Distributed Generation Planning: A Case Study Comparison of California and New York Proceedings

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The increasing deployment of solar energy in the United States has spurred attention from utilities, regulators and policymakers at the state level. In particular, California and New York have embarked on ambitious regulatory proceedings that seek to better characterize the impact of distributed energy resources (DERs) on grid operations, state energy markets and policy goals as well as to plan for better integration of DERs with the rest of their energy systems.

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This paper provides technical, market and policy context for distributed generation planning and compares the California and New York approaches. We find that while California's Distribution Resources Plan (DRP) Proceeding has a comprehensive focus on technical grid impacts, New York's Reforming the Energy Vision (REV) Proceeding takes a more policy-driven approach to setting new market rules and operational practices. Together, these proceedings illustrate two pathways regulators can take to respond to and plan for increasing DER deployment.

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Introduction

Solar energy use is growing rapidly in the United States. Installed capacity has increased from 18 megawatts (MW) in 2000 to over 40 gigawatts (GW) today.[1,2] Renewable energy holds tangible promise to boost the U.S. economy through technology innovation and to mitigate climate change impacts; however, its expanded use also poses challenges and opportunities for utilities and electric grid operators. As its cost continues to fall, more and more customers are choosing solar.

Customer-facing renewable energy is frequently deployed on the distribution grid as one form of distributed energy resources (DERs). Several factors will affect the ability to achieve higher DER penetrations without compromising grid safety, reliability and cost-effectiveness. These include regulatory and market barriers, operational challenges and technical issues linked to grid integration. To date, DERs in the United States have been deployed at relatively low penetrations and rarely relied on for capacity value or grid services. Yet as the costs of renewable energy continue to fall, increasing the deployment of renewable DERs is becoming a significant component of state energy goals.

California and New York are currently engaged in regulatory proceedings that seek to 1) understand and quantify the impact of various ways of deploying DERs and 2) guide new DER deployment in desirable ways through policies, incentives and market rules. Both goals require strong policy backing, regulatory support and a comprehensive understanding of the energy system and market environment in each state. Both states have experience with renewable energy generation, but setting up the right regulatory structure is critical to reaching higher levels of DER penetration. DER deployment has technical, economic and social implications that need to be considered in designing a robust and sustainable energy system. This paper will seek to understand and assess the approaches being used in California and New York and their impact on the design of regulations and structuring of new markets for DER deployment.

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Considerations for Distributed Solar Deployment

To begin, it is instructive to consider solar photovoltaic (PV) systems as a case study of distributed energy resources. While California and New York both define DERs more broadly, including not only renewable energy but also demand-side management strategies, solar illustrates the considerations required in designing a robust strategy for DER deployment.

Technical Implications

For a grid that was designed to deliver one-way power flows from substations to customer loads, variable DER generation at the feeder level can pose

1 Barbose, Galen, Naim Darghouth. Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States. Lawrence Berkeley National Laboratory. August 2016. Available at: **https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report.pdf**.

2 GTM Research and Solar Energy Industries Association. "U.S. Solar Market Insight Executive Summary 2016 Year in Review." March 2017. Available at: **http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review**.

technical challenges. While numerous studies have sought to assess the potential grid impacts of DERs,[3] the complexity of this question does not lend itself to easy answers. Variables such as DER size and location, inverter type and feeder characteristics can lead to vastly different value propositions. The impact of new solar generation on grid operations is determined by size and location and by whether any accompanying equipment is required (e.g., storage, smart inverters, etc.). For example, the locational placement of PV can impact line voltage, the coordination of protection equipment and the capacity value of the PV resource.

Distributed solar deployment can benefit the grid if done strategically, but high penetrations can create technical challenges. Identifying where benefits and costs occur is not straightforward, and the higher the penetration, the more important it is to have a comprehensive understanding of impacts.

Economic Implications

Net energy metering (NEM) laws govern how energy customers are compensated for PV generation in much of the United States. Typically, NEM credits consumers for the energy produced by rooftop PV at a rate equivalent to the retail prices they pay for electricity. This compensation structure places a higher priority on energy production than on other grid services. For example, the "duck curve" is a well-known industry concept that alludes to the impact of solar and wind during periods of high solar production. As PV penetration increases, solar production during peak hours is projected to reduce net demand so significantly as to create a steep ramp heading into the late afternoon and evening.[4] Compensating PV for energy production effectively encourages south-facing panel orientation to capture as much sun as possible. However, the duck curve suggests that west-facing PV panels, which capture more late afternoon sun and smooth the ramp into the evening, could actually be more valuable. Current NEM tariffs do not account for this nuance, but a compensation mechanism that provides an incentive for energy production when it is needed rather than when the most energy is available could serve as a step toward more sustainable PV deployment.

This example illustrates the potential impact of economic levers that, when designed correctly, can help to more sustainably integrate PV production into the grid. Increasing PV penetrations will inevitably spur discussion about compensation mechanisms and the economic implications of setting new rate structures. Pricing structures that may, for example, reflect compensation for grid services in addition to energy generation, could improve how solar works with the grid.

Social Implications

While PV adoption is growing rapidly in the United States, the most widespread business model for deployment, residential rooftop solar, artificially limits adoption to a particular subset of electricity customers. Specifically, researchers have found that factors such as home ownership and access to sufficient roof

3 Cohen, M.S., D.S. Callaway. "Effects of Distributed PV Generation on California's Distribution System, Part 1: Engineering Simulations." Solar Energy. 2016, 128, 126-138.

4 Denholm, P., M. O'Connell, G. Brinkman, J. Jorgenson. "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart." National Renewable Energy Laboratory Technical Report. November 2015.

space restrict solar adoption under traditional business models to less than 49 percent of U.S. households and 48 percent of businesses.[5] If solar PV is a good economic proposition, the industry is overdue for a thorough consideration of new business models and tariff designs that can expand access to underserved sectors. Ideally, a comprehensive policy and market planning approach that seeks to sustainably integrate DERs into state energy systems should consider the implications of prioritizing certain business models in the market.

