utility cost recovery from DER owners).

[97] For examples, see Melissa Whited et al., Synapse Energy Econ. (prepared for Consumers Union), Caught in a Fix: the Problem with Fixed Charges for Electricity 26-27 (2016), https://perma.cc/RJ33-B8X7.

[98] The Louisiana Public Service Commission's recently adopted net metering reform, which authorizes utilities to recover lost revenues due to excess generation exported to the grid by DER owners, is an especially clear example. Catherine Morehouse, *Louisiana Utilities to Pay Less for Rooftop Solar Power Under New Net Metering Rules*, UtilityDive, Sept. 13, 2019, https://perma.cc/2HGH-B6TL.

[99] Naïm R. Darghouth, Nat'l Renewable Energy Lab., Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment 2 (2015), https://perma.cc/53G8-58PK.

[100] Herman K. Trabish, *Renewables: As Rooftop Solar Expands, States Grapple with Successors to Net Metering*, UtilityDive, Sept. 13, 2018, https://perma.cc/FU64-8RXA.

[101] Some states are simply retaining NEM. In Maine, the election of a Democratic Governor and legislature led to the reversal of plans to adopt a NEM replacement that would compensate excess generation based on a static value that reflected avoided utility costs only. Me. Rev. Stat. tit. 35-A, § 3209-A (West 2019) (codifying An Act to Eliminate Gross Metering).

The case for replacing net energy metering with a value stack

If implemented well, a value stack *can* improve on all aspects of NEM without sacrificing the certainty made available from NEM's simplicity. Whereas NEM fails to capture temporal and locational variations in value, a value stack uses them to inform stakeholders and optimize system planning by indicating where DERs can or cannot add value. Whereas NEM ignores values not reflected in retail rates, a value stack can reflect the wider array of values that materially affect stakeholders and system planning. And whereas NEM invites misguided debates over fairness, a value stack can remove the motive and need for such debates by demonstrably compensating program participants for the value they add and nothing more.

It is important to note, however, that a value stack mechanism is an interim and partial solution. The ultimate and complete solution would not stop with owners of DERs but would make the prices that *all* electricity customers pay for electricity services sensitive to costs that change across times and locations. This would level the playing field for investments that can only reduce behind-the-meter consumption such as energy efficiency, and investments that can reduce consumption and inject, such as solar PV. That solution would also expand the list of costs that factor into electricity prices to include emissions of greenhouse gases and ambient air pollutants. However, recognizing that interim steps are often inevitable (if not entirely necessary) to reach this ultimate goal, this report encourages regulators capable of doing so to begin compensating DERs using a value stack. This value stack should reflect temporal and locational differences and encompass more than just avoided utility costs.

NEM and post-NEM programs currently being implemented or considered

1. Retain NEM and ease eligibility limits to allow new categories of participants and larger volumes of participating capacity (example: Washington State).[102]
2. Retain NEM but put curbs on participant compensation (e.g., higher noncoincident demand charges for participants or caps on how much capacity can participate) to (a) offset the revenue utilities lose when DG owners buy less electricity and (b) eliminate cost-shift from participants to non-participants (example: Arkansas).[103]
3. End NEM and adopt a "NEM 2.0" program that employs time-of-use (TOU) rates and locational targeting for program participants (example: California).[104]
4. End NEM (for some or all customer classes) and establish a successor program that credits excess generation based not on retail rates but on a static value that is updated annually (example: Minnesota).[105]
5. End NEM and establish a successor program centered on a value stack whose components are dynamic and whose broad perspective encompasses pollution factors as well as avoided bulk power system and distribution system costs (example: New York).[106]

[102] Wash. Rev. Code Ann. § 80.60.005 (West 2019) (codifying Solar Fairness Act).

[103] Ark. Code Ann. § 23-18-603 through 605 (West 2019). Decision Adopting Successor to Net Energy Metering Tariff, Cal. Pub. Utils. Comm'n Decision 16-01-044 (Jan. 28, 2016), https://perma.cc/DHZ9-U8NW.

[104] Decision Adopting Successor to Net Energy Metering Tariff, Cal. Pub. Utils. Comm'n Decision 16-01-044 (Jan. 28, 2016), https://perma.cc/DHZ9-U8NW.

[105] Minn. Stat. § 216B.164, subd. 10 (West 2019); *see also* Benjamin Norris et al., Clean Power Research (for Minn. Dep't of Commerce), Minnesota Value of Solar: Methodology (Apr. 2014), https://perma.cc/DE53-43R4.

[106] Stanton, *supra* note 4, identifies eight types of response by commissions to the increasingly obvious problems with NEM as the solution for compensating DER contributions to electricity service provision: NEM 2.0 or successor [included VDER]; comprehensive rate design review and update; changing rates for "net excess generation"; higher monthly fixed charges for mass market customers; creation of new DER customer class for separate treatment; authorizing third-party or utility ownership of DERs; authorizing community solar.

Table 7 below summarizes the dynamic components that can be combined by a value stack to inform the value of a DER's contributions—viewed from a societal perspective—to providing electricity services.

Table 7. Value stack components, their underlying dynamic metric(s), and their temporal and locational parameters.

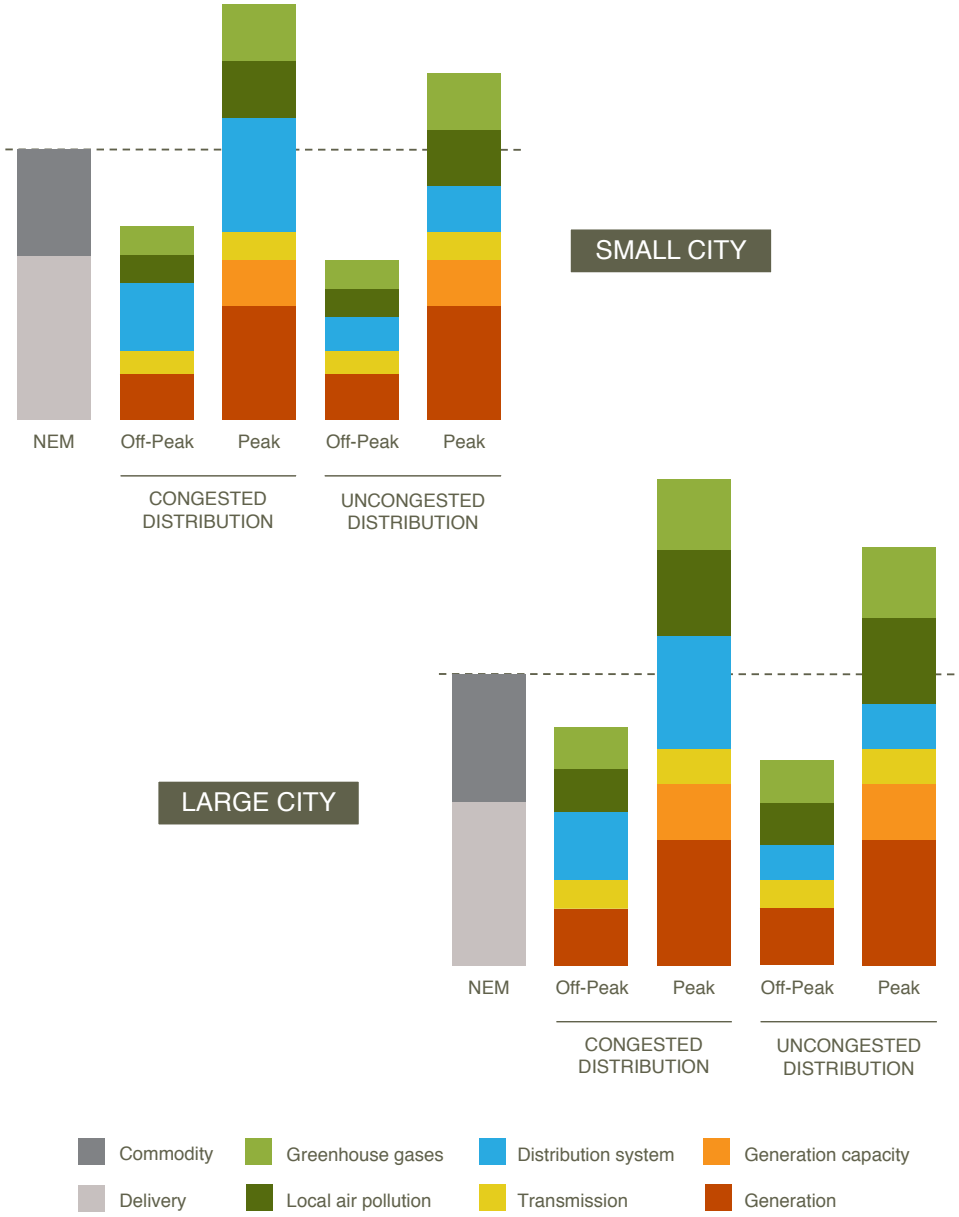
Component	Metric and/or Units	Interval	Geography
Wholesale energy (including generation, congestion, and line losses)	LMP [$/MWh]	Hour	Wholesale market node (or zone)
Wholesale capacity	Installed capacity or "ICAP"[107]	*Varies by jurisdiction*	
Transmission	*Varies by jurisdiction;*[108] *LMP & ICAP capture some but not all capital and O&M costs of transmission*	Six months	
Distribution system capacity and line losses	Utilities' marginal costs of service	Decade	As local as possible: primary feeder, lateral feeder, transformer
Greenhouse gases	[CO_2e / MWh]	Hour	Wholesale market zone
Ambient air pollutants	[PM, SOx, NOx / MWh]	Hour	*As granular as is supported by available tools e.g., EASIUR, InMap*
Resilience	*Varies by jurisdiction*	*Varies by jurisdiction*	Distribution utility service territory

The Metric column contains items described in part II; the Interval column indicates how frequently those metrics should be updated to stay accurate; and the Geography column indicates where the metric pertains. In a "stack," these assembled metrics look like figure 8, below, which shows how they compare to the flat retail rate that informs NEM program compensation.

[107] A California Public Utilities Commission proceeding investigated two different use cases, one for the short term that uses a version of ICAP payments as a proxy for capacity value, and one for the long term that uses the cost of new entry (CONE). *See* Locational Net Benefit Analysis Working Group Long Term Refinements Final Report, Cal. Pub. Serv. Comm'n Rulemaking 14-08-013, at 49-52 (Jan. 9, 2018), https://perma.cc/4JXJ-BYZ8.

[108] *See, e.g.,* ConEdison, Benefit-Cost Analysis Handbook v.2.0, at 20-24 (2018), https://perma.cc/2GPL-5GL3; *see also* Paul Denholm et al., Nat'l Renewable Energy Lab., Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System 34-37 (2014), https://perma.cc/F5XB-W5VH (listing three possible approaches to calculation).

