BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19M-0061EG

IN THE MATTER OF THE IMPLEMENTATION OF § 40-3-117, C.R.S. REGARDING AN INVESTIGATION INTO PERFORMANCE-BASED RATEMAKING.

COMMENTS OF THE INSTITUTE FOR POLICY INTEGRITY

The Institute for Policy Integrity at New York University School of Law (Policy Integrity)[1] submits these comments in the Public Utilities Commission of the State of Colorado (Commission) proceeding to investigate performance-based ratemaking (PBR), and more specifically in response to the May 6, 2020 Interim Decision of Hearing Commissioner John Gavin Requesting Comments on Distributed Energy Resources and Carbon Emissions.[2]

Policy Integrity is a nonpartisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and environmental policy. Policy Integrity's staff, including its Faculty Director and Energy Policy Director, have published several articles and reports on valuing distributed energy resources (DERs), with a particular focus on incorporating emissions impacts (or their avoidance) into the policies that determine DER valuation and compensation.[3] Policy Integrity

[1] No part of these comments purports to present the views of New York University.

[2] Decision No. R20-0343-I (May 6, 2020).

[3] *See, e.g.*, Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Modernizing Rate Design*, 44 HARV. ENVTL. L. REV. 44 (2020); Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 HARV. ENVTL. L. REV. 44 (2017); JUSTIN GUNDLACH & BURCIN UNEL, INST. FOR POL'Y INTEGRITY, GETTING THE VALUE OF DISTRIBUTED ENERGY RESOURCES RIGHT: USING A SOCIETAL VALUE STACK (2019), https://policyintegrity.org/files/publications/Value_of_DER_Report.pdf; JEFFREY SHRADER, BURCIN UNEL & AVI ZEVIN, 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/files/publications/Valuing_Pollution_Reductions.pdf.

has also participated for years in proceedings focused on this subject in multiple states,[4] and remains actively engaged in efforts to improve the approaches taken by various state regulators and energy agencies to the valuation and compensation of DERs for, among other things, the emissions they potentially avoid.[5] We have also submitted comments to the Commission on other topics, such as how to interpret and apply the Social Cost of Greenhouse Gases.[6]

1. Background

CRS § 40-3-117, the statutory provision that prompted this proceeding, calls on the Commission to "review performance-based regulation (PBR) and performance-based incentive mechanisms (PIMs)," and by November 30, 2020 to issue a report to the legislature that examines:

> financial performance-based incentives and performance-based metric tracking to identify mechanisms for aligning utility operations, expenditures, and investments with various public benefit goals, including safety, reliability, cost efficiency, emissions reductions, and expansion of distributed energy resources.

Decision No. C19-0969, issued in December 2019, organized this proceeding into three rounds of comments and workshops, to be completed by July 2020 and to inform a report to the

[4] *See, e.g.*, Policy Integrity Comments (three rounds), Connecticut Dep't of Energy & Envtl. Pol'y & Pub. Utils. Reg'y Auth'y Joint Proceeding on the Value of Distributed Energy Resources, Docket No. 19-06-29 (Aug. 21, 2019; Sept. 18, 2019; Feb. 14, 2020); Policy Integrity, Environmental Value of Distributed Energy Resources in New York State, presentation to Value of Distributed Energy Resources Value Stack Working Group (July 11, 2018); Policy Integrity, Comments on NARUC Manual on Distributed Energy Resources Compensation (Sept. 2, 2016); Joint Comments of EDF and Policy Integrity, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology (Apr. 18, 2016).

[5] *See, e.g.*, Justin Gundlach, Arkansas PSC Docket 16-028-U, DER Workshop Presentation: "Getting the Value of DERs Right," May 8, 2020, *available at* http://www.apscservices.info/DER/upcoming/; Comments of Policy Integrity on Proposed Clean Peak Energy Portfolio Standard, Mass. Dep't of Energy Resources (Oct. 30, 2019), https://policyintegrity.org/documents/Policy_Integrity_WattTime_Comments_on_Clean_Peak_Standard.pdf.