Distributed Resources Planning in California

During the last decade, domestic installed PV capacity rose from several hundred megawatts to over 40 gigawatts today.[6,7] The largest contribution came from California, where the California Solar Initiative (CSI) was driving distributed generation policy.[8] Passed by the state legislature in 2006 and implemented in 2007, the CSI program provided state rebates for solar adopters. It facilitated a smooth transition to a robust solar market and provided valuable performance and installation data to "regulators, developers, installers, customers, researchers and policymakers."[9] The program surpassed its goal of placing 2000 MW of solar on rooftops well ahead of its initial 2016 target.[10] The CSI program's legacy is hundreds of thousands of new solar installations and the continued growth of distributed renewables on California's distribution grids.

California has an ambitious renewable portfolio standard (RPS), which was recently amended to require 50 percent of the state's electricity to come from renewable sources by 2030.[11,12] Since the state currently gets approximately 27 percent of its electricity from RPS-compliant renewables,[13] achieving the RPS target will likely motivate the deployment of additional solar arrays. While most distributed solar does not currently count towards California's RPS,[14] the rapid growth of California's distributed solar market has inspired a statewide reckoning regarding the economic and technical implications of increasing deployment. In 2013 the state legislature passed Assembly Bill (AB) 327, a comprehensive bill addressing rate design as well as compensation for rooftop

Since the state currently gets approximately 27 percent of its electricity from RPS-compliant renewables, achieving the RPS target will likely motivate the deployment of additional solar arrays.

5 Feldman, D., A.M. Brockway, E. Ulrich, R. Margolis. "Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation." National Renewable Energy Laboratory Technical Report. April 2015.

6 Barbose, op. cit.

7 GTM Research and Solar Energy Industries Association, op. cit.

8 Go Solar California. "About the California Solar Initiative (CSI)." State of California, California Energy Commission and California Public Utilities Commission. Accessed November 25, 2016. Available at: http://www.gosolarcalifornia.ca.gov/about/csi.php.

9 Constantine, Sachu. "Distributed Generation Solar in California: Framework for Policy and Regulatory Oversight in the Post-California Solar Initiative Era." California Center for Sustainable Energy. July 2013.

10 Lacey, Stephen. "The End of a Solar Era: The Legacy of the California Solar Initiative." Greentech Media. November 2014. Available at: https://www.greentechmedia.com/articles/read/the-legacy-of-the-california-solar-initiative.

11 California Code. Clean Energy and Pollution Reduction Act of 2015. Senate Bill No. 350. Available at: http://www.leginfo.ca.gov/pub/15-16/bill/sen/sb_0301-0350/sb_350_bill_20151007_chaptered.pdf.

12 State of California. "California Climate Change Legislation." Accessed December 6, 2016. Available at: http://www.climatechange.ca.gov/state/legislation.html.

13 California Energy Commission. "Tracking Progress: Renewable Energy." October 11, 2016. Accessed December 6, 2016. Available at: http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

14 Pyper, Julia. " California Passes a Bill Targeting 50% Renewables by 2030." Greentech Media. September 12, 2015. Available at: https://www.greentechmedia.com/articles/read/california-bill-50-percent-renewables.

solar customers.[15] Moreover, the bill added Section 769 to the California Public Utilities Code, instituting distribution resource planning (DRP) as part of the state's overall planning process and utility rate case proceedings. It is through this process that California regulators now seek to create a framework to forecast the continuing deployment of distributed resources, identify optimal grid locations for new solar arrays and steer solar to these locations through policies and incentives.[16]

Distribution Resources Plan Proceeding

California's AB 327 required the state's three investor-owned utilities (IOUs) to submit DRP proposals to the California Public Utilities Commission (CPUC) by July 1, 2015. The bill directed utilities to "identify optimal locations for the deployment of distributed resources" by "evaluat[ing] locational benefits and costs" with a focus on capacity needs. It also directed the utilities to determine the ability of existing infrastructure to accommodate new resources and the potential for distributed resources to provide safety and reliability benefits. In the context of this legislation, DERs are defined to include "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles and demand response technologies." The utilities were further asked to weigh in on how potential mechanisms—such as tariffs, contracts, policies and incentives—could be best coordinated to "maximize the locational benefits and minimize the incremental costs of distributed resources."[17]

The CPUC further refined these instructions through rulemaking.[18] Michael Picker, the commissioner assigned to the DRP proceeding, issued guidance in February 2015 asking the IOUs to standardize the format of their responses and develop "analytical frameworks" addressing grid integration capacity, quantifying locational value and forecasting the future growth of DERs. The utilities would then test these analytical frameworks through demonstration and deployment projects to assess the capability of DER technologies to fit "grid planning and operational objectives."[19]

The utility DRPs are comprehensive. Taken together, they total over 1,000 pages.[20,21,22] These plans serve as a starting point for the statewide DRP proceeding led by the CPUC. Therefore, it will be instructive to consider how the utilities arrived at their recommendations and assess the evidence they presented to policymakers. To illustrate the kind of evidence presented, this paper will focus on the DRP from Pacific Gas and Electric (PG&E) and introduce additional details from the DRPs of Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) where the information is different and notable. Some smaller utilities were also asked to submit simplified DRPs, but those will not be reviewed here.

15 California Code. Assembly Bill No. 327. Available at: **https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327**.

16 California Public Utilities Commission. "Distribution Resources Plan (R.14-08-013)." Accessed December 6, 2016. Available at: **http://www.cpuc.ca.gov/General.aspx?id=5071**.

17 California Code. Assembly Bill No. 327. op. cit.

18 California Public Utilities Commission. "Distribution Resources Plan (R.14-08-013)." op. cit.

19 Picker, Michael. "Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769." California Public Utilities Commission. February 6, 2015.