Figure 8. Conceptual comparison of retail rate (and NEM) to value stack compensation across times (peak and off-peak) and locations (congested and uncongested distribution grid sections in a large and small city)



There is an important difference between what the NEM bars indicate and what the others do. The NEM bars' heights indicate what a DER would be compensated by a NEM program in each city over a full billing period. By contrast, the other bars' heights indicate how much a DER would be compensated by a value stack in select places and select times within a billing period.

Figure 8 illustrates how compensation for DERs in accord with this report's proposed value stack would respond to different settings and circumstances. Before exploring how the value stack bars in the figure reflect responses to those settings and circumstances, it is useful to first understand the delivery and commodity components of the NEM bars. As explained above, most retail rates do not reflect the costs of providing electricity services at particular times and locations. Instead, they reflect average values, arrived at by taking the utility's costs of providing electricity in an entire service territory for each billing period, summing those costs and then parceling them out to different classes of ratepayer as "flat" rates. Because NEM mirrors retail rates, NEM generally compensates DER owners based on these homogenized, "flat" values.

This is why, in Figure 8, the delivery component (light grey) in each city is proportionate to the average of the distribution system costs (blue) in the four different settings shown for that city. Even though distribution system costs might be higher in congested areas, the utility does not charge customers served by congested facilities more. And so, NEM compensation does not rise in congested areas or fall where there is no congestion. Similarly, the commodity component (dark grey) of the NEM bars is proportionate to the average of the bulk power system costs (yellow, orange, and red) in the corresponding value stack bars. Even though those costs differ significantly across both congested and uncongested areas and peak and off-peak times, retail rates flatten out these differences. And NEM compensation, which mirrors flat retail rates, ignores those differences too.

Unlike the NEM bar components, the value stack bars' components respond to changes in load (i.e., on- or off-peak), the presence of congestion in the local distribution system, the number of people exposed to air pollution released by nearby generation facilities, and the volume of greenhouse gas pollutants emitted.

Peak/Off-peak. At peak times, the bulk power system incurs costs to generate electricity and transmit it to load centers. And, because enough capacity to supply peak load must be maintained, the bulk power system also incurs capacity costs at peak times. At off-peak times, demand is lower, so energy costs are lower and capacity costs fall to zero. The value stack translates a DER's ability to help avoid costs at these times into commensurate compensation—more at peak times, less at off-peak.

Distribution system congestion. Congestion also makes a distribution system more expensive to operate and can spur expensive capital investments. So, as reflected in the value stack, a DER's ability to help avoid congestion is valuable at all times, and especially at times of peak load. It is important to note that the timing of this congestion may or may not correspond with the bulk power system peak.

City size. The public health costs of local air pollution are a function of the pollution's severity and the number and demographics of people it affects. It follows that those costs are higher in a large city because more people are affected, even if the volume of emissions is the same as that emitted near or in a small city. The value stack compensates a DER for its ability to help avoid these costs.

Greenhouse gas emissions. The generation fleet depicted in Figure 8 resembles those that operate in the NYISO and California ISO. There are no large, coal-fired generators, and the nuclear and renewable resources that supply most generation during off-peak times do not emit. At peak times, especially in cities with constrained transmission access, natural gas and dual-fuel resources operate as well. And so, both the volume of greenhouse gas emissions and the value of DERs' ability to avoid them tracks generation peaks. The large city is home to more load, higher peaks, and thus more emissions. In the PJM Interconnection region—which covers 13 states from the Midwest to the Mid-Atlantic and is home to much of the country's coal-fired generation capacity—these values would be quite different.

Figure 8 makes two important points especially clear. First, the different heights of NEM and value stack compensation in each scenario highlight that NEM programs often ascribe inaccurate values to DERs. Such inaccuracy in NEM-based compensation necessarily leads developers to put DERs in the wrong place, i.e., where they will add little or no value. The second point is that ignoring the costs imposed by emissions—and so ignoring the value of avoiding them—also leads to an under-valuation of DERs. Recognizing DERs' full value requires adopting a broader perspective on costs and benefits than that of a utility and its ratepayers.

Circumstances important to the effectiveness of a value stack

Administering a value stack effectively requires gathering and analyzing a great deal of granular information on an ongoing basis. And it requires regulatory authorities, utilities, and other stakeholders to work together to translate that information—particularly as it relates to various costs—into a single, dynamic price, on an ongoing basis, even as circumstances change. This means deploying AMI and pursuing integrated distribution system planning in a way that balances program design priorities.

When deciding how to compensate DERs, transparency and predictability can be as important as accuracy and precision. The primary goal of the compensation scheme should be the development of the right DERs in the right places, and the avoidance of unnecessary and unduly costly alternatives. Regulators and stakeholders in California and New York have both learned that implementing a value stack in a world rife with transaction costs and risk-aversion requires striking a balance between accuracy, transparency, and predictability.[109] New York's market for solar PV slowed in 2018 after compensation efforts prioritized accuracy without due concern for the other two priorities.[110] That slowdown followed the PSC's Value of Distributed Energy Resources Phase One Implementation Order, which directed that the distribution component of the value stack would be revised every three years based on input from utilities.[111] Investors and the DER developers that rely on them anticipated from this the elimination of revenue for any project beyond a three-year time horizon.[112] Regulators learned from this experience, and in 2019 adjusted the DER compensation scheme by (among other things) "locking in" the distribution component's value for 10 years—the same time horizon used by New York's retail utilities for amortizing distribution grid assets.[113]

---

[109] *See* Herman K. Trabish, *Unnecessary Complexity? Assessing New York and California's Landmark DER Proceedings*, UtilityDive, Apr. 4, 2018, https://perma.cc/8N8H-3WGN.

[110] *See* John Weaver, *Community Solar Spurns New York's VDER, Seeks a Return to Net Metering*, PV Mag., June 20, 2018, https://perma.cc/Q9ED-XRKG.

[111] Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources 11-13 (Sept. 14, 2017), https://perma.cc/52PH-X238.

[112] Jeff St. John, *Why Solar Advocates Are Crying Foul Over New York's Latest REV Order*, UtilityDive, Sept. 19, 2017, https://perma.cc/DM6F-3YZL; see also Comments of the Clean Energy Parties, N.Y. Pub. Serv. Comm'n Case 15-E-0751, Value of Distributed Resources Phase One Implementation Plans 5 (July 24, 2017), https://perma.cc/2VU7-ZCWY ("It is much harder to design customer products and finance projects if there are key values that are unpredictable, irretrievable, or subject to utility interpretation.").

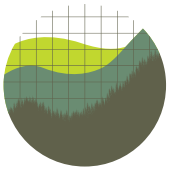
[113] Order on Value Stack Compensation, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources 20-21 (Apr. 18, 2019), https://perma.cc/8NBD-FVKP.

Conclusion

The value of particular electricity resources to different stakeholders and to society as a whole depends on multiple factors, several of which are sensitive to where and how those resources operate. For instance, in a region where load growth is on pace to exceed the capacity of existing generation or transmission, DERs whose operation will reduce load peaks can help to defer or wholly avoid the costs of importing more electricity from other regions or developing new generation and transmission facilities. Similarly, in an area burdened by a congested distribution system, DERs that alleviate one or more sources of congestion can thereby reduce costs and, potentially, improve reliability. And DERs located in communities served by fossil-fueled generation facilities can displace those facilities' operation and thereby deliver environmental and public health benefits. If the displaced facilities burn coal or oil, the benefits of their displacement are likely to be especially large. Capturing these sorts of benefits requires adopting a perspective that recognizes them. Such a perspective must be broader than that of an electric utility and should be broad enough to recognize benefits and costs accruing to society as a whole, such as the benefits to public health of avoiding local pollution.

NEM programs generally do a poor job of translating these determinants of value into appropriate compensation for DERs. This deficiency owes to NEM programs' embodiment of a cramped perspective (that of a utility, rather than society) and reliance on flat retail rates that ignore the importance of timing and location to value. State regulators considering how best to compensate DERs should make those two features—a broad perspective on benefits and costs, and sensitivity to timing and location—basic to whatever programs they adopt. A value stack is the logical mechanism for translating these features into compensation for DERs, and thereby informing decisions about whether solar PV, energy storage, another type of DER, or no DER at all would add the most value in a given set of circumstances.

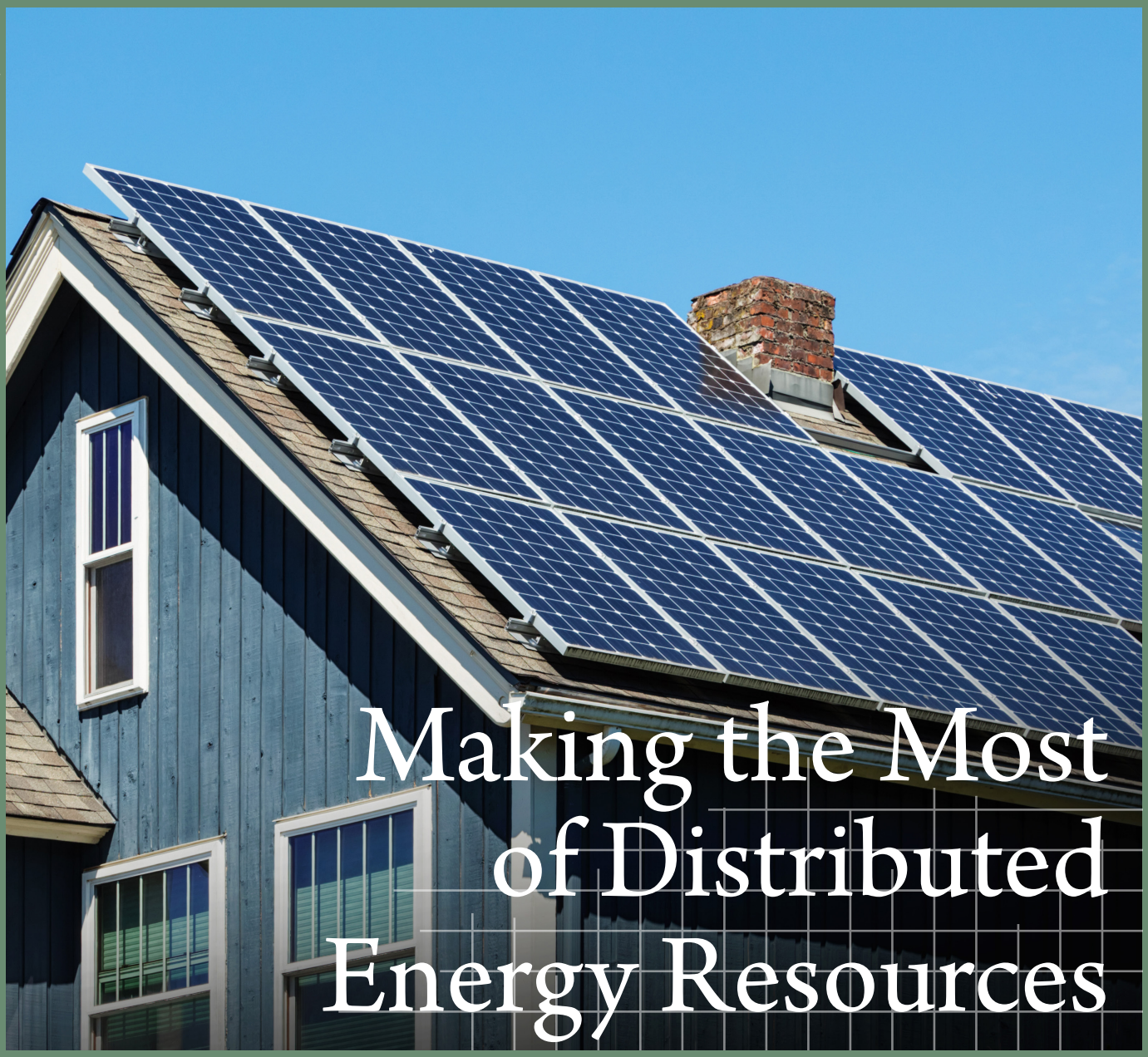
As several states have discovered, implementing a value stack requires commissions to strike a balance between the competing priorities of accurate valuation, transparent access to information about the local and regional electricity grid, and predictability with regard to sources of DER compensation. All three are indispensable, and ensuring that a DER compensation program embodies all three requires thoughtful engagement with stakeholders both before and after a commission adopts a value stack. Commissions just now undertaking to examine and possibly move beyond their NEM programs should look to both the processes and the outcomes in states that have led, even if they have sometimes stumbled along the way.