[6] *See, e.g.*, Comments from the Institute for Policy Integrity on the Interim Decision Proposing Additional Rule Revisions on the Social Cost of Greenhouse Gases, Colo. Pub. Util. Comm'n Proceeding No. 19R-0096E (Apr. 10, 2020).

legislature.[7] According to the Commission's decision, this round—the third of three—is meant to consider "emissions reductions and expansion of distributed energy resources."[8]

Although none of the questions posed in Decision No. R-0343-I asks about the value of avoided emissions, the Decision makes clear that this third round of comments is meant to elicit information and insights about that as well as the value of avoiding other costs, like upgrades to transmission and distribution facilities. As such, Policy Integrity's comments address Question 7(d), "What metrics can be used to measure the ability of DERs to reduce overall system costs by avoiding or deferring transmission and distribution system upgrades?", and also discuss how to measure DERs' ability to avoid emissions as well. The points that follow are drawn in large part from our December 2019 report, *Getting the Value of Distributed Energy Resources Right: Using a Societal Value Stack*,[9] and our March 2018 report, *Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources*.[10]

2. DERs' Potential Benefits and Costs

The value available from a given DER is the net benefit it provides relative to the costs that would otherwise be incurred to perform comparable functions. As described briefly below, measuring that value requires specifying an analytical perspective; identifying, quantifying, and comparing benefits and costs; and ensuring that the tally of benefits and costs accurately reflects how the DER performs in its particular circumstances.

---

[7] That Decision notes that "[t]he sole purpose of this proceeding is to address the requirements of § 40-3-117, C. R. S. and submit the required report to the Senate Transportation and Energy Committee and the House of Representatives Energy and Environment Committee." Decision No. C19-0969, at 2.

[8] *Id.* at 5; *see also* Decision No. R-0343-I, at 2 (repeating phrase).

[9] GUNDLACH & UNEL, *supra* note 3.

[10] SHRADER, UNEL & ZEVIN, *supra* note 3.

Analytical Perspective. Because the value of resources—distributed or centralized—that provide electricity services accrues differently to different groups of stakeholders, estimating that value requires adopting the perspective of one or more of those groups. 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. The Commission has recognized the relevance of perspective to energy resource valuation, authorizing several applications of a Modified Total Resource Cost test, which takes the combined perspective of utilities and program participants, to specify a benefit-cost ratio for various programs and plans.[11]

Benefits and costs. The tables below list benefits and costs related to installing and using DERs.[12] We include "potential" in the description of Table 1 because a DER's ability to perform a given function more cost-effectively than available alternatives depends not only on its inherent features but also on the physical and regulatory circumstances in which it operates. DERs' costs, by contrast, are generally less dependent on circumstance, though regulatory requirements can certainly lead to higher or lower costs to install and/or operate a DER.

---

[11] *See, e.g.*, Xcel Energy/Public Service Company of Colorado, 2019/2020 Demand-Side Management Plan Electric and Natural Gas 10 n.9 (2019), https://drive.google.com/file/d/1x-oZSIoXWRQ5P0_e6o2DVUyF4oghji1p/view?usp=sharing; *see also* Colo. Rev. Stat. § 40-1-102(5)(a) (defining "cost-effective" with respect to demand-side management programs).

[12] These tables appear in GUNDLACH & UNEL, *supra* note 3, at 11–12.

Table 1. 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

Table 2. 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*

Importance of timing and location. Measuring DERs' ability to avoid costs and thereby add value requires taking temporal and locational factors into account. The value of a given DER is only partly a reflection of that DER's functional capabilities and capacity—it is substantially also a reflection of temporal and locational features of the circumstance in which that DER is installed, and hence what usages of central grid resources that DER can avoid. And so, the magnitude of costs potentially avoided by the same solar+storage installation will vary depending on whether, among other things:

- interconnecting that installation would create a risk of exceeding local distribution system capacity constraints, alleviate distribution system congestion, or a combination of the two;
- interconnecting that installation would alleviate transmission system congestion;
- use of that installation would tend to reduce generation from resources that are relatively more expensive to operate; and/or
- use of that installation would tend to reduce generation from polluting resources.

3. Actually Measuring DERs' Value: Analytic Steps and Metrics

Translating the concepts above into quantified and then monetized values involves performing a series of analytic steps on data that reflect particular metrics.

Steps. Valuing DERs by comparing the benefits and costs tabulated above involves the following steps:

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

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

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

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

(5) Determine the appropriate frequency of and process for updates.