20 Pacific Gas and Electric Company. Electric Distribution Resources Plan. July 1, 2015.

21 Southern California Edison. Distribution Resources Plan. July 1, 2015.

22 San Diego Gas and Electric. Distribution Resources Plan. July 1, 2015.

Integration Capacity Analysis

The first analytical framework requires utilities to evaluate the capacity of their distribution systems—"down to the line section or node level"—to host additional DERs. The CPUC asked the three IOUs to develop a standard methodology. In response, all three utilized circuit modeling and analysis through dynamic software planning tools. In their DRPs, the IOUs emphasized the importance of time-series simulations to account for the impact of DERs on the system by considering the expected timing of load and generation. Base goals include ensuring that 1) grid infrastructure (i.e., substations, distribution equipment and lines) are "not loaded beyond safe operating limits," 2) the power supplied to the customer meets standard voltage and power quality requirements and 3) system reliability is maintained.[23] The utilities categorized these base goals into four power system criteria: thermal, power quality/voltage, protection and safety/reliability. These criteria are technical in nature. Thermal limits are assessed via power flow simulations that determine whether adding DERs in a particular location will cause existing equipment to exceed its thermal rating. The power quality/voltage criterion considers the potential impact of DERs on transient voltage flicker throughout the circuit and of variable generation on voltage relative to circuit impedance. Distribution circuits have existing protection schemes to isolate faults during adverse events; the protection criterion kicks in when additional DER generation would cause a change in power flow that would disrupt these schemes. Finally, the safety and reliability criterion focuses on preventing islanding conditions, where locally generated power flows on the distribution circuit even in the event of a system outage, and limiting power flow from the distribution circuit to the transmission level.[24]

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The CPUC gave the IOUs the option to perform the analysis on their whole system or on a representative set of circuits. PG&E performed its analysis on approximately 500,000 nodes located on 102,000 line sections spanning over 3000 feeders.[25] Due to previous investments in advanced power flow and load analysis tools, PG&E was able to use hourly load and DER generation data to inform its modeling efforts. The utility set DER capacity limits by evaluating the amount of DER permitted by each criterion, then taking the most limiting criterion as the overall result for a given line section. For this study, PG&E only analyzed some of the identified elements within each overall criterion; PG&E suggests that future analysis may consider additional factors (Appendix A).

SCE used a similar power flow analysis but directly studied only 30 representative circuits at the line level. It then "extrapolated the results . . . to the remaining 4,636 distribution circuits."[26] SCE stated broad trends about how the hosting capacity varied across circuits, suggesting that higher hosting capacities are typically present on circuits operating at higher voltage levels and at circuit locations closer to a substation.[27]

23 Pacific Gas and Electric Company. op. cit.
24 Ibid., pp.32-36.
25 Ibid., p.23.
26 Southern California Edison. op. cit.
27 Ibid.

SDG&E used an in-house approach to model a set of its circuits and an external party (Integral Analytics) to cross-check its work.[28] The utility set a cap for the maximum DER circuit capacity by reference to load forecasts predicting the minimum daytime load (smallest power demand between 9 a.m. and 6 p.m.) on its distribution circuits. SDG&E's goal was to prevent reverse power flow from the DERs through the substation on any circuit at any time when there is insufficient load to absorb the energy generated at the distribution level. SDG&E indicated that this restriction would be removed for future, more granular analyses. Even with the limit, SDG&E anticipated finding over 1000 MW of additional DER hosting capacity across its system.[29]

Using the most limiting criterion as the measure of DER hosting capacity makes PG&E's estimate of allowable capacity very reflective of the state of its current system. For example, perhaps three of the four criteria on a given line section would allow additional DER capacity but one criterion is particularly limiting. PG&E would still report the hosting capacity permitted by the most limiting criterion as the hosting capacity of the overall line. While this may be reasonable given the status quo, this analysis does not account for the possibility of potential or even planned upgrades. If the thermal loading of a line or a particular piece of equipment is close to its limit, it is likely that a utility would upgrade that piece of equipment in the near future even without accounting for the potential of additional DER on the system. In this way, it is theoretically possible to easily increase the amount of DER that can be placed on the system either through routine upgrades or by prioritizing upgrades that that make it easier to site DER.

To its credit, PG&E does allow for slightly more flexibility by publishing two hosting capacity values for each analyzed line section: minimal impact, which is "expected to not cause significant impacts or upgrades," and possible impact, or the "average capacity value for the line section that may or may not cause significant impacts or upgrades and will be based on where on the line section the DER is interconnecting" (Appendix A).[30] While the possible impact value is still generated based on the most limiting criterion, the publication of two values does allow for some indication of the flexibility of a given line section to accommodate additional DER capacity.

PG&E further refines these numbers by analyzing hourly load and generation profiles and the geographic dispersion of existing DER. PG&E uses hourly data to determine whether solar electricity is being generated in a given location during the hours of the day that it is in fact used locally, rather than exported to the broader system. Coupled with an analysis of existing DER locations, including "1) installed capacity by county, 2) penetration of installed capacity to peak load by county and 3) highly penetrated substations," PG&E can then identify how much remaining hosting capacity is available on a given feeder.[31]

PG&E published the results of its analysis in a renewable auction mechanism

28 San Diego Gas and Electric. op. cit.
29 Ibid.
30 Pacific Gas and Electric. op. cit.
31 Ibid.

(RAM) map available on its website.[32] This map depicts the results of the feeder analysis via a green, yellow and red coloring scheme, making it easy to visualize the results of its simulation. The map comes along with an additional note of caution: Because PG&E's analysis did not include transmission-level impacts, it is possible that deploying the maximum allowable hosting capacity on individual nearby feeders could result in aggregated impacts at the system level.[33] Therefore, PG&E implicitly assumes that not all feeders in a given location would receive their maximum allowed hosting capacity. SCE and SDG&E published similar maps.[34,35]