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

J Horrocks



Making the Most of Distributed Energy Resources

Subregional Estimates of the Environmental Value of Distributed Energy Resources in the United States

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

September 2020

Matt Butner, Ph.D.
Iliana Paul
Burcin Unel, Ph.D.

Copyright © 2020 by the Institute for Policy Integrity.
All rights reserved.

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

Matt Butner is an Economic Fellow at the Institute for Policy Integrity at NYU School of Law, where Iliana Paul is a Senior Policy Analyst and Burcin Unel is the Energy Policy Director.

Please contact burcin.unel@nyu.edu with any questions or correspondance about this report.

The authors would like to thank Derek Sylvan and Richard L. Revesz for their valuable feedback.

This report does not necessarily reflect the views of NYU School of Law, if any.

Table of Contents

Figures and Tables

Executive Summary

Distributed Energy Resources (DERs), like rooftop solar and battery storage, have the potential to generate significant social benefits by displacing pollution-emitting electricity generators. Accurately compensating DERs for this environmental and public health value, which some regulators and experts call the "E-Value," is imperative for making the most out of DERs' potential. Doing so will ensure DERs are deployed, and used, when and where they create the most value for society. In practice, however, calculating the E-Value of DERs is difficult without a detailed model of the electric power sector because the benefits of avoided air pollution can vary significantly by location and time of day or time of year.

This report provides a new set of hourly E-Values for the whole United States, broken down into 19 subregions, using an open-source reduced-order dispatch model.[1] Critically, these granular estimates are shown to vary considerably by geography, hour, and season. The patterns uncovered by these estimates can help policymakers design economically efficient DER policies to reduce air pollution from electricity generators. Because these results come from an open-source model, they can be particularly useful for regulators with mandates to use publicly available data in their decisionmaking[2] or for those who desire to do their own analysis.

This report reveals three novel insights based on the hourly E-Values generated by the model. First, the E-Values of DERs depend crucially on the location of the DER, as some regions have more pollution-intensive electricity generators than others. Second, unlike the production cost savings of DERs (which are generally greater during periods of high electricity demand), there is no general and consistent pattern that can effectively characterize the E-Value of DERs throughout the day. Finally, the E-Value of DERs can be large – potentially greater than the benefits of avoided electricity production costs, and generally greater than what commonly used heuristics would suggest.

Policymakers can use these estimates and insights to create effective DER policies and programs. These findings highlight the need for more accurate and granular valuation of DERs, without which investments in DER technologies are likely to be either meager or misdirected. Policymakers using E-Value estimates in the design of DER compensation schemes or the assessment of other DER policies can rest assured they are making the most of DERs' potential to deliver social benefits in their jurisdiction.

The modeling results make clear four specific policy implications. First, the relative magnitude of E-Value can tip the scales in favor of DERs. Accounting for both the E-Value and the benefits of avoided energy of DER deployment nearly doubles the benefits of DERs in comparison to valuing the avoided energy alone. Ignoring the E-Value of DERs will therefore result in the deployment of fewer DERs than what is optimal.

Second, the E-Value can identify where in the country different DER technologies are most effective. For example, investing in energy efficiency lightbulbs create the most value where the nightly E-value is the largest, and likewise, efficient air-conditioning and rooftop solar should be directed towards the regions with a high E-Value during summer's midday. Policymakers should use the E-Value when deciding which technologies to support and where they should be deployed.

Elena Elisseeva

Third, general policies rewarding DERs during certain times of day might not effectively capture the benefits of DERs because there is no general and consistent daily pattern in E-Values across all regions. Instead, policymakers interested in granular time-of-day policies must model the specific benefits of a DER's deployment within their region.

Finally, policies must account for both the climate and public health benefits of DERs when calculating the E-Value. Each component makes up roughly half of total E-Value's on average. Ignoring the either component of the E-Value will result in inefficient DER deployment even if the other component is accounted for.

This report proceeds by first establishing the elements that determine the E-Value of DERs, including marginal generators, marginal emissions, pollutant type, location, and timing. With that established, this report then briefly characterizes the model used to calculate the subregional E-Values of DERs and finally summarizes the modeling results. Before concluding, this report discusses the important role of E-Value in policymaking and the several policy implications. Interested readers are directed to Appendix A to learn more about the reduced-order dispatch model, and Appendix B for a table of average E-Values for each subregion, season, and time-of-day.

The Environmental Value of Distributed Energy Resources

DERs are small energy resources that can reduce or supply a portion of onsite demand for electricity.[3] Most DERs do not emit greenhouse gases or local air pollutants that can be harmful to human health and the environment.[4] When a pollution-free DER reduces the need for pollution-emitting bulk power generation, there are benefits – potentially large benefits – from the avoided pollution. These environmental benefits are fundamental to the characterization of a DER's overall value to society, and, when monetized, are referred to as the E-Value of a DER.

Businesses and individuals typically consider only the benefits of avoided electricity costs when deciding how to invest in and operate DERs. This means that they are bound to ignore the E-value of DERs when making their decisions in the absence of any policy intervention. Because they consider a limited scope of benefits, this behavior results in an underinvestment in DERs.

In response to this problem, some jurisdictions have implemented policies to encourage adoption of additional DERs for the purpose of decarbonizing the electricity grid; this trend is expected to continue as the need to decarbonize electricity grows.[5] However, as regulators strive to understand how to fit DERs into the larger electricity landscape, it is essential that they not only incorporate the E-Value of DERs, but do so accurately. If not, DERs could be deployed in an inefficient way that does not maximize the benefits they can provide or even work against state policy goals.[6]

Fortunately, there are readily available concepts and tools to help policymakers quantify the E-Value of DERs.[7] The rest of this section describes the determinants of the E-Value of DERs and the general procedure to calculate it.

Elements Determining the E-Value of DERs

Unlike the private benefits of DERs, such as avoided energy costs, which can be easily deduced from the price of electricity, calculating the E-Value of DERs requires multiple steps. These straight-forward steps to calculate the E-Value of DERs are summarized below, and the rest of this section goes into more detail on those different steps.

Marginal Generator and Marginal Emissions

A major determinant of a DER's E-Value is which electricity generator it displaces. Although many generators produce electricity simultaneously, usually only one responds to DER-induced changes in the demand for bulk-power electricity. The responding generator must adjust its production to match marginal changes in demand in real time. For this reason, the generator responding to DERs at any given moment is the **"marginal generator."**

Identifying the marginal generator displaced by a DER is the crucial first step in calculating the E-Value of a DER. The marginal generator could be a high-polluting oil plant or a relatively low-emissions natural gas plant, which means that a DER could displace either a larger or smaller amount of harmful emissions. The electricity grid operator, managing the balance of supply and demand in real time, determines which generator is marginal and can directly report this

information to the public. Alternatively, because the market operator follows consistent rules to balance supply and demand, the marginal generator can be deduced from a simulation of the electric power sector.

The pollution emissions avoided when the marginal generator decreases its electricity production by a marginal amount are the **"marginal emissions"** of electricity in that moment.[8] The volume and type of pollutant avoided vary depending on the marginal generator's fuel type and other characteristics, like plant efficiency or pollution-control technology. Therefore, knowing only the generator type is not enough to accurately determine the environmental and public health effects. Instead, it is important to have direct observation of marginal emissions from the marginal generator.

Marginal Emissions vs. Average Emissions

The marginal emissions of electricity are different than average emissions of electricity. Marginal emissions capture how generators (and emissions) respond to DER-induced changes in electricity demand and supply. Average emissions, in comparison, represent all pollution from electricity divided by the quantity of electricity generated in a given time period. This means that average emissions fail to capture the true change in pollution due to DERs.

Pollutants, Location, and Timing

The environmental and public health effects of marginal emissions depend crucially on the type of marginal emissions, as well as the location and timing of those emissions. In particular:

(a) Different pollutants have different environmental and health effects. While greenhouse gases accumulate globally and cause global damages, some air pollutants remain local and cause harm relatively nearby. Local air pollutants, like sulfur dioxide, particulate matter, and nitrous oxides, contribute to serious human health consequences for populations near where they are emitted, like asthma and heart disease.[9] Policymakers can use a number of public health models to quantify how different doses of these pollutants affect human health.[10] They can then monetize these health effects using standard estimates, like the value of statistical life;

(b) Pollutants emitted in densely populated areas or near highly vulnerable populations, like low-income communities and communities of color, will cause more damage because of whom or how many people they harm; and

(c) Pollutants can have different effects depending on ambient weather conditions, like sunlight or temperature, so policymakers should know the precise timing of the marginal emissions.

Putting all of these elements together allows policymakers and stakeholders to quantify and monetize the E-Value of DERs. To do so accurately requires granular data on detailed marginal emissions rates and public health models.

Straight-forward Steps to Calculate the E-Value of DERs

1. **Identify the electricity generator on the margin.**
   This "marginal generator" is the last generator required to balance supply and demand. As a result, this generator (or group of generators) will reduce their output in response to DER-induced reduction in demand for bulk-power electricity.