As explained more fully in our 2018 and 2019 reports, these steps apply somewhat differently to different categories of avoided cost.[13] For instance, the grid-based generation potentially displaced by operation of a DER can change from hour to hour, with peak hours being more valuable to avoid than off-peak. The value of avoiding local air pollutants from grid-based generation changes from hour to hour as well, but also depends, unlike generation, on where the

[13] *Id.* at 16–22; SHRADER, UNEL & ZEVIN, *supra* note 3 at 22–25.

pollutants are emitted—emissions from a remote facility are likely to cause less damage to public health than from a facility upwind of a large population center.

Metrics. The May 6, 2020 Interim Decision to which these comments respond seeks input on metrics useful for estimating the value of avoided transmission and distribution system upgrades. We list several in sections 3.1 and 3.2 below, as well as metrics useful for valuing avoided pollution costs in section 3.3.[14] The items below are not "plug-and-play" because such metrics often grow out of the idiosyncratic features of their home jurisdiction, and so are likely not transferrable to Colorado without adjustment. Furthermore, they vary in how accurately they reflect the costs that DERs can potentially avoid by being installed and operated in a particular place and at particular times. Nonetheless, we include them here because they provide examples of distinct approaches taken by other jurisdictions that Colorado could imitate or improve upon.

3.1. Transmission system

The transmission system costs that DERs can potentially defer or wholly avoid include congestion (that is, capacity constraints that cause load to be served by more expensive generation), line losses, and upgrades or capacity additions. The following descriptions reflect different approaches taken to translating those costs into DER compensation by California, New York, and Minnesota.

California. California ratepayers' bills include a Transmission Access Charge (TAC), which reflects the Federal Energy Regulatory Commission-approved revenue requirement of California's three Transmission Owners.[15] DER advocates have said in recent proceedings before the California Public Service Commission that the TAC serves "as a simplified proxy for the

[14] We do not describe metrics for generation, generation capacity, and resilience here; metrics for each of these are discussed in our 2019 report.

[15] Cal. Pub. Utils. Comm'n, *Transmission Rates*, https://www.cpuc.ca.gov/general.aspx?id=4425 (accessed May 28, 2020).

avoided transmission costs associated with DER deployment," and—even though TAC leaves out the transmission costs recovered from customers that pay a demand charge—broadly support its use for that purpose while a more accurate calculation is developed.[16] Integration of the TAC and transmission system line losses are both captured in the Avoided Cost Calculator developed and periodically updated by E3 for use by California utilities, regulators, and other stakeholders.[17] (Notably, the TAC is not the only metric employed by California utilities to calculate avoided transmission system costs.)

New York. Different metrics are used to estimate the transmission capital costs and operational costs that DERs might avoid in New York. The state's retail utilities have recently updated the methodologies they employ in the Marginal Cost of Service (MCOS) studies they develop to identify, among other things, capital costs that DERs might avoid, including those incurred through both transmission and distribution system investments.[18] At present, New York's retail utilities develop their MCOS studies somewhat differently.[19] Central Hudson, for instance, has opted to use a probabilistic assessment of load growth on each of its feeders to determine where, if anywhere, transmission system upgrades were expected—and thus could

[16] *See* Reply Comments of the Clean Coalition Regarding Proposed Decision on 2020 Policy Updates to the Avoided Cost Calculator, RM 14-10-003, at 4 (Apr. 7, 2020), https://perma.cc/N6FC-9PSW (arguing for refinement of calculation to improve on TAC's approximate value).

[17] To access the 2020 version of the Avoided Cost Model as well a explanatory materials, visit https://www.ethree.com/public_proceedings/distributed-energy-resources-der-avoided-cost-proceedings/ and click on the "2020 Avoided Cost Model and Documentation" link. The Avoided Cost Calculator reflects design parameters articulated by the California Energy Division in 2019 based in part on stakeholder input. *See* CALIFORNIA ENERGY DIVISION WHITE PAPER ON AVOIDED COST AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES (2019), https://perma.cc/4E59-USD9.

[18] *See* Joint Utilities of New York, *Marginal Cost of Service ("MCOS") Studies* 4 (June 28, 2019), https://perma.cc/6VGW-ZTVT (noting different uses of MCOS studies).