Optimal Location Benefit Analysis

The second analytical framework asks utilities to propose a method to quantify how much value additional DERs would bring to a given location. Through this framework, the CPUC required the three utilities to develop a consistent "locational net benefits methodology" to assess the potential of new DER deployment to reduce capital and operating expenditures at the distribution, substation, subtransmission and transmission levels. This involves considering system capacity and flexibility, voltage requirements, power quality, reliability and resiliency, as well as applicable societal and public safety costs. To conduct their value analysis, the three IOUs adopted the Environmental + Energy Economics (E3) Distributed Energy Resources Avoided Cost (DERAC) Calculator,[36] while considering the additional value components identified by the CPUC in its rulemaking.[37]

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For each category of costs, the utilities provide a rigorous definition of what is required for the DER to truly serve as a benefit to the grid. For example, to calculate the potential capacity value of proposed DER resources, PG&E stated:[38]

"With respect to DER deferral of distribution project costs, a benefit can occur only if all of the following four conditions hold: (a) there is an identified need to make distribution capacity expenditures; (b) DER capacity in the correct amount is certain to be available at the time of the relevant circuit or substation transformer peak (capacity need); (c) the DER is connected at the correct locations; and (d) the DER is controlled or managed to avoid any unavailability that could affect reliability or safety."

32 Pacific Gas and Electric Company. "Solar Photovoltaic and Renewable Auction Mechanism Program Map." July 1, 2015. Accessed December 7, 2016. Available at: **https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page**.

33 Pacific Gas and Electric. op. cit.

34 Southern California Edison. "Distributed Energy Resource Interconnection Maps." July 1, 2015. Accessed December 7, 2016. Available at: **https://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7**.

35 San Diego Gas & Electric. "Interconnection Information and Map." July 1, 2015. Accessed December 7, 2016. Available at: **http://www.sdge.com/generation-interconnections/interconnection-information-and-map**.

36 Energy + Environmental Economics. Available at: **https://www.ethree.com/public_proceedings/energy-efficiency-calculator/**.

37 Picker, Michael. op. cit.

38 Pacific Gas and Electric. op. cit.

Then, the actual net value of DER to the system is generally the difference between its potential capacity value and the cost for interconnecting the resource, considering all potential impacts and necessary upgrades. SDG&E went further to state that while "optimally located DERs can . . . provid[e] an alternate to or possibly avoid the capacity investments" that are necessary to accommodate increasing electricity demand, they are unlikely to defer upgrades related to aging equipment, operation and maintenance, and control and monitoring of the overall system.[39] Even these potential capacity deferrals require closer monitoring and/or the installation of smart inverters to better manage the output of DERs.

Most of the criteria for assessing DER value are very technical in nature and reflect engineering implications of DER integration as well as their associated monetary costs and benefits. However, the CPUC also asked the utilities to address DER value associated with societal and public safety avoided costs.[40] The utilities' responses to these two criteria all sidestep the exercise of including them explicitly in their value methodologies. PG&E suggests that societal avoided costs have been "internalized" by the CPUC's "ratemaking and procurement rules and decisions" and accounting for them directly would therefore lead to double counting. Similarly, public safety avoided costs are defined by PG&E as "the costs to obtain a higher level of electric system reliability and resiliency;" the utility argues that they are already internalized in other criteria and any additional benefits can be considered qualitatively.[41]

SCE acknowledges that benefits to society from DER deployment can include emissions reductions, improved land use management and "economic growth and innovation, leading to improved standards of living, higher tax receipts and an increase in housing values." Yet SCE argues that quantitative assessments of these benefits are currently "highly speculative" and that the best way to consider them in the overall methodology is through qualitative means. Moreover, SCE dismisses the public safety benefit criteria, suggesting that it is "unable to identify realizable value that can be attributed to improvements in public safety due to DER deployment."[42]

SDG&E limits discussion of societal benefits to emissions reductions and proposes to use CalEnviroScreen, a tool available through the California Office of Environmental Health Hazard Assessment (OEHHA) to screen for environmental benefits.[43] The utility suggests that the best way to evaluate societal benefits is to use "energy prices that fully reflect the GHG costs." Rather than discussing potential public safety benefits, SDG&E emphasizes that DERs may pose safety costs by complicating outage restoration procedures for grid management personnel and other potential equipment malfunctions. The utility states that these issues will be evaluated qualitatively.[44]

39 San Diego Gas and Electric. op. cit.
40 Picker, Michael. op. cit.
41 Pacific Gas and Electric. op. cit.
42 Southern California Edison. op. cit.
43 Office of Environmental Health Hazard Assessment. "CalEnviroScreen Version 2.0." October 1, 2014. Accessed December 8, 2016. Available at: **https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20**.
44 San Diego Gas and Electric. op. cit.

DER Growth Scenarios

Utilities were asked to analyze growth scenarios forecasting potential deployment and geographic dispersion of DERs under trajectory (projected business-as-usual increases from the status quo) and high growth scenarios as defined by the California Energy Commission's Integrated Energy Policy Report[45] and a third, very high growth scenario, which the IOUs developed separately for different DER technologies by projecting current growth and cost trends into the future.[46]

While predicting DER growth is currently a common exercise in the industry, the CPUC asked the IOUs to couple their general forecasts with an analysis of projected geographic dispersion. PG&E called this requirement "an industry-leading practice . . . the IOUs are among the first utilities required to establish projections of DER dispersion at this level of granularity."[47] PG&E and SCE took similar approaches to estimating the geographic dispersion of technologies by considering customers' demographic information as an indicator for their likelihood to adopt certain kinds of technologies, then projecting the adoption of those technologies in specific locations onto their systems.[48,49] SDG&E took a more general approach by allocating DER types by geography, for weather-dependent DER (e.g., solar) or evenly across its service territory.[50]

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Demonstration and Deployment

The CPUC directed the three utilities to propose demonstration projects to evaluate their proposed methodologies and develop a deeper understanding of the potential impacts of DERs on the grid. Specifically, the CPUC asked for projects that would a) assess the utilities' integrated capacity analysis through even more granular modeling of power flow in a particular location, b) demonstrate how utilities' proposed value methodology could be implemented for a particular location, c) demonstrate DER locational benefits, d) demonstrate how grid operations would be affected under high DER penetrations and e) demonstrate how grid operators might dispatch DERs to meet reliability needs.[51]

Each of the utilities proposed specific locations on their distribution systems at which to implement, monitor and assess the implications of deploying additional DER and using DER for grid services. Through these projects, the utilities promise to deliver additional data and quantitative assessments of how DER will interact with their grids.