2. **Quantify the marginal emissions from the marginal generator.**
   These are the pollution emissions per unit of additional electricity from the marginal generator. This varies by fuel type and electricity generator attributes (e.g. fuel, efficiency, and other technologies) and so is best measured directly (e.g. through EPA's Continuous Emissions Monitoring System (CEMS)).[11]

3. **Monetize the environmental and public health damages of the marginal emissions.**
   These monetized harms of pollution emissions depend on the type of pollutant, where the marginal emissions are located, and when the pollutants are emitted – both in terms of time of day and time of year. These public health effects can be quantified and monetized using several possible tools.[12]

4. **Calculate the benefits of avoided pollution per unit of DER deployment.**
   Multiplying the marginal emissions (tons/MWh) by the monetized damages per unit of emissions ($/ton) gives an economic value for the environmental benefit of avoided pollution per MWh reduction in bulk-power electricity.[13]

Trong Nguyen

General Model Description

This section presents a brief outline of the reduced-order dispatch model. Interested readers are directed to Appendix A for a more detailed description of the model and its application in this report.

The reduced-order dispatch model uses publicly available data on large fossil-fuel electricity generators to simulate historical hourly electricity production in a pre-specified geographic area.[14] For every week in the sample period, the model ranks electricity generators from lowest cost to highest cost.[15] This reflects the fact that low-cost electricity generators are typically called on to produce electricity before high-cost ones. With this weekly ranking, the model then identifies for every hour which electricity generators can be called upon to collectively produce enough electricity as was produced historically for the hour, but at the lowest possible total cost.

In this way, the model identifies the last electricity generator required to balance supply and demand as the marginal electricity generator. The pollution emitted from the marginal generator (in tons/MWh) represents the marginal emissions for that hour – the increase (or decrease) in pollution for a one-unit increase (or decrease) in the demand for fossil-fuel electricity.

Although this model is relatively simple, it captures several of the complexities inherent in the electric power system, including the required downtime of thermal plants and weekly variation in plant efficiency and fuel prices. However, it does not capture transmission or distribution constraints, nor does it model non-fossil resources.[16]

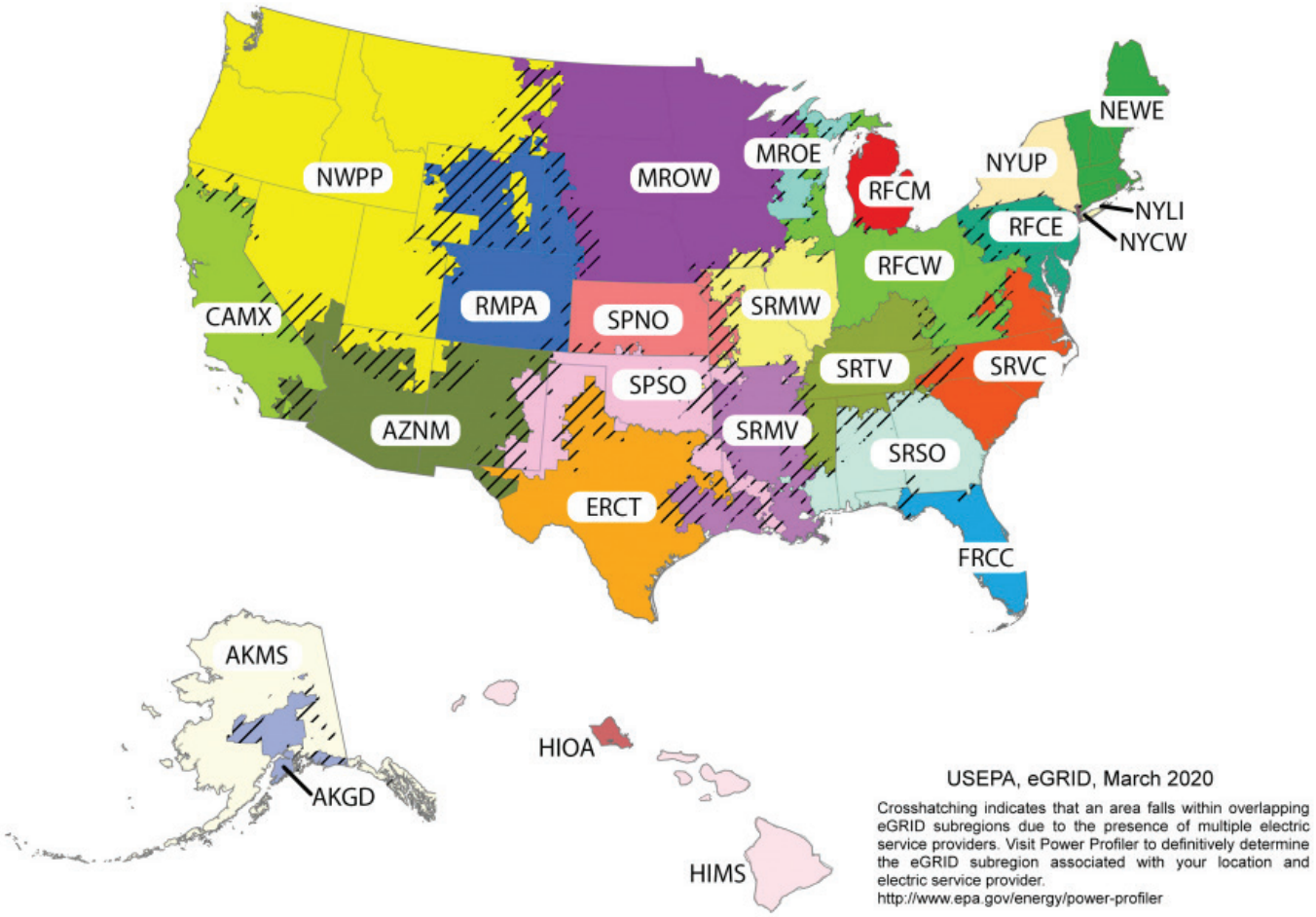
This report presents results using the reduced-order dispatch model with data from the year 2018, and geographic regions based on EPA's Emissions & Generation Resource Integrated Database (eGRID) regions as displayed in Figure 1.[17] This modeling exercise directly outputs hourly marginal emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) for each subregion, and therefore simultaneously completes steps 1 and 2 required to calculate the E-Value. For step 3, this report uses location-specific monetized damages of NO_x and SO_2 from the Estimating Air pollution Social Impact Using Regression (EASIUR) model, and monetized damages of CO_2 based on to the Social Cost of Carbon (SCC) developed by the federal Interagency Working Group (IWG).[18] Finally, in step 4, this report calculates the hourly E-Value by multiplying the marginal emissions and monetized damages for each pollutant and summing the resulting product across all pollutants measured.

Data limitations prevent this report from monetizing the damages of primary particulate matter pollution emitted from electricity generators (i.e., black carbon) because EPA's CEMS does not report primary particulate matter pollution data. Rather, the E-Value estimates in this report quantify only the damages of secondary PM2.5 that are produced from chemical interactions in the atmosphere involving SO_2 or NO_x. Because PM reductions are responsible for a significant portion of benefits from federal regulations of emissions from power plants, and so a "substantial portion of the benefits of all federal regulation,"[19] it stands to reason that the omission of this important data means that the E-Value estimates presented in this report are a lower bound.[20]

Evidence suggests that PM is a non-threshold pollutant, which means that it is harmful even at low doses.[21] Therefore, it is important to know the full magnitude of PM emissions. In order to incorporate the full effects of particulate matter into the subregional E-Values, hourly primary particulate matter pollution estimates must be imputed from annual

measurements from electricity generators or modeled directly.[22] With these estimates, the E-Value can be updated to include total harms of particulate matter using location-specific monetized damages of primary particulate matter from the EASIUR model. Incorporating the total harms of particulate matter from the marginal electricity generator will increase the E-Value estimates in some regions and may change when and where the E-Value is the greatest.

Figure 1 – eGRID subregions defined by the EPA



Note: NYUP, NYCW, NYLI, and NEWE are aggregated into a single region (NPCC) in the E-Value modeling exercise.

Results

The reduced-order dispatch model and monetization tools uncover the hourly environmental value of DERs for 19 regions in the continental United States. As a reference for policymakers, the season and time-of-day average E-Values are presented in Appendix B. The modeling results show the following conclusions.

The E-Value of DERs Varies by Region

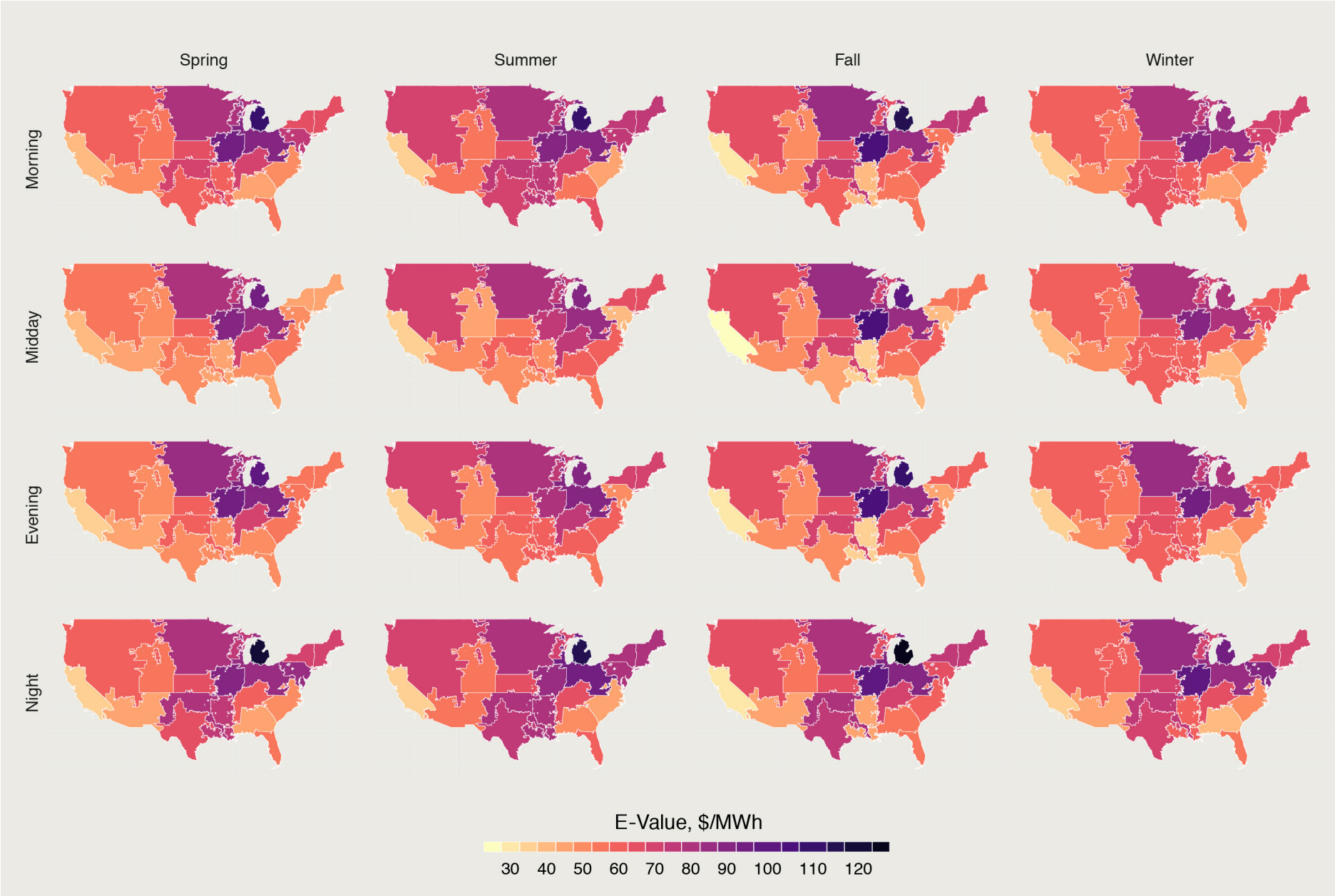
Results from the reduced-order dispatch model suggest the E-Values of DERs can vary significantly by subregion. Figure 2 displays hourly maps of the E-Value of DERs for each subregion averaged by season and time of day. This figure shows that the E-Value depends largely on the geographic region, and less so on the time of day and season. This variation is because some regions use more pollution-intensive fuels to generate electricity than others. For example, the Great Lakes and Ohio Valley regions are heavily dependent on coal electricity generators, which emit a large amount of CO_2 and SO_2 per MWh. The E-Value is relatively small in California where little-to-no electricity is generated by coal electricity generators.