[19] For a critical survey of each utility's approach, see Preliminary Comments of the Clean Energy Parties to New York State Department of Public Service on Utility Marginal Cost of Service Studies, N.Y. Pub. Serv. Comm'n Case 19-E-0283 (Nov. 29, 2019), https://perma.cc/58ZF-YTP2.

potentially be avoided by DER deployment.[20] As for the operating costs of transmission, the New York Independent System Operator (NYISO)'s Location Based Marginal Price (LBMP) for wholesale energy includes a factor reflecting the costs of transmission system line losses and congestion.[21] NYISO also conducts routine projections of those costs in its biannual Congestion Assessment and Resource Integration Study,[22] which retail utilities use to estimate the value of Non-Wires Alternative (NWA) projects and energy efficiency investments.[23]

Minnesota. The Value of Solar rubric developed by Minnesota's Commerce Department to value costs avoided by community-scale and (potentially) rooftop solar installations includes an estimate of avoided transmission capacity costs as well as line losses.[24] The capacity cost estimate is based on data reported by the Midwest Independent System Operator (MISO) regarding transmission system adequacy relative to load. It identifies transmission system upgrades or other fixed costs that cannot be avoided except by the installation of distributed solar that would reduce coincident local load peaks.[25]

---

[20] Demand Side Analytics (for Central Hudson Gas & Electric Corp.), 2018 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods 17–21, 30, 32 (2018).

[21] *See* Mathangi Srinivasan, NYISO, *Market Overview Course: Locational Based Marginal Pricing* 25–32 (Mar. 12, 2019), https://perma.cc/HVU7-KEST.

[22] *See, e.g.*, NYISO, 2017 CARIS Report: Congestion Assessment and Resource Integration Studies (2018), https://www.nyiso.com/documents/20142/2226108/2017-CARIS2017-Report-FINAL.pdf/7d228b1b-eb5a-8288-370d-1d4d07bc5168; NYISO, DRAFT for April 23, 2020 ESPWG 2019 Congestion Assessment and Resource Integration Study; Comprehensive System Planning Process, Phase 1 (2020), https://www.nyiso.com/documents/20142/12126107/03%202019_CARIS_DraftReport.pdf.

[23] *See, e.g.*, Consolidated Edison, Inc., Benefit Cost Handbook v.1.2, §§ 4.1.2 – 4.1.4 (2018), https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en.

[24] BENJAMIN L. NORRIS, MORGAN C. PUTNAM & THOMAS E. HOFF, CLEAN POWER RESEARCH (for Minnesota Department of Commerce), MINNESOTA VALUE OF SOLAR: METHODOLOGY 16–19, 31–34 (2014) [hereinafter "MINN. VOS"], http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf.

[25] *Id.* at iii; *see also* Frank Jossi, *What Goes into Calculating Minnesota's Groundbreaking 'Value of Solar' Rate?*, ENERGY NEWS NETWORK, Sept. 9, 2019.

3.2. Distribution system

The distribution system costs that DERs can potentially avoid include line losses and capacity upgrades or additions.[26] As with transmission, the descriptions below reflect different approaches taken by leading states to translating those costs into DER compensation.

California. As with avoidable transmission system costs, metrics for estimating avoidable distribution system costs are incorporated into the Avoided Cost Calculator model developed for the CPUC.[27] That model compiles three future phases of distribution costs: near-term, transition, and long-term. Near-term costs are derived by comparing a baseline scenario of distribution system upgrades in the absence of new DER deployments to a scenario in which DERs are deployed. Long-term costs are derived from the marginal distribution capacity cost projections submitted by utilities to the CPUC in their triennial General Rate Case filings. Those projections vary by climatic zone, but include costs that are not necessarily avoidable by deploying additional DERs. A "transition" calculation serves as an accounting bridge between these near and long-term estimates.

New York. As noted above, New York utilities are charged with conducting MCOS studies that identify expected marginal distribution system costs over a ten-year time horizon. Those studies provide key data inputs into one element of the New York Public Service Commission's Value of DERs Value Stack: the Locational System Relief Value (LSRV), which reflects how much the deployment of DERs in a designated area can help to relieve system congestion and thereby defer or wholly avoid system upgrades. Another element of New York's Value Stack that captures avoidable distribution system costs is the Demand Reduction Value

---

[26] GUNDLACH & UNEL, *supra* note 3, at 20–21 (highlighting that some costs cannot be avoided with DER deployment).