45 California Energy Commission. "California's Energy Policy: Integrated Energy Policy Report." Accessed December 6, 2016. Available at: http://www.energy.ca.gov/energypolicy/.
46 Southern California Edison. op. cit.
47 Pacific Gas and Electric. op. cit.
48 Ibid.
49 Southern California Edison. op. cit.
50 San Diego Gas and Electric. op. cit.
51 Picker, Michael. op. cit.

California Takeaways

The CPUC's key questions for the DRP process illustrate the quantitative focus of this planning effort. In an early DRP process workshop,[52] CPUC posed these framing questions:

> "How can the cost of DER deployment be minimized? How can the marginal net cost of DER be accurately compared with the cost of other types of resources, especially central station renewables? What is the relationship between optimal location, optimal portfolio and optimal dispatch/control for DER?"

Ultimately, these results may also lead to increased focus on the economic implications of DERs and, thereby, more comprehensive discussion by utilities on the kinds of policy and incentive structures that might make sense to create a sustainable grid.

In response, the three California IOUs have proposed plans to delve deeply into the technical considerations and potential impacts of deploying high penetrations of DERs. The utilities' efforts to map their distribution networks and provide guidance to DER developers constitute a structured and comprehensive approach to ensure that DER deployment will not adversely impact the grid. The demonstration projects proposed by the California utilities are still in progress; their results are expected to provide actionable data to further refine the understanding of how DERs can work best with each entity's distribution grid. Ultimately, these results may also lead to increased focus on the economic implications of DERs and, thereby, more comprehensive discussion by utilities on the kinds of policy and incentive structures that might make sense to create a sustainable grid.

There are several places where the California approach diverges from this wholly grid-centered focus. The CPUC's effort to value societal and public safety benefits in the overall methodology for considering DER benefits and costs is notable; however, so too is the utilities' general resistance to doing such analysis. Additionally, the questions raised about DER geographic dispersion provide an opportunity for utilities to consider demographic adoption data and, therefore, the potential social implications of specific DER business models. However, so far it seems that utilities are reacting to the dominant type of customer-facing DER deployment in California—residential rooftop solar—rather than using this demographic exercise to consider whether alternative business models may lead to other kinds of DER deployment.

Of course, the DRP is not the CPUC's only proceeding related to the development of distributed resources. Other initiatives outside of the scope of this project relate to residential rate reform and DER tariffs and may consider societal and safety issues more comprehensively.[53] So far, it seems that the DRP proceeding largely prioritizes grid implications when considering the framework for high DER penetration in California.

52 California Public Utilities Commission. "Distribution Resources Plan (DRP) Workshop II." January 8, 2015.
53 California Public Utilities Commission. op. cit.

Distributed Energy Resources in New York

Hurricane Sandy, which hit New York City and surrounding areas in fall 2012, spurred an increased focus on the resilience of New York's electricity grid.[54] In April 2014, Governor Andrew M. Cuomo announced a new statewide initiative, Reforming the Energy Vision (REV), that laid out an ambitious plan to reorganize the state's energy sector and upgrade its infrastructure.[55] The REV challenges the assumptions that the most efficient and resilient grid is based on centralized energy generators and that customers should not participate in the market as energy producers. Central to the concept is REV's proposed reorganization of the state's distribution utilities into distributed system platform providers (DSPPs) who "will create markets, tariffs and operational systems" to enable the efficient use of behind-the-meter resources such as "energy efficiency, predictive demand management, demand response, distributed generation, building management systems, microgrids and more."[56,57] By 2030, REV aims to achieve a 40 percent reduction in the state's greenhouse gas emissions from 1990 levels, a generation mix relying on renewable sources to serve at least 50% of load and a 23 percent reduction in building energy consumption from 2012 levels.[58,59]

Reforming the Energy Vision: Increasing Reliance on DERs

The cornerstone of REV is the goal to increase the planning and coordination of resources at the distribution level as a primary mechanism to improve efficiency, manage the overall electric grid and reduce reliance on centralized generators. While California seeks to evaluate the suitability of using DERs to provide generation capacity and grid services, New York appears to take as a given that "the intelligent integration of DER can solve distribution system planning challenges and improve the resilience of distribution systems."[60]

Key to this effort is the creation of a market-based role for utilities as distribution service providers (or DSPPs). New York asks utilities to be responsible for planning, designing and managing their distribution systems in the context of increased DER integration while "ensur[ing] that distribution systems are capable of safely and reliably meeting projected loads to ensure the long-term reliability of the grid."[61] In addition:

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54 Kammen, Daniel M., Craig Lewis. "Lessons From New York: How Hurricane Sandy's Aftermath Is Creating a Smarter Power System." Greentech Media. July 24, 2014. Available at: **https://www.greentechmedia.com/articles/read/winds-of-change-hurricane-sandy-is-ushering-in-a-smarter-power-system**.

55 New York State Department of Public Service. "Reforming the Energy Vision." Staff Report and Proposal. April 4, 2014. Available at: **http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E**.

56 Ibid.

57 Tweed, Katherine. "New York Launches Major Regulatory Reform for Utilities." Greentech Media. April 28, 2014. Available at: **https://www.greentechmedia.com/articles/read/new-york-launches-major-regulatory-reform-for-utilities**.

58 New York State Department of Public Service. "Reforming the Energy Vision: About the Initiative." Updated January 28, 2016. Accessed December 8, 2016. Available at: **http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2**.

59 Governor Andrew M. Cuomo. "Governor Cuomo Announces Establishment of Clean Energy Standard that Mandates 50 Percent Renewables by 2030." August 1, 2016. Available at: **https://www.governor.ny.gov/news/governor-cuomo-announces-establishment-clean-energy-standard-mandates-50-percent-renewables**.