Other than geographic location, population density can be a large determinate of the E-Value of DERs. Densely populated areas experience more damage from a given amount of pollution as more people are exposed. Results in Figure 2 show there are consistently higher E-Values in the Northeast compared to the Rocky Mountains, in part because the former is more densely populated than the latter. Analysis on the electric power sector done by the EPA illustrates this point in the context of PM2.5: a ton of PM2.5 released in the eastern region of the United States causes between $130,000 and $320,000 in damages, whereas the same ton in the western part of the United States causes $24,000 to $60,000 in damage.[23]

Heidi Besen

E-Values vary by geographic region because some regions use more pollution-intensive fuels to generate electricity than others.

Figure 2 – Map of Subregional Average E-Value by Season and Time-of-Day



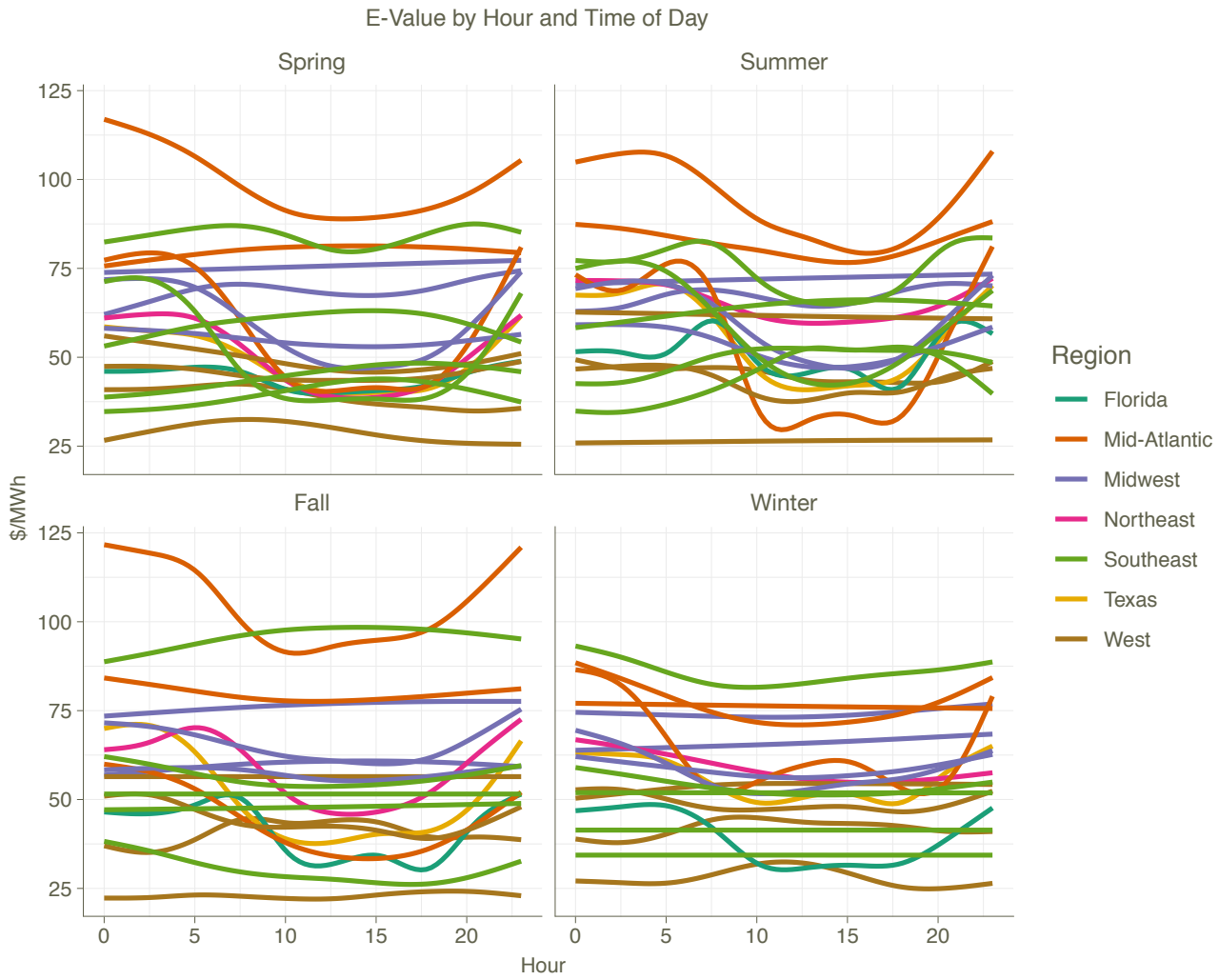
Seasons are defined according to equinoxes and solstices. Each time period is 6 hours long; Morning begins at 4 am, Midday at 10 am, Evening at 4 pm, and Night at 10 pm.

The E-Value of DERs Does Not Follow a General or Consistent Daily Pattern

Generally, the hourly E-Value can vary significantly throughout the day, as the marginal electricity generator, marginal emissions, and associated health benefits change hourly. If the hourly E-Value were to follow a consistent and general daily pattern, policymakers could use this information to better design DER compensation policies by, for example, compensating DERs the most during the time of day they generate the most social value.[24] But, if the E-Value does not follow a consistent and general pattern, policy makers would have to directly observe hourly marginal emissions or model the specific region to accurately compensate DERs for their intra-day variation in E-Value.

Figure 3 presents the average hourly E-Value for each subregion and season in an attempt to uncover whether there is any general pattern that can inform DER compensation policies that vary throughout the day. This figure shows there is no consistent and strong pattern throughout the day or season, especially in comparison to the variation among regions at a specific time of year. If anything, there is sometimes a pattern that is contrary to the pattern in energy costs: In some subregions, the E-Value of DERs is smaller in the middle of the day during "peak demand" periods. This is likely because a natural gas plant is the marginal generator during the day, and a relatively more pollution-intensive coal electricity generator is the marginal generator during the night.

Figure 3 – Smoothed Hourly Average E-Value of Subregions by Season

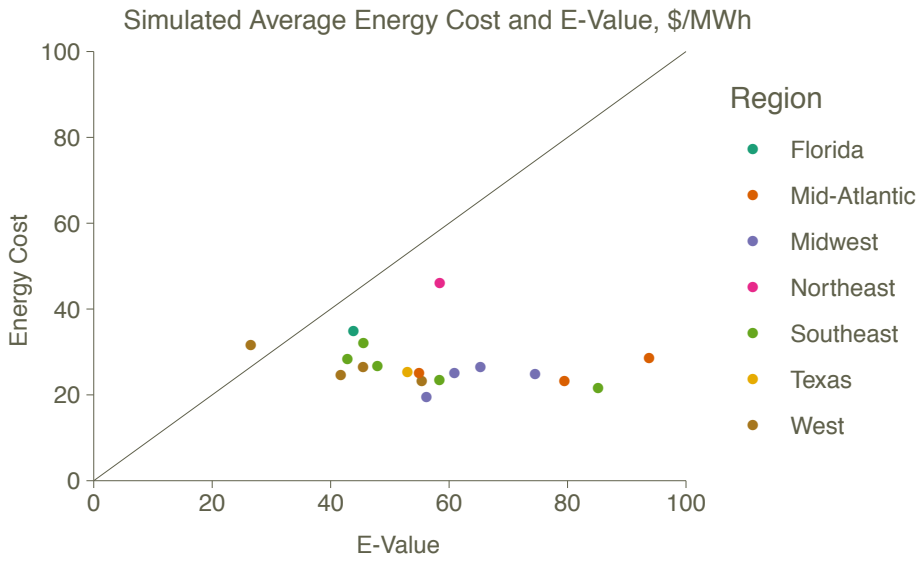


Each subregions color is based on the geography of the corresponding NERC region.[25]

The E-Value of DERs Can Be Large

The average E-Value of DERs, across all 8760 hours in a year and 19 geographic regions, was $57/MWh (with a median of $54/MWh). This value is nearly twice the average cost of electricity simulated by the reduced-order dispatch model ($27/MWh), and greater than the national average wholesale price of electricity in 2018 ($44/MWh).[26] Figure 4, which displays the simulated average production cost and average E-Value of DERs in every subregion, shows this relationship holds for every subregion except one.

Figure 4 – Simulated Energy Cost Compared to the E-Value of DERs

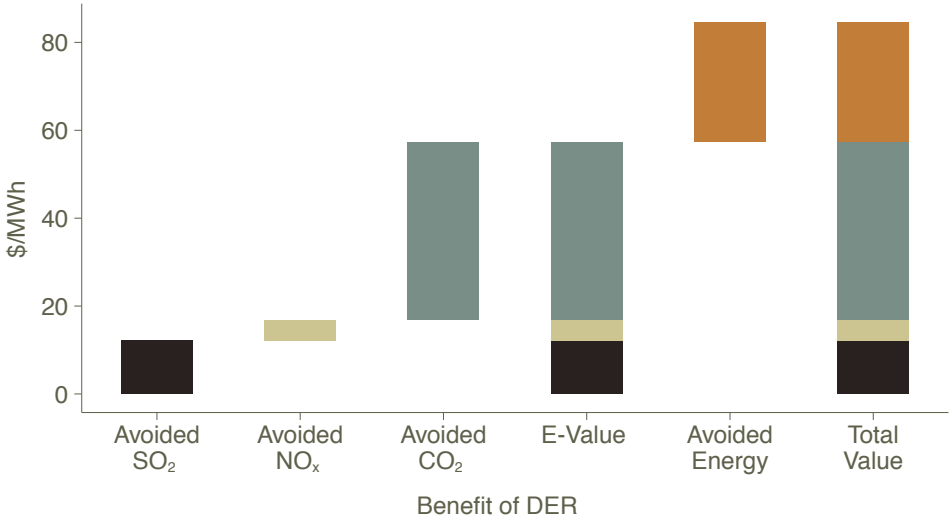


Each subregions color is based on the geography of the corresponding NERC region. The diagonal line represents equality between the two values, and subregions to the lower right of the diagonal lines have an average E-Value greater than average simulated energy cost.