[27] *See supra* note 17.

(DRV), which captures how well a given DER contributes to local demand reductions during peak times.[28]

Minnesota. The Value of Solar rubric developed by Minnesota's Commerce Department provides for two different approaches to calculating avoidable distribution system capacity costs—one systemwide, the other specific to a given area.[29] The systemwide calculation reflects an average load-peak value based on 10 years of historical load growth data and is less likely to accurately reflect the costs that any particular DER might avoid.[30] The location-specific approach uses a Peak Load Reduction value to estimate how much the excess generation from DERs in a given distribution system location can reduce local load peaks, and thereby avoid distribution system capacity costs.[31]

3.3. Emissions

DERs can avoid material quantities of greenhouse gas emissions and local air pollutants, and failing to compensate them for doing so means mis-specifying their value and inviting their installation and operation in locations and at times that will not necessarily make the electricity system cleaner.[32] Policy Integrity recognizes that the Commission has not settled on when exactly the emissions avoided by DERs should be considered by utilities or other stakeholders,

---

[28] For short summary descriptions of the LSRV and DRV metrics, see the "Documentation" tab of the Value Stack Calculator v 2.3, accessible at https://www.nyserda.ny.gov/-/media/NYSun/files/VDER-ValueStack-Calculator.xlsb. Other materials describing the formulation and operation of the Value Stack are available at N.Y. State Energy Res. & Dev. Auth'y, *NY-Sun (Solar Initiative): The Value Stack*, https://www.nyserda.ny.gov/All%20Programs/Programs/NY%20Sun/Contractors/Value%20of%20Distributed%20Energy%20Resources.

[29] MINN. VOS, *supra* note 24, at 34.

[30] *Id.* at 2, 34–36.

[31] *Id.* at 2, 36–39. For a thorough description of Minnesota's current VOS rubric and potential improvements, see Comments of Gabriel Chan & Matthew Grimley, Univ. Minn. Ctr. for Sci., Tech., & Envtl. Pol'y, Methodologies for the Avoided Distribution Cost Component of the Minnesota Value of Solar, Minn. Pub. Serv. Comm'n Docket Nos. M-13-867 & M-14-65 (May 5, 2020), https://perma.cc/3N34-4UNJ.

[32] GUNDLACH & UNEL, *supra* note 3, at 21–22; *see also* Scott Burger et al., *Why Distributed?: A Critical Review of the Tradeoffs Between Centralized and Decentralized Resources*, 17 IEEE POWER & ENERGY MAG. 16, 16 (2019) (highlighting factors that can enable distributed renewables to outperform utility-scale renewables).

much less whether or how they should be valued and their value translated into compensation to DER owners for excess generation.[33] Nonetheless, we mention here metrics that Colorado could use to estimate emissions-related costs that DERs could potentially avoid (the analytic steps involved resemble those listed on page 6, above).[34] Further, we recommend that the Commission encourage the appropriate monetization of pollution costs and benefits whenever such information would be relevant and useful for the decisionmaking process.

Several types of metric are relevant for valuing avoided emissions. 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. The marginal emissions rate for each generation facility (or a close proxy) is thus the key metric for emissions volumes. For avoided emissions' value, the key metric depends on the type of emissions. 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.[35] For local pollutants, several tools exist for estimating the monetary value of damage