60 New York State Department of Public Service. op. cit.

61 Ibid.

"The DSPP will be responsible for monetizing the value of DER products, targeted to meet specific identified needs, measuring and verifying that such resources have actually been used to meet such needs, effecting payments to reflect the value of such DER in meeting those needs and reconciling such transactions as necessary."[62]

In all, the REV framework places significant responsibility on distribution utilities to act as market operators and planners. The authors of the proposal acknowledge that the relatively omniscient role expected of the DSPPs will require infrastructure and technology improvements and enhanced communication among all players in the market. The document describes the desired infrastructure functionalities and includes technology development, adoption and learning as significant requirements to achieving REV objectives.

Benefits and Costs

Like the California proceeding, the REV authors designate categories of benefits and costs that must be assessed to create an efficient and robust market for DERs (Appendix B). Here, however, the benefits and costs are not framed as decision points to determine whether the transformation to the desired energy system is feasible; rather, they are levers to which policymakers can explicitly assign value to properly shape the overall functioning of a statewide energy market. From the guidance document:[63]

"Importantly, these potential benefits and costs need to be understood along two dimensions: 1) Those that are monetized directly within the existing market structure vs. those that are not, and 2) How each benefit or cost accrues to different stakeholders within the system."

The authors go on to explain that the desired value categories not currently or sufficiently represented in the existing market structure should be given economic weight via new regulations. New York regulators are seeking stakeholder input on the best way to calculate costs and benefits. However, the authors suggest that "some degree of uniformity" is needed in determining values for these resources and, barring "unacceptable market distortions," "the pricing of DER products or services should provide clear signals to incent movement toward achieving articulated policy objectives."[64]

On July 1, 2015, following release of the initial REV guidance document, New York State's Department of Public Service (DPS) staff issued a white paper proposing a benefit-cost framework for considering utility initiatives under the program.[65] (Notably, this is the same date that the California IOUs filed their DRPs.) This benefit-cost framework focuses primarily on utility actions rather than directly addressing DER value. However, it still provides useful information about the criteria the state considers relevant in the context of rulemaking. The proposed framework calls for transparency regarding technical assumptions and calculated costs and asks utilities to "identify ways that various DER alternatives can be substituted for traditional grid-based solutions; compare

62 Ibid.
63 Ibid.
64 Ibid.
65 New York State Department of Public Service. "Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding." July 1, 2015.

the costs of DER to the costs of traditional grid-based solutions; and compare the costs of alternative DER solutions to each other."[66]

Beyond traditional grid-related costs and benefits, the DPS staff's document insists that benefit-cost frameworks must consider social value and full life-cycle analyses of environmental impacts. However, the authors ask that individual utilities develop value methodologies to account for DER resource profiles and how they can fit into overall grid needs. To this end, the staff offers its guidance on the proposed benefit-cost criteria largely from the standpoint of market operation. For example, avoided generation capacity and energy costs are discussed in the context of spot auctions and market clearing prices.[67] In January 2016 after soliciting stakeholder comments, the state's Public Service Commission (PSC) released an Order Establishing the Benefit-Cost Framework.[68] This document largely maintained the previous market-based discussions and called on utilities to propose more granular methodologies.

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Distributed System Implementation Plans

The PSC directed the state's utilities to file distributed system implementation plans (DSIPs) by June 30, 2016. Consolidated Edison's DSIP, discussed here as an example, states that the utility's goal is to integrate approximately 800 MW of DER by 2020.[69] Consistent with the California utilities, ConEd defines feeder hosting capacity as the amount of DER that can be added to a feeder "without adversely impacting power quality or reliability under current electric system configurations and without requiring infrastructure upgrades" (author's emphasis). In its DSIP, ConEd emphasizes the need to establish contract requirements for DER providers to ensure the continued safety and reliability of the electric grid. At the same time, ConEd proposes streamlining the interconnection process to ensure that a customer's first DER-related contact with the utility is "as seamless as possible."[70]

REV's overall focus on market intervention—i.e., adapting market rules to support policy goals—comes through in ConEd's DSIP. The utility comments on the importance of developing proper valuation frameworks for DERs to "evolve the business model and compensation mechanism for these resources, recognizing that current compensation at retail rates (through a process known as "net metering") is not sustainable at higher levels of solar resource penetration."[71] The REV framework allows utilities to plan for and manage DERs in their service territories, thereby supporting greater utility input concerning retail compensation that customers will receive for the energy they provide to the grid.

Through REV, utilities were specifically asked to propose projects that would meet capacity needs with "nonwires alternatives." ConEd is implementing three demonstration projects: demand-side management through direct customer engagement, energy efficiency and demand response for commercial

66 Ibid.
67 Ibid.
68 State of New York Public Service Commission. "Order Establishing the Benefit Cost Analysis Framework." January 21, 2016.
69 Consolidated Edison. "Distributed System Implementation Plan (DSIP)." June 30, 2016.
70 Ibid.
71 Ibid.

customers and a solar-plus-storage demonstration project for residential customers.[72] The utility's DSIP forecasts system load and DER deployment, factoring in the nonwires alternative projects. To better plan for additional DER capacity, ConEd is creating hosting capacity maps[73] and reaching out to potential DER providers located in areas where DER might be beneficial to the overall system. Moreover, ConEd identifies upgrades to communication infrastructure and additional smart meter deployment on the distribution system as key initiatives that will aid the creation of a cohesive DER market in its service territory.[74]

Despite these efforts, the top-down market approach described in ConEd's DSIP suggests that proposed DER projects are likely, for the time being, to still be evaluated on an individual basis. One reason for this approach might be a notable difference between ConEd's system and the distribution grids operated by the three California IOUs. Distribution grids in the United States, including those in California, are largely radial systems in which power is delivered from a substation to customers in branching lines. However, ConEd's territory primarily covers New York City. Urban grids are more likely to be networked systems that already account for multidirectional power flow. ConEd suggests in its DSIP that it may be easier to accommodate DERs on a networked system, at least at low penetrations, because the optimal location for DER deployment is less affected by the physical shape of the feeder lines.[75] While DERs are still best placed close to load, ConEd is still dealing with relatively low renewable penetrations and thus the utility may have more time to experiment with strategies that will integrate high penetrations of DERs into its system.