Benefits from avoided greenhouse gas emissions make up nearly half of the E-Value. Decomposing the E-Value of DERs, as done Figure 5, shows the avoided CO_2 pollution is a large component of a DER's benefits on average across all regions and hours. By using the Social Cost of Carbon, the E-Values presented in this report capture, at least in part, the large future damages from climate change (including from coastal storms, extreme weather events, and human health impacts, such as mortality from heat-related illnesses induced by the use of fossil-fuels). Ignoring the benefits of avoided greenhouse gas emissions will provide an underestimate of the total benefits of DERs. For example, recent analysis by the EPA evaluating only the public health benefits of DERs, excluding avoided GHG emissions, range from $17 to $40/MWh on average.[27]

Finally, the E-Value of DERs are large relative to the estimated environmental value based on average pollution emissions from electricity production. This means that basing policy decisions on the commonly used heuristic of average pollution emissions instead of marginal pollution emissions leads to inefficient deployment. The divergence between the average pollution emissions and the marginal emissions depends on how the marginal electricity generator differs from the average electricity generator in terms of fuel-type, efficiency, location, and other technical features. The E-Value using the marginal emissions is greater than an E-Value equivalent based on average emissions when, for example, an oil plant is on the margin in a region composed largely of relatively cleaner natural gas electricity generators.

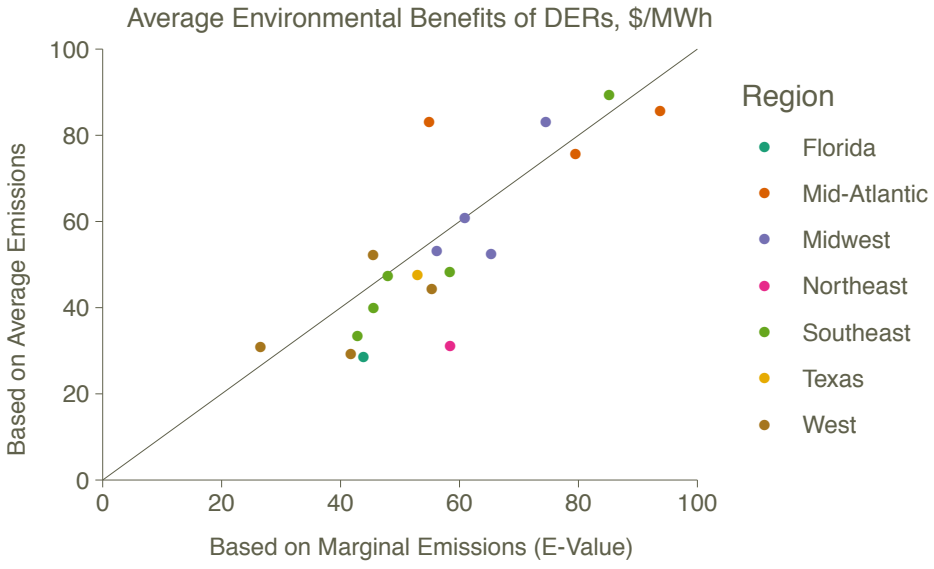
Figure 5 – Decomposition of a DERs' Benefits



Average hourly benefit of DERs across all hour-subregions in 2018. Avoided pollution (SO_2, NO_x, and CO_2) are monetized as described in the General Model Description section of this report. Avoided Energy represents the avoided fuel, operations, and management costs of bulk-power electricity by DERs. These benefits are not exhaustive; DERs can provide additional benefits not listed in this figure such as avoided line losses and avoided capital costs.[28]

The output of the reduced-order dispatch model shows an E-Value equivalent based on average emissions is less than the E-Value based on marginal emissions in 75% of hourly subregion observations. Figure 6 supports this statistic by showing the sample mean of each measure across all 19 subregions. Here, the E-Value of DERs is larger on average when it is based on marginal emissions. Because the reduced-order dispatch model does not include pollution-free resources like nuclear power and hydroelectric dams, the E-Value using actual average emissions (instead of simulated) would likely be even smaller – suggesting a heuristic based on average emissions could greatly undercount the benefits of DERs.

Figure 6 – Comparing E-Value Based on Average and Marginal Emissions



Like Figure 4, regions are defined according to the general geography of NERC regions and the diagonal line represents equality between the two values.

E-Value and Public Policy

DERs are becoming a fixture in the modern grid and policymakers have a variety of reasons for intervening to support DER deployment. First, policies that traditionally guide the electricity market are not designed to govern decentralized resources and so do not consider locational factors. Second, many longstanding policies overlook external costs that come with electricity production from thermal electricity generators, and so do nothing to correct a serious market failure which DERs can address. Third, newer policies to reduce greenhouse gas emissions can be complemented by – or even heavily rely on – greater deployment of DERs.

The E-Value can and should have significant bearing on how DER-focused policies are shaped. This section explores both the general importance of using the E-Value in DER policy and the implications of this report's specific findings.

The Importance of E-Value for DER Policy

Several states are adopting policies that support DER deployment as part of their emissions-reduction goals. Considering the E-Value for different DER technologies can help determine if DER-bolstering policies can achieve the desired pollution reductions. The E-Value can also highlight important policy impacts, such as whether DERs are providing the maximum possible social benefits or which type of DER offers the most benefits in a certain location. In practice, the E-Value can be applied anytime a DER reduces demand from the bulk-power system. The environmental and public health benefits the DER provides are applied in proportion to the number of MWh of bulk-power avoided. This information can ensure that the right type of DER is being deployed at the right time and location by sending the proper price signals.

The E-Value can help policymakers optimize policies that target specific DER technologies or programs, like distributed solar generation, battery storage, and energy efficiency. For example, a solar panel generating 1 MW of electricity reduces the demand for bulk-power electricity and so provides society the benefit of reduced air pollution, represented by the hourly E-Value at that point in time. So, if solar panels generate electricity when and where E-Value is highest, they can provide greater benefits to society. This is why establishing a tax credit offsetting installation costs of rooftop solar will benefit society more if it supports the deployment of solar that displaces an oil plant situated in a low-income community. Accounting for the E-Value when designing such a tax credit would accomplish exactly that.

DERs Policies Can Directly Incorporate the E-Value of DERs

The E-Value can not only inform DER investment, it can also be directly incorporated into policy design. For example, most rooftop solar is compensated a flat rate based on the retail rate of electricity through **net energy metering** policies. As an alternative, regulators can use a **value-stacking approach that is based on DERs' various attributes or services**. A value-stacking approach would compensate DERs for their avoided energy and their E-Value. This is more economically efficient than net energy metering because it accounts for all of the values DERs bring to the power grid.[29]

Similarly, if decisionmakers know the E-Value of charging (or discharging) an energy storage system at any given point in time, they can use this information to determine the values to bill (or compensate) energy storage assets in order to maximize their benefits. A battery discharging 1 MW of electricity generates environmental benefits that are best captured by the E-Value for that hour. If energy storage owners discharge their batteries when the E-Value is high and charge their batteries when the E-value is low, they can provide social benefits by decreasing environmental damages of electricity production.[30] Because energy storage technologies can more easily respond to price signals than most other DERs, it is crucial they are compensated and charged the E-Value accordingly.

Demand response is another similar case: Demand response that conserves 1 MW of electricity not only avoids the cost of electricity production but also provides society with the benefits of avoided pollution, an economic benefit equal to the E-Value for that hour. But, without the E-Value, customers might reduce their demand only when retail electricity prices are high, rather than when the sum of the E-Value and electricity prices are high. The latter approach produces greater social benefits.

The E-Value can also help demonstrate in what parts of the country implementing different energy efficiency policies can create the most benefit. Energy efficiency measures, like replacing incandescent lightbulbs with LEDs, provide greater social benefits when they are deployed in places that rely on electricity from more pollution-intensive electricity generators, like parts of the Midwest, or places with a higher nighttime E-Value.[31] Similarly, locations with a higher E-Value during summer's midday should potentially deploy more efficient air-conditioning before investing in energy efficiency lighting. Knowing the E-Value can also aid federal programs – like the Department of Energy's Weatherization Assistance Program – so that they direct energy efficiency investments towards regions with a higher E-Value on average.

The E-Value should be used in DER policy and can be applied across DER technologies. The next part of this section goes into greater detail about the specific policy implications of the subregional E-Values in this report's findings.

Policy Implications of Results

The Relative Magnitude of E-Value Can Tip the Scales in Favor of DERs

When decisionmakers know that E-Values can be relatively large compared to costs in the electric system, they are better equipped to set welfare-maximizing policies. The average E-Value of DERs across this report's findings was $57/MWh (with a median of $54/MWh). This value is nearly twice the average cost of electricity simulated by the reduced-order dispatch model ($27/MWh), and greater than the national average wholesale price of electricity in 2018 ($44/MWh).[32] The fact that the average E-Value exceeds production costs and wholesale electricity prices should clearly signal to policymakers and other stakeholders that DERs can be a worthwhile investment on their environmental merits alone. In states where DERs are being targeted by policies to reduce greenhouse gas emissions, this makes the case very clear cut. But even in states where investments in DERs are primarily weighed based on private costs and benefits, showing that the E-Value *can* exceed private costs creates a strong signal about optimal resource allocation.

E-Value Can Indicate Where Different DER Investments Are Most Effective

When E-Value is not a deciding factor in setting policy or making DER investments, these policies inevitably exclude considerations of location and scale. This is because absent a DER policy to account for each resource's E-Value, private

investment and use of DERs is governed largely by their private benefit – avoided production costs, without regard for location. This suggests DER policies based only on the private production costs are ignoring most of the social value of DERs, and so will likely deploy DERs ineffectively. For example, DER investment based only on the cost of electricity would occur largely in the Northeast, whereas the environmental and public health benefits of DERs suggest they should be a higher priority in parts of the Midwest and Mid-Atlantic.

State policymakers can look at the results presented in this report and see if and when their state has a high E-Value. Though an E-Value of any magnitude should be accounted for in DER policy, states with high E-Values may choose to prioritize DER investment because the benefits can be so large.

General Time-of-Day Policies May Not Be Effective for DERs

Designing policies according to general patterns is common practice for setting retail electricity rates. For example, utilities, or policymakers, sometimes identify a "peak demand" period during the day and set rates higher during that period to disincentivize electricity use. These rates make sense in the context of electricity production. For example, periods of "peak demand" in the summer are generally associated with the highest production costs. If E-Values were to follow a similar daily pattern, smart policy design could compensate DERs for the hours of the day in which they generate the most benefits to society. For example, if the E-Value was consistently greatest in the early morning, retail rates encouraging the use of DERs in the morning would generate more benefits to society than a policy that ignores daily patterns in the E-Value.