---

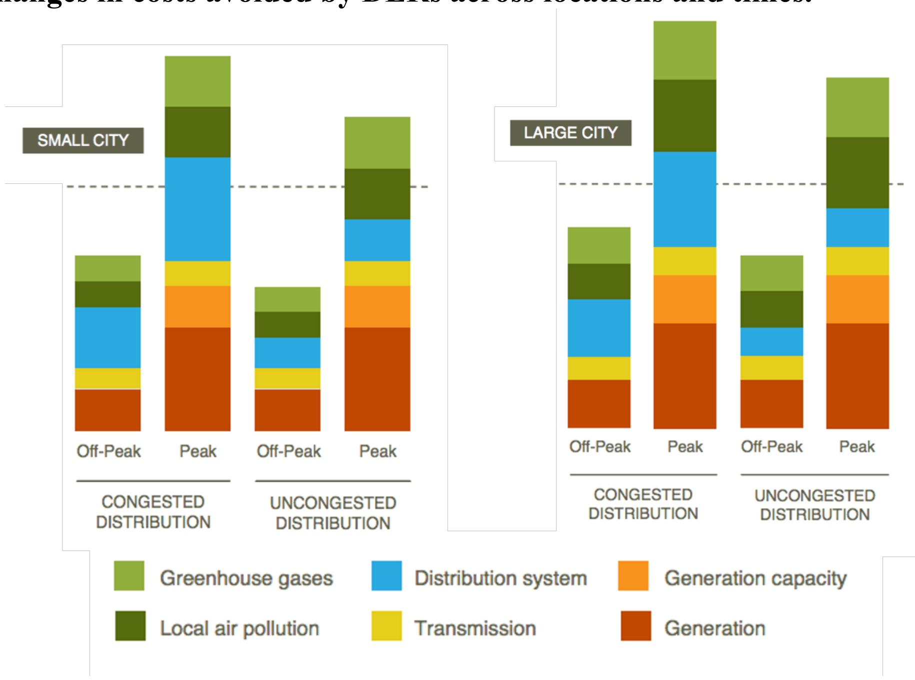
[33] *See* Decision No. C20-0207-I, Interim Decision Scheduling Hearing, Proposing Additional Rule Revisions, and Soliciting Further Comments, Colo. Pub. Serv. Comm'n Proceeding No. 19R-0096E, at 13, para. 32 (Apr. 2, 2020) (noting that Proposed Rule 3551(b)(II) would remove DERs from the list of resources for which proceedings must determine "the social cost of carbon dioxide emissions"); Joint Supplemental Comments of Colorado Energy Office et al., Colo. Pub. Serv. Comm'n Proceeding No. 19R-0096E (Dec. 20, 2019) (proposing addition of rule § 3604(m), directing utilities to "present at least two alternative plans that demonstrate additional greenhouse gas reductions through the inclusion of increased amounts of renewable energy resources, distributed energy resources, energy storage, electric vehicles, and Section 123 resources . . . when compared to the reference plan.").

[34] *See* SHRADER, UNEL & ZEVIN, *supra* note 3, at i–iv. For a condensed version, see GUNDLACH & UNEL, *supra* note 3, at 22.

[35] 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.

done, including BenMAP, EASIUR, AP2, and COBRA.[36] Notably, whereas valuing avoided greenhouse gas emissions—pollutants with global rather than local effects—depends on the different marginal emissions rates of whatever resources the DER's operation displaces, valuing local air pollution depends not only on the marginal emissions rate of displaced generation but also the proximity and vulnerability of affected populations downwind of displaced resources and prevailing weather patterns. We depict how a DER's ability to avoid emissions-related costs varies in the figure below.[37] It reflects that variation in the value of avoiding greenhouse gas emissions depends on the type and volume of emissions (thus that value is shown to be nearly the same at peak times in both the small and large cities), while variation in the value of avoiding local pollutants also depends on other factors, such as the size of the population downwind from the emitting resource (thus that value is significantly greater at peak times in the large city).

Figure 1. Changes in costs avoided by DERs across locations and times.



[36] SHRADER, UNEL & ZEVIN, *supra* note 3, at 22–24.

[37] The original version of this figure appears in GUNDLACH & UNEL, *supra* note 3, at 30 fig.8. Discussion at 30–31 explains that figure in more detail.

4. Conclusion

As the Commission explores options for valuing DERs in various contexts—including infrastructure planning, PBR, and others—Policy Integrity encourages it to consider not only the metrics identified above but also the analytical steps involved in employing those metrics effectively. DERs' presence is growing in Colorado and the Commission should take care to steer their deployment in ways that maximize the benefits they can deliver to the grid and to society as a whole.

Respectfully submitted this 5th day of June, 2020.

/s/ Justin Gundlach
Justin Gundlach, Senior Attorney
Jason Schwartz, Legal Director
Burcin Unel, Ph.D., Energy Policy Director
INSTITUTE FOR POLICY INTEGRITY
139 MacDougal Street, Third Floor
New York, NY 10012
justin.gundlach@nyu.edu
jason.schwartz@nyu.edu
burcin.unel@nyu.edu