Additional Market Interventions

The REV's engagement with its utilities to design a more comprehensive system for incorporating DERs into their operations is comparable to California's approach. However, the REV initiative also incorporates market interventions not mentioned in California's order. Specifically, the REV seeks to increase the market opportunity for community solar, improve access to renewables for low-income customers and provide options for community choice aggregation.[76]

The New York State PSC issued an order in July 2015 establishing a statewide shared renewables program.[77] Community solar advocates have praised this as a well-designed initiative to increase access to DERs for customers who cannot or choose not to place solar on their own rooftops.[78] The program allows community arrays up to 2 MW to utilize the state's net energy metering rules to deliver electricity benefits to participants. The initial design of the program prioritized proposed projects distinctly serving low-income populations or

72 Ibid.

73 Consolidated Edison. "Distributed Generation: Hosting Capacity." Accessed December 8, 2016. Available at: **http://legacyold.coned.com/dg/dsp/hostingCapacity.asp**.

74 Consolidated Edison. "Distributed System Implementation Plan (DSIP)." op. cit.

75 Ibid.

76 New York State Department of Public Service. "Reforming the Energy Vision: About the Initiative." op. cit.

77 Shared Renewables HQ. "USA Shared Energy Map: New York." Accessed December 8, 2016. Available at: **http://sharedrenewables.org/community-energy-projects/**.

78 Trabish, Herman K. "Inside New York's aggressive new community shared renewables program." UtilityDive. Available at: **http://www.utilitydive.com/news/inside-new-yorks-aggressive-new-community-shared-renewables-program/402896/**.

set up specifically to provide grid benefits. Therefore, the shared renewables initiative complements the utility planning processes by inviting project deployment within utility-designated "opportunity zones."[79] However, this initiative also is an example of how policy drivers, rather than technical and operational considerations raised by utilities, are guiding the REV. When state utilities challenged the timeline and details of the shared renewables plan, the PSC declined to extend the timeline or markedly change the program to alter their vision.[80] In April 2016, the New York State Energy Research and Development Agency (NYSERDA)[81] announced the first shared renewables project in New York designed under these regulations.[82]

Under the REV, the state also is considering other mechanisms to expand low-income participation in renewable energy programs. Debates are ongoing about appropriate financing schemes and the relative merits of utilities versus smaller solar providers serving this market. It seems there is some disagreement between the New York PSC and NYSERDA about what additional steps to take, but the REV maintains the importance of including low-income participation in DER projects.[83]

Community choice aggregation (CCA) programs empower municipalities to purchase energy generation (typically from renewables) on behalf of their residents. In most programs, this enables electricity customers to choose an alternative electricity mix from the default mix offered by their energy supplier, which is typically their utility. Allowing CCA programs within the REV creates an opportunity for municipalities and other jurisdictional entities to participate directly in the energy procurement process. This initiative, too, is integrated with the overall vision of incorporating higher renewable penetrations into the New York grid. New York municipalities participating in the program can choose to displace power with locally generated green energy. Moreover, the proposed CCA structure enables the municipalities to participate in demand response markets and thereby aid the overall operation of the grid.[84]

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These initiatives are clearly driven by policy rather than utility considerations about grid management. The inclusion of such programs in the REV is notable in that it shifts the focus of the overall planning process from purely technical implications of DER integration to considering the economic and social context in which higher penetrations of DERs will be deployed.

79 Ibid.

80 Ibid.

81 NYSERDA is a public benefits corporation created in 1975 to pursue three objectives: "1) attract the private sector capital investment needed to expand New York's clean energy economy, 2) overcome barriers to using clean energy at a large-scale in New York, and 3) enable New York's communities and residents to benefit from energy efficiency and renewable energy." **https://www.nyserda.ny.gov/About**.

82 New York State Energy Research and Development Agency. "NYSERDA, DPS, EnterSolar and Clean Energy Collective Announce First Shared Renewables Solar Project in New York State." April 27, 2016. Available at: **https://www.nyserda.ny.gov/About/Newsroom/2016-Announcements/2016-04-27-First-Shared-Renewables-Solar-Project-in-New-York-State**.

83 Friedrich, Kat. "New York Debates How to Finance Low-Income Solar." Clean Energy Finance Forum. Yale Center for Business and the Environment. October 10, 2016. Available at: **http://www.cleanenergyfinanceforum.com/2016/10/10/new-york-debates-how-to-finance-low-income-solar**.

84 Tweed, Katherine. "New York Towns Aim for Solar PPAs and Smart Thermostats Under Community Choice Aggregation." Greentech Media. April 14, 2016. Available at: **https://www.greentechmedia.com/articles/read/New-York-Town-Aims-For-Solar-PPAs-and-Smart-Thermostats-Under-Community-Cho**.

New York Takeaways

New York's Reforming the Energy Vision proceeding is a major holistic effort to consider how DERs can best support the power grid, energy markets and electricity customers in the state. REV's foundation in the aftermath of Hurricane Sandy is perhaps somewhat explanatory: the focus on resilience to avoid negative consequences from major disruptions is not just a question pertaining to the electricity grid but a larger concern about the robustness of the overall energy system and the people and organizations it benefits. It is perhaps instructive to consider the key questions identified in the original REV guiding document:[85]

> "What should be the role of the distribution utilities in enabling system wide efficiency and market based deployment of distributed energy resources and load management? What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives?"