However, the results show that even though the hourly E-Value can vary significantly throughout the day - as the marginal electricity generator, marginal emissions, and associated health benefits change – there is no general and consistent daily pattern of E-Values across all subregions. This means that even granular E-Value compensation policies that try to capture hourly variation could be ineffective unless they are based on real-time marginal emissions factors. Accordingly, policymakers that wish to accurately compensate DERs for the E-Value must conduct modeling specific to the location and DER technology under consideration. Blanket policies based on conventional wisdom might incorrectly compensate distributed energy resources the most when they are actually generating the least amount of environmental value.

DER Policies Should Monetize Avoided Climate Damages and Public Health Benefits

Finally, policymakers should ensure that they overlook neither the climate nor the public health aspects of the E-Value. The effects of greenhouse gases and local pollutants vary geographically, so although the greenhouse gas component of the E-Value is significant in some regions, it is outweighed by the public health component in others. Figure 5 shows that damages from CO_2 make up about half of the total E-Value on average. Internalizing the negative public health externalities from local air pollutants is necessary for properly valuing DERs, but it is not sufficient: excluding the negative environmental (i.e. climate) externalities would lead to a serious underestimate of the E-Value in some places. In addition, climate damages themselves reflect public health consequences that are not attributable to local air pollutants, like increased mortality from extreme weather events, so the picture of public health effects is not complete without them.

Luckily, there is a readily available tool that policymakers can use to monetize the benefits from avoiding a marginal ton of CO_2 emissions, the IWG's Social Cost of Carbon.[33] The Social Cost of Carbon should be used anytime a decision will affect greenhouse gas emissions, as is the case with many policies that affect DER deployment. In fact, because

DERs are often targeted by greenhouse gas reduction policies, using the Social Cost of Carbon in the E-Value makes the effectiveness of these policies more apparent.

In densely populated urban areas, it's possible the public health benefits of avoided local air pollution exceed the climate benefits of avoided greenhouse gas emissions. This is because the harms of local air pollutants, like particulate matter, increase in proportion to the number of people exposed to pollution. Monetizing the benefits of avoided greenhouse gas emissions is necessary for the reasons outlined above, but it is also not sufficient. DER policies must monetize both sets of benefits to ensure DERs are deployed at a scale that is economically efficient and provide the greatest possible benefit to society.

Conclusion

Policymakers looking to achieve efficient deployment of DERs in their jurisdiction must accurately compensate DERs for all of their benefits, including the E-Value. If they fail to do so, DERs are likely to be misemployed, meaning society misses out on important and cost-effective benefits of reduced air pollution. In practice, quantifying a DER's E-Value is difficult to do without specifically modeling or observing which electricity generators are displaced by DERs in any given hour and using a public-health model or other tool to monetize the benefits of avoided air pollution.

This report presents the average E-Value of DERs for 19 subregions in the United States using historical data from 2018. The results show that the E-Values are large relative to the benefits of avoided production costs, the public health benefits alone, and what hourly average pollution emissions would suggest. The most important factor in determining the E-Value of DERs is location. DERs in the Great Lakes and Mid-Atlantic region can provide benefits almost twice what they can in California. Finally, there is no general pattern of the E-Value of DERs throughout the day, suggesting policies that try to capture hour-to-hour benefits of DERs require real-time data on pollution from the electric power sector or modeling results specific to the region under consideration.

Although informative, these results paint only part of the picture. The E-Value presented in the report does not monetize the benefits of avoided primary PM2.5 pollution due to DERs. Incorporating these benefits of DERs can only increase the E-Value, possibly by a significant amount. In addition, modeling limitations prevent a more thorough analysis that considers how DERs might displace non-fossil resources like nuclear electricity generators or hydroelectric storage. Finally, as the grid transitions towards more utility-scale renewable generation and less pollution-intensive thermal resources, the E-Value of DERs is likely to change considerably. This suggests there are real benefits to updating E-Values used in policy making on a regular basis.

Appendix A: Reduced-Order Dispatch Model

This report uses an open-source reduced-order dispatch model to quantify the historical hourly marginal emission of electricity generation in a pre-specified region. This model uses publicly available data on historical fuel costs and electricity production to simulate which combination of electricity generators can generate the same electricity as was historically produced, for every hour, while minimizing production costs and respecting historical downtime requirements of thermal generators.

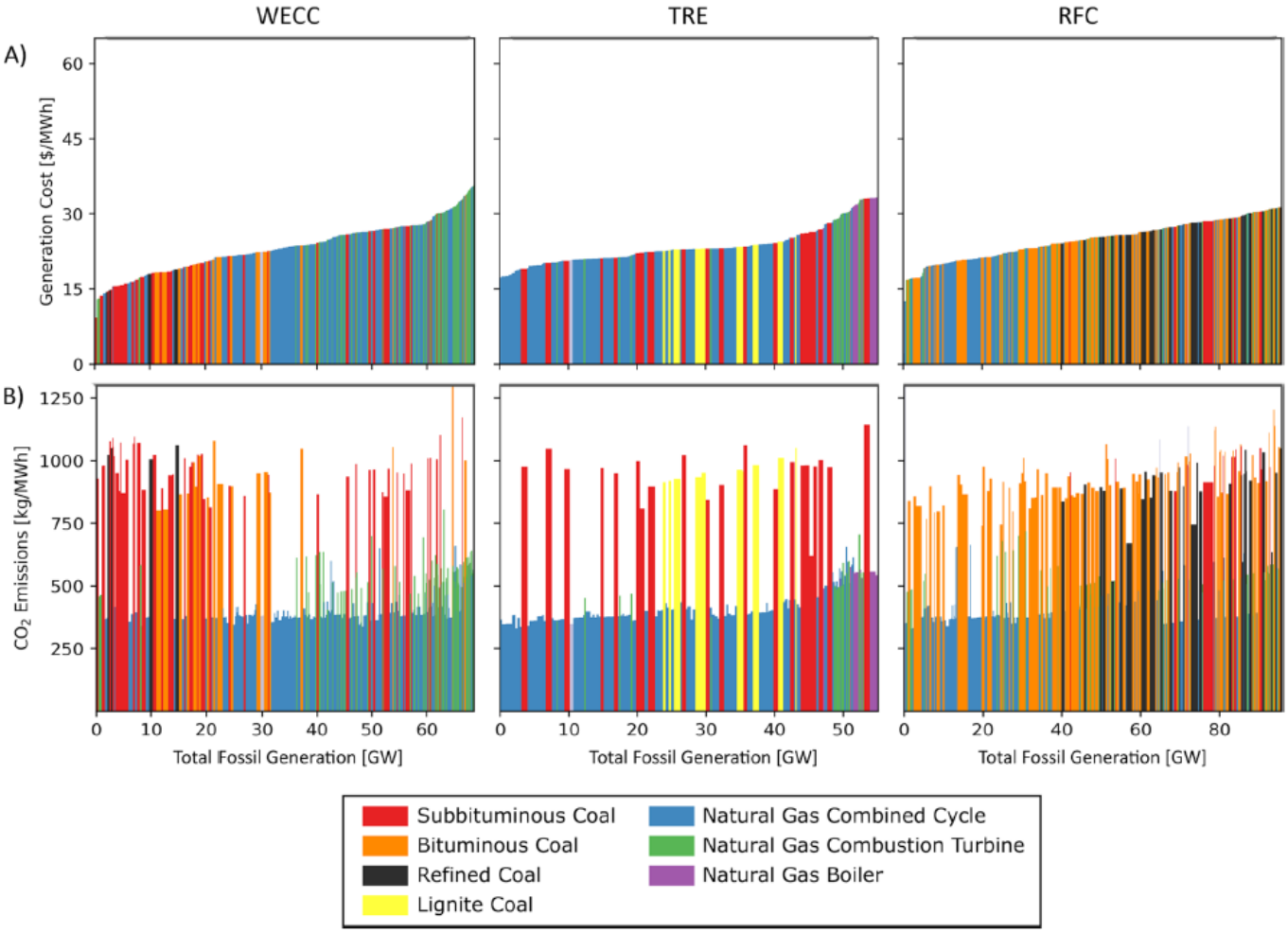
The model accomplishes this by constructing a "bid-stack" for every week on the sample year which ranks large fossil-fuel electricity generators according to their cost to produce electricity.[34] A separate set of bid-stacks are created for each subregion. This bid-stack varies week-to-week according to publicly available fuel prices and observed plant-specific efficiency rates. An electricity generator's costs includes fuel costs specific to the power plant when available, as well as general variable operations and maintenance costs based on the fuel type and power plant age. Figure 7 presents example "bid-stacks" for three regions for the first week in August of 2017 from Deetjen & Azevedo (2019). This figure also shows the weekly marginal emissions of CO_2 (per MWh) for each electricity generator in the bid-stack.

For every hour in the sample, the model determines which combination of resources could have produced the same quantity of electricity as historically produced by large fossil-fuel electricity generators, but at the lowest possible price by finding where the bid-stack intersects with the demand for electricity generated by large fossil-fuel electricity generators for that hour. In doing this, this model respects weekly limits on minimum and maximum output for each electricity generator, as well as required down time of larger fossil-fuel electricity generators. The last generator called upon to balance supply and demand for that hour is the marginal electricity generator, and the marginal emissions for that hour are based on the marginal emissions of that electricity generator.

Although the model is simple, it does a good job reconstructing the marginal electricity generator using historical data. Because it is a simulation, it allows for nuanced hourly emissions that might not be possible with regression-based estimates. In addition, it allows for counterfactual modeling exercises that can assess how pollution emissions would change if a carbon price were implemented in the electric power sector. The model could be improved upon, however, by incorporating non-fossil resources, transmission constraints, and the startup costs of electricity generators.

The Python code to run the reduced order dispatch model is publicly available.[35] For this report the code was modified to allow for more granular market definitions based on eGRID regions, as shown in Figure 1, and updated to more recent data from 2018. All the data required to run the model are publicly available, so the model can be updated in future years to reflect the changing electric power sector.

Figure 7 – Illustration of a Bid-stack and the Corresponding Marginal Emissions



The first figure from Deetjen & Azevedo (2019), supra note 1, showing example bid-stacks and the marginal emissions of each electricity generator in the bid-stack. Reprinted with permission from Reduced-Order Dispatch Model for Simulating Marginal Emissions Factors for the United States Power Sector, Thomas A. Deetjen and Inês L. Azevedo, Environmental Science & Technology 2019 53 (17), 10506-10513, DOI: 10.1021/acs.est.9b02500. Copyright 2019 American Chemical Society. Merit order – ascending in order of operation cost – for the first week of August for three NERC regions showing (A) generation cost and (B) CO_2 emissions rates. Note that (A) and (B) have the same ordering of power plants.