These questions acknowledge the central position of the state's utilities and power providers, but focus on the energy system as a whole, rather than just on the grid itself. The REV proceeding is framed around energy policy goals; the initiatives related to grid integration are presented as mechanisms to achieve those goals. The proceeding's authors largely take for granted the potential of DERs to improve grid reliability and the impending shift of the system to a greater reliance on renewable resources. While the PSC has set up an overall framework for how DERs should be used to achieve policy goals, details about technical implementation are left primarily to the state's utilities. Similarly, where potential benefits and costs for a transition to a high penetration DER grid are discussed in the REV document, New York's Department of Public Service refers to them in the context of the overall energy market (i.e., the quantity of ancillary services required in the system) rather than grid considerations on specific distribution feeders.

The societal implications of a DER transition, while expressed in the overall grid integration benefit and cost analysis, are more clearly addressed by the additional REV initiatives. Specifically, the shared solar framework, continued focus on low-income participation in renewable energy and options for municipalities to engage directly in energy markets through CCA programs, are all examples of policy-driven initiatives that appear to be considered alongside, not subordinate to, the grid integration questions.

85 New York State Department of Public Service. "Reforming the Energy Vision." op. cit.

Conclusion

The New York REV and the California DRP have different approaches but similar goals to holistically incorporate high penetrations of distributed renewable energy into their state's electric grid. In their DRP proceeding, California's regulators focus heavily on the technical implications of DER deployment, while New York's regulators, through REV, are undertaking a broader initiative that more directly incorporates the overall market structure and utilizes the policy context for encouraging more renewables in the state's energy system. One possible explanation is that while California and New York say that they have similar percentages of renewables in their electricity mix, California's policies focus on nonhydro renewables while New York relies heavily on hydropower. With a lower relative percentage of solar penetration, New York may have more opportunity to consider holistic market improvements, while it makes more sense for California's efforts to focus on grid impacts from high penetration DERs.

Nevertheless, both states are taking ambitious steps to plan for the increased penetration of DERs in their electric grids. Proceedings in California and New York are in progress, and specific quantitative evidence on the potential to incorporate greater DER penetrations is still in development through distribution system analyses and individual demonstration projects. Yet it is clear that both states intend to rely on granular analyses of their energy system as well as increased communication and monitoring to create a foundation for major changes in their electricity systems. California and New York are laying the pathway for a new approach to direct engagement between energy customers, distribution utilities and state policymakers and regulators. Inevitably, their efforts will lead to greater understanding and dissemination of ideas to other states that may be inclined to follow suit.

Appendix A: Power System Criteria in California

POWER SYSTEMS CRITERIA TO EVALUATE CAPACITY LIMITS

Power System Criteria	Initial Analysis	Potential Future Analysis
Thermal	✓	✓
– Substation Transformer	✓	✓
– Circuit Breaker	✓	✓
– Primary Conductor	✓	✓
– Main Line Devices	✓	✓
– Tap Line Devices	✓	✓
– Service Transformer		✓
– Secondary Conductor		✓
– Transmission Line		✓
Voltage/Power Quality	✓	✓
– Transient Voltage	✓	✓
– Steady State Voltage		✓
– Voltage Regulator Impact		✓
– Substation Load Tap Changer Impact		✓
– Harmonic Resonance/Distortion		✓
– Transmission Voltage Impact		✓
Protection	✓	✓
– Protective Relay Reduction of Reach	✓	✓
– Fuse Coordination		✓
– Sympathetic Tripping		✓
– Transmission Protection		✓
Safety/Reliability	✓	✓
– Islanding	✓	✓
– Transmission Penetration	✓	✓
– Operational Flexibility	✓	✓
– Transmission System Frequency		✓
– Transmission System Recovery		✓

Source: PG&E's Distribution Resources Plan, p. 33.

KEY INTEGRATION CAPACITY VALUES

Result Name	Description
Line Section Limits	Limits that can associated to only the nodes and line segments within the selected line section.
– Minimum Impact	Lowest capacity value for the line section that is expected to not cause significant impacts or upgrades.
– Possible Impact	Average capacity value for the line section that may or may not cause significant impacts or upgrades and will be based on where on the line section the DER is interconnecting.
Substation Limits	Limits that can be associated to all line sections that are attached to the associated substation.
– Feeder Limitation	Total feeder capacity value that would cause significant impact by one or multiple DER in aggregation. If interconnecting on multiple line sections on the same feeder, it will be important to not exceed this limit.
– Bank Limitation	Total substation transformer bank capacity value that would cause significant impact by one or multiple DER in aggregation. If interconnecting on multiple line sections on the same substation bank, it will be important to not exceed this limit.

Source: PG&E's Distribution Resources Plan, p. 38.

Appendix B: Benefit and Cost Categories in New York

CATEGORIES OF BENEFITS AND COSTS

Energy Load Reduction	• Energy generation • System losses
Capacity Load Reduction	• Generation capacity • Transmission and distribution capacity
Grid Support Services/Ancillary Services	• Reactive supply and voltage control • Regulation and frequency response • Energy and generator imbalance • Synchronized and supplemental operating reserves • Scheduling, forecasting and system control and dispatch
Financial Risk	• Fuel price risk/hedge • Market price response
Security Risk	• Reliability and resilience
Transactional Platform	• Advanced Distribution System Management capital and operating expenses
Environmental	• Carbon emissions • Criteria air pollutants • Water • Land
Social	• Resilience of critical facilities • Improved housing stock • Economic development (jobs and tax revenues)
Other	• Administrative costs • Resource diversity and flexibility

Source: New York State's Reforming the Energy Vision guiding document, p. 17.

MONETIZABLE VS. NON-MONETIZED BENEFITS AND COSTS

Monetizable Within Existing Market Structure	Non-Monetized
• Energy and capacity values • Some ancillary service benefits • Operational and capital system impacts • Financial credits or penalties associated with emissions or resource use • Commodity hedging values • Reliability (where a performance-based contract exists) • Tax revenues	• Some ancillary service impacts • Reliability (where performance contracts do not exist) • Resource diversity • Environmental impacts without market pricing mechanisms • Economic development (e.g., job creation, business diversification) • Community development and housing impacts

Source: New York State's Reforming the Energy Vision guiding document, p. 18.

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