Appendix B: Environmental Value Reference Table

Table 1 – Average E-Value of DERs for 19 Subregions by Season and Time-of-Day

eGRID Region	Spring				Summer				Fall				Winter			
	Morning	Midday	Evening	Night	Morning	Midday	Evening	Night	Morning	Midday	Evening	Night	Morning	Midday	Evening	Night
AZNM	42.23	38.37	35.63	39.23	46.90	44.42	42.90	47.82	41.47	43.87	40.06	36.88	42.45	43.61	42.37	39.09
CAMX	32.00	30.32	26.05	27.26	25.69	27.20	26.82	25.92	22.91	22.34	24.04	22.57	28.00	31.70	25.52	26.62
ERCT	52.62	41.21	43.25	58.80	64.31	42.27	48.90	67.65	54.09	38.63	43.90	68.60	57.38	50.97	52.24	62.53
FRCC	46.25	39.96	43.80	46.74	55.59	46.03	49.09	52.91	47.75	33.21	36.20	47.61	43.85	31.33	34.20	47.04
MROE	70.74	67.79	70.60	66.08	68.24	65.44	69.40	64.93	59.99	60.35	60.98	57.45	66.25	63.74	68.59	64.77
MROW	74.92	74.39	78.24	74.67	73.33	71.83	72.95	70.23	76.03	77.25	78.13	73.86	74.94	71.23	75.52	75.26
NPCC*	57.10	39.55	45.25	60.38	69.06	59.21	61.52	72.05	66.63	47.06	54.83	66.47	63.80	53.94	54.71	63.14
NWPP	51.84	45.89	46.92	53.83	62.91	60.52	61.39	61.94	57.47	57.18	55.63	55.50	54.64	53.65	54.69	51.63
RFCE	66.70	41.41	46.86	77.81	69.36	32.53	41.29	71.94	48.95	34.72	37.30	56.17	60.46	58.76	54.83	80.76
RFCM	102.21	89.24	92.10	111.74	102.85	84.36	82.85	106.02	106.31	93.68	100.53	119.20	76.22	71.73	73.48	86.71
RFCW	80.31	79.88	82.16	76.87	82.34	78.40	80.72	86.78	79.12	78.20	79.41	82.32	77.31	73.41	77.66	76.83
RMPA	45.42	43.92	44.44	47.97	45.68	38.33	41.95	47.04	44.98	42.47	40.10	49.90	48.60	47.81	47.23	52.51
SPNO	56.62	53.13	53.65	57.07	56.96	47.76	50.89	58.48	59.29	55.14	57.05	58.45	59.55	55.49	58.06	61.74
SPSO	64.69	48.88	53.66	71.25	66.88	50.19	53.06	70.59	66.44	61.50	62.70	72.17	56.04	53.85	56.36	66.03
SRMV	53.15	38.39	41.98	69.20	66.78	44.94	51.74	73.21	30.37	28.30	26.11	35.75	52.17	50.34	50.94	54.14
SRMW	86.45	81.04	85.89	83.91	80.42	66.95	73.57	78.94	95.84	97.73	98.14	90.90	82.92	82.77	85.90	91.25
SRSO	37.57	42.83	42.20	35.89	48.63	51.97	52.08	44.56	47.61	47.32	49.03	47.61	36.22	33.23	34.00	33.97
SRTV	60.17	62.32	62.13	53.48	62.20	66.04	66.77	59.86	54.97	54.59	55.42	61.00	53.96	51.71	51.25	57.73
SRVC	42.57	45.42	49.40	40.97	39.13	50.91	51.30	37.00	53.03	51.21	51.17	50.77	41.57	40.64	41.59	41.78

*E-Value of DERs ($/MWh) for 19 subregions based on eGRID regions as defined in Figure 1. The cells in this table are shaded in proportion to E-Value for each time period and subregion. *Note "NPCC" represents an aggregation of the NYLI, NEWE, NYUP, and NYCW eGRID regions in the Northeast as shown in Figure 1.*

Endnote

1 *See* Thomas A. Deetjen & Inês L. Azevedo. *Reduced-Order Dispatch Model for Simulating Marginal Emissions Factors for the United States Power Sector*, 53 Envtl Sci. & Tech. 10506 (2019). Appendix A of this report describes the application of this model in detail.

2 *E.g.,* New Jersey's Clean Energy Act of 2018 requires that "[t]he methodology, assumptions, and data used to perform the benefit-to-cost analysis [for energy efficiency programs] shall be based upon publicly available sources." N.J.S.A. 48:3-87.9(d)(2)

3 Examples include distributed electricity generators (i.e. modular solar panels or other small-scale electricity generators), energy storage (e.g. batteries that charge and discharge electricity onsite or with the grid), demand response practices (i.e. a system that can use battery storage, 'smart' residential or commercial appliances, and other technologies to reduce demand for electricity when called upon), and energy efficiency investments (i.e. efficient appliances, weatherization, and other technologies that reduce energy consumption onsite).

4 Some DERs, like small diesel generators, do generate pollution. For others, the associated pollution is uncertain. For example, distributed battery storage can contribute to more pollution if the electricity generator charging the battery produces more pollution than the electricity generator the battery displaces when it is discharged. *See* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas Emissions*, 42 Harv. Env'tl L. Rev. 139 (2018). The E-Values in this report are still beneficial to policymakers so long as DERs are accountable for the pollution they induce (via electricity generation or otherwise).

5 *See* Mass. Inst. of Tech., The Future of the Electric Grid 110 (2011).

6 For example, without accounting for the E-Value of DERs it is possible that rooftop solar could end up displacing electricity generated from wind turbines, and areas with serious air pollution might not invest in energy efficiency or demand response programs at the scale that is best for society.

7 *See* Jeffrey Shrader et al., Inst. for Pol'y Integrity, Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources (2018).

8 Marginal emissions are measured as a rate, in mass of pollution (e.g. tons) per unit change in electricity demand (e.g. megawatt-hours (MWh)).

9 *See* Shrader et al., *supra* note 7 at 19-21; *see also* Richard L. Revesz & Jack Lienke, Struggling for Air: Power Plants and the "War on Coal" 11 (2016).

10 *See* Shrader et al., *supra* note 7, at 12-13.

11 For other available tools to determine marginal emissions, *see* Shrader et al., *supra* note 7 at 14, Tbl. 2: Databases for Calculating Emission Rates.

12 *See* Shrader et al., *supra* note 7, at 22-25.

13 If the DER itself produces any emissions, the effects of those must be accounted for as well.

14 *See* Deetjen & Azevedo, *supra* note 1. In this setting, large fossil-fuel electricity generators are greater than 25 MW in capacity and regularly report to EPA's CEMS.

15 In this report, the sample period is the year 2018. An electricity generator's cost to produce electricity includes marginal fuel costs as well as variable operations and maintenance costs.

16 Ignoring non-fossil resources will not bias the marginal emissions estimates so long as non-fossil resources are not marginal. This is typically the case for nuclear and renewable resources but not for load-following hydro resources.

17 eGRID regions are defined by the EPA as partitions of more aggregate North American Electric Reliability Corporation (NERC) regions. Although there might be several market operators in a single eGRID region (e.g., NWPP) and perhaps a single market operator in multiple eGRID regions (both RFCW and RFCE are a part of the PJM RTO), eGRID regions are a fair approximation to granular market operators and transmission connections within the United States.

18 *See* Jinhyok Heo, Peter J. Adams, & H. Gao, *Reduced-Form Modeling of Public Health Impacts of Inorganic PM2.5 and Precursor Emissions*, 137 Atmospheric Env't 80 (2016); *see also* Richard Revesz et al., *Best Cost Estimate of Greenhouse Gases*, 357 Sci. 655, 655 (2017).

19 Kimberly M. Castle & Richard L. Revesz, *Environmental Standards, Thresholds, and the Next Battleground of Climate Change Regulations*, 103 Minn. L. Rev. 1349, 1353 (2019).

20 *See* U.S. Envtl. Prot. Agency, Regulatory Impact Analysis for the Clean Power Plan Final Rule ES-6 n. 2 (2015), https://www3.epa.gov/ttn/ecas/docs/ria/utilities_ria_final-clean-power-plan-existing-units_2015-08.pdf [hereinafter "CPP RIA"] (noting that benefits from directly emitted PM2.5 accounted for approximately 10% of total monetized health co-benefits).

21 Castle & Revesz, *supra* note 19, at 1401.

22 For example, the EPA National Emission Inventory report provides annual estimates of particulate matter pollution from electricity generators. And the EPA AVoided Emissions and geneRation Tool (AVERT) directly models particulate matter pollution from electricity generation in each state or county.

23 CPP RIA, *supra* note 20, at 4-23.

24 Alternatively, policymakers could compensate a DER more if it reduced the demand for bulk-power electricity during the time of day when the E-Value is largest on average.

25 For example, Mid-Atlantic represents the RFC NERC region that consists largely of the PJM RTO.

26 *See* U.S. Energy Info. Admin.. Wholesale Electricity and Natural Gas Market Data, https://www.eia.gov/electricity/wholesale/, (last visited on Aug. 28, 2020) (showing average hourly price across all nodes in 2018 was $44/MWh).

27 *See* U.S. Envtl Prot. Agency, Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report 25 (2019). https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf. (showing the average low estimate of 1.7 cents per kilowatt hour ($17/MWh) and average high estimate of 4 cents per kilowatt hour ($40/MWh) for the public health benefits of DERs.) For comparison, the hourly marginal emissions of NO_x and SO2 from the reduced-order dispatch model described in this report correspond to public health benefits (not including GHG emissions) of $17/MWh on average across all regions, with the highest public health benefits in Michigan ($46/MWh on average).

28 *See* Justin Gundlach & Burcin Unel, Inst. for Pol'y Integrity, Getting the Value of Distributed Resources Right: Using a Societal Value Stack 11 (Dec. 2019), https://policyintegrity.org/files/publications/Getting_the_Value_of_Distributed_Energy_Resources_Right.pdf. (showing a more complete characterization of DERs' potential benefits.).

29 For more details on the value stacking approach to compensating DERs *see* Gundlach & Unel, *supra* note 28.

30 *See* Revesz & Unel, *supra* note 4, at 163.

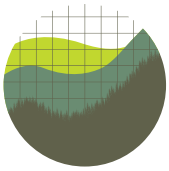
31 *See* Natalie Mims, Tom Eckman & Charles Goldman, Time-Varying Value of Electric Energy Efficiency at ix fig. ES-1, 32–36 (2017) (quantifying value of carbon dioxide emissions reduction available from different forms of energy efficiency across different regions).

32 *See* U.S. Energy Info. Admin., *supra* note 26.

33 *See* Iliana Paul et al., Inst. for Pol'y Integrity, The Social Cost of Greenhouse Gases and State Policy: A Frequently Asked Questioned Guide (2017), https://policyintegrity.org/publications/detail/social-cost-of-ghgs-and-state-policy.

34 In this setting, large fossil-fuel electricity generators are greater than 25 MW in capacity and regularly report to EPA's CEMS.

35 The entirety of the Python code is available here: https://github.com/tdeetjen/simple_dispatch.



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